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FERC/FEDERAL MISO

Trump Officially Names Rosner, a Democratic Appointee, FERC Chair

FERC

President Trump picked Democratic Commissioner David Rosner, nominated by former President Biden, to run FERC over Republican Commissioner Lindsay See, a surprise to many stakeholders. Trump has nominated two Republicans to fill the two currently open seats on the commission.

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MISO STAKEHOLDER FORUM

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MISO States Split on FERC Complaint to Unwind $22B Long-range Tx Plan (p.22)

The Organization of MISO States is divided over a complaint filed by several of its members on the RTO's long-term transmission planning.

NYISO

Nexamp

Nexamp Complains of Unfair IC Cost Increases by National Grid (p.29)

The complaint alleges that National Grid violated New York PSC requirements for distributed energy resource interconnection.

CAISO/WEST

BPA

BPA Preparing to Deliver Power Under New Multiyear Contracts (p.9)

With the culmination of BPA's Provider of Choice process, the agency now has contracts and policies in place it hopes will serve for the next two decades.

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In this week's issue

Recent MISO Complaint Undermines Regional Transmission Planning Framework

By Ted Thomas


Ted Thomas

A new attack on regional transmission planning threatens to unravel a decade of progress toward a more reliable, affordable and interconnected electric grid.

A group of state utility commissioners recently *filed a complaint* with FERC opposing the cost allocation for a new set of regional transmission projects known as Tranche 2.1 in the MISO region. This *3,631-mile 765-kV backbone* portfolio of projects is expected to deliver up to *$72 billion in net benefits* across the system.

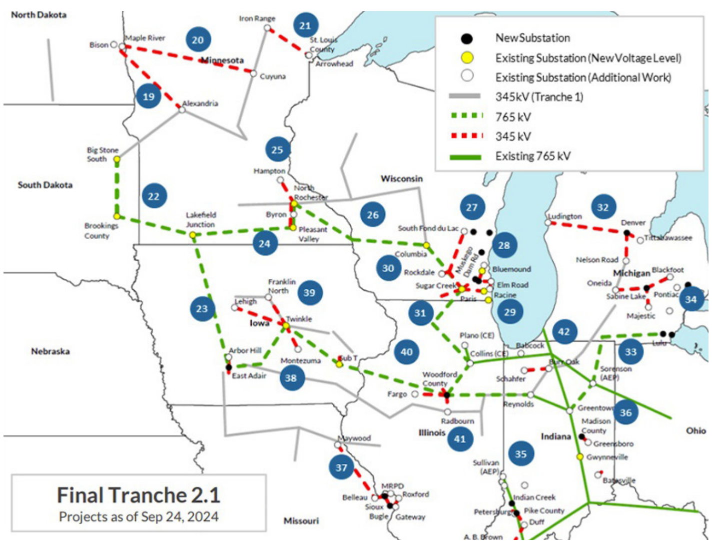
Their argument? That these projects don't serve the broader region and should be funded only by the states they physically pass through. It's an appealing message — no one wants to pay for something they can't see. But it's also oversimplified and short-sighted, and it risks undermining the premise of regional planning and cost sharing that keeps the grid reliable and affordable.

At its core, the complaint misunderstands how regional transmission works. High-voltage transmission lines are not local infrastructure, they are the backbone of the electric grid. They enable power to flow across hundreds of miles, balancing supply and demand in real time and delivering affordable electricity to customers even when local conditions falter. Transmission lines provide shared benefits far beyond state borders.

This is why MISO — a region with a history of collaboration — created the Multi-Value Project (MVP) framework. When the first round of multi-value transmission projects was approved over a decade ago, they weren't built just to serve one state or one utility, but to address regional reliability needs, reduce congestion and provide access to low-cost generation across MISO's 15-state footprint.

Independent studies later showed those projects will return up to *$52.6 billion* in benefits over the next 20 to 40 years — benefits that are shared by customers throughout the region and a *20% increase* from the original estimate.

Tranche 2.1 projects follow the same planning logic. Though individual lines may be in specific states, MISO plans them as part of a broader portfolio designed to work together to ease systemwide transmission bottlenecks, enabling cheaper and more reliable electricity to flow across MISO. These projects were approved through a rigorous, transparent regional planning process that evaluated systemwide impacts, not just local needs, and conservatively estimated the benefits of the projects. That's why MISO's board agreed these projects should be treated as MVPs and funded accordingly.



Routes of MISO's final LRTP II portfolio in dotted lines | MISO

To argue now that these projects should be paid for only by the states in which they're located is to undermine the premise of regional collaboration. If every state were allowed to pick and choose which projects they want to fund, the grid would be more fragmented and inefficient and less resilient than it already is. Regional transmission planning works only when everyone contributes to — and benefits from — the shared infrastructure we all rely on.

Moreover, refusing to share costs for regionally beneficial projects will hurt customers in the long run. Without large-scale transmission, we'll be forced to rely on more expensive local generation, endure greater price volatility and face more frequent reliability challenges as demand grows and extreme weather becomes more common. That's a cost nobody wants to bear, especially when the alternative is a well-planned, cost-effective solution that has already proved its worth.

Arkansas is a prime example of how regional planning delivers value. We benefit when low-cost power from elsewhere can flow into Arkansas during times of high demand or generation shortfalls — and vice versa. Regional planning has brought long-term stability to power prices and improved reliability, especially in rural areas that often are more vulnerable to outages and price spikes.

Despite this, the complaint threatens to erode the regional planning framework, and to do so in the context of a transmission plan that does not even allocate costs to three of the states that filed the complaint, including Arkansas.

Rather than obstructing new energy infrastructure, we must recognize the urgent need to build for the future and meet demand. FERC should reject this complaint and reaffirm the principles that have made MVPs successful. Tranche 2.1 projects are part of a broader strategy to modernize the grid, reduce costs and ensure a reliable electricity system across the region.

If we want a grid that works for everyone, we need to keep investing in shared solutions. Transmission isn't local. Neither are its benefits. Let's not let short-sighted politics get in the way of smart regional planning. ■

Ted Thomas is the founder of Energize Strategies and a former chairman of the Arkansas Public Service Commission.

Trump Officially Names Rosner, a Democratic Appointee, FERC Chair

By James Downing

President Donald Trump made it official Aug. 13, naming David Rosner as the new chair of FERC several workdays after former Chair Mark Christie resigned.

"I am honored to serve as chairman and excited to continue working with my colleagues on the commission and FERC's extraordinary staff to enable reliable, affordable and abundant energy for all Americans," Rosner said in a statement. "Energy lights our homes, powers our businesses, and we need it more than ever to grow the innovative industries of the future."

Trump picking a Democratic nominee to run the agency over a well-qualified Republican, Commissioner Lindsay See, was a surprise. (See *FERC Independence Likely Coming to an End with Christie's Exit*.)

But the position could be interim, as two nominees from the president are awaiting Senate confirmation sometime after that body returns from a summer break. Laura Swett is widely reported to be in line for the chair. Like Rosner before he was elevated to the commission, she is a former FERC staffer — having worked for former Chair Kevin McIntyre and former Commissioner Bernard McNamee.

Rosner has been a commissioner since June 2024 and brings two decades of experience to the job across energy technologies, market design and energy policy issues. He was an energy industry analyst for FERC and spent two years on detail to the Senate Energy and Natural Resources Committee, where former Sen. Joe Manchin (I-W.Va.) became a big supporter for his nomination as commissioner.

Before coming to FERC, Rosner was a senior policy adviser for the Department of Energy's Office of Energy Policy and Systems Analysis and was an associate director at the Bipartisan Policy Center's energy project.

Rosner earned master's degrees in economics and public policy from American University and a bachelor's in economics from Tufts University. He lives in the D.C., area with his family.

NERC was quick to congratulate Rosner.

"Chairman Rosner has been a strong voice supporting abundant and reliable electricity to serve the nation's growing energy needs," the ERO said. "We look forward to continued work with Chairman Rosner on advancing the reliability and security of the electric grid."

Other congratulations came through on social media, with McNamee *posting* on X that Rosner "will do a great job."

WIRES Group Executive Director Larry Gasteiger *posted* congratulations on X, saying the trade group "looks forward to working with you and your colleagues on getting the energy infrastructure built to meet the nation's growing needs."

David Rosner | *FERC*

Coal power trade group America's Power welcomed Rosner being named chair with a statement from CEO Michelle Bloodworth.

"Chairman Rosner is an experienced policymaker with the skills, knowledge and open mindedness necessary to assure that FERC continues its work to improve the reliability of our nation's electricity grid," she said. ■

IRS Guidance on Wind and Solar Credits Not as Bad as Feared

4-year Completion Window Retained for 45Y and 48E Qualification

By John Cropley

The Trump administration is tightening the rules on qualifying for tax credits on new wind and solar construction, but not as much as some feared it would.

IRS *Notice 2025-42* released Aug. 15 indicates the Five Percent Safe Harbor provision for the clean energy production and investment credits will be eliminated for new solar facilities larger than 1.5 MW and new wind facilities that start work after Sept. 2, 2025.

It is being replaced with a protocol to establish that significant physical construction has been started before July 5, 2026; proceeded continuously; and was completed within four calendar years to establish eligibility for the tax credits.

This is not as harsh as it could have been, or as some in the clean energy industry had feared — some companies in the sector saw their stock prices soar later Aug. 15 as the guidance was digested.

As the S&P 500 and Nasdaq closed fractionally lower, NextEra Energy closed 4.4% higher, Enphase Energy 8.1%, First Solar 11.1%, Nextracker 12.2% and Sunrun 32.8%.

Research and strategy firm Jefferies called it a win for utility-scale renewables and a huge win for residential solar, saying the guidance was "significantly better than expected."

The sector's trade organization, the American Clean Power Association, was critical of the guidance but struck a more measured tone than it has with some of the many setbacks President Donald Trump and his cabinet agencies have dealt to renewable energy in his second term.

Why This Matters

The tax guidance is a break in the string of bad news for the U.S. solar and wind energy sectors.

Construction in progress is shown at a wind power facility. | *Shutterstock*

CEO Jason Grumet said: "The Treasury Department's decision to accelerate the phaseout of clean energy tax credits undermines the integrity of our energy grid and our legislative process. In the One Big Beautiful Bill Act, Congress explicitly chose to provide energy companies with one year to phase out tax credits to keep energy prices low while meeting growing power demand."

But he continued: "We acknowledge and appreciate the hard work of senators who led the effort to elevate pragmatism over partisanship in the legislative process. Their continued advocacy to protect this legislative agreement was instrumental in avoiding greater impediments to energy deployment."

On July 4, Trump signed the bill, which contained provisions accelerating the phaseout of the Clean Electricity Production Tax Credit and Investment Tax Credit — 45Y and 48E, respectively.

Some Republicans in Congress wanted the credits eliminated immediately, and Trump was widely reported to have won their support for OBBBA and its slower phaseout by promising a firm hand carrying out OBBBA's provisions.

Trump followed up on July 7 with an executive order directing Treasury to issue new guidance on 45Y and 48E and directing the Department of the Interior to review and revise all policies deemed preferential to wind and solar facilities within 45 days of OBBBA's enactment. (See *U.S. Clean Energy Sector Faces Cuts and Limitations* and *Trump Executive Order Targets Renewable Energy Tax Credits.)*

Interior already has issued a series of policy changes to comply with the order that most observers would characterize as harsh. (See *Dept. of Interior Launches Overhaul of OSW Regs* and *Feds Pile on More Barriers to Wind and Solar*.)

Treasury dropped the next shoe on Aug. 15. More is to come, however, including guidance on the safeguards Trump ordered against foreign entities of concern. ■

Advanced Nuclear Fast-track Effort Gets First 11 Projects

DOE Pilot Program Goal: At Least 3 Operational Reactors by July 4, 2026

By John Cropley

The U.S. Department of Energy has chosen 11 advanced nuclear projects as the first tranche of its Nuclear Reactor Pilot Program.

The program was formed in June, a month after President Donald Trump issued a *series of executive orders* in an attempt to spur a U.S. nuclear renaissance. *One of the orders* gave the DOE a direct role in facilitating testing of next-generation nuclear power generation technology. (See *Trump Orders Nuclear Regulatory Acceleration, Streamlining*.)

DOE said Aug. 12 that it will work with the 10 companies on their 11 projects with the goal of constructing, operating and achieving criticality with at least three reactors by July 4, 2026, on sites outside national laboratories.

It is a new pathway toward fast-tracking commercial licensing. Trump directed this streamlining in his executive orders, saying over-regulation was stifling progress and was unnecessary, given the nuclear industry's safety record.

Skeptics countered that nuclear energy is safe because it is well-regulated, and worried about the effects of speeding the regulatory process on new reactor designs.

And there are many, many new designs in various stages of development: The Nuclear Energy Agency in July updated its *Small Modular Reactor (SMR) Dashboard*, analyzing no fewer than 74 SMR designs in progress worldwide. The greatest number of designers —27 — have their *headquarters in the United States*.

DOE alluded to this in its Aug. 12 news release, writing: "The diversity of applications received shows the remarkable breadth of innovation and ingenuity in American reactor developers."

DOE chose two designs from Oklo for the pilot program and one each from Aalo, Antares Nuclear, Atomic Alchemy, Deep Fission, Last Energy, Natura Resources, Radiant Industries, Terrestrial Energy and Valar Atomics.

Why This Matters

Successful prototype operation is a critical step for small modular reactors.

Participation in the pilot program will give them a fast-tracked approach to future commercial licensing. It also may help unlock private funding. Each company is responsible for all costs for designing, manufacturing, constructing, operating and decommissioning their test reactors.

When it *announced the pilot program* June 18, DOE said it builds on existing efforts to demonstrate advanced reactors on DOE sites through microreactor test beds and other projects led by the Department of Defense or private industry. It is not, however, designed to demonstrate suitability of reactors for commercial purposes.

One of the companies that won designation for the pilot program, Aalo, said in an *Aug. 12 news release* that a key part of the pilot program is cutting red tape.

Participating companies will be assigned a DOE concierge team to cut through governmental red tape, so that, for example, a developer would wait just days for a sign-off authorization that previously might have taken weeks or months to secure.

"This is a pivotal moment for advanced nuclear, and we're proud to be at the forefront," CEO Matt Loszak wrote.

The Roster

The companies chosen for the pilot program show the diversity of the advanced nuclear sector as it scrambles to develop safe, affordable, workable and scalable reactor designs and fuel supply chains:

- *Aalo* is developing a sodium-cooled, uranium-dioxide-fueled experimental reactor that will form the basis of its Aalo Pod, a highly modular 50-MWe reactor targeted at the data center industry.
- *Antares* is developing a kilowatt-scale reactor for special purposes including underwater and outer space use.
- *Deep Fission* proposes to build 15-MWe SMRs one mile underground.
- *Last Energy* is developing a 20-MWe micro modular nuclear power plant; the company was in the news earlier in 2025 with a plan to place 30 of them behind the meter at a Texas data center.
- *Natura Resources* is advancing a liquid-fueled, molten salt-cooled reactor that could have multiple end uses beyond power generation, including desalination and hydrogen or steel production.
- *Oklo* is updating existing technology to design liquid metal-cooled fast reactors.
- *Atomic Alchemy*, which Oklo *acquired earlier in 2025*, is developing a radioisotope supply chain.
- *Radiant* is pursuing mass-produced microreactors that can be transported via truck like a shipping container; this month it announced an agreement to deliver its 1-MW Kaleidos to the Department of Defense in 2028.
- *Valar Atomics* is building a 100-kW TRISO-fueled high-temperature gas reactor — in the Philippines, because of the regulatory burden that the company says the Nuclear Regulatory Commission would place on the effort if carried out in the U.S..

Valar was in the news earlier in 2025 when it joined a group of states and startup companies in a lawsuit arguing that the NRC should regulate the existing fleet of gigawatt-scale reactors and leave regulation of SMRs to states, because SMRs' small size is accompanied by small potential risk.

"Should our suit succeed, Valar Atomics and our colleagues in this industry will provide abundant energy for all mankind," *wrote CEO Isaiah Taylor*, the self-taught engineer who founded Valar. ■

WIRES Report Includes Survey on Industry's Views of Advanced Tx Tech

By James Downing

WIRES Group released a *report* Aug. 6 looking into advanced transmission technologies (ATTs) and how they can help cost-effectively expand the transmission grid.

Prepared by London Economics International, the report includes a survey of 20 WIRES members, including transmission owners and technology providers, on their experiences with ATTs and best practices. It refers to "ATTs and innovative practices" collectively as "ATT+."

"Transmission capacity will need to expand in order to support economic development and meet the rapid increase in electricity demand, while also maintaining system reliability and resiliency in the face of more frequent extreme weather events across the country," the report said. "ATT+ can help TOs address various needs in certain situations and should be thought of as one of the tools in the toolbox to complement and supplement traditional transmission system capital investments."

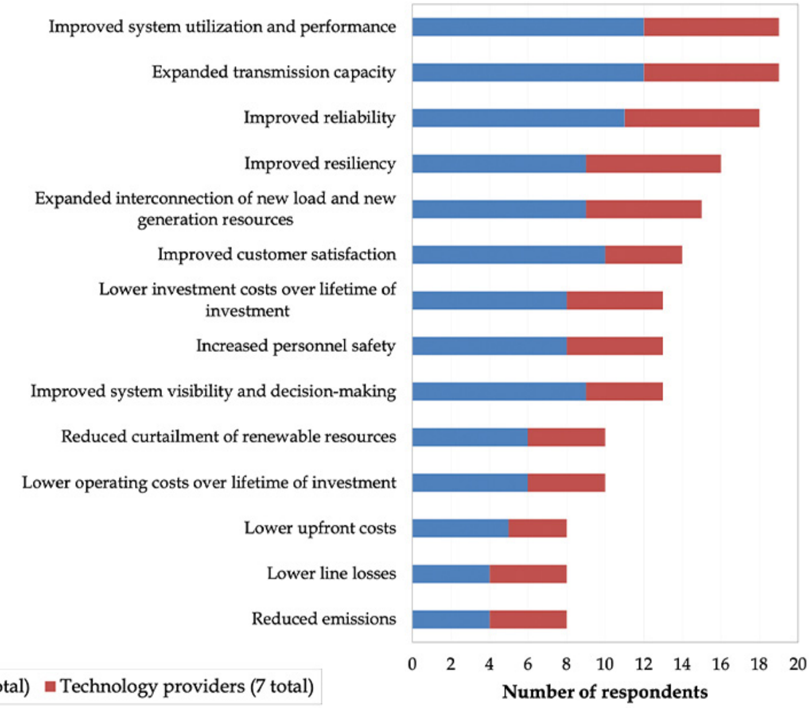
The definition of an ATT can vary depending on who is using the term and can include grid-enhancing technologies (GETs) and advanced conductors. But the paper considered a broad range of technologies that it put in three categories: siting and design, construction, and operations.

Siting and design ATTs include artificial intelligence-powered software that can speed up permitting; compact line designs that use less space for high-voltage transmission; and innovative approaches to expediting permitting processes.

For construction, the report looks into exoskeletons that add additional circuits above existing lines, helicrane construction that can install equipment in hard-to-reach areas, and modular tower raising systems that can lift up transmission towers without de-energizing lines.

Why This Matters

WIRES' latest report looks into how transmission owners view ATTs and what can be done to expand them.



What WIRES Group members rank as the major benefits of advanced transmission technologies | *London Economics International*

The operations side of ATTs involves the most diverse range of technologies and is broken down into three subsections. Hardware components include advanced conductors, advanced flexible transformers and digital substations. GETs include dynamic line ratings, advanced power flow controllers and topology optimization.

Compact lines use new designs for towers that take up less space. The report cites a design used by American Electric Power from BOLD Transmission in Indiana in 2019. The towers were shorter and narrower, allowing for smaller easements, cutting costs and helping to minimize impacts on neighborhoods. It also allowed for more capacity than traditional designs.

