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YES ENERGY

# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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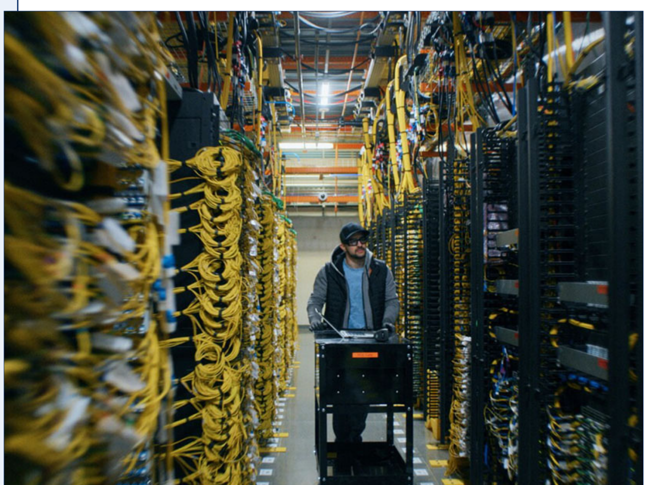
CAISO/WEST FERC/FEDERAL MISO

## Amazon Files Complaint Against PacifiCorp for Lack of Data Center Power



Amazon Web Services

Although PacifiCorp has yet to file a formal response to Amazon's complaint, the company said in a statement that it must balance data center demand with affordability and reliability for other customers.

CONTINUED ON P.13



PJM

Mikie Sherrill for New Jersey

### N.J. Backs Clean Energy Democrat for Governor (p.34)

New Jersey ratepayers saw a 20% hike in electricity bills in June, and the state expects a shortfall in electricity supply as data centers proliferate. Sherrill's pledge to freeze electricity rates drew some skepticism from analysts, who wondered if the governor will have the power to make such a move.



CAISO/WEST

New Mexico Renewable Energy Transmission Authority

### WRAP Day-Ahead Market Task Force Looks to Future After Commitments, Withdrawals (p.14)

With more clarity on which entities will participate in WRAP, the task force must now reassess its role and consider whether optimization between EDAM and Markets+ should remain the key goal.



SPP

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### SPP Board Approves 2025 ITP with 4 765-kV Projects (p.45)

The SPP board has approved the RTO's 2025 Integrated Transmission Plan that includes four 765-kV projects, but not without addressing concerns about affordability. The grid operator has agreed to several cost-containment measures to help utilities with their consumers.

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## In this week's issue

# How Rising Wildfire Risks are Rewiring the Future of Power Systems

*By Dej Knuckey*

Dej Knuckey

A drone shot follows wind blowing through tinder-dry grass to transmission lines that clank ominously in the Sierra Nevada foothills. The opening scene of *Apple TV+'s The Lost Bus* is not subtle: The electric utility is painted as the villain behind the fire the down-on-his-luck school bus driver hero has to overcome.

The movie was based on the real-life tragedy that unfolded when a *97-year-old suspension hook* (C-hook) broke, causing a transmission line to fall and spark a fire that took lives, destroyed 18,000 structures and nearly wiped Paradise, Calif., off the map. The 2018 Camp Fire forever harmed the public's trust. In a rare criminal case against a corporation, Pacific Gas and Electric *pleaded guilty* to 84 counts of involuntary manslaughter.

Since then, there have been many other massive wildfires throughout the United States, most notably in Hawaii and California. Some have been *blamed directly on utilities*, such as the Maui fire that destroyed Lahaina. The Palisades and Eaton fires in early 2025 in California caused an estimated $28 billion to $35 billion of insured property losses, the highest wildfire loss *estimate* yet in the U.S.

Grid operators and utilities no longer can afford to view climate-change-fueled wildfire risk as merely an environmental or safety issue. It's a systemic reliability, financial and governance challenge. And it has implications for operations, investment strategy and long-term planning.

This is the third in a series of how extreme climate events affect the grid, following previous features on *extreme heat* and *extreme precipitation*.

## The Climate-wildfire-electricity Nexus

While fires always have been a risk, multiple studies conclude climate change has "led to an increase in wildfire season length, wildfire frequency and burned area," according to *EPA*.

Utility crews working to restore basic services following the Eaton fire in Altadena | *U.S. Forest Service / Benjamin Cossel*

### Why This Matters

To mitigate wildfire risk and minimize future liability, utilities need to integrate climate risk — from fires, floods, and storms — into every capital and operational decision.

The science is straightforward: Higher temperatures and longer dry seasons pull moisture out of vegetation, making it easier to burn. Precipitation that may end a drought also can create excessive growth in grasses and undergrowth, adding fuel for future fires.

Climate change also causes *an increase in lightning strikes*, the main natural cause of wildfires, responsible for 15% of wildfires and 60% of acres burned. That risk will continue to grow: Each 1-degree Celsius increase in global temperature increases lightning strikes by about 12%.

Grid operators and utilities have double exposure to the increasingly fire-prone environment: Grid assets can cause fires and be damaged by them.

There's also a feedback loop when it comes to liability, particularly for investor-owned utilities, according to a *report* from Stanford University's *Climate and Energy Policy Program (CEPP).*

"Because the economic damages from a single catastrophic wildfire can reach into the billions of dollars, the possibility that a utility could be found liable for a fire as a result of its infrastructure causing an initial ignition creates serious financial challenges for utilities," the report said. "This makes IOUs riskier investments, which, in turn, makes it more difficult and expensive for them to access the capital needed to build infrastructure."

Oregon PUC Chair Letha Tawney said liability fears impede data-sharing that could help the industry better understand the root causes of fires. (See *Retribution Fears Impede Wildfire Mitigation, FERC Conference Speakers Say*.)

### 3 Lines of Defense for Wildfire Risk Management

One approach to wildfire risk is to think about preventive measures, proactive response when fires happen and post-fire recovery. An IEEE paper defined these three lines of defense: "The first line of defense focuses on strategies to prevent wildfires from occurring in the first place." It includes prediction, detection and vegetation management.

"The second line of defense is focused on mitigation strategies and proactive response to minimize hazardous impacts of wildfires on the power system and its surrounding natural and built environment, should a wildfire spark." This includes modeling active fires to predict their path and de-energizing lines ahead of the fire's spread.

"Finally, if a wildfire sparks and spreads, we need a third line of defense that is focused on resilience-building measures and recovery preparedness so the system can bounce back to its pre-wildfire condition as quickly as possible without suffering devastating losses."

This includes not only immediate temporary support, but also investing in resilient rebuilding, such as how PG&E is installing distribution lines underground as it rebuilds Paradise, Calif.


IEEE's Three Lines of Defense for Wildfire Risk Management in Electric Power Grids | *IEEE*

### Playing Defense in an Offensive Environment

Utilities, particularly those in the West and Southwest, are taking action, particularly on the first line of defense. For example, PG&E conducts aerial line inspections using LiDAR to identify trees that need trimming. Utilities are hardening lines, replacing aged components and undergrounding selective circuits, an expensive process. In 2023, PG&E lowered the cost of its undergrounding program from $4 million per mile to less than $3 million per mile.

On dry, windy days with high fire risk, utilities can preemptively power down lines. Public safety power shutoffs (PSPS) may lower risk but create public backlash when they stretch into days. It's an example of how utilities must juggle tradeoffs between safety and reliability, as well as liability and service continuity.

Technology is helping to both monitor and manage the grid's wildfire risk, with solutions ranging from pole-based monitoring, such as Gridware, to overhead line sensors, like those from Sentient Energy, as well as hardened components from hardware suppliers like ABB and Eaton.

Fires also complicate forecasting load and, where there are lots of solar assets, generation. "Wildfire smoke causes wiggling in the PV power output, which has the potential to impact the frequency stability of the grid," a research paper found.

Some utilities have tried to get ahead of the financial risks, too. For example, the three largest California IOUs have started a California Wildfire Fund, with a $3 charge each month for account holders; however, the massive 2025 fires will drain funds earlier than expected. A group of policy experts proposed a national wildfire fund to spread risk across states.