Modular tower raising uses hydraulics that are mounted on the inside body of an existing transmission line, which can raise the tower to allow new framing to be installed without de-energization. Ampjack's Tower Raising system has completed more than 750 tower raises, the report said.

Transmission asset inspections and maintenance are typically conducted by engineers climbing up pylons or using helicopters, but drones and robotics can do the same work with less money, especially in areas that are hard to reach. Using drones and robots for such work is safer, cuts down time and can enable more data collection on asset conditions.

The survey asked 13 TOs and seven technology providers about the benefits of ATTs. The top responses were improved system utilization and performance, expanded transmission capacity, improved reliability, improved resilience, and expanded interconnection of new load and generation. ATTs can also lower costs for customers by minimizing the need for capital investments and cutting operating costs, they said.

The survey also asked what is holding companies back from deploying ATTs. The top answers were a lack of operational expertise, uncertainty about the technology's capabilities and value proposition, and performance risks. Some firms listed the regulatory framework's disincentives, but it was the lowest-ranked answer.

"Preference for technologies with low uncertainty (and therefore known benefits and costs) is not unique to the electric transmission sector," the report said. It cited the diffusion of innovations theory by sociologist Everett Rogers, which was focused on the field of communications and posits that widespread adoption of new technologies only occurs as uncertainty decreases.

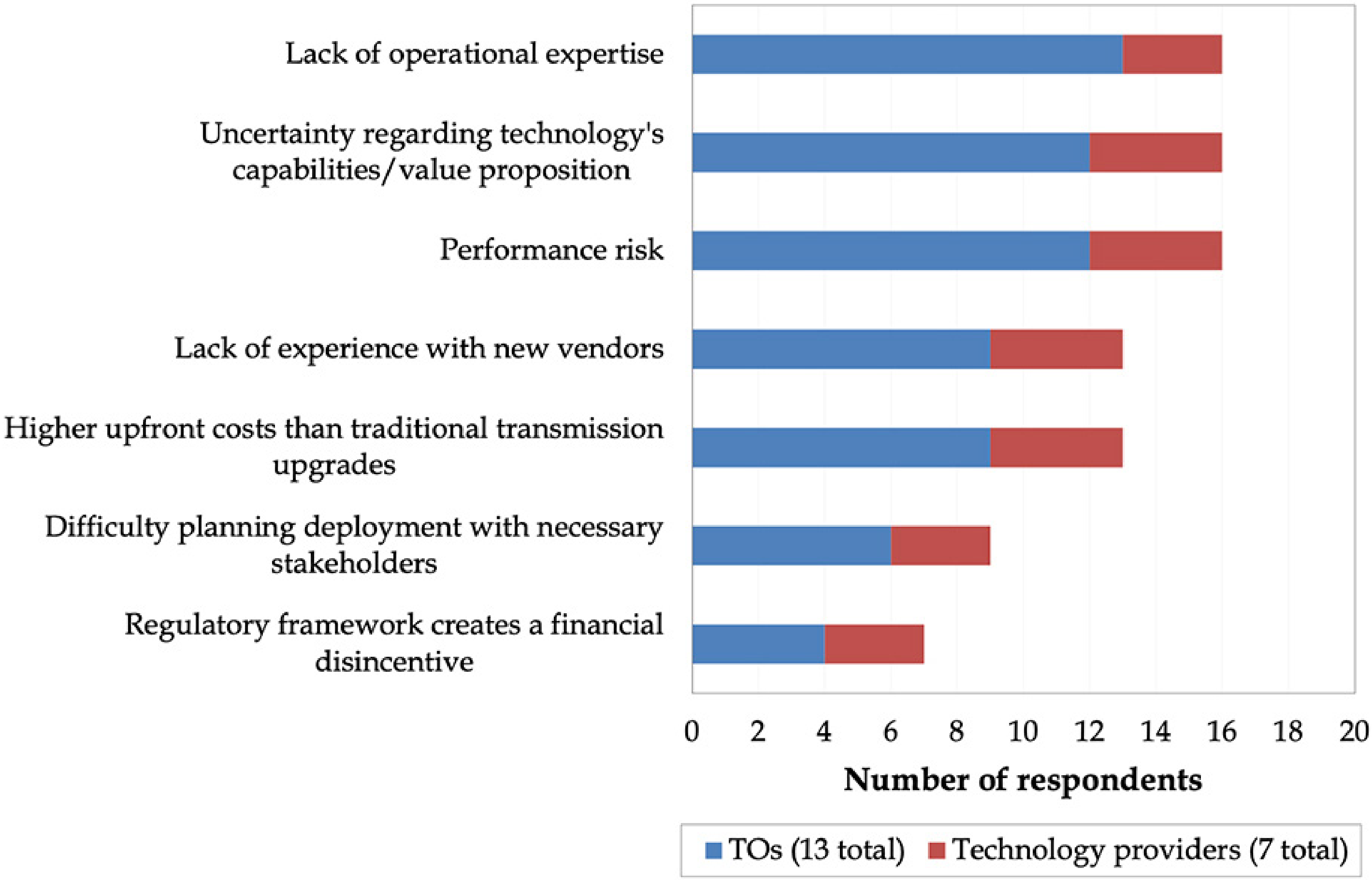
"LEI observed similar themes throughout interviews with technology providers and TOs," the report said. "Regulators, system planners and TOs, by the nature of their priorities (where providing reliable electricity service at reasonable cost is paramount), tend to prefer technologies with proven track records over new technologies that are not yet commercially available or widely deployed under various real-world conditions due to uncertainty around performance under unexpected future operational conditions, and also potential ambiguity in future benefits and costs."

The current regulatory structure in many regions tends to focus on nearer-term planning horizons of five to 10 years, which can lead to incomplete cost-benefit analyses for some ATTs that put more weight on near-term benefits. That is not helped by uncertainty around longer-term projections of benefits, which can make regulators overly cautious about using them, the report said.

Some opponents of transmission investments have argued that utilities are biased against ATTs because their earnings are lower than spending on wholly new infrastructure.

"It is inaccurate and overly simplified to claim that TOs do not benefit financially from ATTs that impact operating costs because of the cost-of-service environment," the paper said. "In fact, regardless of whether a TO operates under stated rates or transmission formula rates, there is often some regulatory lag inherent in a cost-of-service environment, so TOs can reap some financial benefit from operating cost savings. Furthermore, the financial incentives and business factors that drive investment and operating decisions of TOs are much more complex because of the multiple objectives that TOs need to meet (reliability, policy and overall cost minimization) and constraints they face in their regulatory and business environments."

Still, aligning financial incentives and implementing regulatory mechanisms that can level the playing field between operating versus capital investment-oriented ATTs, and between ATTs and traditional investments, would make cost impacts more transparent and encourage focusing more on the benefits side of the equation, the report said. That would lead to greater use of the technologies, it argued. ■



What WIRES Group members view as the main obstacles to rolling out ATTs | *London Economics International*

BPA Preparing to Deliver Power Under New Multiyear Contracts

Agency Finalizes 'Provider of Choice' Process

By Henrik Nilsson

The Bonneville Power Administration will begin to issue long-term contract offers under its Provider of Choice (POC) initiative after finalizing the set of policies and decisions that will guide the 20-year contracts.

On Aug. 14, BPA released several documents under its POC policy: POC Contract Record of Decision, Contract High Water Mark Implementation (CHWM) Policy and accompanying Record of Decision, New Resource Rate Block Policy and final POC CHWM contract templates. (See related story *BPA Issues Final Long-term Power Contract, Updates Strategic Plan*.)

With the *documents finalized*, BPA can now begin to issue contract offers to customers. The goal is to complete all contract offers by Sept. 30 and for customers to return signed contracts by Dec. 5, allowing BPA to execute them by the end of the year. BPA will now focus on implementation and preparation for power deliveries under the new contracts, which are set to begin Oct. 1, 2028, according to a news release.

"While this multiyear effort will not be complete until signed contracts are in hand, the contracts, policies and records of decision released this summer are a significant culmination of work," said Kim Thompson, BPA vice president for Northwest Requirements Marketing. "Thanks to the significant time, thought, leadership and attention to detail from power, legal and other supporting staff, BPA will have policies and contracts that serve BPA and its customers for decades to come."

Bonneville delivers power to regional public power customers under contracts executed in 2008. The agreements provided approximately 76% of BPA's power services' revenue requirement in 2022, according to a concept paper. (See *BPA Close to Issuing New Long-term Power Contract*.)

The long-term contracts by statute cannot exceed 20 years, and BPA launched the POC initiative to begin contract discussions with stakeholders before the current agreements expire in 2028, according to the paper.


BPA transmission line | © *RTO Insider*

Why This Matters

With the culmination of BPA's Provider of Choice process, the agency now has contracts and policies in place it hopes will serve for the next two decades.

BPA must also offer contracts to investor-owned utilities under the Pacific Northwest Electric Power Planning and Conservation Act. However, no IOU has requested a new contract. Instead of drafting new contract language for IOUs, BPA developed the NR Block Policy, outlining how the agency would establish contracts and product offerings if IOUs should request them, according to a news release.

Another new feature relates to the CHWM.

CHWM determines how much power a customer can buy at the Priority Firm Tier 1 rate, which represents most of BPA's power sales. Under the new contracts, BPA will calculate CHWMs once in 2026, and those will be fixed for the duration of the contract to reduce the Tier 1 load service uncertainty for customers. (See *BPA Customers to See Increased Power, Transmission Rates*.)

"CHWMs were a significant focus during the policy development and remain a focal point of customers," Sarah Burczak, policy lead for Provider of Choice, said in a statement. "CHWMs set customer-specific limits for buying power at what is typically BPA's lowest rate. The CHWM Implementation Policy addresses specific eligibility, calculation, process and adjustment details. The policy establishes clear expectations for how CHWMs will be established and provides assurances for how BPA will conduct ongoing related processes." ■

BPA Issues Final Long-term Power Contract, Updates Strategic Plan

By Henrik Nilsson

The Bonneville Power Administration has finalized the set of policies and records of decision (RODs) underlying its long-term power sales contracts and has also taken additional steps to align with President Donald Trump's priorities, CEO John Hairston said during the agency's quarterly business review Aug. 14.

The policies and RODs build on the agency's Provider of Choice policy issued in March 2024 and provide more details about the products and services it now offers under the new long-term contracts. The goal is to complete all contract offers by Sept. 30 and for customers to return signed contracts by Dec. 5, allowing BPA to execute them by the end of the year, Hairston said. (See *BPA Close to Issuing New Long-term Power Contract*.)

"This has been an incredibly iterative and collaborative process," Hairston noted. "BPA greatly appreciates the time and energy invested by so many people to ensure we establish a foundation for stable, competitively priced and flexible power sales. The long-term certainty provided by these contracts will support regional economic stability and help ensure a more reliable and affordable power supply for customers we serve."

Additionally, BPA has updated its strategic plan in accordance with the Trump administration and the Department of Energy's goal to provide "more secure, reliable, abundant and affordable energy," Hairston said.

One change, Hairston added, is that the agency has removed objectives related to diversity, equity and inclusion to align with executive orders issued shortly after Trump took office.

What's Next

BPA's goal is to complete all contract offers by Sept. 30 and for customers to return signed contracts by Dec. 5, allowing the agency to execute them by the end of the year.

BPA Administrator John Hairston | *BPA*

"Other minor refinements reflect the department's focus on energy addition, not subtraction, and strengthening grid reliability and security," Hairston said.

Hairston also highlighted other BPA projects, including a partnership with Energy Northwest to increase the output of the Columbia Generating Station by 162 MW in a $700 million project, and an upgrade to Montana-to-Washington transmission aimed at expanding capacity.

He also commented on BPA's new power and transmission rates for fiscal 2026 to 2028. Customers' power rates will increase by about 8 to 9% over the next three years, while transmission rates will jump by an average of nearly 20%. (See *BPA Customers to See Increased Power, Transmission Rates*.)

"The new rates balance the need to keep rates low and stable while supporting power and transmission system investments to meet customer load growth and connect new generation," according to Hairston. "The rates we adopted are the product of multiple settlements that required hard work and collaboration."

The administrator also noted the June 12 presidential memo directing the federal government to withdraw from a deal the Biden administration signed that eventually could have led to breaching several dams operated by BPA on the Snake River. (See *Trump Directs Feds to Withdraw from Deal on Snake River Dams*.)

"The federal parties provided notice of withdrawal on June 24, which also made clear that the federal government is willing to engage in good faith efforts to seek a satisfactory solution to the pending litigation and concerns of various stakeholders," Hairston said.

Financial Outlook

BPA's forecast for net revenue in the third quarter of 2025 is $184 million, a $26 million decrease from the second quarter but higher than the $70 million target.

Power services' net revenue forecast is $105 million, $27 million above target. Transmission services' net revenue forecast is $73 million, $80 million above target.

"BPA's above-targets results are mainly due to higher power and transmission revenues, lower-than-predicted Integrated Program Review expenses and debt-management actions," according to a news release. "Notably, BPA was able to use liquidity tools to offset its largest power purchases in January and February through a federal debt-management transaction that allowed BPA to realize significant gains." ■

BPA Supported by Trade Orgs in Suit over Day-ahead Market Decision

Trade Groups Seeking to Intervene Argue BPA's Decision Best for Pacific Northwest

By Henrik Nilsson

Trade organizations for utilities and large energy consumers seek to intervene in the lawsuit filed in the 9th Circuit Court of Appeals challenging the Bonneville Power Administration's decision to join SPP's Markets+ instead of CAISO's Extended Day-Ahead Market (EDAM).

SPP, Public Power Council (PPC), Alliance of Western Energy Consumers (AWEC), Pacific Northwest Generating Cooperative (PNGC) and Northwest Requirements Utilities (NRU) all filed motions to intervene in late July and early August, citing their members' "interest" in the lawsuit. (See *BPA Sued in 9th Circuit over Day-ahead Market Decision*.)

PPC represents the Northwest's extensive network of publicly owned utilities that make up BPA's base of "preference" customers. The organization has been a strong supporter of BPA's day-ahead market decision, saying in its motion to intervene that the case could impact BPA's transmission services and PPC members.

Why This Matters

The motions to intervene are another indication that the day-ahead market debate in the West shows no signs of slowing down.

"PPC intervening in the case is an absolute reflection that a strong majority of Northwest public power supports BPA's decision and the extensive public process they ran to arrive at the Markets+ outcome," PPC Executive Director Scott Simms said in an email to *RTO Insider*.

Simms reiterated arguments that supporters of Markets+ have highlighted throughout BPA's day-ahead market process, such as the market option's governance approach and "overall design."

BPA headquarters in Portland, Ore. | *DOE*

(See *BPA Selects SPP Markets+ in Draft Policy*.)

"As for the significance of the case, it's interesting to see just how political the day-ahead markets space has become — evidenced by the named plaintiffs in this case," Simms added.

The dispute stems from a lawsuit filed on July 10 by NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board and the Sierra Club.

Represented by Earthjustice, the group asked the court to review and vacate BPA's day-ahead market decision. They allege BPA did not consider the environmental impacts and failed to properly assess the purported benefits of CAISO's EDAM.

According to the suit, the agency now risks increasing costs for customers by not joining EDAM, which the group says has a larger market footprint than Markets+. Additionally, the group claims BPA ignored its obligations to prioritize conservation and renewable power.

The suit brings claims under the National Environmental Policy Act, the Pacific Northwest Electric Power Planning and Conservation Act and the Administrative Procedure Act.

"The participation of these intervenors in the case highlights the importance of this decision by Bonneville, which will have a major impact on the cost of electric power in the Pacific Northwest," Jaimini Parekh, senior attorney with Earthjustice, said in an email. "That is why we have challenged Bonneville's decision. State agencies in Washington and Oregon found that had Bonneville made a different decision, and joined EDAM, it could have saved ratepayers billions of dollars."

'As Disappointing as it is Unsurprising'

More parties could join the case, as the deadline for intervening is early September. Still, those who have filed petitions so far have done so in support of BPA.

Continued on page 13

Calif. Agencies Ponder Interconnection Timelines, Load Uncertainty

Out-of-state Wind Resources Need Attention, CAISO Says

By David Krause

California energy officials are recognizing the need to work together to prioritize a long list of transmission and distribution interconnection projects as the state's load growth accelerates due to expected data center development.

At an Aug. 11 joint agency workshop, representatives from the California Energy Commission, California Public Utilities Commission, CAISO and other entities discussed how to accelerate interconnection timelines in the Golden State, with conversations focusing on the various types of new load coming online and bringing out-of-state wind power to California's borders.

Why This Matters

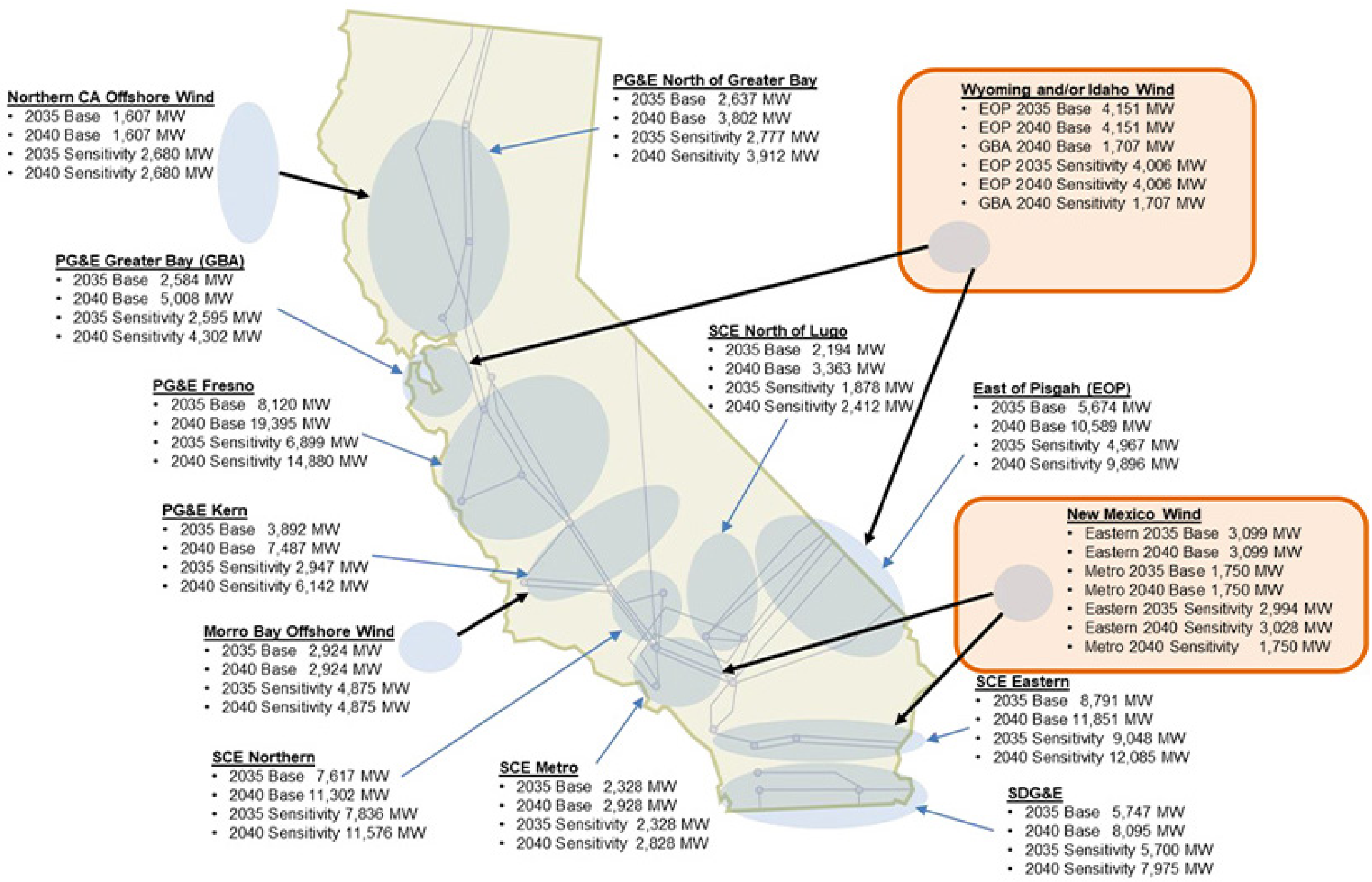
California needs 100 GW of new resources by 2040, but it also needs to make serious upgrades to its infrastructure to transport that electricity.

"In a big, complicated state like California … it's really great to have this platform to do some level setting," CEC Commissioner Andrew McAllister said at the workshop.

"I've really learned to appreciate the complexity of our roles," CEC Vice Chair Siva Gunda added. "One of the things we're dealing with across demand forecasts, whether it's distribution planning or integrated resource planning, is the uncertainty — the vast uncertainty — in demand, because of electrification, climate impacts and new loads that may come [or] may not come."

Gunda asked Neil Millar, CAISO vice president of infrastructure and operations planning, to explain how the ISO is thinking about protecting electricity rates while at the same time future-proofing investments in energy infrastructure and resources.

"I think the most important part [of this effort] is about the sensitivity work that goes into considering options," Millar said.



Major competitively procured transmission projects under development | *CAISO*

"And part of that includes picking options that are always a good first step and not necessarily always … going for the fences with a transmission project."

Instead, agencies could focus on picking scalable options because, once a project is a few years down the path, there's "always a risk that the load growth softens," Millar said.

"Then you're not dependent on some next step in order to achieve the actual benefit of the plan," Millar said. "Our focus has normally been to try to achieve the required in-service data, monitor the load growth, and make adjustments if necessary, but also to [consider] the sequencing of transmission projects."

Load forecasts in California and the West have been escalating, which increases energy resource and transmission requirements in the region, Millar said during his presentation. CAISO is dealing with new types of loads, such as those caused by data centers in particular, he said.

CAISO's 2025/26 transmission planning process continues to rely on accessing out-of-state resources, particularly wind, Millar said. These out-of-state wind resources will need more attention over the coming years to bring them to California, he added.

Millar specifically highlighted 12 major transmission projects — each from CAISO's transmission plans from 2018 to 2025 — that are under development. However, about 12.9 GW of renewable resources could be delayed due to transmission delays, Brian Biering, counsel for American Clean Power, California (ACP), said in a presentation at the workshop. As of April, the region has about 28.4 GW total of new renewable generation and storage resources with signed interconnection agreements, he said.

To help solve these delays, ACP recommended energy officials consider requiring an independent transmission construction monitor (ITCM) that would increase the transparency and enhance staff understanding of transmission construction for projects above 1,000 MW.

The ITCM should be able to request data directly from transmission owners and report directly to the CPUC and CAISO, Biering said.

Investor-owned utilities in California have 715 transmission projects under development that have planned in-service dates between 2025 and 2033 and an expected cost of $1 million or greater, said Molly Sterkel, interim director of electricity supply, planning and costs at CPUC. Of those 715 projects, CAISO has approved 140, while 575 are non-approved, Sterkel said.

California needs 100 GW of new resources by 2040, said Danielle Mills, CAISO principal of infrastructure policy development. The ISO has "more than sufficient resources in the queue to meet those needs," Mills said.

"In fact, we still worry sometimes … that we have too many projects in the queue that are lingering, that we need to find some alternative pathway for, either withdrawal or transitioning those resources to some other type of resource," Mills said. ■

BPA Supported by Trade Orgs in Suit over Day-ahead Market Decision

Continued from page 11

For example, SPP said the plaintiffs' suit challenges the agency's decision "to pursue participation in SPP's Markets+ instead of an alternative day-ahead market preferred by petitioners."

SPP, which is the operator for Markets+, added that it has "significant interest" in the suit, noting that BPA's participation "will significantly impact the scope and operation of Markets+."

NRU, whose 58 utility members buy power from BPA on a preferential basis, has similarly supported the agency in its decision-making process and filed a motion to intervene to defend BPA, NRU Executive Director Zabyn Towner told *RTO Insider*.

"The fact that a few outside interests are taking legal action to try to force BPA to pursue a day-ahead markets policy that is consistent with their own stated goals is as disappointing as it is unsurprising," Towner said. "NRU takes serious issue with the plaintiffs' stated grounds for their challenge and joined the case with the intent to zealously defend BPA, its ability to make decisions in the best interests of public power and the resulting decision to pursue participation in SPP's Markets+ day-ahead market."

Bill Gaines, executive director of AWEC, also said Markets+ is preferable for the Pacific Northwest region because of the day-ahead market's design and because of "governance shortcomings in the CAISO EDAM market that the California legislature has been unwilling to remedy."

Much of the success of EDAM hinges on a bill in the California legislature that would allow CAISO to relinquish market governance to an independent "regional organization" being established by the West-Wide Governance Pathways Initiative. The bill has been delayed after 21 organizations pulled their support following amendments they found concerning. (See *Newsom Reiterates Support for Western Regional Market Push*.)

Richard Stover, chief legal officer at PNGC, said BPA's decision "is very important to PNGC as we enter into new long-term contracts with BPA. On behalf of our members, PNGC intervened to protect its long-term interests and that of its members."

When asked for a response, BPA said it doesn't comment on active litigation. ■

CAISO Monitor Sees 'Gaming' Potential in Battery Bid Cost Recovery

Revising Approach Should be 'Top Priority' for CAISO, DMM Says

By David Krause

CAISO's Market Monitor is concerned about potential gaming and inefficient bidding behavior in CAISO's bid cost recovery (BCR) process for battery storage resources.

The current BCR design creates gaming opportunities for battery storage units, "especially through manipulation of various biddable parameters used to manage [a battery's] state-of-charge," CAISO's Department of Market Monitoring (DMM) said in its annual market performance *report*, published Aug. 7.

"Gaming concerns are exacerbated by the fact that bid cost recovery payments are partly driven by submitted bid prices, meaning that inflated bids can cause BCR payments to drastically exceed any economic losses caused by reversal of day-ahead schedules," DMM said in the report.

Battery storage capacity in California has grown from 500 MW in 2020 to almost 14,000 MW as of August. An additional 14,000 MW of battery storage capacity is planned to be online by 2030, pushing CAISO's total to about 28,000 MW by that year.

In 2024, battery storage facilities received about $18 million in real-time bid cost recovery — about 11% of all bid cost recovery in the year. However, battery storage resources are different from conventional resources: They do not have start-up, shut-down, minimum load or transition costs — the primary drivers of BCR, the report says.

Why This Matters

With California's battery storage capacity expected to reach about 28,000 MW in 2030, CAISO's Market Monitor is recommending changes to how batteries are compensated for the energy they provide to the grid.

Historically, BCR has applied to generation facilities as a method to reduce their risk of receiving insufficient revenue to cover start-up and minimum load costs, the report says. As opposed to conventional thermal resources that are incentivized to bid their marginal energy production costs, storage resource bids do not solely represent the costs to discharge or charge energy in a given interval, CAISO said in a November 2024 *letter* to FERC on the issue.

"As a result, bid cost recovery payments to storage resources may result in compensation exceeding the resource's costs," CAISO said in the letter.

In its Aug. 7 report, DMM recommended that battery storage resources should be, in general, ineligible for BCR, with a limited number of conditions in which they would be eligible for BCR. The report notes that batteries do have certain limits that can result in BCR payments, specifically state-of-charge constraints that limit a battery storage unit's charging and discharging behavior.

But, as a general principle, when batteries are constrained by operational parameters set by unit operators to manage battery operation, "batteries should be ineligible for BCR payments," the DMM's report says.

Additional Revisions

In November 2024, CAISO filed a tariff amendment to address the battery storage BCR gaming concern. The tariff amendment caps battery bids when calculating bid cost recovery payments, which will mostly address the ability of batteries to inflate unwarranted BCR payments, DMM's report says.

However, unwarranted BCR payments will continue after the policy change is implemented because batteries with day-ahead schedules will continue to have distorted bidding incentives in real time, DMM's report says. This is because the largest driver of real-time battery

BLM California

BCR is due to lost revenues of buying or selling back day-ahead schedules, the report says.

The current BCR design "essentially removes the economic incentive for battery operators to bid in a way that is likely to ensure that batteries are fully charged up at the start of the peak net load hours when prices are highest and batteries are most needed for system reliability," the report says.

Responding to questions from *RTO Insider*, a CAISO spokesperson said the ISO and stakeholders last year developed market design changes to eliminate the potential for strategic bidding that would unduly inflate battery BCR payments. While those changes addressed an important concern, CAISO is working through additional issues related to market efficiency and improving the incentives for batteries to bid in a manner that is cognizant of real-time prices, the spokesperson said. BCR payments to batteries have remained stable even with significant battery fleet growth, they said.

CAISO is currently working on additional revisions to the BCR process within the agency's storage design and modeling initiative that started in 2025. ■

Calif. Utilities Move Cautiously on Dynamic Pricing

Goal is to Reduce Energy Use at Peak Hours

By Elaine Goodman

Despite a state mandate to implement dynamic pricing, two of California's publicly owned utilities told regulators they're not ready to make the leap to rates that change hourly or more often.

The two utilities — Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP) — outlined the challenges of dynamic pricing in reports submitted to the California Energy Commission.

The reports are intended to show utilities' compliance with the CEC's load management standards, which include a requirement to offer customer rates that can respond to hourly or sub-hourly price signals.

The commission on Aug. 13 approved compliance plans from SMUD and LADWP, as well as from two community choice aggregators: the Clean Power Alliance of Southern California and Ava Community Energy Authority, which serves the East Bay.

The dynamic pricing requirement is based on the idea that electricity customers can use smart devices, such as thermostats, water heaters and EV chargers, to reduce or shift their electric loads in response to price or other signals.

In addition to saving money for customers, the rates may encourage the use of energy at off-peak hours, improve grid reliability, decrease the need for new electrical capacity, and reduce fossil fuel consumption and greenhouse gas emissions.

SMUD, which was the first utility in California to implement time-of-day pricing, said in its plan that it is "fully supportive of the goals of the LMS regulations."

"We are focused on scaling up programs, including programs that can help reduce the need to purchase costly resource adequacy and to avoid the need to upgrade neighborhood transformers as EV charging loads grow," Katharine Larson, SMUD's regulatory program manager, told the commission.

But with projected net annual costs of $2.4 million to $3.7 million to implement hourly or sub-hourly pricing, dynamic pricing wouldn't be cost-effective, SMUD said.

Customer Interest Uncertain

SMUD was also concerned about a potential lack of interest in such a program. The utility cited its experience with its critical peak pricing (CPP) plan, in which customers agree to pay a higher rate when the utility calls a "peak event" in exchange for discounted rates at other times.

The peak events can occur at any time of day during the summer and can last from one to four hours. Program participants must allow automatic adjustments of smart devices enrolled with SMUD.

After two years of active recruitment for CPP, fewer than 700 customers have signed up for the program.

The commission approved SMUD's compliance plan with the condition that the utility provides an updated cost-effectiveness analysis for dynamic pricing by August 2028.

In its compliance plan, LADWP said implementing dynamic rates by the load management standard's April 1, 2026, deadline wouldn't be feasible and would cause an "extreme hardship" for the utility.

LADWP doesn't have advanced metering infrastructure needed to implement dynamic rates, but its plan includes other programs to encourage customers to shift their loads. Those include an electric vehicle managed-charging program.

Among the CCAs, Ava said it doesn't yet have enough information to know whether dynamic rates would be cost-effective or benefit customers.

Ava said "significant uncertainties exist" regarding the potential for load-shift under dynamic pricing, customer acceptance of a complex new rate and administrative costs of the program. To help answer those questions, Ava is participating in a dynamic pricing pilot program with PG&E.

> **Why This Matters**
>
> The CEC's load management standards, including the dynamic-pricing component, could be a way to facilitate automated and continuous management of electricity loads in California.

Similarly, the Clean Power Alliance plans to participate in Southern California Edison's expanded dynamic rate pilot through 2027.

Customizing Compliance

The commission's vote Aug. 13 follows compliance plan approval for six other utilities in May. The commission will consider plans from another nine CCAs at a future meeting.

Commissioner Andrew McAllister said CEC staff had done a good job in "almost customizing" the implementation of the load management standards for each utility, "responding to the realities on the ground."

"We have a big, diverse state," McAllister said. "We're doing something new; we're sort of creating a new playing field."

The CEC approved an update to its load management standards in October 2022. (See *California Moving to Dynamic Pricing for Retail Customers*.)

In addition to requiring dynamic pricing, the update directs utilities to maintain up-to-date rates in a database called the Market Informed Demand Automation Server (MIDAS).

Utilities also must develop a standard tool to support third-party services' access to rate information for their customers. The commission voted to extend the deadline for submitting the tool to May 8, 2026. ■

State Tx Entity, Regional Markets Feature in Ore. Energy Strategy

Draft ODOE Plan Calls for Creation of State Body to Speed up Transmission Development

By Robert Mullin

The Oregon Department of Energy's new draft energy strategy points to the importance of new transmission development and expanding electricity markets for meeting the state's energy goals.

ODOE's draft *Oregon Energy Strategy*, released for public comment Aug. 14, sets out recommendations by which the state can meet its greenhouse gas emissions policy objectives, which call for fully decarbonizing investor-owned utility electricity deliveries by 2040 and, by 2050, reducing fuel emissions by 90% and economy-wide emissions by 80%.

"An energy strategy could help align policies and programs; it could help navigate hard decisions with a focus on how to maintain affordability and reliability, [and] keep an eye on economic growth, on advancing equity and maximizing benefits, while minimizing harms," Edith Bayer, ODOE energy systems senior policy analyst, said during an Aug. 14 call to discuss the draft document.

The wide-ranging strategy document identifies five "pathways" for meeting state objectives, including improving energy efficiency, increasing electrification across the economy, investing in clean electricity infrastructure, using low-carbon fuels in hard-to-decarbonize sectors and strengthening "resilience" throughout the energy system.

A section describing the clean electricity pathway warns that the state presently lacks the infrastructure needed to meet its energy transition goals.

"There is not currently sufficient transmission capacity, generating resources or storage to reliably power Oregon's future electricity needs, particularly if new data centers come online as quickly as forecasted," ODOE writes, pointing to the need to prioritize construction of new utility-scale resources, which often take years to site, plan, permit, build and interconnect with the grid.

"Failure to develop sufficient resources will not only threaten system reliability and hinder progress toward Oregon's clean energy objectives, but will inhibit economic development and discourage new businesses from entering the state," the report says.

ODOE's top recommendation for addressing the challenge: establish a state "transmission entity" — one that appears to be modeled on New Mexico's *Renewable Energy Transmission Authority* and the *Colorado Electric Transmission Authority*.

Why This Matters

Buildout of new transmission and participation in regional electricity markets will be key components of Oregon achieving its clean energy goals, according to a draft report from the state's Department of Energy.

The Oregon Energy Strategy document calls out the state's vital need to develop more transmission to meet its clean energy targets. | *© RTO Insider*

The department says the Oregon entity should be given authority to "identify and designate transmission corridors," undertake "partial siting and permitting approvals" for projects in the corridors and offer direct financial support "through state bonds for projects that are determined to benefit the public interest."

"Across the Pacific Northwest, transmission constraints hinder access to least-cost generation and contribute to reliability concerns," the agency wrote. "Line expansions and additions are not proceeding at the pace or scale necessary to meet Oregon's policy objectives."

ODOE said the new entity could help simplify the process of siting and permitting transmission lines that traverse both state and federal jurisdictions, a key challenge in a region in which the Bonneville Power Administration controls more than 70% of the transmission network.

"To reduce this barrier, a new state entity could establish designated corridors for transmission development and obtain limited siting approval for development within the corridor, including development of enhanced, expanded or new transmission facilities but also of storage and electric generating resources," the report notes. "Having a new state entity pursue limited siting approval for an entire corridor would retain Oregon's historic focus on robust siting and permitting processes, while enabling individual projects within a given sited corridor to proceed more rapidly than is currently possible."

Bayer noted the recommendation might resemble an Oregon House of Representatives bill (*HB 3628*) to establish a state transmission authority that failed to emerge from committee during the 2025 session.

"We hope that the text in the draft report captures the potential value that such an entity could provide, as well as the potential risks," she said. "There's near-universal agreement in all of our engagement and everything that we heard that transmission is one of the most critical areas to meet our goals of clean, reliable and affordable energy."

Coordination Through Markets

The strategy document also urges Oregon to step up collaboration with its neighbors, specifically through increased engagement with regional markets and other grid efforts.

ODOE calls out the "billions of dollars" the West has *saved* through expanded participation in CAISO's real-time Western Energy Imbalance Market since 2014 and notes the development of the region's two competing day-ahead markets: the ISO's Extended Day-Ahead Market and SPP's Markets+.

"Utilities in the region are moving toward more organized power markets to reduce costs and improve reliability. This is essential to more efficiently utilize existing infrastructure and to benefit from geographic and resource diversity across the region," the agency wrote.

It said regional diversity will become "increasingly important" as states decarbonize, with a more diversified supply mix allowing load-serving entities to "take advantage of different weather patterns, resource mixes and time zones to integrate more renewable generation while mitigating risks from weather changes, including extreme weather events and wildfires."

ODOE said movement toward an RTO would be "an important step to improve West-wide coordination and reduce costs for consumers."

The document mentions also the two efforts managed by the Western Power Pool: the Western Resource Adequacy Program to develop regionwide RA requirements, and the Western Transmission Expansion Coalition to identify cost-effective interregional transmission projects.

"It is important that the state of Oregon engage in these activities to advance state energy policy objectives, ensure that regional activities are consistent with state policy and strengthen Oregon's cooperation on vital areas including market development, resource adequacy, emissions accounting and transmission planning," the report says.

The comprehensive strategy document recommends a wide range of additional energy-related actions, including those dealing with the electrification of buildings, transportation and industry; energy efficiency and conservation improvements; developing and expanding adoption of low-carbon fuels; and reducing vulnerabilities in the state's energy system. It also explores equity issues stemming from the transition to cleaner sources of energy, including jobs impacts. ■

NEPOOL Nears Vote on 1st Phase of ISO-NE Capacity Auction Reforms

By Jon Lamson

ISO-NE presented the final design details and tariff changes for the first phase of its Capacity Auction Reforms (CAR) project at the summer meeting of the NEPOOL Markets Committee on Aug. 12-14 in preparation for a stakeholder vote in October.

The first phase of CAR is centered around transitioning ISO-NE's Forward Capacity Market to a prompt design, with auctions held less than one month before the start of each annual capacity commitment period (CCP). It includes significant changes for resource deactivation and wide-ranging conforming changes to prepare for the new auction format. The RTO aims to file the proposal with FERC before the end of the year.

After completing the first phase of work, ISO-NE plans to ramp up stakeholder discussions on the second phase of the CAR project, which will focus on resource accreditation and dividing CCPs into distinct seasonal periods.

As stakeholders near a vote on the first CAR filing, the Massachusetts Attorney General's Office has called for more quantitative analysis of the impact of the changes.

In a *memo* published prior to the MC meeting, the AGO asked ISO-NE to provide "whatever qualitative or quantitative information it can on the impact of the [prompt market proposal] as a stand-alone market design."

The office noted that developing the seasonal and accreditation changes "involves significant design, regulatory and implementation risks, which could potentially delay or otherwise derail" the implementation of the second phase of the CAR project and "leave the auction for capacity commitment period 2028/29 to be conducted under the [prompt] design only."

ISO-NE commissioned a preliminary impact *analysis* in late 2023, which projected a prompt and seasonal capacity market to reduce capacity market costs by about 12% compared to the FCM. The study estimated that a prompt-annual design would reduce costs by 10 to 11% relative to the existing design. (See *NEPOOL Markets Committee Briefs: Jan. 11, 2024*.)

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

Why This Matters

The proposed capacity market changes, intended to increase market efficiency and reduce overall costs, necessitate wide-ranging changes across ISO-NE processes.