While these approaches are needed, many are reactive and localized, focused on risk reduction, not system transformation.

### Operating in the Heat of the Moment

When a wildfire starts, utilities must decide whether and where to power down the transmission and distribution lines. In the 2025 Altadena fires in the Los Angeles area, Southern California Edison (SCE) was criticized for powering down only four of the 12 circuits in the community.

Technology can give utilities and emergency services real-time fire monitoring and precise modeling of where and how fast the fire is likely to spread, based on satellite monitoring feeding into models that account for topography, wind, vegetation cover and more. OroraTech's map of the spread of part of the Eaton fire shows how sophisticated this modeling has become.

Communication between grid operators and emergency services is critical, but often challenging, during a fire. The Associated Press reported that during the 2023 Lahaina wildfires on Maui, dispatchers, the local fire department and the utility, Hawaiian Electric Co., had significant difficulty coordinating. The culprits? Failing cellular networks, downed towers and separate radio channels.

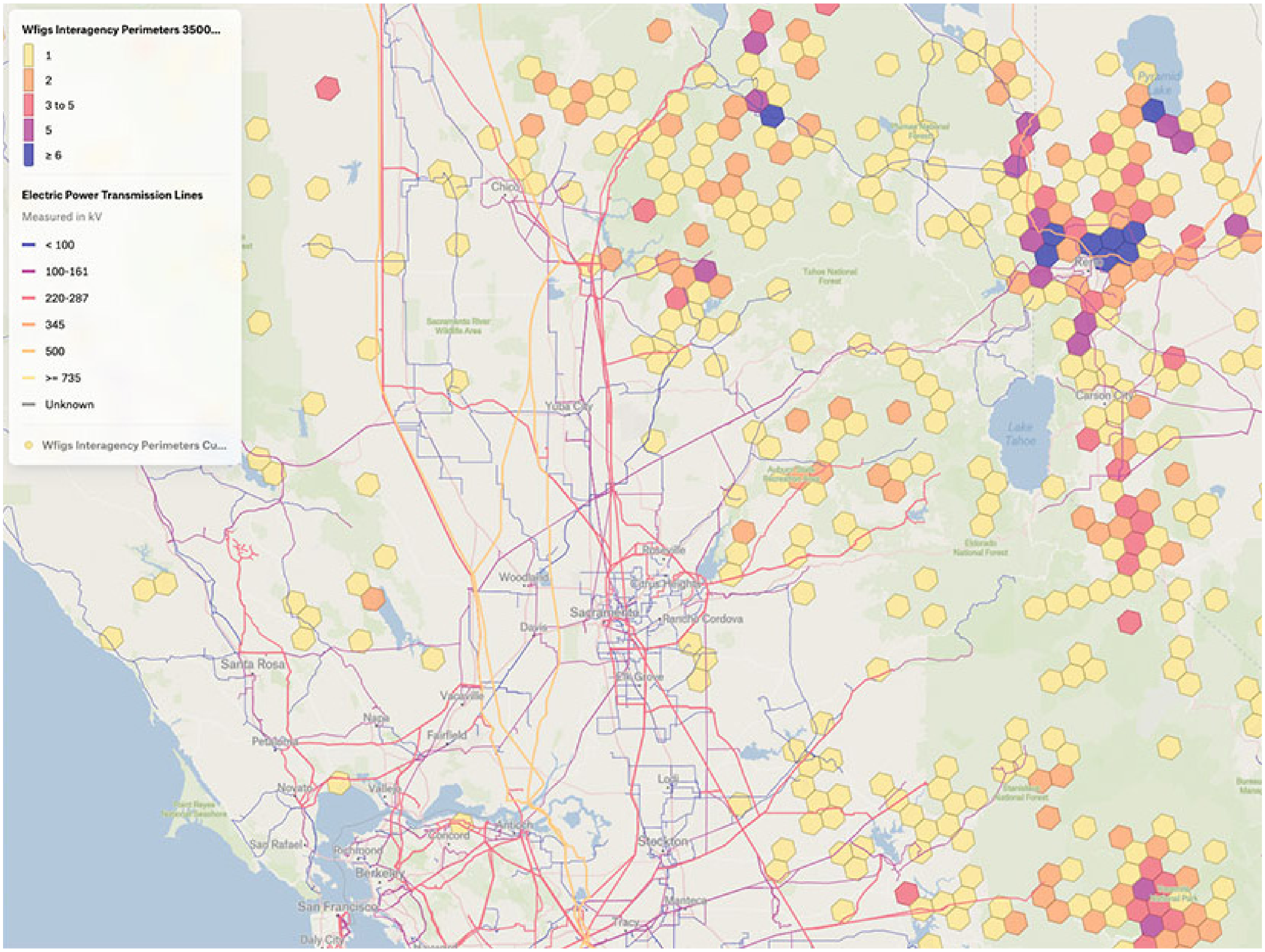
### Toward Climate-adjusted Grid Architecture

Utilities in areas with wildfire risk must treat that risk as a fundamental design parameter, in the same way they plan for load growth or changing generation mix.

There are questions for asset siting: Should critical lines or substations even be in fire zones? And for resilience planning: How should fire exposure be reflected in reliability metrics such as SAIDI and SAIFI? And for investment frameworks: How should regulators support preemptive resilience spending, not just post-event recovery?

The goal should be a climate-adjusted grid architecture with distributed, flexible and modular systems that can operate safely in fire-prone regions. Software, sensors and hardware solutions need to be designed to make a grid that can fail safely or self-isolate.

As remote communities consider their future resilience, the "grid edge" shifts. The main hospital in Paradise, for example, was rebuilt with an islandable 1-MWh energy storage and 425-kW solar microgrid to protect against PSPS and outages. Grid-attached microgrids and




Mapping transmission lines against historic wildfire locations may help utilities plan. | *Felt and National Interagency Fire Center data*

stand-alone systems should be explored for remote communities, a strategy that has worked in *fire-prone remote areas in Australia*, where removing the connection to the grid reduces fire risk for grid and off-grid customers.

The changing insurance and finance landscape will constrain the buildout of climate-adjusted grid architecture: Utilities are facing harder capital environments due to fire risk exposure.

## From Centralized Risk to Distributed Resilience

To achieve a grid that is less likely to cause fires and more able to react to and rebuild resiliently after, there are policy levers at federal and state levels that can help.

While the federal government has reduced incentives for many types of renewables, utilities should lobby to reinstate incentives that support distributed resilience investments.

At the state level, regulators need to assess nontraditional infrastructure investments with an eye on their lifetime value, especially given that the value may be measured in not only homes but also lives saved. The gnarliest issue for regulators is how to balance cost recovery for proactive adaptation while keeping utility bills reasonable.

## The Fire Next Time

Wildfire risk is reshaping the grid faster than most planning cycles can adapt. Yet for utilities and grid operators, rebuilding better after fires and getting ahead of future fires is not optional, it's essential. Without moving from reactive defense to proactive resilience, the grid's assets and their owners' financial health will be at risk.

To mitigate wildfire risk and minimize future liability, utilities need to integrate climate risk — from fires, floods and storms — into every capital and operational decision. As the industry adapts to these risks, there are opportunities to develop innovative business models centered on resilience as a service. There also is a need to build cross-sector partnerships to facilitate smooth coordination with first responder groups on the ground when fires happen.

Wildfire is a risk no one wants, but it's a reality that no longer is a seasonal hazard. Industry leaders who shift their organization's mindsets from "compliance operators" to "resilience stewards" will be best positioned to survive in this new era. ■

*Power Play Columnist Dej Knuckey is a climate and energy writer with decades of industry experience.*

# Turning Industrial Electrification into a Grid Solution

*By Cihang Yuan*

Cihang Yuan

Every day, we push the grid harder — and expect it to keep up. Large new loads like data centers are arriving in clusters, EV sales continue climbing, renewables are growing quickly, and transmission and interconnection timelines run long. In fact, by the end of 2024, *nearly 2,300 GW* of generation and storage were waiting in interconnection queues.