Responding to the request, the RTO has said it will wait to conduct a more comprehensive impact assessment once it has completed the bulk of the work on both phases of the project.

ISO-NE spokesperson Matt Kakley noted that the 2023 analysis "showed numerous benefits to consumers and suppliers, as well as market efficiency gains" and said the RTO "has worked closely with stakeholders to provide additional information about the impacts and efficiency gains associated with the move to a prompt auction."

Seller-side Market Power

Also at the MC, ISO-NE economist Andrew Copland provided an update on the RTO's proposal for mitigating seller-side market power.

Similar to the current mitigation rules in the FCM, ISO-NE would require capacity resources to submit a cost workbook to the Internal Market Monitor if they offer above a price threshold, which the RTO defines as "the average of two prices: (i) the previous capacity clearing price and (ii) the price on the upcoming auction's [marginal reliability impact] demand curve corresponding with the previous auction's total cleared" capacity supply obligation (CSO).

Resources bidding above this threshold that fail both an IMM pivotal-supplier test and a contact test are subject to a binding price determined by the Monitor.

Copland said ISO-NE does not plan to change the "underlying cost review threshold methodology" for the threshold but will propose to change the name of the threshold from the "dynamic de-list bid threshold" to the "capacity offer price threshold."

Andrew Gillespie, director of governmental and regulatory affairs at Calpine, pushed ISO-NE to update its methodology for calculating the cost review threshold. He said the existing method is "somewhat backward-looking as it relates to changing market conditions" and could lead to the threshold being set at an artificially low level in future auctions.

Gillespie noted that ISO-NE would determine the threshold for its first prompt auction about five years after the most recent Forward Capacity Auction. He pointed to the multiple significant capacity scarcity events that have occurred since this auction and said high-performance penalty costs incurred during them could put significant upward pressure on capacity prices in future auctions.

Instead of relying on past auction results, Gillespie recommended that ISO-NE base the threshold on the "common value component," which is calculated by multiplying the expected number of hours with capacity conditions by the expected balancing ratio and the performance payment rate.

"The common value component is the lowest competitive bid, and hence the threshold should be no lower than that," Gillespie said.

He said this methodology would be more forward looking and would avoid issues associated with adapting historical data to the new prompt-seasonal format.

The proposal was well received by multiple stakeholders at the meeting, while ISO-NE expressed concern about challenges and complications related to relying on expectations for capacity scarcity hours and the balancing ratio. The RTO reiterated that it does not plan to overhaul the threshold methodology as a part of the CAR project but said more discussion on the threshold will be needed during the second phase of the project to prepare for a seasonal auction design.

Noncommercial Capacity

Under the new capacity market format, ISO-NE would not differentiate between new and existing capacity resources, and all new resources would have to demonstrate they have reached commercial operations to participate in capacity auctions.

The RTO previously has allowed noncommercial resources to participate in FCAs, which were held over three years prior to each CCP. Under the FCM rules, new resources are subject to critical path schedule (CPS) monitoring, allowing the RTO to track their progress toward reaching commercial operations.

At the MC meeting in July, ISO-NE said it plans to continue CPS monitoring until mid-2028 for noncommercial resources that received CSOs in past FCAs. (See *NEPOOL Markets Committee Briefs: July 8-9, 2025*.)

The RTO changed its proposal at the MC meeting in August and now plans to continue CPS monitoring "until all projects on monitoring are either completed, withdrawn or terminated," said Matt Brewster, senior manager of capacity requirement and qualification at ISO-NE.

Brewster said the approach "seeks to accommodate decisions made by participants under the current rules and facilitate the move to commercial-only participation in the prompt market."

He noted that, starting with the 2028/29 period, "capacity on CPS monitoring cannot acquire CSO for any additional CCP until it is commercial."

Also at the MC, Brewster discussed ISO-NE's planned approach toward resource repowering and material modifications. He said qualified capacity would generally be based on a resource's performance from the past five years, and ISO-NE plans to largely maintain existing processes for "reflecting measurable increases or decreases in capability and changes to technology, characteristics or composition."

For resources that can demonstrate increased or decreased capacity compared to the historical data prior to each annual auction, ISO-NE will update the lookback period "to exclude data for periods preceding the change," he noted.

In cases of modifications to a resource's technical characteristics, such as a change to its intermittency, ISO-NE would require resources to submit data on the modification "for the next annual or monthly qualification process," Brewster said. ■

FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States

By Amanda Durish Cook

FERC said MISO should spread the costs of keeping a Michigan coal plant running past its retirement date over the RTO's entire Midwest region.

The commission issued an Aug. 15 decision on the cost allocation of the J.H. Campbell coal-fired power plant, which is slated to run through Aug. 21 on an order from the U.S. Department of Energy. The plant originally was scheduled to wind down operations May 31. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

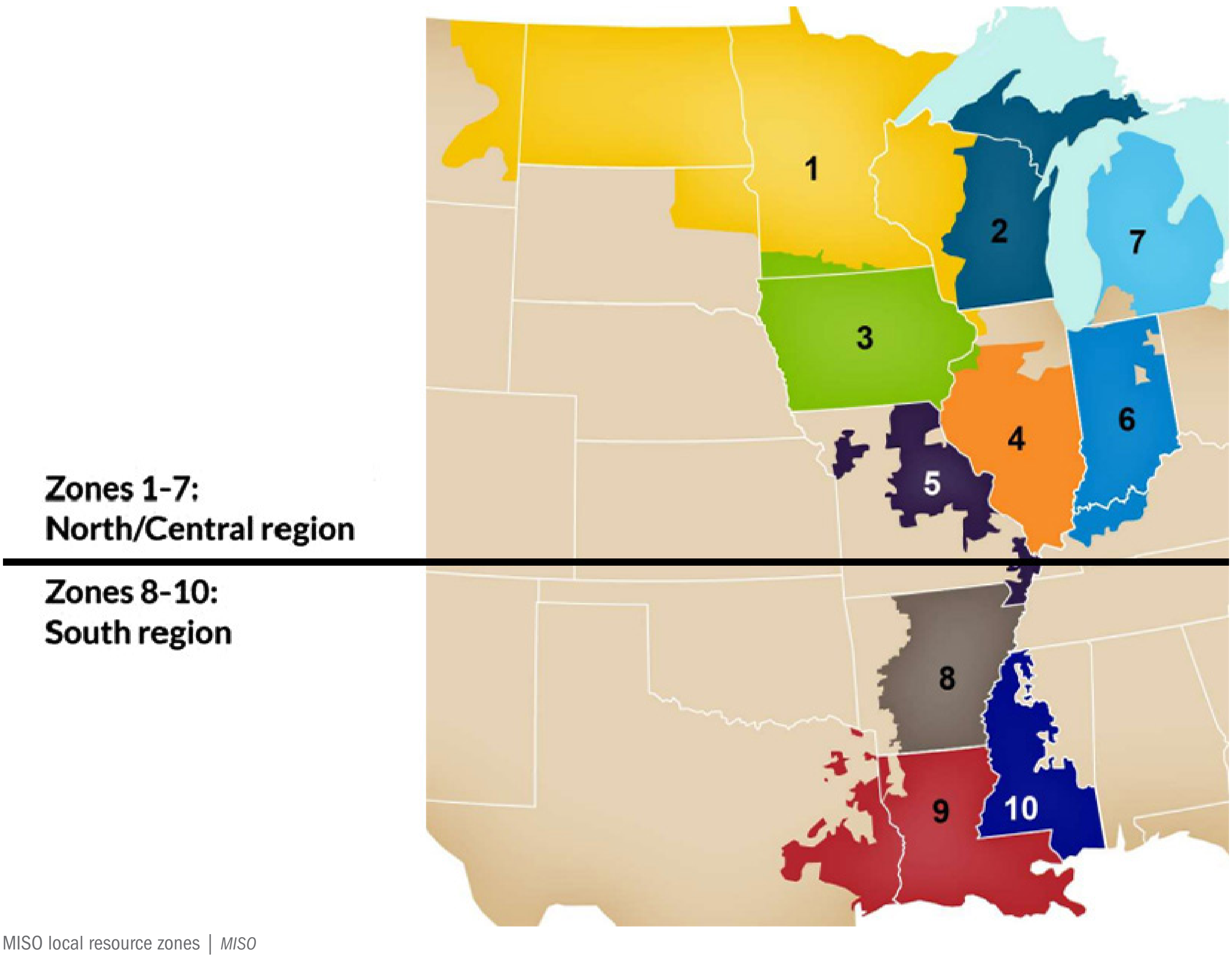
FERC said it's appropriate that MISO split the costs of running the plant on a load ratio share among local resource Zones 1-7, which includes Wisconsin, Minnesota, the Dakotas, a section of Montana, Iowa, parts of Missouri, downstate Illinois, Indiana and a slice of Kentucky in addition to Michigan (*EL25-90*).

FERC said the allocation design is in line with its cost causation principle, reasoning that the cost split would "allocate costs in accordance with the scope of the emergency as described by the DOE order."

"We acknowledge that parties have presented different interpretations of how the DOE order defined the geographic scope of the emergency. However, we find that the most reasonable reading of the DOE order's intended scope is that the emergency necessitating the continued operation of the Campbell Plant is in the MISO North and MISO Central

What's Next

FERC directed MISO to draft a compliance filing within a month to enact the new allocation. It also told the RTO to define a load ratio share and how it plans to calculate each load-serving entities' load ratio share.



MISO local resource zones | *MISO*

regions, i.e., local resource Zones 1-7," FERC said.

Plant owner Consumers Energy asked the commission for a Zone 1-7 rate recovery, claiming beneficiaries could be found among all Midwestern zones. However, Great River Energy and various public interest organizations argued that load-serving entities in Zones 1-7 already met their resource adequacy requirements, as evidenced by MISO's 2025/26 Planning Resource Auction and would not benefit from bonus capacity from the Campbell plant. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Great River Energy argued the DOE mandate focused on the local impacts of generation retirements, which should mean that costs of the plant fall to Michigan's Zone 7 alone. It said, "allocating costs of complying with the DOE order beyond Consumers' own load is not supported by the cost causation principle."

Michigan Attorney General Dana Nessel contended that the DOE order applied to the whole footprint and FERC should order a cost allocation that includes MISO South.

But FERC said it relied on the DOE citing a MISO presentation of the 2025/26 PRA results, where MISO said that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspension/retirements and external resources" in MISO Midwest. The commission said it seemed resource adequacy concerns in the subregion drove the DOE to issue the order.

FERC directed MISO to draft a compliance filing within a month to enact the new allocation. It also told the RTO to define a load ratio share and how it plans to calculate each load-serving entities' load ratio share.

According to a recent Securities and Exchange Commission filing from Consumers Energy, J.H. Campbell cost $29 million to run from May 23 to June 30. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month*.)

The commission declined to grant the Organization of MISO States, the Illinois Attorney General and the Illinois Commerce Commission's request that it instruct MISO to initiate stakeholder discussions on who should foot the bill for the plant's extension. FERC said further procedure was unnecessary.

FERC also rejected requests to delay its cost allocation decision until rehearing requests on the DOE's mandate are resolved.

"We find that arguments against adoption of the proposed tariff provision, such as that imposing the costs of keeping the Campbell Plant in operation violates the tariff and the [Federal Power Act] if the DOE order is deemed unlawful are beyond the limited scope of this proceeding and were not referred to the commission by DOE," FERC wrote.

FERC similarly refused to address the creation of a provision to refund upgrade costs recovered under the cost allocation should the Campbell plant be subject to another stay-open order beyond Aug. 21. It said any such potential procedure was outside the "limited" nature of the allocation docket.

FERC also appeared to cover its bases should the DOE's order for the coal plant to keep operating not hold up in court.

"While this order approves the cost allocation methodology in the proposed tariff provision, it does not approve recovery of actual costs," FERC said.

FERC said Consumers Energy needs to petition it in a separate proceeding "at a later date" for approval to recover costs associated with the DOE's order "before ratepayers can be charged for such costs."

"Parties may raise issues related to the scope of costs prudently incurred pursuant to the DOE order in that proceeding," FERC said. It added that parties to the complaint could "take appropriate steps, such as requesting rehearing in this proceeding, to preserve arguments" that FERC should order refunds should the DOE order be modified, or "otherwise revisit its approach to matters that DOE referred to the commission in connection with the DOE order." ■

MISO States Split on FERC Complaint to Unwind $22B Long-range Tx Plan

By Amanda Durish Cook

Members of the Organization of MISO States are divided on whether the organization should register comments in a FERC complaint that could fundamentally change the way MISO can plan its long-view transmission.

The rift among the states shows how contentious the late July complaint is.

The public service commissions of North Dakota, Montana, Mississippi, Louisiana and Arkansas have sought reclassification of MISO's $22 billion, mostly 765-kV second long-range transmission portfolio and have contested the RTO's business case for the lines through a FERC complaint. The complaint could have FERC halting a regional cost-sharing of the lines across MISO Midwest and could upend MISO's long-range planning process. (See *Five Republican States File FERC Complaint to Undercut $22B MISO Long-range Tx Plan*.)

FERC has allowed MISO until Sept. 9 to respond to the complaint, 10 days shorter than the monthlong extension MISO originally requested. (See *MISO Requests Month to Respond to States' Long-range Tx Complaint*.)

Organization of MISO States Executive Director Tricia DeBleeckere said the complaint positions OMS in a tough spot because five OMS members lodged the complaint in the first place.

DeBleeckere suggested that OMS refrain from filing comments in the docket but said she would defer to what a majority of members want.

OMS President Asks States to Back MISO Planning

Joseph Sullivan, president of the Organization of MISO States and vice chair of the Minnesota Public Utilities Commission, said he'd like to see OMS membership who didn't bring the complaint file comments defending MISO's planning process.

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Notable Quote

"Now, there are different ways to do cost-benefit calculations. But this is coming nine months after MISO approved the lines in December 2024 and more than a year and a half after it was clear that this would be the approach."

Joseph Sullivan, president of OMS and vice chair of the Minnesota PUC, on the five states' complaint against MISO's second LRTP

"I would like to see if we can get to a majority to file comments in support of the process. Now, there are different ways to do cost-benefit calculations. But this is coming nine months after MISO approved the lines in December 2024 and more than a year and a half after it was clear that this would be the approach," Sullivan told other regulators at an Aug. 14 OMS Board of Directors meeting.

Sullivan said regulators should remember that the lines are meant to accommodate load growth and economic development while modernizing the MISO system. He said even if the ensuing portfolio isn't exactly what some states had in mind, MISO states agreed to the MISO process. He added that MISO is an outlier among other RTOs for successfully planning long-range transmission.

"We are the only region that succeeds at this, and that's because we are working together. [That's] in no small part because of OMS," he said.

Sullivan pointed out that OMS in 2019 adopted principles on how MISO should approach long-range transmission planning and followed up in 2021 with a cost-allocation principles document and a filing in support of MISO's postage-stamp-to-load allocation design. He said MISO's resulting, second long-range portfolio is "consistent" with the OMS principles.

Sullivan said the five states' request that MISO going forward submit future long-range transmission business cases to FERC for approval would be "a pretty significant federal takeover of state resource adequacy and utility planning in the modern age."

"A purist may say 'not so,' but in the age of RTOs, that is exactly what this is. We all rely on each other and having the FERC say yes or no is something we should push back vigorously on. Fundamentally, this process is the culmination of the MISO stakeholder process and the aggregation of state and utility resource plans," he said.

Sullivan said he hoped the remaining OMS members could band together in opposition against the complaint. He said OMS members should all be thinking about the "practical knock-on-effects" should FERC grant the complaint.

The second long-range portfolio already is included in all MISO modeling, Sullivan said, including expedited transmission project review, the 2022 cycle of generator interconnection requests and the interconnection queue fast lane.

"So, there will be major upheavals impacting potentially hundreds of projects, many already approved by our commissions. … Because this filing was so late in the process, it will have massive effects on everything we have already done — much of it to meet the moment on artificial intelligence, data centers, load growth and re-industrialization," Sullivan warned.

Wisconsin Public Service Commissioner Marcus Hawkins said he would support a majority OMS filing on the complaint, or a filing from a subset of MISO states.

States that brought the complaint forward opposed a majority filing from OMS in the docket.

Barton Norfleet, counsel for the Mississippi Public Service Commission, said he thought OMS should sit this docket out. Noel Darce, counsel for the Louisiana Public Service Commission, also agreed that comments should come from individual states, not the organization itself.

South Dakota Public Utilities Commissioner Chris Nelson said his commission is holding off on communicating a position on the complaint and would weigh making a filing once MISO has responded.

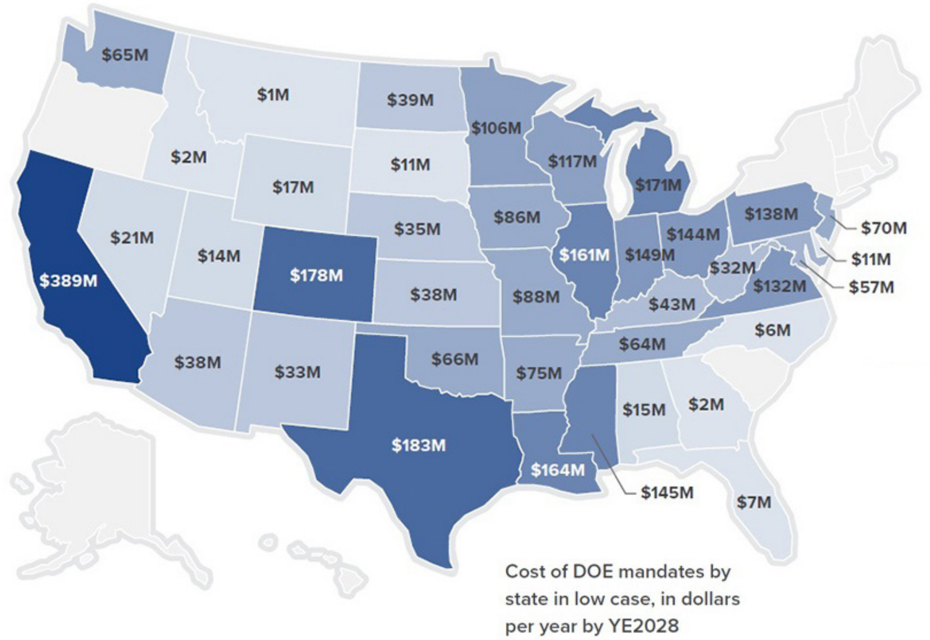
"This is a really divisive issue," Nelson said.

North Dakota Public Service Commissioner Jill Kringstad said North Dakota has long communicated its disillusionment with the MISO portfolio. She said North Dakota is exercising its right to have FERC take an "objective" view at the long-range transmission.

Sullivan said he thought states and OMS board members should "find the common denominator over the next couple of weeks and develop a set of baseline comments defending the process." ■

New Report: Consumers Could Pay $3B More Annually if DOE Stay-open Orders Persist

By Amanda Durish Cook



Grid Strategies' estimated cost of possible DOE stay-open mandates per state by the end of 2028 | *Grid Strategies*

A new Grid Strategies report concludes that if the U.S. Department of Energy continues to supersede retirement decisions for fossil-fueled power plants, it could cost consumers an extra $3 billion annually in a little more than three years.

The report, "*The Cost of Federal Mandates to Retain Fossil-Burning Power Plants*," said if the DOE's trend of stay-open orders persists, it could affect the 34.95 GW of large fossil power plants scheduled to retire between now and the end of 2028.

The Aug. 14 report estimated the cost of DOE mandates on the almost 35 GW of generation could climb to $260 million due monthly by January 2029.

Author and Grid Strategies Vice President Michael Goggin said added costs could surge to nearly $6 billion per year at the end of 2028 if owners of other aging power plants, enticed by revenue guarantees associated with the DOE's mandates, announce earlier retirement dates.