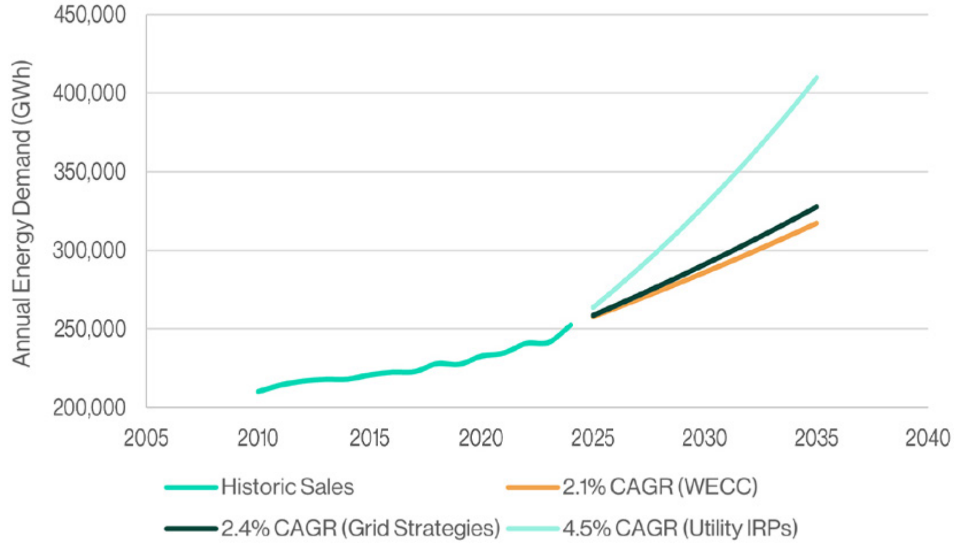
The default solution to these challenges — building our way out of this only with new generation and higher-capacity wires — is expensive and slow. But there's another critical lever to consider: managing when electricity is used, not just how much.

Industrial electrification can help ease grid pressures when it is designed and meaningfully incentivized for flexibility. When paired with thermal storage, electrified heat allows facilities to draw electricity when it is most cost-effective and clean and deliver heat whenever needed.

Industrial heat pumps add controllability, while targeted process scheduling and onsite resources can further smooth a facility's net load. Together, these measures can turn portions of new industrial electrification demand into targeted, verifiable relief at the times and locations the grid needs most.

## Why This Matters

How America chooses to integrate industrial electrification will define the grid for a generation. Treating this new demand as "just more load" risks billions of dollars in avoidable grid upgrades and continued reliance on fossil-fueled peaker plants, says Cihang Yuan, an energy officer for the World Wildlife Fund.




Load growth projections | *WRA*

### What's Stressing the Grid

Today's grid challenges are not just about growth, but about the nature of that growth. Demand is becoming spikier, more concentrated and less predictable.

**Fast, lumpy load growth**: Electricity demand from data centers is surging and is expected to double or even triple by 2028, according to *the DOE projection*. This growth arrives in large, geographically concentrated blocks, stressing local capacity and pushing resource adequacy to its limits. This dynamic dramatically elevates the value of locational, time-specific flexibility — the exact kind that flexible industrial loads are well positioned to provide.

**Supply-side growing pains**: As renewable penetration rises, the grid needs immense flexibility to manage steep ramps, absorb midday solar surplus and reduce costly curtailment. Simultaneously, interconnection backlogs are delaying the supply-side resources needed to meet demand. With the median time from a generation project's grid request to its operation now *at five years*, demand-side solutions that can be deployed faster no longer are a luxury, but a necessity.

**Peak-driven cost pressure:** System peaks drive a disproportionate share of grid costs, from capacity procurement to transmission and distribution investments. Even a modest reduction in peak demand through targeted flexibility can yield significant savings.

### Why Industrial Load is Different — and Useful

While data centers and EVs represent significant new loads, industrial facilities offer a unique combination of scale, predictability and inherent flexibility that makes them ideal grid partners.

**Orchestrating flexibility at scale:** A single industrial facility can offer megawatts of verifiable, dispatchable flexibility. This allows utilities to coordinate with a few large counterparties rather than attempting to aggregate thousands of smaller, less predictable residential devices. While data centers offer similar scale, their uptime and latency requirements limit their flexibility. Industrial processes, by contrast, often are better suited for deeper, more dependable demand-side response.

**Harnessing intrinsic thermal flexibility:** Most industrial processes rely on heat carried in water, steam or storage media. Electrifying heat and adding thermal storage decouple electricity draw from heat delivery. A thermal battery can be charged during low-cost — and usually renewable-abundant — windows while supplying steady 24/7 process heat from stored energy. This powerful load-shifting — further enhanced by controllable industrial heat pumps, hybrid systems and optimized process scheduling — transforms a constant thermal need into a flexible electrical load, well suited for shaving peaks and filling overnight valleys.

**Delivering surgical grid support:** Flexible industrial load can provide targeted relief exactly where it's needed, serving as a non-wires alternative to defer or downsize costly grid upgrades. By adjusting demand at specific substations and during critical hours, these facilities can alleviate local congestion, absorb surplus renewable energy that otherwise might be curtailed and improve overall asset utilization.

## What it Will Take to Unlock Flexible Industrial Load

Realizing this vision requires a strategic shift in how utilities, regulators and industrial customers collaborate. The following steps are critical:

**Illuminate the path with data:** Utilities and grid operators must provide more granular, accessible data on system conditions, such as through public hosting capacity maps. This visibility allows industrial customers to identify locations where the grid can accommodate new load and to right-size their investments in on-site storage and flexible equipment.

**Foster proactive collaboration:** Unlocking industrial flexibility begins with a transparent exchange of information. Utilities should communicate clearly where and when their systems are constrained and define the attributes of the flexibility they value most. In turn, industrial customers should share their electrification road maps and the operational flexibility they realistically can offer. This shared understanding prevents surprises, enables quicker wins and builds a foundation for scaling flexibility over time.

**Price flexibility accurately:** The value of flexibility must be reflected in the price of electricity. Regulators and utilities should design rate structures that align more closely with the real-time system value of flexibility. Today, most rates smooth out the real cost volatility between off-peak and peak hours. For flexibility to scale, pricing needs to move closer to reflecting real system conditions. This can be achieved through sharper, more granular time-of-use differentials, locational or congestion-based rate adders, or multipart dynamic rates that reflect real-time system needs. When industry sees the true value of shifting its load, it will invest to capture it.

**Modernize demand response programs**: For decades, industrial customers have been a critical part of demand response. But most existing programs were built for emergency, event-driven curtailments and haven't kept pace with what newer technologies like thermal storage and flexible heat pumps can offer. Programs should be created or expanded to value load shifting as much as load shedding. By offering simple enrollment and predictable compensation for services like valley filling and peak shaving, utilities can give industrial customers the confidence to invest in the technologies that make their facilities dynamic grid assets.

## Turning New Demand into a Grid Asset

Industrial electrification is coming, and how we choose to integrate it will define the American grid for a generation. Treating this new demand as "just more load" risks billions of dollars in avoidable grid upgrades and continued reliance on fossil-fueled peaker plants.

But a better path is available. For the first time, the very technologies driving new demand — smart heat pumps, thermal storage and advanced controls — also are the tools that can help manage it. By embracing this inherent flexibility, we can turn industry from an electricity consumer into one of the grid's most reliable partners.

Proactive collaboration gives utilities a dynamic lever to manage system stress, offers manufacturers a competitive edge through lower energy costs and cleaner processes, and provides regulators a pathway to a greener grid without increasing energy costs for consumers. The time for collaboration is now. ■

*Cihang Yuan is the World Wildlife Fund's senior program officer for climate and renewable energy.*

# Duke Paper Lays out How FERC Can Make Flexibility for Large Loads Reality

*By James Downing*

FERC can make large load flexibility a reality through the implementation of the Department of Energy's Advance Notice of Proposed Rulemaking on large load interconnections, according to a recent policy *paper* published by Duke University's Nicholas Institute for Energy, Environment & Sustainability (*RM26-4*).

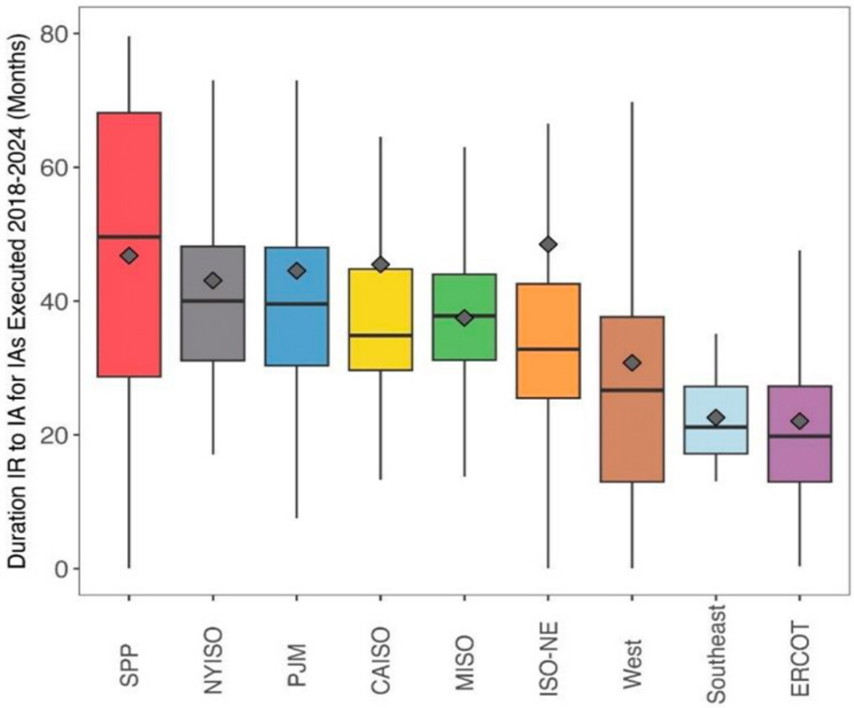
The paper — "How DOE's Proposed Large Load Interconnection Process Could Unlock the Benefits of Load Flexibility" — was written by a group of lawyers from Roselle, a firm "focused on the energy transition," and former FERC Commissioner Allison Clements, now with 804 Advisory. The Nicholas Institute produced a paper on data centers and load flexibility earlier in 2025 that found just 0.5% flexibility could unlock nearly 100 GW of headroom for new data centers. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

The ANOPR mentions flexibility as one way to increase speed to market. The paper is meant to flesh out the details of what FERC can do in the rulemaking to make its use widespread, Roselle partner and co-author Sam Walsh said in an interview Nov. 7.

"There are huge benefits potentially from these kinds of flexibility commitments, [and there are] benefits in terms of speed to power, because if you commit to a flexible operation, there may be fewer needs for upgrades [and] less capacity that needs to be procured," Walsh said. "It's kind of easier for the interconnecting transmission owner to bring you onto the grid, and so the whole thing should be able to be achievable on a faster timeline."

Flexibility from large loads means other ratepayers will not be on the hook for as many upgrades as would be required by data centers and others requiring firm service at peak demand times, he added.

"What we tried to do in the paper is start to kind of roll up our sleeves. … DOE is opening the door to, No. 1, creating a new rule that asserts jurisdiction over large loads interconnecting to the transmission system," Walsh said. "And No. 2, it is urging that load flexibility, curtailability, to be part of that. Then what are they going to actually need to do in this rulemaking to make it happen?"




The Nicholas Institute's policy paper used a chart from Berkeley National Lab that shows how much quicker generator interconnection times are under ERCOT's "connect and manage" approach. | *Lawrence Berkeley National Laboratory*

## Why This Matters

With lengthy times to build new generation or upgrade the grid, load flexibility is an important tool to help large loads like data centers connect to the grid quickly while taking pressure off energy prices and infrastructure costs.

The paper noted that the ANOPR will also set up a jurisdictional battle over interconnection of customers, which historically has been left to the states. The National Association of Regulatory Utility Commissioners is debating a *resolution* at its Annual Meeting on that jurisdiction issue. The meeting, which began Nov. 9 in Seattle, will conclude just over a week before the first round of comments are due *Nov. 21*. (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

Data centers can offer flexibility in several ways, such as by cutting energy use at the sites themselves, sending compute to another site or using on-site resources. Those can include backup diesel, which comes with issues around air permits, and co-located generation and/or batteries.

"Energy supply resources may also be located adjacent to (but not behind the meter of) load, integrating with load to provide joint value (reducing net capacity market impacts for the combined load-supply pair and, largely, the transmission impact), but otherwise operating independently," **the paper says.** "Data center developers have indicated that these types of arrangements are often more commercially workable than the fully integrated energy park model."

Commitments to flexibility can be temporary on behalf of large loads so they can connect to the grid before the five years on average it takes to build a new generator or the transmission grid and distribution system are fully upgraded. Or it could be a permanent commitment.

"Both can provide value to customers: Bridge flexibility can accelerate site energization, defer major upgrades and help ensure affordability and reliability in the near term, while permanent flexibility supports enduring grid optimization," the paper says.

FERC needs to work through several issues to make large load flexibility a reality, including rules around how often data centers would be expected to curtail and what notice they get, Walsh said.

"Similarly, if you're going to enable flexibility to reduce upgrades, you need to have a study process that incorporates that," he added.

Interconnection studies now take a customer's largest load and assume it will fall on the hours that the grid is most stressed, but that will not be the case with flexible loads, Walsh said. "They would need to build in these flexibility commitments into the modeling in order to see … what upgrades might be needed and might not be needed if they operate flexibly."

In regions with capacity markets, large loads should be eligible for at least some kind of discount, allowing them to be non-capacity-backed loads, as PJM originally proposed, Walsh said. (See *PJM Drops Non-capacity Backed Load, Shifts Focus to Resource Queue, PRD*.) The loads themselves will need to face requirements so that they actually curtail when that is needed, he added.

The paper argues that "FERC could consider requiring transmission providers to offer non-firm network transmission service. Such an offering would allow a greater array of hybrid facility and adjacent load-supply arrangements to facilitate additional speed-to-power benefits, perhaps using technical approaches and business models we cannot currently foresee. As more load connects to the system and load interconnection studies more frequently identify network upgrades, such service arrangements could be valuable tools in providing speed to power."

It points to ERCOT's "connect and manage" approach to interconnecting generators as a possible model, as it has helped the Texas market achieve faster interconnections than others.

Flexibility can also help hybrid resources work, Walsh said. The ANOPR discusses such arrangements and indicates pairing supply and demand could be one way to offer hyperscale customers speed to market.

"What we're talking about really is kind of vital to the success of hybrid resources," Walsh said. "If you get into the paper, we talk a fair bit about making sure that flexible loads and hybrid resources have access to non-firm, injection and withdrawal rights. We think that's really critical. There are very few data center operators that don't also want grid access. Even if they have a co-located generator, they want grid access to ensure their uptime." ■

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# Former State Regulators Form Affordability Council

*By Amanda Durish Cook*


*Shutterstock*

The Regulatory Assistance Project (RAP) has assembled nine former state utility regulators to try to make electricity more affordable for ratepayers.

RAP announced the initiative Nov. 6 and said the former commissioners will try to influence regulatory initiatives to "secure access to clean, affordable and reliable energy for all."

The bipartisan council includes:

- Jay Griffin, former chair and commissioner of the Hawaii Public Utilities Commission and executive chair of RAP's U.S. program;
- Kent Chandler, former chair and vice chair of the Kentucky Public Service Commission;
- Megan Decker, former chair and commissioner of the Oregon Public Utility Commission;
- Sarah Freeman, former commissioner on the Indiana Utility Regulatory Commission;
- Carl Linvill, former commissioner on the Nevada Public Utilities Commission;
- Michael T. Richard, former commissioner on the Maryland Public Service Commission;
- Ted Thomas, former chair of the Arkansas Public Service Commission;
- James Van Nostrand, former chair of the Massachusetts Department of Public Utilities; and
- Carrie Zalewski, former chair of the Illinois Commerce Commission.