Environmental nonprofits Earthjustice, Environmental Defense Fund, Natural Resources Defense Council and Sierra Club commissioned the report after the DOE in May issued two mandates to keep Constellation Energy's Eddystone oil and gas power plant in Pennsylvania and Consumer Energy's J.H. Campbell coal plant in Michigan operating about three months past their announced retirement dates. (See *DOE Orders PJM, Constellation to Keep 760-MW Eddystone Generators Online* and *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

"Based on the trend to date and indications that DOE has approached the owners of many retiring fossil power plants about potentially mandating their retention, DOE may attempt to mandate the retention of nearly all large fossil power plants slated for retirement between now and the end of 2028," Goggin wrote.

The report used the 34.95 GW slated for retirement in a low-end estimate and 66.34 GW in a high-end estimate, in which it assumed other plants would announce accelerated retirements.

To arrive at the 66 GW tally, Grid Strategies combined the 35 GW in confirmed announcements with another 31.39 GW of fossil fuel generation across 36 plants that are at least 60 years old.

The nearly 35 GW figure did not include the little more than 8 GW of retiring fossil plants that have at least some replacement fossil capacity planned on site. It also excluded about 310 MW of retiring fossil plants that are smaller than 50 MW.

The report said in all, the DOE could deliver mandates to 90 aging power plants across the country.

Grid Strategies noted that MISO's median retirement age for its coal plants is around 60 years, while data from the U.S. Energy Information Administration pins the median age of coal plant retirement at 54 years in 2024. Goggin wrote that the 60-year age screen "should provide a conservative estimate of the total fossil capacity that is likely to retire."

Grid Strategies used an average $89,315/MW-year cost of keeping a plant open, bringing the total annual ratepayer cost by the end of 2028 to $3.121 billion in the low gigawatt estimate and $5.925 billion in the high estimate.

The consulting firm calculated a weighted average cost of recent reliability-must-run (RMR) contracts across the country to come up with the $89,315/MW-year value. It reviewed RMR contracts for Brandon Shores, Wagner and Indian River in PJM; Lakefront Unit 9 and Rush Island in MISO; Braunig Unit 3 in ERCOT; and six units including Midway in CAISO. Contract costs ranged

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The Bottom Line

Consulting firm Grid Strategies' new analysis finds that consumers could be paying an extra $3 billion per year by the end of 2028 if the DOE mandates keeping open the nearly 35 GW of fossil fuel plants set to retire soon.

DOE Environmental Review of Grain Belt Express Devalues Line's Carbon-cutting Ability

By Amanda Durish Cook

Drafted during a different presidential administration, the Grain Belt Express' final environmental impact statement downplays the potential environmental benefits of the line.

The Trump administration's U.S. Department of Energy Loan Program Office released the final review days after withdrawing a $4.9 billion conditional loan commitment for the 800-mile HVDC line. (See *DOE Pulls $4.9B in Funding for Grain Belt Express*.) Line owner Invenergy has vowed to move ahead with the project.

While the final *impact statement* finds the same adverse impacts to soil, vegetation, land, recreation and water and points to mitigation on Invenergy's part, the completed document also diminishes the emissions that Grain Belt could avoid or reduce from 2.8 to 3.1 million tons to just 175,000 metric tons annually. The 175,000-ton figure is based solely on a 3% percent transmission efficiency improvement that the line, at a capacity of 2,500 MW, would foster through decreased line losses.

The DOE erased a draft finding that an alternative scenario where Grain Belt is not built "would not support" the Biden administration's circa-2021 target to cut greenhouse gas emissions anywhere from 50-52% from 2005 levels by 2030. The department also excised sections of the more than 440-page report that assumed the line would help new renewable energy projects access the grid, potentially avoiding up to a cumulative 5.15 million tons of greenhouse gases annually while supporting 3 GW of new renewable generation capacity.

The Bottom Line

The DOE has revised the Grain Belt Express' greenhouse gas reduction potential from from 2.8 to 3.1 million tons annually to just 175,000 metric tons per year. The department only considered line loss improvements to come up with the new figure.

Instead, the DOE emphasized that Grain Belt cannot discriminate between coal, natural gas or renewable resources when

Grain Belt Express route map | *Invenergy* deciding whose power to transmit. It said it expected the line to carry "diverse power mixes," including existing baseload and dispatchable energy facilities.

"Following publication of the draft [environmental impact statement] in January 2025, a number of policies were enacted that facilitate the development of baseload and dispatchable energy. It is too soon to foresee the impact that these policies may have on market conditions and demands for certain types of energy in the vicinity of the project," the DOE said.

The agency deleted a previous finding that there would be a "significant cost barrier for any new or existing coal generation projects to tie into the project" and struck a note that no new natural gas generation projects are planned to be built near the point of injection.

It also nixed an explanation that HVDC technology doesn't "easily allow" for new connections along the line without building intermediate converter stations, "which requires significant modifications to the overall design as well as notable increased costs."

The DOE edited out a scenario in the draft report where the agency assumed the line wasn't built because it refused to provide federal financial support to Invenergy.

The department also deleted more than 20 pages on environmental justice considerations, since environmental justice factors now are outside the scope of the environmental review under the National Environmental Policy Act, pursuant to President Donald Trump's executive orders. It scrapped all mentions of the DOE's discontinued Climate and Economic Justice Screening Tool that helped track effects on disadvantaged communities.

Grain Belt's draft environmental impact statement paid special attention as to whether minority and low-income communities would experience about the same construction disruption as wealthier counterparts. The DOE in early 2025 concluded in the draft document that the line wouldn't disproportionally burden low-income populations.

The DOE eliminated instances of "climate change" from the final report and deleted sentences pondering the potential for more intense weather to affect Grain Belt facilities once built. It also removed references to EPA's 2022 finding that human-driven greenhouse gas emissions are the "leading cause of the Earth's rapidly changing climate." ■

New Report: Consumers Could Pay $3B More Annually if DOE Stay-open Orders Persist

Continued from page 24

from $49,858/ MW-year for Wagner to $167,619/ MW-year for Lakefront Unit 9.

Goggin said the contract costs should provide a reasonable proxy for ratepayer subsidies paid out under DOE mandates. However, he acknowledged that the first two plants to be kept online are in uncharted territory, with "scant precedent for determining ratepayer subsidy costs for keeping plants open past their scheduled retirement date" due to DOE intervention.

Consumers Energy reported that the J.H. Campbell plant accumulated $29 million in costs after a little more than a month of extended operations. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month*.) Goggin said if that "cost trend were to persist, that would translate to $279 million in annual cost or $178,559/ MW-year, almost exactly twice our estimate."

The report also noted that the *Citizens Utility Board* estimates the cost for the Campbell and Eddystone plants at a weighted average annualized cost of $181,200/MW-year, more than twice the report's estimate.

Grid Strategies determined that California has the most to lose in the low-end estimate, at an annual cost of $389 million by the end of 2028. Texas and Colorado follow at $183 million and $178 million, respectively, per year. Michigan, Louisiana and Illinois — all MISO states — also would register noteworthy costs at $171 million, $164 million and $161 million, respectively.

The report assumed that states that don't contain plants slated for retirement, including the six New England states, New York, Hawaii, Alaska, Oregon and South Carolina, would be unaffected by DOE stay-open mandates in the low-end scenario. In all, it said ratepayers in 39 states and the District of Columbia stand to incur costs if the DOE doles out mandates to all plants currently counting down to a retirement date.

The analysis assumed plants don't begin receiving funds to stay open until a month after their scheduled retirement. Goggin noted that the DOE could issue mandates earlier than that.

Grid Strategies said it chose to include potential plants that aren't yet slated for retirement in the high estimate because the DOE's actions could create a "perverse incentive" for plants to declare earlier retirements, so they're paid to remain open.

"This perverse incentive is what economists would call a moral hazard," Goggin wrote.

Goggin wrote that the report's eye-popping cost estimates conflict with the April presidential *executive order* that charged the DOE with issuing mandates, which emphasized rising demand from AI data centers and domestic manufacturing and protecting the "the national and economic security of the American people." Goggin said it's "intuitive and inherent" that the DOE keeping plants operating would drive up customer bills.

"Power plants have been slated to retire because their owners and state regulators have determined they are no longer economic or needed. DOE mandates override those well-informed decisions, inflating electric bills for homeowners and businesses and undermining the competitiveness of U.S. factories and data centers," the report said. ■

Members Say MISO RA Better off Under Seasonal Capacity Auctions, Sloped Curve

By Amanda Durish Cook

MISO members largely agreed that MISO's new capacity auction structure — featuring individual seasonal auctions and a sloped demand curve — is better for the health of the system.

MISO's Advisory Committee said the 2025/26 Planning Resource Auction (PRA) results from April likely show that future auctions would spur more actions to sustain reliability. The Aug. 13 talk via teleconference was part of the committee's "current issue" series.

Wisconsin Public Service Commissioner Marcus Hawkins said the auction is "paying dividends and supporting reliability in a major way."

"I think we're seeing those signals play out to retirement decisions," Hawkins said.

MISO's 2025/26 auction cleared at a record-breaking $666.50/MW-day for the summer season as members claimed 1.9% above the 7.9% summer planning reserve margin requirement. The padding in cleared reserves occurred even as MISO experienced a steady decline in spare capacity.

MISO's 2025/26 surplus was 2.6 GW, a drop of 43% compared to the 4.6-GW surplus of summer 2024 and much lower than summer 2023's 6.5-GW excess. More than 90% of load was secured before the voluntary auction. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

The 2025/26 auction was the second to feature offers divided by seasons and the first to ditch MISO's vertical demand curve, which foreclosed the option for additional capacity beyond the reserve margin to hold value.

John Wolfram, representing MISO transmission owners, said the narrowing summertime capacity stores evidenced by the auction should send good signals to members for "firm capacity resource development" and generation retirement delays.

Why This Matters

About four months after MISO's revamped capacity auction, the Advisory Committee weighed in on how auction performance is set to help the footprint.

We Energies announced in June that it would delay retirement of its Oak Creek Power Plant for another year into 2026. | *Bechtel*

Sharon Segner, senior vice president for competitive transmission developer LS Power, agreed that MISO's system tightness today means that developers and stakeholders must ensure that "what is planned for the system gets online in time."

But Sam Lukens, of the Illinois Office of the Attorney General, said the premium put on capacity is due largely to expected large loads from data centers and raises the question of whether consumers should bear the added costs.

Lukens said MISO should consider holding meetings to discuss whether consumers should be shielded from the costs of added demand on the system. He said the cost-causers should pay for the demand they introduce on the system.

"I still think the PRA is a short-term signal," Lukens said. "There needs to be more discussion about how these large load forecasts are influencing consumers. In Illinois, consumers are really feeling the impact of the PRA."

Attorney Jim Dauphinais, representing multiple industrial end-use customers, said the auction results and prices "properly" sent "a signal that capacity supplies are diminishing." However, he said MISO's preliminary public auction data communicated a significant shortfall, which thankfully didn't pan out.

"We think the preliminary PRA data needs to be looked at more carefully," Dauphinais suggested. He said more accurate data would give members better indication on how to prepare. ■

MISO Could Replace Up to 3 Board Members by Year End

By Amanda Durish Cook


The MISO Board of Directors meets December 2024 in The Woodlands, Texas. | © *RTO Insider*

MISO might replace up to three members on its board of directors as they reach term limits at the end of 2025.

Board members Todd Raba, H.B. "Trip" Doggett and Barbara Krumsiek are to conclude their third and final terms at the end of 2025. Though they're term-limited, all have expressed interest in serving a maximum fourth term that is allowable through a special waiver of MISO's rules. (See *Extensions Likely for MISO's Term-limited Board Members*.)

MISO's Nominating Committee has said it may decide to use the waiver provision for the exiting directors to retain members' expertise and prevent too much board turnover from one year to the next.

During an Aug. 13 MISO Advisory Committee teleconference, Nominating Committee member Brian Drumm, of ITC, said Chicago-based search firm Russell Reynolds Associates in the spring presented 20 external board candidates. The Nominating Committee first narrowed that slate down to seven external candidates to be considered alongside the three incumbent directors. Drumm said that after interviewing the three incumbents and seven external candidates in July, the Nominating Committee has assembled a slate of two director candidates for each of the three open Board positions. He declined to comment during the meeting on whether the Nominating Committee is recommending any waivers at all.

The Bottom Line

MISO's Nominating Committee has said one or two of the three MISO directors hitting their term limits could stick around through 2028 through a special waiver. That may leave up to two slots for fresh faces on the Board of Directors at the beginning of 2026.

Drumm said some Advisory Committee representatives had opposed use of the waiver or had said one to two waivers are necessary to avoid excessive board member attrition. Drumm said names of outside candidates remain confidential. He said stakeholders would learn more during MISO Board Week in mid-September in Detroit.

MISO Board Chair Raba said in June that MISO's Nominating Committee had a lot of work ahead of it to make decisions on who might stay to serve a fourth and final three-year term and how many fresh faces could earn a spot on the board.

The Nominating Committee is charged with vetting and selecting MISO Board of Director candidates, who are put to a vote of membership. The committee's members change annually, and the committee is composed of three MISO board members and two MISO stakeholders, one of whom typically is from a state public service commission. This year, directors Bob Lurie, Jeff Lemmer and Nancy Lange sit on the Nominating Committee alongside Drumm and Illinois regulator Michael Carrigan.

Elections for MISO's Board of Directors are held in the fall, with the Nominating Committee advancing one candidate per open seat. MISO members vote electronically on whether they support the candidate. MISO's board elections require candidates to earn a majority of votes in support among membership. MISO members can vote for or against or abstain from selecting any of the candidates. The elections require a minimum 25% participation rate among the voting-eligible members of MISO's 197 members to achieve a quorum. ■

Nexamp Complains of Unfair IC Cost Increases by National Grid

By Vincent Gabrielle

Community solar developer Nexamp has filed a complaint against National Grid with the New York Public Service Commission accusing the utility of unfair price increases and violating state interconnection process agreements (*25-E-0469*).

The Boston-based company contested about $3.6 million in additional interconnection costs for 14 projects that it says is a 52% increase over what it originally was quoted by the utility. It asked the PSC to "scrutinize" National Grid's interconnection practices and policies, alleging widespread impacts across all developers.

"Nexamp anticipates receiving similarly egregious and improper final reconciliation invoices for 41 additional Nexamp-owned solar projects in various stages of development with National Grid," it said in its 27-page complaint, filed Aug. 7.

Why This Matters

The complaint alleges that National Grid violated New York PSC requirements for distributed energy resource interconnection.

The company said the cost increases were driven by National Grid's reliance on external contractors that caused final labor costs to "more than double" over the original estimates. It also said the utility had an "egregious disregard" for the PSC *regulations* setting a 60-day deadline for issuing reconciliation invoices.

The projects range from 2.3 to 5 MW, totaling over 61 MW of solar capacity, and took about three to five years to develop. Most received permission to operate (PTO) in late 2024.

"The projects were all in National Grid's queue for multiple years prior to PTO, raising legitimate concerns about National Grid's inability (or neglect) to manage its queue in a manner that would have avoided (or at the very least mitigated) the need to mobilize external contractors at the scale and expense that National Grid claims here," the company said.

The company also complained that National Grid was using stale material cost data and potentially double charging for taxes.

Nexamp did not respond to a request for comment. National Grid declined to comment.

Nexamp calls itself the largest community solar developer in the U.S., operating 1 GW of projects nationwide and 400 MW of solar and storage in New York. The company says it has 250 MW of assets under development. ■

King Road solar farm in Middletown, N.Y. | *Nexamp*

New York PSC Denies NYPA's Clean Path Transmission Priority Status

By Vincent Gabrielle

> **Why This Matters**
>
> The New York Power Authority attempted to save the Clean Path project by filing for priority status with the Public Service Commission. The denial may be the end for the project.

The New York Public Service Commission has denied the New York Power Authority's petition to grant the Clean Path New York transmission project priority status, finding that the utility did not demonstrate it would relieve congestion (*20-E-0197*).

Instead, the PSC said, NYPA relied "on a recitation of the state's future needs for renewable generation and the presence of a significant amount of proposed projects in the NYISO interconnection queue to justify designating the project as a" priority transmission project (PTP).

"NYPA does not provide any evidence of existing congestion and does not even meet the standard … for establishing a need to unbottle renewable resources," the PSC wrote in its Aug. 14 ruling. "This approach overlooks the [PSC's] emphasis" in its criteria for identifying PTPs "on the need to unbottle existing generation, and therefore misses the mark."

| © RTO Insider

The PSC noted that recent NYISO studies and the Coordinated Grid Planning Process do not show Clean Path being needed "expeditiously." It cited the ISO's 2023-2042 System and Resource Outlook, which found that Clean Path would reach only 47% utilization by 2040.

"Even if we assume the project is technically capable of meeting future needs, designating it as a PTP now would mean charging ratepayers for transmission facilities that will not begin conducting significant amounts of generation until a point in the future that may be two decades away," the PSC wrote.

Clean Path originally was an $11 billion project that included transmission and renewable generation components. In 2024, NYPA terminated Clean Path's renewable energy certificate by mutual agreement with the New York State Energy Research and Development Authority. In February 2025, it submitted an updated petition for the transmission portion that came in about $5.2 billion. (See *NYPA Argues Clean Path Potential Benefits Outweigh Cost*.)

The PSC found that Clean Path could not be justified as a near-term solution to the ongoing reliability issues affecting New York City because NYPA's petition did not identify any new renewable generation that would be delivered through it.

"The record does not show that the project will deliver significant amounts of generation output to the New York City grid until the 2040s," the PSC wrote. "If reliability issues arise in the 2030-2035 time frame, the project would not provide a solution."

The project would have included 178 miles of HVDC line between upstate New York and Queens.

The PSC broadly agreed with NYPA that new transmission is necessary but that projects based on "generation to be built in the future" do not rise to the same urgency as unbottling existing generation. The commission also rejected NYPA's argument that the existing planning processes take too long to develop a solution to New York's reliability issues. ■

NYISO OC Approves SIS for Micron Fab Interconnection

ALBANY — The NYISO Operating Committee on Aug. 14 approved the system impact study for the second of Micron Technology's semiconductor chip manufacturing centers slated to begin construction *later in 2025* in the town of Clay, N.Y.

Micron's facilities, also known as fabricators (or "fabs"), are a major contributor to the forecasted load growth in New York state, according to NYISO. This facility, "Fab 2," will draw 576 MW from the grid. When combined with another fabricator at the same site, the total load will be 1,056 MW. Two other fabricators are also planned at the site over the next 20 years.

Clay is a mostly residential suburb of Syracuse with a population of roughly 60,000, according to census data. Micron's facility will be the largest electric customer in the town by far. When completed, the chip factory will be the largest manufacturing facility in Onondaga County.

The SIS found that the Micron facility will require upgrades to the local grid. Overloads would occur on several local 245-kV lines and substations, so a new substation will be needed. The study also found voltage transfer degradation, which would require upgrades to nearby interfaces.

National Grid estimated that $139.7 million in network upgrades are required, and the new substation will cost $122.2 million. Other upgrades to nearby transmission interfaces would total about $17 million.

The OC also approved eight SIS scopes, all for data centers spread out across the state. If completed, these data centers would collectively draw over 2,100 MW from the grid. ■

— Vincent Gabrielle

Rendering of Micron's planned semiconductor fabrication facility | *Micron Technology*

NYISO BIC Dissects Power Prices During June Heat Wave

July Ops Report Discussed

By Vincent Gabrielle

Shutterstock

NYISO shared a detailed *analysis* of New York's late June heat wave, in which significant operating reserve shortages elevated energy prices.

"We had committed mostly everything that was available on the system, as well as the fact that we went short on reserves throughout the [state] for the peak hour," Nate Gilbraith, manager of energy market design for NYISO, told the Business Issues Committee on Aug. 13. "That means the day-ahead market did not procure the full 2,620-MW reserve requirement."

NYISO was short about 300 MW of reserves. The real-time market scheduled energy that did not have a corresponding day-ahead energy schedule to meet the needs because the day-ahead market did not "foresee" scheduling needs, Gilbraith said.