RAP said the council is necessary as the grid becomes strained by growing demand. It said the group can "speak candidly and with authority" to current commissioners "on what's holding back progress in U.S. energy systems."

## Why This Matters

Nine former commissioners from states spanning the country stand ready to counsel existing regulators and others on how to ensure rates are affordable.

Griffin said the council will offer advice to utility regulators on how to achieve the most meaningful changes through commission action.

"This group understands the pressures on regulators and will serve as trusted peers to commissions throughout the U.S.," Griffin said in a press release.

"At a time when energy issues are becoming increasingly politicized, this council's experience will help today's decision-makers cut through the noise, focus on the most urgent challenges and set the course toward the affordable, safe and secure energy all Americans deserve," RAP CEO Katherine Dixon said in a press release.

Griffin told *RTO Insider* that RAP doesn't plan for the council to weigh in on individual proceedings like rate cases, but it would release statements on topics it deems important.

RAP staff and senior advisers, including some council members, will continue to release reports on regulatory topics and engage directly with commissions, other government entities, utilities and stakeholders, he said. RAP assembled the council "to support today's leaders in state commissions across the U.S."

RAP will hold its first full meeting with the council in December and plans to hold a second meeting in February, Griffin said. It plans to maintain the council for the foreseeable future and is working out the details of council members' terms. He said some "natural turnover" could occur, and he anticipates more former commissioners serving as senior advisers to RAP.

Nationwide, electricity prices have jumped approximately 40% since February 2020, according to the U.S. Bureau of Labor Statistics. The increase is *attributed* to grid modernization, rising data center demand and higher natural gas prices.

Household debt in the U.S. reached a record $18.59 trillion in the third quarter of 2025, up $197 billion from the previous quarter, according to data from the Federal Reserve Bank of New York.

Financial outlets increasingly refer to a bifurcated, "K-shaped economy," where the upper arm of the "K" represents upper-class Americans' income and spending growth since the COVID-19 pandemic, while the lower arm depicts lower- and middle-class Americans struggling with inflation, debt and increasingly expensive necessities like housing and health insurance. ■

# Congress Continues Work on Permitting, but Passing a Bill Faces Major Obstacles

*By James Downing*

WASHINGTON — Permitting legislation is still being developed on Capitol Hill, but the government shutdown and the Trump administration's actions against clean energy projects in Democratic-led states could stop it from happening this Congress.

The Conservative Energy Network (CEN) and Grid Action held a "fly-in" Nov. 5, in which state leaders, business voices and experts held more than 35 meetings with members of Congress and senior staff to push for permitting reform legislation. The meetings included those with members of the House Energy and Commerce, House Natural Resources, Senate Environment and Public Works, and Senate Energy and Natural Resources committees.

"Our permitting system makes it impossible to do things in a reasonable time frame," Rep. Mariannette Miller-Meeks (R-Iowa) said at a press conference hosted by CEN. "And the government, whether it be local, state or federal, is often standing in the way of the market meeting the needs, especially the needs for increased energy demand."

Congress has been working on the issue for years, and the fact that major infrastructure like transmission can take the better part of two decades to build shows change is needed, as Americans pay more for energy than they would otherwise, she added. Miller-Meeks supports the SPEED and Reliability Act, which would amend the National Environmental Policy Act to speed up agencies' review of infrastructure projects. (See *Permitting Hearing Shows Tricky Politics of Getting a Bill Passed*.)

"We have an urgent, growing demand, and the question is whether Congress will act decisively or [continue] to tinker around the margins," Miller-Meeks said.

Asked about the biggest obstacle to legislation this year, Miller-Meeks blamed the government shutdown "created by the Democrats," which officially became the longest in history on the day of the press conference.

Speaking on a webinar hosted by Americans for a Clean Energy Grid (ACEG) in October, Rep. Sean Casten (D-Ill.) noted that Democrats have a different road block for bipartisan legislation.

"The currency of trust is so low when the White House is refusing to even honor existing congressionally mandated spending [and] congressionally mandated legislation," Casten said. Talking about compromising on permitting legislation now is "a little bit like compromising with somebody who just robbed your house and is saying 'you can trust me this time.'"

Grid Action Executive Director Christina Hayes, Rep. Mariannette Miller-Meeks (R-Iowa), and Conservative Energy Network CEO John Szoka at a press conference on Capitol Hill on Nov. 5. | © *RTO Insider*

## Why This Matters

Congress is at work on permitting, but politics mean an actual bill is unlikely in the near future.

While that issue has cut the probability of legislation for now, Congress can still work on developing good policy for "when that door next opens," Casten said.

When it comes to the grid, the issue has less to do with permitting and more to do with the right economic incentives, he argued.

"That sounds crazy," he said. "You'd never know that if you read all the talking heads, or if you looked at the legislation going through Congress." But regulated utilities can build rate-based generation and get it connected to their systems, and the natural gas industry has no problem getting pipelines built despite environmental risks that are arguably bigger than those of high-voltage transmission, he argued.

"The truth is, we have a profit problem," Casten said. "The way that our energy markets are structured, we do not have an incentive to deploy cheap energy. And it comes from the fact that if you are an incumbent in the electricity sector, you lose money if a competitor builds a system on your grid that can underprice you."

Casten said he did not blame utilities because they were following the incentives, so the goal for any legislation should be to change them. The Cheap Energy Act, which he introduced with Rep. Mike Levin (D-Calif.), aims to do that. (See *Federal Energy Policy News Roundup: House Bills and DOE Returns $13B*.)

"How should we rethink the way that electricity markets are structured so that we don't wind up in a situation where every single person who deploys a zero-marginal-cost generator doesn't essentially eat their own investment thesis?" Casten said. "Because, after all, if everybody built renewable power plants and our whole grid was served with renewables, the marginal price of power would be zero, and consumers would win, but there'd be no incentive to build anything. That's not some innate flaw. It's just a problem with the way that we've regulated the structure. We fix that."

As both a policy and political matter, any permitting legislation needs to be technology neutral, Bill Parsons, Berkshire Hathaway Energy vice president of federal legislative affairs, said on the ACEG webinar.

"Now, some people will say, 'Well, as long as the reforms to NEPA and other permitting statutes apply to everything, then that's tech neutral,'" Parsons said. "I think we do need to go a bit further here. There's going to need to be a transmission title."

BHE supported the Energy Permitting Reform Act of 2024 from former Sen. Joe Manchin (I-W.Va.) and Sen. John Barrasso (R-Wyo.). That could be a starting point for a future permitting deal, he said.

"I think we make a mistake when we get overly binary about the policy choices here, and it's either the status quo or a complete federal takeover of transmission," Parsons said. "That's a false choice. There is an opportunity to hive off a very limited number of high-priority national lines, describe them objectively, so people can understand ahead of time what qualifies and what doesn't for consideration at FERC."

The National Governors Association weighed in on the permitting debate recently, releasing a *bipartisan proposal* headed by NGA Chair and Oklahoma Gov. Kevin Stitt (R) and Pennsylvania Gov. Josh Shapiro (D).

"This isn't a Republican or [Democratic] issue. Every American needs to heat their home and power their vehicle," Stitt said in a statement. "As the demand for energy rises as we bring new technologies and AI online, we need to complete energy infrastructure projects in a faster, more efficient way."

The governors' proposal includes reforms for FERC that would have it create a National Interest Designation Process that lets a transmission facility be declared in the national interest after the hearing and consideration of several factors and consultation with the states. Groups of states could nominate National Interest Electric Lines.

FERC would get greater flexibility to allocate the costs of interstate and offshore transmission lines among all beneficiaries.

The governors also want changes to ISO/RTO governance, including giving states, or organizations of states, "jump ball" or complementary filing rights at FERC. ISO/RTOs would be required to improve interregional planning and more robustly consider states' alternative planning options.

Another legal change would be to require ISO/RTOs to process interconnection requests for generation and storage within six months of an initial application. ■

# Amazon Files Complaint Against PacifiCorp for Lack of Data Center Power

## Case at the OPUC Involves 4 Oregon Facilities

*By Elaine Goodman*

Amazon filed a complaint with the Oregon PUC that accuses PacifiCorp of violating agreements to provide power to four data center campuses, saying it had exhausted "all reasonable efforts for resolution."

Amazon Data Services (ADS) filed the *complaint* Oct. 30 with the Oregon Public Utility Commission, saying it had exhausted "all reasonable efforts for resolution with PacifiCorp." Amazon said it invested in the data centers based on PacifiCorp's agreement to provide service.

Amazon is asking the commission to require PacifiCorp to supply the agreed-upon power — or to move the data centers into the territory of another utility that's willing to provide electricity.

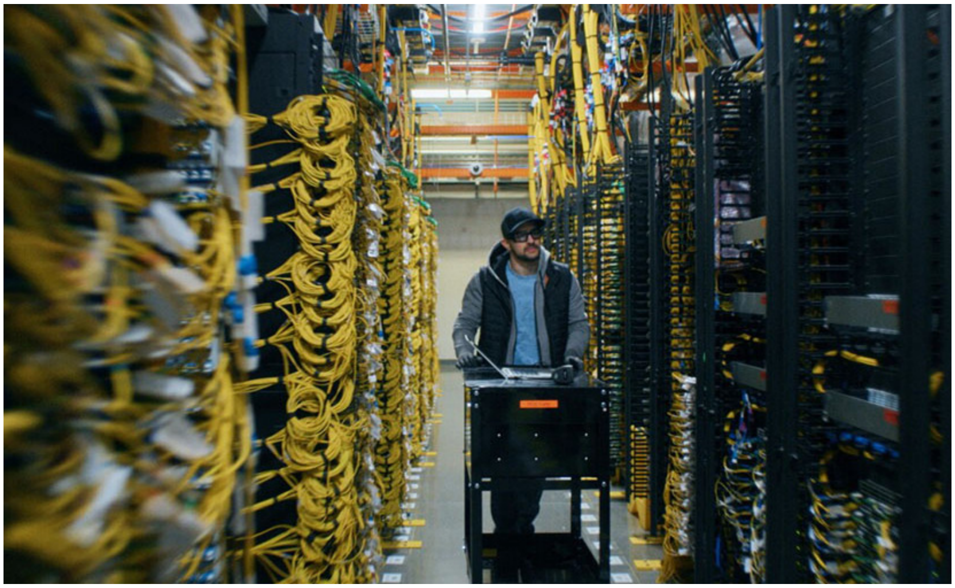
"Despite ADS paying PacifiCorp … under binding contracts, PacifiCorp breached its statutory obligations and contractual duties by failing to supply ADS with the promised power," Amazon said in the complaint.

In a statement provided to *RTO Insider*, PacifiCorp said it has been "acting in good faith to serve Amazon's significant load in a manner that would achieve Amazon's operational goals while protecting PacifiCorp's existing customers from increased costs and reliability issues."

"We are open to ongoing discussions with Amazon to reach a resolution that achieves these goals," the utility said. "It is PacifiCorp's policy position to avoid direct and indirect harms between customers. This is consistent with Oregon law, which ensures new data center loads do not jeopardize customer affordability."

### Why This Matters

Although PacifiCorp has yet to file a formal response to Amazon's complaint, the company said in a statement that it must balance data center demand with affordability and reliability for other customers.



A worker inside an Amazon data center in eastern Oregon | *Amazon Web Services*

PacifiCorp's response filing with the PUC is due Nov. 19; the company asked the commission to extend the deadline for filing a response and a potential motion to Dec. 19.

Amazon said it has been working since 2021 to develop four new data center campuses in PacifiCorp territory in Oregon.

For the first campus, called Specialized, PacifiCorp is "supplying significantly less power than promised," Amazon alleged. A second campus, called Litespeed, hasn't received any power from PacifiCorp, according to the complaint.

And for two other data center campuses, known as Pivot and Gray, PacifiCorp "has refused to even complete its own standard contracting process," Amazon contended.

Amazon also accused PacifiCorp of trying to increase Amazon's costs in the form of a 32.6% "tax gross-up" on capital contributions.

For the Specialized and Litespeed data centers, Amazon and PacifiCorp entered into a series of three agreements. The first two covered preliminary design and engineering work. The third agreement, known as a master electric service and facilities improvements agreement (MESA), required PacifiCorp to complete particular improvements and then deliver power as specified in the contract.

The Gray and Pivot campuses didn't move beyond the first two agreements with PacifiCorp to a MESA agreement. According to Amazon, PacifiCorp told Amazon to forfeit the contracts for the Specialized and Litespeed campuses if it wants agreements for Gray and Pivot.

Amazon's complaint, which was heavily redacted before being filed in the public docket, doesn't show the amount Amazon has spent on capital improvements and development costs under the contracts with PacifiCorp. It also doesn't give the exact location of the data centers, other than saying they're in PacifiCorp territory.

Amazon said the four data centers in its complaint would complement existing data centers in the region. The company's data center portfolio includes facilities in Morrow and Umatilla counties in Eastern Oregon. ■

# WRAP Day-Ahead Market Task Force Looks to Future After Commitments, Withdrawals

## Group Holds 1st Meeting After WRAP Binding Phase Deadline

*By Henrik Nilsson*

The Western Resource Adequacy Program's Day-Ahead Market Task Force held its first meeting after the program's binding decision deadline, with members exploring how the new, smaller participant footprint will affect transmission connectivity and other issues.

The task force was created to make WRAP compatible with the soon-to-be-launched SPP Markets+ and CAISO Extended Day-Ahead Market (EDAM). WRAP was designed before the two markets completed their designs. (See *WRAP Day-Ahead Market Task Force Moves Forward on Concept Paper*.)

Task force members in the Nov. 4 meeting discussed how to move forward after it became clear that most of the entities signing up for the WRAP's first financially binding deadline have committed or lean toward Markets+.

"The DAM Task Force's first meeting after the binding decision deadline was focused on understanding how the group should advance given the change in footprint and committed binding participation," Michael O'Brien, WPP's senior policy engagement manager for the WRAP, said in an email to *RTO Insider*.

New Mexico Renewable Energy Transmission Authority

"They agreed to explore how Markets+ could be leveraged to serve committed WRAP participants: those participating in Markets+ and those not participating in Markets+, while keeping an eye on how those who gave exit or may join in the future can leverage the DAM Task Force proposal to ensure they also receive the benefits of WRAP should they decide to participate in a binding season at some point," O'Brien said. "It is a priority for WPP and a stated priority of the DAM Task Force that the proposals remain inclusive of future broader participation in WRAP."

Interested participants had until Oct. 31 to commit to the program's first binding season. Of the 16 committing, just two — Idaho Power and Seattle City Light (SCL) — have expressed leanings in favor of EDAM, although SCL's geographic position adjacent to future Markets+ members — including BPA — could make participation in the CAISO market a challenge. (See *WRAP Wins Commitments from 16 Entities*.)

Among the five utilities withdrawing from the WRAP, four (NV Energy, PacifiCorp, Portland General Electric and PNM) have committed to joining the EDAM, while Eugene Water & Electric Board will be participating in Markets+ by virtue of its location within the Bonneville Power Administration's balancing authority area.

With more clarity on which entities will participate, the task force should prioritize transmission connectivity, Matt Hayes, task force co-chair and program manager at the BPA, said at the Nov. 4 meeting.

"I think this group really needs to prioritize how we can bridge that gap between … the commercially available transmission, which is extremely limited, and the connectivity that the markets have throughout the region, which is pretty ample," Hayes said.

Hayes said the task force must push WRAP "to not only be something that holds people accountable but leverages to the greatest extent possible the geographic diversity we have and the diversity of resources to … not only ensure the resource adequacy is met but also make it as cost-effective as possible for us."

### Why This Matters

With more clarity on which entities will participate in WRAP, the task force must now reassess its role and consider whether optimization between EDAM and Markets+ should remain the key goal.

He noted some entities still are exploring whether to join a day-ahead market, saying, "I would caution about being too quick to focus on any one particular path."

For Idaho Power, which is leaning to EDAM and committed to the WRAP's first binding season — while expressing concerns about the program's readiness, a key issue is connectivity requirements and how the utility should navigate between WRAP entities in the Desert Southwest with those in the Pacific Northwest, said Benjamin Brandt, director of load-serving operations at the utility.