Real-time load exceeded the day-ahead forecast and market expectations. Imports from other regions, also affected by the heat wave, were much lower. Some generators experienced outages and derates, with some of those because of the heat wave. Actual load increased real-time market needs by over 900 MW. (See *NYISO Issues Energy Warning as Heat Wave Boils New York*.)

"What I am hearing you say is, as a consequence of having a tighter system, [reserves] aren't there anymore as something that can be grabbed when you need them," said Doreen Saia, chair of Greenberg Traurig's energy and natural resources practice. "So we need to be much more purposeful when we're looking at the day-ahead forecast."

"I'll say it back to you in another way: I think we need to make sure our operators have the tools to ensure reliability in real time," Gilbraith said. "The fact we came out of the day-ahead market a bit short raises some questions … with how we set our market rules."

In some areas, transmission flows met or exceeded facility ratings, causing transmission shortage pricing to occur. This was particularly acute on Long Island, where congestion exacerbated already high statewide prices. On June 24, during the peak evening hours, statewide prices were $2,000 to $3,000/MWh. On Long Island, prices exceeded $7,000/MWh.

A stakeholder asked whether there was more information on how much behind-the-meter solar and special-case resources contributed to load reduction. Gilbraith said that beginning at 6 p.m., BTM solar dropped off very rapidly and so did not contribute as much. Additional analysis of SCRs will be forthcoming, he said.

Stakeholders also asked why neighboring regions did not provide imports as expected. This was in part because the weather was much hotter than forecasted across multiple footprints.

"What we saw on this day was really across the entire Eastern Seaboard," Gilbraith said. "So everyone is now in a situation where they do not have their reliability reserve requirements. … It was one of those emergency drills that we run through that you don't ever want to actually be in."

July Market Performance

NYISO also presented its *July market performance report* to the committee. The locational-based marginal price for July was $78.89/MWh, higher than the $58.96/MWh seen in June and far higher than the $47.42/MWh seen in July 2024.

Natural gas prices and distillate prices were both higher than in June. This was the largest driver of price increases in New York, according to the ISO.

NYISO noted that for the past couple of months, there have been overestimations in BTM solar forecasts relative to the actual power they provided. Some of this is because of smoke from the Canadian wildfires. The ISO is working on figuring out how much of the overestimation is from the smoke compared to forecasting issues. ■

The Bottom Line

Neighboring RTOs cut back on interregional transactions during the heat wave at the same time as operating reserves were tight.

N.J. Puts on Hold Remaining Pieces of $1.07B OSW Transmission Project

Postpones Infrastructure Work by 30 Months

By Hugh R. Morley

Bringing to a halt two major outstanding elements of New Jersey's once-aggressive offshore wind plans, the state Board of Public Utilities postponed by 30 months all activities on onshore infrastructure intended to connect the wind farms to the grid.

The three BPU board members voted unanimously to delay all possible expenditures on the $1.07 billion project, which was approved in October 2022 and would deliver 6,400 MW of offshore wind generation. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.) Two seats on the five-member board are vacant after Commissioner Marian Abdou stepped down in July.

The project, at its outset, was widely seen as groundbreaking because it was conceived under FERC Order 1000's State Agreement Approach, which enabled the BPU and PJM to work together to shape the plan. The project included three points of interconnection on Jersey Central Power and Light's transmission system and included a new substation adjacent to the company's Larrabee substation. BPU officials said at the time the project would save $900 million over a baseline scenario in which the projects were not coordinated.

Genevieve DiGiulio, project manager of offshore wind for the BPU, said that once the 30-month hold is over, there is a specific schedule for the projects to move forward. The BPU board at that time, however, will decide what happens next, she said.

The three commissioners also voted unanimously Aug. 13 to accept a request by Atlantic Shores, the state's only remaining active wind project, to terminate its Wind Renewable Energy Agreement with the BPU. The project developer in June said it would put the 1.5-GW project on hold because of opposition from the Trump administration. (See *Developer Shelves Atlantic Shores, Seeks to Cancel ORECs*.)

"Obviously some federal uncertainty has created a situation where we need to make sure that we're acting in a way that we always do what's in the best interest of ratepayers," said BPU President Christine Guhl-Sadovy. "And so this, along with some of the other actions today, are in response to some of those federal decisions around clean energy."

The New Jersey League of Conservation Voters, saying the decision was a result of "President Trump's clean energy ban," called it a setback that nevertheless will "not stop our fight for a clean energy future in New Jersey."

"Offshore wind is critical to our clean energy portfolio and to protecting our health, environment and economy. Every delay forces our residents — especially low-income families and communities of color — to breathe dirty air and bear the brunt of climate change," said Ed Potosnak, executive director of New Jersey LCV. "Solar and wind are the cheapest forms of energy, and New Jersey deserves clean, affordable, renewable energy, and we will not stop until we achieve it."

Solar Project Delays

The board also agreed to extend the development deadline for a series of solar projects in the Community Solar and Competitive Solar Incentive (CSI) programs that have been delayed by difficulties with the interconnection process with utilities. The CSI program is a part of the state's Successor Solar Incentive (SuSI) program that sets incentive levels through a bid process for grid-scale projects.

Sawyer Morgan, a project manager in the BPU's clean energy division, said that out of 451 projects in the community solar pipeline and five others in the CSI pipeline, about 160 submitted a request to the BPU for an administrative extension to project completion deadlines.

"The large number of projects entering the program simultaneously resulted in lengthy wait times for completion of facilities or engineering studies," he said.

> **Notable Quote**
>
> "Obviously some federal uncertainty has created a situation where we need to make sure that we're acting in a way that we always do what's in the best interest of ratepayers."
>
> *BPU President Christine Guhl-Sadovy.*

"Stakeholders have reported concerns about the progress of interconnection with EDCs [electric distribution companies] and the opacity and unpredictability of the process."

Most of the delays were created by the slowness in developing engineering studies, Morgan said.

The board agreed to extend the operation deadline for all projects in the two programs by nine months and allowed projects to request an additional six-month extension. The board also agreed to require developers to include a "completed facility study or equivalent feasibility or engineering study" to register a project.

In a bid to move projects forward more quickly, the board also required EDCs to publish a monthly interconnection queue inventory with data including the locations of projects applying for interconnection progress through the process and other requirements.

Commissioner Zenon Christodoulou suggested the BPU needs to orient developers to better handle delays.

"When we talk about unexpected delays, I mean, we've known about interconnection issues for years and years and years," he said. "So these still remain to be issues … but it's still unexpected? I think the developers should understand and should expect this." ■

FERC Partly Grants Complaint on PJM Opportunity Cost Adders

By Devin Leith-Yessian

FERC partly granted a complaint from LS Power challenging the PJM calculation of opportunity cost adders (OCA), requiring operating agreement (OA) revisions to more thoroughly document the inputs and algorithms behind the OCA.

The adder is a component of the cost-based offers that resources submit in the energy market and aims to capture the revenues that may be missed out on if a resource with limited run hours is dispatched when prices are low (*EL24-91*). The commission wrote that market participants do not have adequate information to determine whether their OCAs are accurate and account for all factors that may limit when a resource can be operated.

The order requires that market sellers have access to unit-specific inputs, assumptions and results — including intermediate results; a public posting describing the models and algorithms used in the calculator and hypothetical examples showing how they function; and that the Independent Market Monitor and PJM meet with market sellers on request to discuss assumptions built into the calculator and its results. A compliance filing is required within 45 days of the Aug. 14 order.

"We find that the PJM operating agreement is unjust and unreasonable because it fails to provide market participants with a sufficient level of detail regarding the calculation of OCAs," the commission wrote. "Inaccurate OCAs that are too low (i.e., do not fully reflect the market participant's opportunity costs) could cause resources to prematurely use up their limited run hours when energy prices are lower and render them unable to operate in subsequent periods when prices are higher and they are most needed to provide energy and support the bulk electric system's reliability. As such, accurate OCAs are essential to help ensure the efficient use of energy-limited resources in PJM, support accurate price formation, and increase market participants' confidence in and understanding of how market power mitigation provisions are being implemented."

The complaint, which was filed in March 2024, argued that the Monitor has not provided enough information on its OCA calculator and market participants are not able to replicate its results. In some cases, LS Power said it has identified issues that have led the Monitor to make changes in how it determines the OCA. Overall, however, it argues the Monitor has not engaged in adequate communication with market participants and has been unwilling to make changes when requested. The complaint also argued that PJM's decision to eliminate its OCA calculator in June 2020 and instead rely on the Monitor's calculator should have been brought to the commission as a change to the OA.

| LS Power

Why This Matters

FERC said accurate opportunity cost adders are essential to help ensure the efficient use of energy-limited resources in PJM, support accurate price formation, and increase market participants' confidence in and understanding of how market power mitigation provisions are being implemented.

LS Power wrote that only one pollutant was being modeled for its Chambersburg and Rockford generators, causing their adders to be significantly diminished and resulting in the units being prevented from operating during high pricing periods due to emissions limits on their air permits. It estimated the Rockford adder should have been 25 times higher than what the Monitor calculated. After reporting the issue to the Monitor, the company said it was referred to the Manual 15 language detailing the OCA calculation.

The Monitor responded to the complaint stating that it's the responsibility of market sellers to submit information about the pollutants that can limit a resource's run hours and said it met with the company to discuss the adder several times in April, May and June 2022. After additional pollutant data was provided on July 26, 2022, the Monitor updated its modeling of LS Power's resources.

LS Power also argued the Monitor was calculating different OCAs for the six units at its Aurora Generating Station, despite each unit being identical. The complaint argued the Monitor has not transparently addressed the cause of the difference.

While investigating volatility in the adder calculated for a different resource in June 2022, the Monitor said it identified an error in the calculator, where a flaw in the calculation of shadow prices reduced the output that resource was modeled as produced, causing its emissions to vary. The issue was resolved on June 23, 2022, and the Monitor stated there was minimal impact on LS Power's units.

In a separate issue, the Monitor said there was an error causing variable operating and maintenance costs (VOM) to be double counted for the Chambersburg generator. This was corrected the same day LS Power raised the issue. The primary issue leading Chambersburg to hit its emissions limit in the period discussed in the complaint was PJM dispatchers using the resource to resolve local constraints.

The Monitor defended the transparency of the calculator, stating it is adequately detailed in Manual 15 and the only inputs that are not available to resource owners are locational marginal price (LMP) and gas futures, which are proprietary and confidential data provided by a vendor. It stated it has held multiple educational workshops for PJM stakeholders, with materials available online, and will continue to hold more sessions. It also argued PJM can empower third parties, such as the Monitor, to aid in the calculation of market parameters so long as the RTO is the entity implementing them, which the Monitor said is the case here.

PJM also voiced transparency concerns in its response, stating it has requested access to the software behind the adder, which the Monitor has declined to provide. It supported the Monitor's role in the OCA calculation, however, stating that PJM staff are the final arbiter of the adder to be included in cost-based offers.

The RTO engages in annual reviews of the OCA to ensure the process outlined in the OA and Manual 15 is being followed, in addition to periodic review of adders calculated for individual resources to watch for trends and abnormal values. The RTO wrote it has identified instances where it sought further review and was able to request data and meet with the Monitor.

Responding to LS Power's request that FERC allow market sellers to propose their own adders, PJM said it already has a pathway for alternatives to be submitted so long as it can be demonstrated the default calculation is not representative of a unit's opportunity costs. PJM stated it has approved alternative OCAs in the past.

The commission wrote that more transparency could help identify and resolve the sort of errors the Monitor outlined.

"The IMM acknowledges that some errors occurred in the calculation of some OCAs. While some of these errors may have been limited in scope, such errors nonetheless harm the efficient functioning of markets and undermine market participants' confidence that the market rules are being implemented appropriately. There is also the possibility that there are additional issues with OCA calculations that LS Power and other market participants have not been able to identify due to the opaqueness of current OCA calculation process," the order states.

The commission declined to require that PJM calculate the OCA, finding that it has remained in control of the implementation of the adders, and declined to require that PJM allow alternative OCAs to be provided by market sellers who cannot demonstrate that the default methodology does not account for some limit. The commission said the issue of PJM having access to the calculator is out of the complaint's scope but encouraged PJM and the Monitor to collaborate on allowing access. ■

FERC Approves Cost Allocation for Eddystone Emergency Order

By Devin Leith-Yessian

FERC on Aug. 15 approved PJM's proposal for allocating the costs for Constellation Energy to continue operating its Eddystone Generating Station near Philadelphia under an emergency order by the U.S. Department of Energy (*ER25-2653*).

The cost would be spread across all PJM load, with charges determined by multiplying load-serving entities' share of the RTO monthly unforced capacity obligation by the monthly credit paid to Constellation. The costs to be included in that credit are subject to review by the Independent Market Monitor. The actual costs will be determined through the deactivation avoidable cost credit (DACC), which was designed for resources whose deactivation is being voluntarily delayed while transmission upgrades are built to allow the resource to go offline without reliability issues. (See *PJM Board Selects Cost Allocation for Eddystone*.)

The revisions to the Reliability Assurance Agreement (RAA) are only applicable to the Federal Power Act Section 202(c) order keeping Eddystone online from June 1 to Aug. 28. Any DOE orders pertaining to other resources or to further keep the plant online would require a separate cost allocation filing.

Several public interest organizations protested allocating the Eddystone costs to all PJM load, arguing that the RTO's capacity market procured sufficient capacity to cover the 90 days the emergency order is in effect. They wrote that the order itself stated that there is a shortage of capacity in pockets of PJM, quoting its finding that "an emergency exists in portions of the electricity grid operated by [PJM] due to a shortage of facilities for the generation of electric energy, resource adequacy concerns and other causes." Without further clarification from DOE, they argued, any cost allocation would be arbitrary.

The protest was signed onto by the Environmental Law and Policy Center, Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, Public Citizen, Citizens Utility Board of Illinois and Environmental Defense Fund. They wrote that PJM continuing to export while operating Eddystone during the heat wave in late June shows that the plant is not needed to maintain reliability and the parties benefiting from its continued operation may not be PJM load.

"In sum, PJM's proposal asks ratepayers across PJM to pay for something — resource adequacy — they have already paid for once. PJM ratepayers have no need for, and will not materially benefit from, additional generating capacity. PJM's dispatch of Eddystone during a recent summer heat wave only raises more questions about the beneficiaries of the unit's retention," the organizations wrote.

PJM defended its RTO-wide cost allocation by stating that Eddystone is in the PECO zone, which saw no transmission constraints binding in the 2025/26 capacity auction, and arguing that Eddystone's output is therefore considered deliverable across the RTO. Both Constellation and PJM said Eddystone's operation during the heat wave corresponded to a maximum generation and load management alert, which is a NERC Energy Emergency Alert level 1 event.

The organizations also focused on the notion that the agreement between Constellation and PJM to use the DACC to determine recoverable costs does not fall under FERC oversight, arguing the costs associated with Eddystone's operation should be considered wholesale rates. They noted that PJM's interpretation of which parties are affected by the emergency order and compensation agreement leaves out LSEs and consumers who may be allocated the resulting costs.

"In PJM's view, a Section 202(c) order constitutes a blank check to establish charges that may be passed on to other entities and customers with no opportunity for regulatory review. It ignores the fundamental purpose of the Federal Power Act: to provide a check on private utilities," they wrote.

The organizations also took issue with an operating memo in which PJM and Constellation agreed to allowing Eddystone to be dispatched for system restoration and for any costs to provide black start service to be recovered through the proposed structure. They argue that would saddle all PJM customers with the cost to provide a localized service, which itself already has a FERC-approved cost allocation.

The PJM Industrial Customer Coalition submitted comments supporting the cost allocation proposal but argued that the RTO should be required to file the DACC compensation for FERC approval.

PJM argued that Section 202(c) does not require commission involvement in determining compensation unless the parties involved cannot agree on a methodology. It pointed to San Diego Gas & Electric, in which DOE used Section 202(c) to order CAISO to purchase energy from the spot market; when CAISO sought refunds for the transactions, the commission found that it did not have oversight, as the parties to the sale had agreed to the price.

FERC found that the cost allocation appropriately matches the scope of the emergency identified by DOE. The commission also determined that the emergency order does not require PJM to demonstrate that ratepayers will benefit from Eddystone's operation and said that the compensation methodology itself is out of scope.

"We agree with PJM that the proposed cost allocation recognizes that the emergency order is based on the overall resource adequacy need in the PJM footprint," the commission wrote. "The emergency order describes an 'emergency situation,' referring to PJM's own public statements and regulatory filings, which reflect a 'growing resource adequacy concern' for the entire PJM region.

"The emergency order also states that the retirement of the Eddystone units would 'further decrease available dispatchable generation within PJM's service territory.' These statements support a finding that the retention of the Eddystone units benefits the PJM region in general." ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Aug. 20. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in RTO Insider.

RTO Insider will be covering the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:20-9:25)

The committee will be asked to endorse as part of its consent agenda:

C. *proposed* changes to Manual 11: Energy & Ancillary Services Market Operations, Manual 12: Balancing Operations, Manual 15: Cost Development Guidelines and Manual 28: Operating Agreement Accounting codifying the first phase of PJM's regulation market redesign. The market would use a single price signal to dispatch regulation units up and down, replacing a model with separate long-deployment and fast-response products. (See "Regulation Market Redesign Endorsed," *PJM MIC Briefs: Aug. 6, 2025*.)

Same-day endorsement will be sought at the MC for the revisions to Manual 15.

Issue Tracking: *Regulation Market Design*

Endorsements (9:25-10:45)

1. RPM Seller Credit (9:25-9:40)

PJM's Gwen Kelly will present a *proposal* to add a creditworthiness review in the granting of seller credit in the Reliability Pricing Model. The committee will be asked to endorse the proposed solution and corresponding tariff revisions at this meeting.

Issue Tracking: *Review of RPM Seller Credit Provision for Market Participants*

2. Elimination of First Usage (9:40-9:55)

PJM's Thomas DeVita will present a *solution* to rework how PJM determines whether a wholesale resource interconnecting to a distribution asset falls under federal or state jurisdiction. The "bright-line" test would consider any points of interconnection below 69 kV to be under state or local jurisdiction, whereas higher-voltage facilities would fall under federal jurisdiction, unless FERC and the transmission owner have classified it as a transmission or distribution asset for cost recovery purposes. (See *PJM Proposes Changes to Determination of Jurisdiction over Generation*.)

The committee will be asked to endorse the proposed solution and corresponding tariff revisions at this meeting.

Issue Tracking: *Eliminating "First Use" for Interconnections to Distribution Facilities in PJM*

3. ELCC Accreditation Methodology (9:55-10:45)

A. PJM's Michele Greening will *present* the results of a poll conducted by the Effective Load Carrying Capability Senior Task Force on changes to the effective load-carrying capability (ELCC) calculation and how the ratings it produces factor into resource accreditation.

B. PJM's Pat Bruno will review the RTO's *Package C*, which would add winter deliverability tests and winter installed capacity values to the ELCC analysis and apply weighting to historic performance in favor of more recent events. PJM's proposal will be voted on first as the main motion.

C. Michael Cocco, of Old Dominion Electric Cooperative, will present an *alternative* proposal, Package F, that would reduce the probability of the ELCC modeling drawing resource performance data from the 2014 polar vortex and December 2022's Winter Storm Elliott by 33%.

D. Independent Market Monitor Joe Bowring will present another *alternative* proposal, Package B1, that would shift to unit-specific accreditation, use winter ratings in the ELCC calculation and remove the polar vortex and Elliott performance data on the grounds that PJM has made operational changes that make historic performance unlikely to reoccur. The Monitor will seek an RTO member to move and second the proposal.

The committee will be asked to endorse a proposed solution at this meeting. Same-day MC endorsement may be sought.