"Idaho Power is somewhat between those two areas," Brandt said. "So better understanding of the Markets+ footprint and connectivity … and what that might look like, I think that would be a good place for us to start."

Derek Russell, director of power at Powerex, agreed, saying he wants the task force to refocus on "connectivity and deliverability" to ensure participants can rely on WRAP transfers.

"I think a focus on just reassessing what the region looks like and … how those transfers are enabled between participants, I think that should be a point of emphasis as we kind of go through towards an ultimate solution," Russell said. ■

# Nonprofits Ask 9th Circ. to Vacate BPA's 'Shocking' Day-ahead Market Decision

## Groups File Opening Brief in Suit Over Agency's Markets+ Choice

*By Henrik Nilsson*

The group of nonprofits suing the Bonneville Power Administration in the 9th Circuit Court of Appeals filed its opening brief, saying BPA's decision to join SPP's Markets+ instead of CAISO's Extended Day-Ahead Market "violated clear mandates from Congress."

Shutterstock

The group filed the *opening brief* Nov. 3, urging the court to vacate BPA's record of decision to join Markets+. It also asked the court to order the agency to launch an Environmental Impact Statement (EIS) process.

Represented by Earthjustice, the organizations suing BPA include NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board and the Sierra Club.

"Bonneville's failure to comply with the Power Act's requirement to ensure its policy decision would keep power costs low in the Pacific Northwest while protecting environmental quality, and Bonneville's decision to ignore its obligations under [National Environmental Policy Act], violated clear mandates from Congress," the brief states. "Vacatur is the appropriate remedy here."

On May 9, BPA issued its long-awaited decision to join Markets+ over EDAM. The announcement came after a lengthy debate over which day-ahead market would provide the most benefits to BPA and its customers. (See *BPA Chooses Markets+ over EDAM*.)

The plaintiffs in the underlying suit filed their claims July 10, alleging the agency failed to factor in environmental impacts and financial considerations in violation of the National Environmental Policy Act, the Pacific Northwest Electric Power Planning and Conservation Act and the Administrative Procedure Act. (See *BPA Sued in 9th Circuit over Day-ahead Market Decision*.)

### 'Fight for It'

The opening brief reiterates many of the allegations in the lawsuit. For example, the plaintiffs claim BPA failed to consider several cost analyses showing the purported benefits of EDAM over Markets+.

The brief cites an analysis by state agencies in Washington and Oregon using BPA's data that found the agency could have saved its customers $4.4 billion through 2035 by joining EDAM.

Those arguments follow a production cost study by Energy and Environmental Economics (E3) commissioned by BPA in 2024 that showed participation in EDAM under certain scenarios could deliver the agency up to $106 million in greater benefits than Markets+.

BPA also allegedly violated NEPA by failing to conduct an EIS and assess the environmental effects of its day-ahead market choice, according to the plaintiffs.

"It is shocking that the Bonneville Power Administration chose to undermine our grid reliability and forego $4 billion in reduced power costs for the Pacific Northwest region by choosing Markets+," Jaimini Parekh, senior attorney with Earthjustice, told *RTO Insider*. "Low-cost, renewable power is available to our region if BPA chooses it, and we will fight for it through this case."

A BPA spokesperson told *RTO Insider* the agency does not comment on active litigation. SPP also declined to comment.

However, BPA has argued its day-ahead market process was conducted with significant stakeholder input, noting in its final market decision that other electric utilities weighing which market to join have done so "without public process or transparency."

As for the production cost studies, the agency has contended those failed to factor in other key issues, like governance. BPA says the SPP market's governance structure is "superior" to EDAM's, despite ongoing efforts by the West-Wide Governance Pathways Initiative to relax the state of California's oversight for CAISO's EDAM and WEIM.

Several trade organizations have filed motions to intervene in the suit in support of BPA, including SPP, Public Power Council, Alliance of Western Energy Consumers, Pacific Northwest Generating Cooperative and Northwest Requirements Utilities. (See *BPA Supported by Trade Orgs in Suit over Day-ahead Market Decision*.)

The BPA supporters have also highlighted Markets+'s governance approach and "overall design."

PPC Director of Market Policy and Grid Strategy Lauren Tenney Denison told *RTO Insider* the organization "has repeatedly commented that we disagree with the assumption that Markets+ participation will increase power costs in the Northwest."

Tenney Denison noted E3 has issued an updated analysis that reinforced "PPC's perspective that there are broad directional benefits from day-ahead market participation, but the analysis falls short of encapsulating the aggregate impacts to preference customers of BPA's day-ahead market decision."

"This uncertainty around economic results leads PPC to place a higher importance on other aspects of the decision," Tenney Denison said. "PPC continues to place significant value on the inclusive stakeholder-driven governance framework in Markets+. The value associated with BPA having a voice in how the market develops and responds to regulatory, legislative and operational needs will likely significantly outweigh the differences in market footprint estimated by production cost studies." ■

# 2 Regions Under Elevated Risk in Upcoming WECC Winter Assessment

## Changing Resource Mix Could Pose Challenges, Reliability Analyst Says

By Henrik Nilsson

Idaho Power

The Western Electricity Coordinating Council expects two regions to be under elevated risk as the West heads into the winter, with staff saying a prolonged weather event could impact operating reserves.

Speaking at a Nov. 4 WECC *webinar* about the organization's upcoming 2025 winter reliability assessment, Matt Zapotocky, senior reliability assessments engineer, said the Northwest and Basin regions are at elevated risk — meaning there is potential for insufficient operating reserves in case of an extreme cold weather event coinciding with elevated demand or a significant reduction in resources.

The two regions cover Oregon, Washington, Idaho, Montana, Utah and western Wyoming.

A prolonged cold weather event in those areas could lead to "power not being available and the inability to maintain their operating reserves, and that's why they were suggested as elevated this year in the assessment," Zapotocky said. "However, it should be noted that neither area should have lost load for the upcoming winter, assuming there is import availability for both regions."

James Hanson, manager of operations analysis at WECC, said a major concern is the impact of cold weather events on warmer regions, as seen in January 2024 during Winter Storm Heather.

"There were some significant challenges that parts of the interconnection were facing during that time," Hanson said. "We fared relatively well. I think … readiness plans, making sure critical components on your power plants are able to withstand those extreme colds, I think that really boded well for a lot of our generation."

### Why This Matters

The West enters winter with a changing resource mix that could prove challenging in the case of an extreme weather event.

Still, if cold weather extends into a more temperate area "like the Desert Southwest, we could see some operating challenges for sure," Hanson said.

The resource mix also plays a role in the winter assessment. The West is expected to see approximately 4 GW of coal retirements in 2025, along with about 1 GW of planned natural gas retirements. However, some of the natural gas retirements will be offset by natural gas additions projected to come online in January 2026, Zapotocky said.

Those resources are valuable in the winter and can effectively address unplanned and forced outages, he added.

Though the West will see about 11 GW of solar and 7 GW of wind added across the Western Interconnection, inverter-based resources are more at risk during cold weather events, Zapotocky noted.

"Wind turbines can be susceptible to icing or cold weather cutouts, or even overspeed if the winds are strong enough," Zapotocky said. "Solar capability can either just not be available if it's a morning peak and it's still dark out or just be severely limited due to snow or cloud coverage."

WECC anticipates over 10 GW of battery energy storage coming online this winter, but those systems can only "provide about four hours of discharge," Zapotocky said.

"So if you have a prolonged weather event, that may not be enough to quite get you through it," he added. "There have to be strategies to stagger their use."

The additional capacity of wind, solar and batteries will be of "particular importance" to the Northwest as the region is forecasting a winter peak 9% higher than last year's forecast, according to Zapotocky.

WECC will publish the full winter reliability assessment Nov. 13. ■

# CPUC Approves New SDG&E Electrification Budget

## About $13 Million Allocated for Existing Customer Projects

*By David Krause*

In a rare split decision, the California Public Utilities Commission has approved $51.2 million in additional funds for electrification projects for San Diego Gas & Electric customers to help the state reach its carbon neutrality goal.