Issue Tracking: *Capacity Market Enhancements - ELCC Accreditation Methodology*

Members Committee

Consent Agenda (2:20-2:25)

The committee will be asked to endorse as part of its consent agenda:

B. proposed tariff and Operating Agreement *revisions* intended to make balancing operating reserve credit and deviation charges more accurately reflect whether a resource has followed PJM dispatch. The addition of a tracking ramp limited desired (TRLD) metric would compare resource output over time to dispatch instructions to determine how a resource is responding, while changes to the balancing operating reserve credit calculation would aim to simplify the formula.

Issue Tracking: *Operating Reserve Clarification for Resources Operating as Requested by PJM*

C. proposed Reliability Assurance Agreement *revisions* to revise the definition of dual-fuel capacity resources to include those that have dedicated fuel sources that are not stored on-site.

Issue Tracking: *Dual Fuel Capacity Definitions*

Endorsements (2:25-3:25)

1. Election (9:25-9:40)

PJM's Greening will present a *proposal* to nominate Constellation Energy's Juliet Anderson to serve as 2025 Generation Owner sector whip. The committee will be asked to vote on the nomination upon first read.

2. Regulation Market Manual 15 Revisions (2:35-2:45)

PJM's Ilyana Dropkin will present revisions to Manual 15: Cost Development Guidelines to codify PJM's regulation market redesign (see above). The committee will be asked to endorse the proposed manual revisions at this meeting.

Issue Tracking: *Regulation Market Design*

3. ELCC Accreditation Methodology (2:45-3:25)

PJM's Bruno, ODEC's Cocco and Monitor Bowring will present each of their proposals to rework the ELCC methodology (see above). The committee will be asked to endorse a proposed solution at this meeting.

Issue Tracking: *Capacity Market Enhancements - ELCC Accreditation Methodology* ■

— Devin Leith-Yessian

SPP, Stakeholders Kick off Markets+ Phase 2 Development

RTO's Day-ahead Offering on Way to Becoming 'Real Market'

By Tom Kleckner

PORTLAND, Ore. — Development of SPP's Markets+ is in full swing. Financing has closed. Work teams and their governance structure have been assembled to implement the design. Various entities are registering for the market.

Further proof of the seriousness of the work ahead came with the new faces sprinkled among attendees for the first in-person Phase 2 meeting of the Markets+ Participant Executive Committee (MPEC). One committed participant sent its entire project team.

Jim Gonzalez, SPP's director of seams and Western services, said the developments mark a sea change from a 2022 meeting in Phoenix where staff "pitched the idea" of offering market options in the Western Interconnection.

"That was really the first big stakeholder meeting SPP had with some interested parties in the West just describing what we thought we could do, how we'd like to work together to see if there was a way to create a day-ahead and real-time market for the West," Gonzalez told *RTO Insider* after the Aug. 12 MPEC meeting. "Seeing the stakeholders really take ownership of their market and being comfortable making decisions has been really exciting to watch.

"It's exciting for me thinking about not just the governance, but actually implementing the market itself, having the structure in place to be able to move forward to implement and make the necessary changes we need to as we work through that process," he added.

SPP's Jim Gonzalez (left, with MPEC Chair Laura Trolese, TEA, and Kent Walter, APS) is excited that participants are now building the Markets+ structure. | © *RTO Insider*

Joe Taylor, with Xcel Energy's Public Service Company of Colorado (PSCo), has seen market proposals in the West come and go, including a pair of SPP initiatives in the last decade. This one seems different, he said.

"[We] have a dedicated group of utilities, special interest groups, stakeholders — and we're moving toward an end goal," he said. "It's been funded. It's a real market. We're moving toward the end goal, and it gets a lot more serious and a lot more engagement as folks start to see what impact these decisions are going to have on what this market looks like."

PSCo is one of five balancing authorities planning to be part of Markets+ when it goes live in October 2027, joining Arizona Public Service, Powerex, Salt River Project and Tucson Electric Power. The company received permission from the Colorado Public Utilities Commission to join Markets+ in July. (See *Colo. PUC Approves PSCo's Markets+ Participation*.)

Pacific Northwest balancing authorities Bonneville Power Administration, Chelan County Public Utility District, Grant County PUD, Puget Sound Energy and Tacoma Power have deferred market participation until at least 2028. The PUDs and Tacoma Power are BPA preference customers dependent on the agency's transmission system, as are many entities in the region.

The utility BAs, with the exception of PSCo, have all made funding *commitments* to SPP. PSCo is waiting on an official order from the Colorado commission before agreeing to its portion of Phase 2's $150 million cost.

Asked about the significance of PSCo joining Markets+, Taylor acknowledged its importance.

"We're a fairly large utility with respect to this footprint, so I'm thrilled to be able to support my friends and colleagues throughout the West in their commitment," he said.

Why This Matters

SPP staff and stakeholders have moved firmly into the development phase for Markets+, prompting one participant to say it's beginning to look like a 'real market.'

Staff said 14 new entities have joined Markets+ during Phase 2, with two dropping out. That leaves *40 active* in the phase, having registered— some several times — as various types, with 33 planning on being ready for go-live. The participant categories include:

- BAs or transmission service providers (5)
- Load-serving entities (9)
- Market participants (25)
- Stakeholders (29)

Participants have until Sept. 1 to register as a BA, Oct. 1 as a transmission service provider and Dec. 1 as a market participant.

Network and commercial modeling has already begun in the background. Connectivity testing, the first step before market trials, is scheduled to begin Oct. 1.

'It All Takes Governance'

The meeting marked the official kickoff for the second phase's governance. Based on the increased interest from Phase 2 participants, SPP said staff worked with MPEC and the Markets+ Interim Governance Task Force (MIGTF) to expand the task force from the current nine members to as many as 18. The scope change ensures an equal balance among investor-owned utility, public power and independent representatives, accommodating growth as the sector balance allows.

"It all takes governance to actually make this happen," Gonzalez said.

The task force is responsible for reviewing and recommending changes to governance issues before they go to MPEC during Phase 2. It reports to the committee, along with working groups focused on transmission, market design, seams and reliable operations.

SPP staff will solicit MPEC representatives for public power nominees and send them to the full committee for approval of a balance roster before the next MIGTF meeting.

MPEC approved the rosters for the various working groups and task forces during the meeting, setting their limits at 21 or 24 people. Five of the groups include representation from the Markets+ State Committee (MSC), which comprises regulatory commissioners that are monitoring and providing input into the market's development.

With several contested seats among the stakeholder bodies, SPP staff will again ask MPEC reps for nominees in under-represented sectors. They will provide the committee with a list of nominees and bios for each stakeholder group; MPEC will vote on the nominees by email.

"It's a good problem to have," MPEC Chair Laura Trolese, with The Energy Authority, said in alluding to the lack of nominees during the first phase.

The committee approved all the roster expansions unanimously, with only four abstentions in all. In most cases, the current stakeholder chairs and vice chairs will continue in their roles until November. New leadership nominees will be placed when MPEC gathers in Tempe, Ariz., Nov. 12-13.

Following the meeting, most staff and stakeholders stayed for an in-person meeting of the Markets+ Change User Forum (MCUF). It will serve as a hub for coordinating participant efforts to implement process or system changes affecting market functions, particularly during market trials.

APS' Elizabeth Goodman and Powerex's Derek Russell were seated as the MCUF's chair and vice chair, respectively.

SPP secured the $150 million Phase 2 funding agreement in June after receiving FERC approval of the tariff earlier in 2025. (See *SPP Launches Markets+ Phase 2 With $150M Secured*.)

MSC Funded for Phase 2

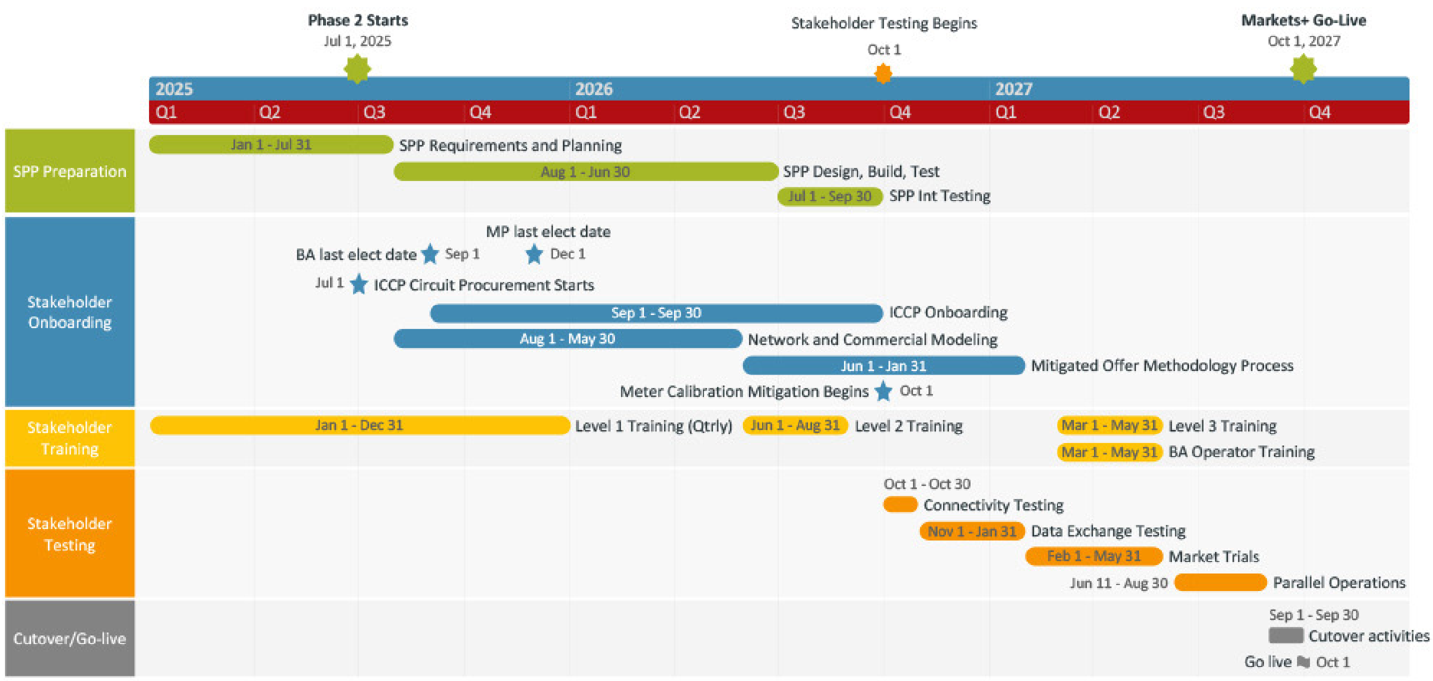
Arizona Commissioner Nick Myers, the MSC's chair, told the MPEC that the commissioners have completed a memorandum of understanding with SPP that sets up a fund mechanism for Phase 2. The Western Interstate Energy Board (WIEB), a regulatory organization of 11 Western states and 2 Western Canadian provinces, supported the MSC during Phase 1.

"We're funded," Myers said. "WIEB has been supporting the MSC on [its] own since the inception of Markets+, so we're glad to have that MOU in place. It further solidifies SPP's support, and all of your support, for the MSC involvement in Markets+."

Myers said also that the MSC will ask MPEC to direct the MIGTF to work with the regulators in investigating the election process for the Markets+ Independent Panel that will eventually oversee the market.

"There was a little disconnect there, and we just want to make sure that any holes might be plugged," he said. ■

M+ IMPLEMENTATION SCHEDULE OVERVIEW



The implementation timeline for Markets+ | *SPP*

Report Urges 5-GW Battery Storage Buildout in SPP

ACP, Aurora Say Reforms Would Clear Path for Reduced Costs, Increased Reliability

By John Cropley

> **Why This Matters**
>
> The analysis warns of the potential consequences of inadequate storage capacity in SPP.

A new report urges SPP to accelerate its interconnection process and reform market rules to allow greater buildout of energy storage.

The report notes that hundreds of battery storage proposals are sitting in the SPP interconnection queue, working through lengthy reviews. Few batteries are deployed in SPP now, but even 5 GW of capacity could boost reliability and reduce costs by a projected $7 billion over the next decade.

Aurora Energy Research issued the report Aug. 12. The *American Clean Power Association* (ACP), which commissioned it, called for SPP and state policymakers to:

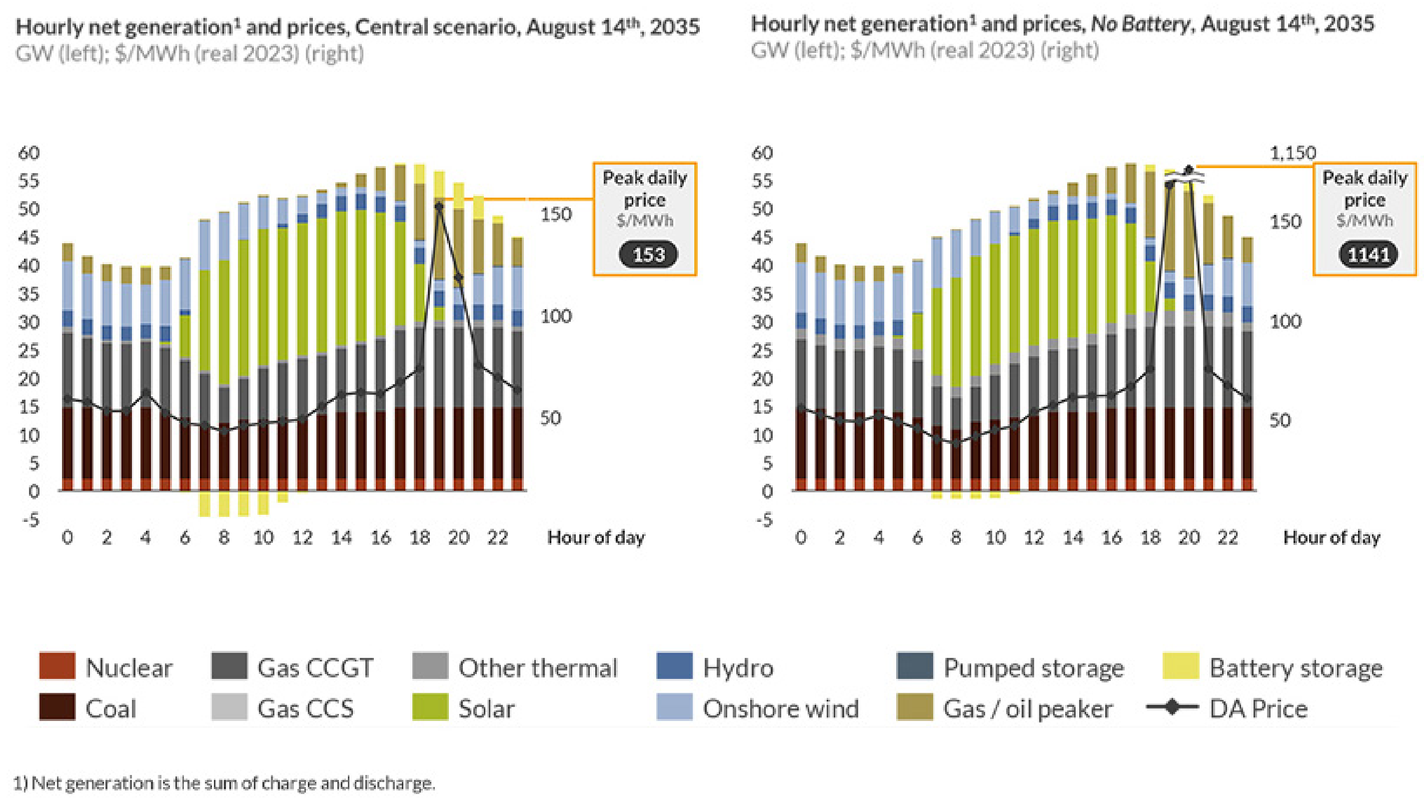
- accelerate interconnection for the quick-to-deploy technology;
- reform market rules to generate price signals that incentivize storage development and recognize the reliability contribution of storage;
- remove ambiguity on when storage must register as a transmission customer and how the associated charges are applied; and
- streamline and clarify state and local permitting with uniform rules and standards to ensure faster, more certain project execution.

SPP did not return requests for comment for this story.

The RTO recently completed a yearslong effort to streamline and integrate its transmission and generation planning: On Aug. 5, *its board of directors approved* the Consolidated Planning Process and asked FERC to approve a March 1, 2026, effective date. (See *SPP Celebrates Novel Consolidated Planning Process*.)

Several statistics provided by Aurora, the Energy Information Administration and SPP itself point to the potential importance of storage:

- SPP is the second-largest RTO in the nation geographically.
- It is expecting the largest peak load growth of any RTO, reaching 69 GW in 2035 due to electrification of oil and gas extraction and data center buildout.
- Thirty-eight percent of its 2024 energy production was from *wind turbines*.
- Wind turbines are highly variable sources of power generation — in the past 30 days, *hourly output nationwide* ranged from 10,352 to 77,765 MWh.
- The SPP interconnection queue is crowded with proposals for solar generation, which also is intermittent if



A report by Aurora Energy Research indicates increased battery storage capacity would reduce energy price spikes during peak demand in the SPP region. | *Aurora Energy Research* more predictable.

- SPP's 2025 accredited summer *battery storage capacity* is 172 MW.
- More than 25 GW of battery capacity proposals entered the SPP interconnection queue in 2024.

Aurora modeled two distinct scenarios in its report: one where restrictions limit 2035 battery capacity to 1.4 GW and the other where 4.7 GW of batteries are deployed, based on economic viability and assuming continuation of various policy reforms such as federal clean energy tax credits and SPP's Consolidated Planning Process.

In 2035, prices during late-afternoon/early evening summer peak demand periods could be $1,141/MWh under the 1.4-GW scenario, compared with just $153/MWh under the 4.7-GW scenario.

Total system costs could be $7 billion higher in 2035, and electricity prices would climb 10.1% from 2029 to 2035 under the 1.4-GW scenario.

Also over the next decade, the report forecasts growing net hourly load ramps due to expected increases in population and solar generation.

Small ramps will decline in number, the authors say, but large ramps will become more numerous: By 2030, more than 700 hours a year will require a ramp greater than 4 GW, compared with 37 hours in 2020.

A storage fleet larger than 5 GW is critical to grid reliability and cost savings, the report states.

It cites the performance of battery energy storage systems in ERCOT, where 15-minute battery discharges as high as 1.97 GW prevented load shed during several high-stress periods in the late summer of 2023.

"Evening power prices could be 80% lower in SPP if the region can build out the battery storage central states need to ensure reliability," Noah Roberts, ACP vice president of energy storage, said in a news release. "As power demand surges, battery storage is one of the fastest and most effective ways to strengthen reliability and lower electricity bills. Grid batteries deliver significant cost savings for families and businesses, and provide the reliability needed to power our economy into the future." ■

Duke Energy Says Combining Carolina Utilities Would Save Billions

By James Downing

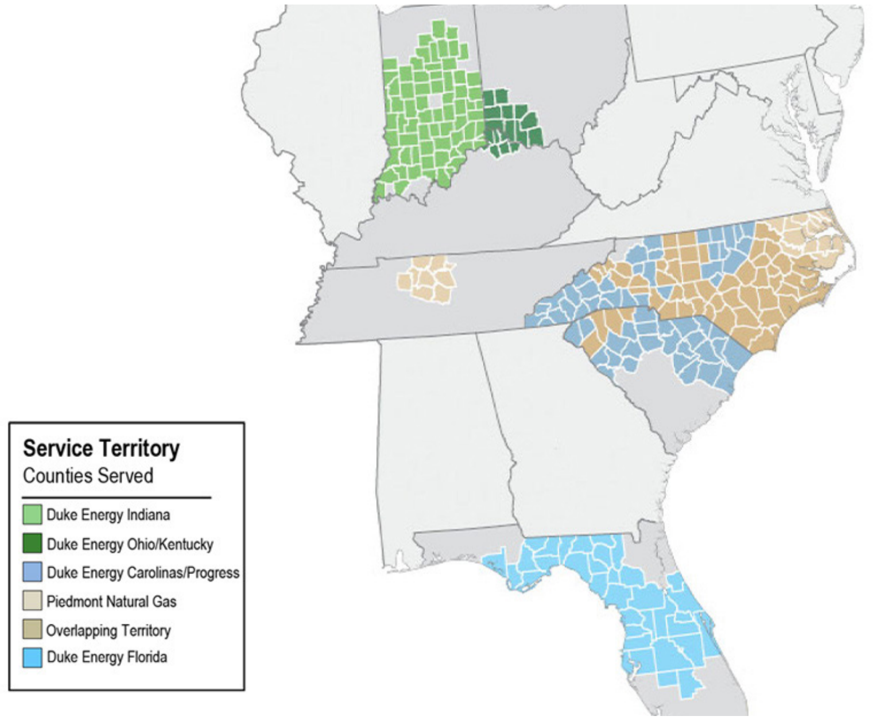
Duke Energy has asked state and federal regulators to combine its two electric utilities that serve the Carolinas in a move it said would save customers billions of dollars.

Duke Energy Carolinas and Duke Energy Progress have operated as separate utilities since the 2012 merger of Duke and Progress Energy. The two subsidiaries' combination is legally classified as a merger, but it is more like reorganizing two corporate divisions into one. If approved, the effective date for the combination would be Jan. 1, 2027.

"Combining our two utilities reduces customer costs, simplifies operations, supports economic growth and promotes regulatory efficiencies, all of which will create value for customers in both states," Duke Energy Carolinas CEO Kodwo Ghartey-Tagoe said in a statement. "There will be no immediate changes to retail customer rates or services. We look forward to sharing more details with our customers on how rates will evolve over time if the combination is approved by regulators."

Why This Matters

Operating as a single utility in the Carolinas would let Duke meet the growing needs for power there at a lower cost due to more efficient planning and an improved ability to avoid redundant investments.



Duke Energy's service territory | *Duke Energy*

Operating as a single utility in the Carolinas would let Duke meet the growing needs for power there at a lower cost due to more efficient planning and an improved ability to avoid redundant investments. The combination would let Duke build fewer assets to meet the combined systems' needs, and spreading infrastructure across the larger customer base would moderate impact on rates.

The combined utilities would be able to run fewer and less expensive units, use less fuel and cut down on units cycling on and off, thus saving maintenance costs.

The combination needs to be approved by the North Carolina Utilities Commission, the South Carolina PSC and FERC.

The combination is expected to save about $1 billion between 2027 and 2038, which is the close of the planning horizon for the 2023 Carolinas Resource Plan. Retail rates would start changing as the combined firm goes before North Carolina and South Carolina regulators in 2027 and later.

Duke Energy Carolinas owns 20.8 GW of generation and supplies power to 2.9 million customers across 24,000 square miles in the Carolinas. Duke Energy Progress owns 13.8 GW and supplies power to 1.8 million customers across 28,000 square miles. ■

Kairos Power, TVA Announce Nuclear PPA

Deal is 1st Involving a U.S. Utility, Assumes Operational SMR in 2030

By John Cropley

The list of firsts for advanced nuclear power grew a little longer Aug. 18 with a power purchase agreement between Kairos Power and the Tennessee Valley Authority.

The electricity — or more exactly, its clean energy attributes — would be assigned to Google data centers.

The terms — only 50 MW, not until 2030, from a technology still being developed — are not by themselves a huge splash in a sector that is projecting a need for dozens of gigawatts of capacity in the next five years.

But it is the first PPA signed by a U.S. utility for the output from an advanced GEN IV reactor, and it is the latest of many indications of the strong interest the tech sector has in next-generation nuclear power, with its promise of emissions-free baseload power and its potential for co-location.

The PPA between Kairos and TVA would deliver up to 50 MW from Kairos' planned Hermes 2 Plant to the TVA grid, which powers Google data centers in Tennessee and Alabama.

It is the first step under Google's October 2024 *agreement with Kairos* on a partnership to develop a 500-MW fleet of advanced nuclear reactors by 2035. (See *Google, Kairos Sign 500-MW Nuclear PPA*.) Kairos will boost Hermes 2's output from 28 MW to 50 MW to reach the PPA's terms.

Kairos is designing a high-temperature small modular reactor fueled with pebble-form TRISO and cooled with low-pressure fluoride salt.

Hermes 1 is a demonstration reactor under construction in Oak Ridge, Tenn., with an anticipated 2027 startup date. It is intended to produce only heat, not electricity. Lessons learned from Hermes 1 will shape the Hermes 2 demonstration reactor, to be built nearby. (See *Kairos Power Cleared to Build Demonstration SMRs*.)

Why This Matters

The agreement is another attempt to make advanced nuclear technology technically and financially viable.

There are two more advanced-nuclear firsts: Hermes 1 was the first GEN IV reactor approved by the Nuclear Regulatory Commission and the first non-light water reactor permitted in the United States in more than half a century.

Also in Oak Ridge, TVA in May became the first U.S. utility to request a construction permit for a small modular reactor — a GE Hitachi BWRX-300. (See *TVA First U.S. Utility to Request SMR Construction Permit*.)

There are many other recent firsts in SMR and advanced nuclear development, but not the most important first: None in this part of the world has entered commercial operation.

Ontario in May authorized construction for what could be the first commercial SMR in North America. (See *Ontario Greenlights OPG to Build Small Modular Reactor*.) But the target date for connection to the grid is not until late 2030.

There is intense interest and effort focused on the development of SMRs, with their promise of faster, less expensive construction. The Nuclear Energy Agency is tracking more than six dozen designs at some stage of development; more than two dozen of the efforts are headquartered in the U.S.

How many of those efforts obtain sufficient capital and overcome technical hurdles to reach commercial viability remains to be seen.

The Trump administration is trying to expedite the process, but the 11 projects recently chosen for a fast-track pilot program will receive no financial assistance — only help cutting through regulatory red tape. (See related story *Advanced Nuclear Fast-track Effort Gets First 11 Projects*.)

Nonetheless, advanced nuclear developers often speak with present-tense confidence about their business models and technologies.

Crews from Kairos Power and Barnard Construction install the reactor vessel support system for its third Engineering Test Unit in May in Oak Ridge, Tenn. | *Kairos Power*

"We build mass-manufactured nuclear plants that will power anything from a data center to a city," *declares Aalo*. In fact, Aalo's liquid-metal reactor design is only in the non-nuclear prototype stage, and the company was a 10-person operation in a coworking space until recently.

Some of the other companies in the SMR race are not as far along as Aalo.

Others are steadily moving closer to splitting their first atoms, aided in some cases by the technical and financial resources of the U.S. government.

In 2021, the U.S. Department of Energy Office of Nuclear Energy put Kairos' Hermes project on its list of "*5 Advanced Reactor Designs to Watch in 2030*." DOE already had begun assisting Hermes financially during the first Trump administration; in 2024 it committed *up to $303 million* in grants to the effort.

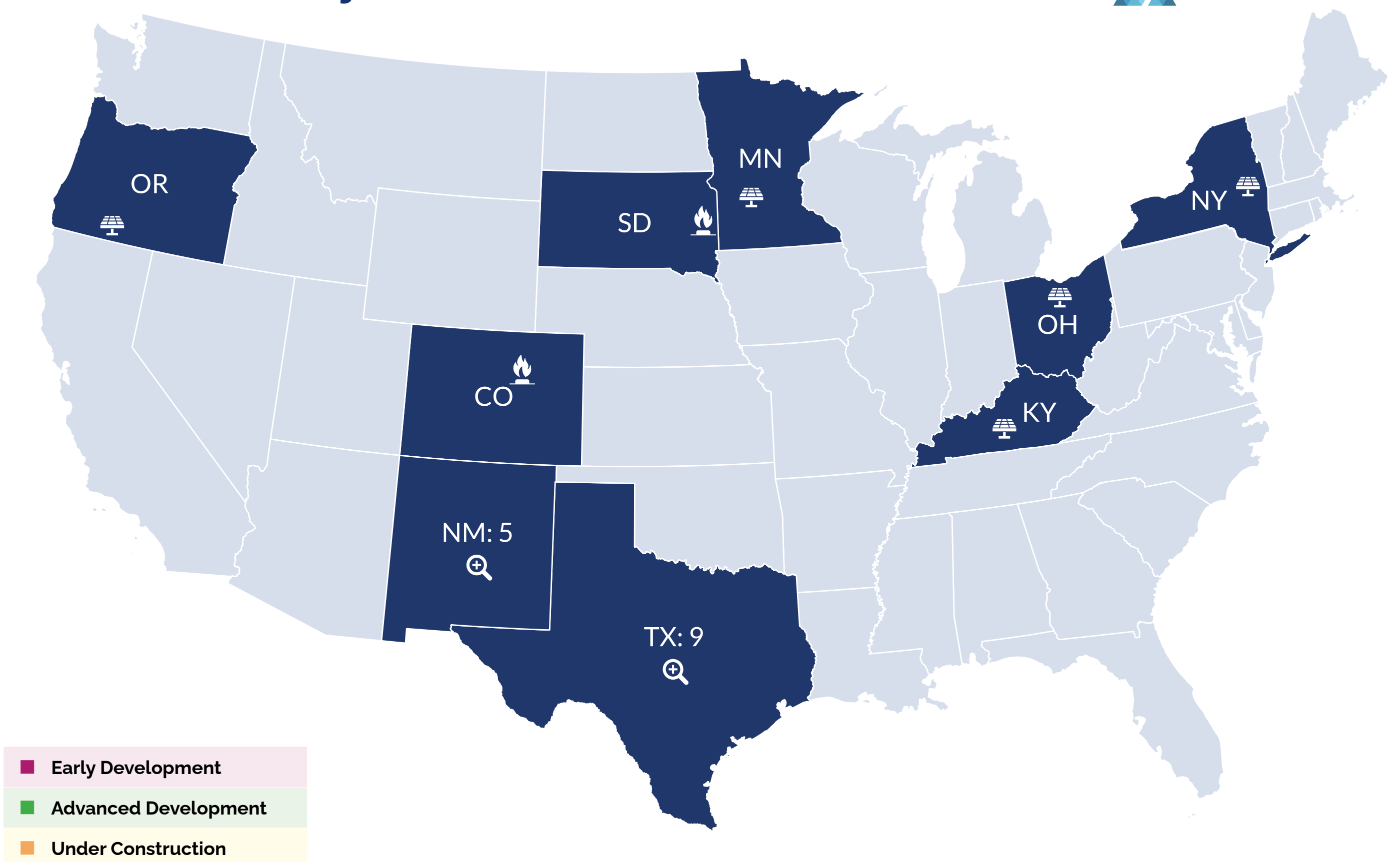
The cost of developing a first-of-a-kind SMR and bringing a working copy online is considerable — $5.6 billion, in the case of the first Ontario reactor, plus a projected $9.6 billion for the three follow-up SMRs planned on the same site.

Google, *Kairos* and *TVA* said the PPA announced Aug. 18 would help ease some of that first-mover cost and drive down the price tag for future reactors.

"Google stepping in and helping shoulder the burden of the cost and risk for first-of-a-kind nuclear projects not only helps Google get to these solutions, but it keeps us from having to burden our customers with development of that technology," said Don Moul, CEO of TVA. ■

Generation Projects Added in the Past Week

YES ENERGY



Solar Wind Energy Stoarage Natural Gas Geothermal Nuclear

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
TCP 272 (Fort Lupton) (Thermo) LMA, LMB, LMC, LMD, LME Replacement	Tri-State G & T	Thermo Cogeneration Partnership L.P.	CO	59	2031
Exie Solar	Brookfield Asset Management	Geronimo Power	KY	110	2028
Gopher State Solar Project	D.E. Shaw Group	Ranger Power LLC	MN	200	2027
Alamogordo Solar Energy Center BESS	TXNM Energy	PSC of New Mexico	NM	6	2027
Deming BESS	TXNM Energy	PSC of New Mexico	NM	6	2027
Meadow Lake BESS	TXNM Energy	PSC of New Mexico	NM	6	2027
Rio Communities BESS	TXNM Energy	PSC of New Mexico	NM	6	2027
San Miguel BESS	TXNM Energy	PSC of New Mexico	NM	6	2027
Jackson Solar 1	Generate Capital		NY	5	2025
Monroeville Floating Solar Installation	Gardner Capital		OH	6	2026
Pilot Rock Solar (Pilot Rock Solar 1 and 2)	Sunthurst Energy	Sunthurst Energy LLC	OR	5	2025
Toronto Power Plant	WMMPA		SD	145	2029
Sim Gideon Gas RICE	Ownership Undisclosed		TX	226	2031
Tolivar Power Plant Phase 2	Ownership Undisclosed		TX	225	2027
Lost Pines Gas RICE Phase 1 / Phase 2	Lower Colorado River Authority		TX	113	2029/2031
Schneider Combined Cycle	Lower Colorado River Authority		TX	880	2030
Schneider Gas RICE Phase 1 / Phase 2	Lower Colorado River Authority		TX	113	2029/2031
Jaguar BESS 1	SER Capital Partners	Perfect Power	TX	157	2026
Alkali Creek Wind	Ownership Undisclosed		TX	474	2028
Barrosos Creek Wind 3 & 4	Ownership Undisclosed		TX	198	2028
Bendito Wind	Ownership Undisclosed		TX	300	2029

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

Ford Announces $2B Investment in EV Assembly Plant

Ford last week announced it would invest $2 billion in an assembly plant in Louisville, Ky., aimed at rolling out more affordable EVs.

The automaker plans to produce a midsize, four-door electric pickup at the plant.

The investment comes on top of $3 billion already planned for a battery park in Michigan.

More: *CNBC*

CenterPoint Energy to Buy RNG Made from Food, Yard Waste

CenterPoint Energy last week said it has signed an agreement to purchase waste-created renewable natural gas and provide it to its customers across Minnesota.

That gas will come from organic food and yard waste in the Twin Cities, as well as waste from farms and wastewater treatment facilities. The waste will be processed and converted to renewable natural gas through a process known as anaerobic digestion by Dem-Con HZI Bioenergy's new facility in Shakopee, set to open in 2027.

After a 15- to 60-day "digestion" period, the gas will be distributed to CenterPoint.

More: *MPR News*

Enterprise Buys Occidental Petroleum Gas Assets

Enterprise Products Partners announced it is acquiring Occidental Petroleum's natural gas gathering affiliate for $580 million.

The assets include about 200 miles of natural gas gathering pipelines that support Occidental's production activities in the Midland Basin.

Enterprise also announced plans to construct the new Athena natural gas processing plant, which will have the capability to process 300 million cubic feet of natural gas per day.

More: *Houston Chronicle*

Federal Briefs

EPA Agrees to Expansion of New Mexico Nuclear Waste Storage Site

EPA has agreed to the Department of Energy's request to dig two new underground areas to store nuclear waste at the only permanent U.S. burial site for radioactive materials in New Mexico.

The DOE sought a change in its permit for the Waste Isolation Pilot Plant due to storage capacity it said was lost from a 2014 drum eruption that forced a shutdown of the site for more than two years. EPA's approval is for two panels that would each contain seven rooms.

"EPA is in general agreement with DOE's approach and DOE's interpretation" of computer modeling showing the two additional areas wouldn't result in excessive radiation releases, Abigale Tardif of EPA's Office of Air and Radiation said.

More: *Axios*

Cleanview: U.S. Clean Energy Growth Slowing in 2025

Combined installations of solar, wind and battery storage systems are on track to climb by around 7% in 2025 from the year before, according to data compiled by energy data platform Cleanview. The increase would mark the smallest year-over-year percentage expansion in more than a decade.

Solar capacity has been the fastest-growing form of clean power generation over the past five years, with national capacity expanding by 181% since 2020 to roughly 136,250 MW as of mid-2025. Total U.S. solar capacity has grown by an annual average of 27% since 2020, but so far in 2025 has only grown by 10% from 2024's total due to a slowdown in developer activity.

Wind capacity growth has been slowing steadily in recent years due to cost increases, as well as difficulties in securing suitable new sites for wind farms. Even so, the 1.8% expansion in total U.S. wind capacity so far this year is the smallest annual increase since at least 2010.

More: *Reuters*

State Briefs

CALIFORNIA

Truck Makers Sue State over Zero-emissions Agreements

A group of truck manufacturers last week filed a lawsuit against Gov. **Gavin Newsom** and the Air Resources Board, contending the state lacks the authority to enforce its heavy-duty vehicle emissions standards that are stricter than federal standards.

The complaint maintains the truck makers should not have to comply with the state's emissions rules after the federal government rendered them "unlawful" in June. Trump revoked the Biden administration's previous authorization of California's emissions standards via the Congressional Review Act, which allows the repeal of recent such approvals with a simple majority. The state had been able to acquire EPA's authorization via a 1970 Clean Air Act clause that allows the state to set stronger emissions rules than those at the federal level.

The Federal Trade Commission later declared that an emissions agreement between California and the truck makers is "unenforceable" as it closed an investigation into whether several manufacturers violated antitrust laws by engaging in a voluntary "Clean Truck Partnership" with the Air Resources Board.

More: *The Hill*; *The Hill*

ILLINOIS

St. Charles Council Rejects 20-year Contract Extension with IMEA

The St. Charles City Council last week voted 8-1 to reject a proposed contract extension with the city's current energy provider, Illinois Municipal Electric Agency.

St. Charles still has 10 years left on its current power contract, but IMEA asked St. Charles and other municipalities to enter new 20-year contracts that would last through 2055.

Council members, residents and local environmental activists have raised concerns over IMEA's reliance on coal.

More: *Shaw Local*

INDIANA

Utility Consumer Advocate Retiring from State Service

Utility Consumer Counselor William Fine last week announced he will leave his post, effective Aug. 31.

Fine has led the Office of Utility Consumer Counselor since 2017. He was appointed by then-Gov. Eric Holcomb and was reappointed in December 2020.

Gov. Mike Braun will appoint his successor.

More: *Indiana Capital Chronicle*

KENTUCKY

PSC Approves Solar Project at Former Coal Mine

The Public Service Commission last week approved the initial phase of a $1 billion proposal by BrightNight to install an 800-MW solar park at a former coal mining site.

The permit issued by the PSC's Electric Generation and Transmission Siting Board concerns the first of four construction phases and covers 210 MW of the overall capacity.

Construction of the project, known as Starfire, is expected to take between 12 and 18 months.

More: *Renewables Now*

MINNESOTA

PUC Approves Xcel's Extension of Prairie Island Operations

The Public Utilities Commission last week approved Xcel Energy's request to extend the operations of the Prairie Island nuclear plant into the early 2050s.

The company said it plans to request a 20-year extension of the plant's operating licenses from the Nuclear Regulatory Commission in 2026. The current licenses for the units expire in 2033 and 2034.

More: *KIMT*

PUC OKs 1st Stand-alone Battery System

The Public Utilities Commission last week approved a site permit for the 150-MW Snowshoe Energy Storage Project near Byron.

The project, which will be constructed by Spearmint Energy, will store excess electricity produced by nearby solar and wind farms.

It is expected to be in service by late 2027.

More: *MPR News*

OREGON

Federal Court Dismisses Enviros' Lawsuit Against EWEB

United States District Judge Mustafa T. Kasubhai on Aug. 8 dismissed a lawsuit brought by environmental groups against the Eugene Water & Electric Board.

The lawsuit argued that EWEB's operation of a hydroelectric project threatens the Upper Willamette River chinook salmon and bull trout.

Kasubhai dismissed the case due to a lack of jurisdiction. According to the judge, EWEB is already actively working with FERC to ensure fish safety.

More: *OPB*

TEXAS

AG Launches Investigation into Utilities Connected to 2024 Wildfires

Attorney General **Ken Paxton** last week announced an investigation into several utilities connected to the 2024 Smokehouse Creek and Windy Deuce fires.

The Office of the Attorney General issued civil investigative demand letters to Xcel Energy, Osmose Utility Services and Southwestern Public Service for documents related to the fires to determine if any laws were violated.

More: *KTR*