Under the *decision* (25-04-015), SDG&E will create a new electric energization memorandum account (EEMA) for energization projects that will be completed outside the utility's approved 2024 general rate case (GRC).

SDG&E originally requested about $310 million for EEMA projects between 2024 and 2026, but the CPUC at its Oct. 30 voting meeting reduced the request by 83%, saying the utility already has other methods for recovering electrification project costs.

"By most measures, SDG&E has been meeting commission goals for interconnection," CPUC Commissioner Matthew Baker said at the voting meeting. "This proceeding is the result of state legislation stemming from concerns that some utilities have been unable to keep up with requests to connect to the grid."

Energization projects include those that connect new customers to the distribution grid and those that upgrade distribution or transmission capacity and infrastructure for new and existing customers.

The decision is part of *Senate Bill 410*, signed by Gov. Gavin Newsom in 2023, which requires the CPUC to ensure that electric utilities can recover energization project costs in a timely and complete manner. Part of the bill intends to increase the speed of energization and service upgrade projects.

About $13.4 million of SDG&E's EEMA budget will be for projects that increase capacity of existing customers; about $27.3 million will be for projects for new customers; and about $10.5 million will be for materials, such as transformers.

Commissioner Darcie Houck voted against the decision, saying it "should not include backward-looking caps for 2024 costs that have already been incurred."

"SB 410 requires the commission to establish annual cost caps, which can be reasonably interpreted to mean cost caps set in advance of the utility incurring those costs," Houck said at the meeting.

CPUC President Alice Reynolds replied that she found Houck's comments "hard to follow."

© RTO Insider

### Why This Matters

The CPUC provided a new cost recovery bucket for SDG&E for customers who are increasing their electricity load. However, some commissioners wondered whether the move will increase customer rates yet again.

"I might have misheard, but I think there were a few inaccuracies, so I'm just gonna try to be really clear," President Reynolds said. "The energization cost caps here are really designed to accelerate energization while also staying grounded in our statutory direction."

Commissioner John Reynolds added that the amount of new ratemaking structures outside general rate cases has made it "harder for us to take [a] holistic view and harder for the public to have a clear picture of rate impacts."

"It also means that rates change more often and we've heard complaints about this from members of the public," he said. "On the other hand, GRCs only occur every four years and technology changes on shorter timescales."

In comments noted in the decision, The Utility Reform Network (TURN) said SDG&E has not demonstrated any need for additional funds over the amounts it received in its GRC to meet customer energization demands.

TURN said that in March, "SDG&E stated that it considered it an 'unlikely event' that the utility would be 'unable to accommodate the full load amount requested by the customer because of an upstream capacity constraint.'"

SDG&E said it will use the funds it seeks in this application to improve its performance for additional types of energization projects, such as extending lines to new developments and electric vehicle charging infrastructure, the decision says. ■

# EDAM Intertie Scheduling Processes Raise Stakeholder Concerns

## CAISO Asked to 'Dumb Down' Language Around Policy

*By David Krause*

More than 400 stakeholders attended a set of workshops where CAISO staff described new processes for scheduling intertie resources and resource adequacy imports in the ISO's Extended Day-Ahead Market, which will begin operation in May 2026.

ISO staff used the Nov. 5 and 6 workshops to review a *white paper* on the subjects.

"I haven't seen [this many participants] on a CAISO call since you were dealing with the 2020 blackouts," said Dan Williams, principal adviser at The Energy Authority.

One of the new EDAM processes involves intertie resource bidding and scheduling. Intertie resources in CAISO are currently modeled at specific scheduling points, but under EDAM, those resources will be modeled at a generation aggregation point (GAP).

A GAP is the collection of supply resources in a balancing authority area or group of BAAs.

EDAM will have three types of GAPs: default, custom and generic. A GAP can be resource specific or not, and its location will be in a Western Energy Imbalance Market (EIM) or non-WEIM BAA where the energy is produced or consumed, CAISO staff wrote in the white paper.

The GAP approach will significantly improve power flow and market accuracy, improve alignment with actual power flows by reducing phantom congestion and reduce operator conformance of transmission limits in real time, staff wrote.

CAISO Executive Principal George Angelidis described five intertie resource types: system resources, intertie transaction resources, intertie generating resources, transfer system resources and mirror system resources.

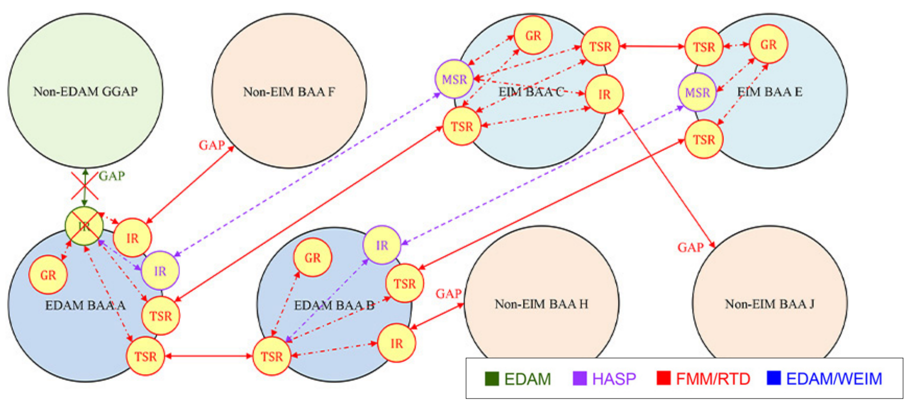
Some participants said they were unclear about these terms.

"I am already a little lost between the difference between a system resource and an intertie generating resource," said Carrie Bentley, CEO of Gridwell Consulting. "The words seem almost exactly the same. I'm wondering if it would be helpful to ground us all in what all these different terms are for and maybe … dumb it down for us."

"Both the system resource and intertie generating resource are registered in the master file," Angelidis said. "The system resources in implementation are non-resource specific intertie resources."

Williams added: "We are seven months out from this [process] being a live part of CAISO's market, and as far as I am aware today, there are sort of two sources of power that trade in the forward market: a CAISO source and a non-CAISO source."

"Western markets are not set up to be trading with any amount of liquidity on a resource-specific basis in the pre-day-ahead market space," Williams said.




This is an example of how intertie scheduling from/to a non-EDAM GGAP will work in EDAM | *CAISO*

### Why This Matters

CAISO's Extended Day-Ahead Market will begin operations in May 2026, and ISO staff are working through many complex implementation processes.

The paper introduced indirect intertie scheduling in EDAM. CAISO currently offers direct scheduling at interties but will now include indirect scheduling in EDAM to allow non-EDAM BAA resources to wheel power through a WEIM BAA that requires explicit wheel-through schedules, the paper says. Indirect scheduling is more complicated than direct scheduling and requires coordinating schedules of multiple resources, the paper says.

EDAM's implementation overall has been "going smoothly," although the schedule remains "very tight and very aggressive," CAISO staff said in October. (See '*Aggressive' EDAM Schedule 'Going Smoothly' for PacifiCorp, PGE.*)

### RA Import Changes

The paper also described generic RA import requirements.

CAISO tried to simplify monthly RA showings in EDAM. Monthly generic RA showings will not be resource specific, and scheduling coordinators who have generic RA import obligations will show these obligations in the ISO's customer interface for resource adequacy (CIRA) system.

The paper also described requirements for imports of flexible RA. Monthly flexible RA will be resource specific, and CIRA will confirm that a scheduling coordinator has obtained the maximum import capacity at the intertie. If the source of the flexible RA obligation is in a non-WEIM BAA, the custom GAP must be the location of a physical resource in that non-WEIM BAA, the paper says. ■

# IESO Preps for 'Virtual' Corporate PPAs

## Off-site Generators Gain Eligibility in Industrial Conservation Initiative

*By Rich Heidorn Jr.*

IESO will begin allowing corporate energy buyers to purchase power from off-site renewable generators next spring, giving loads another way to reduce their Global Adjustment (GA) charges.

The new policy will be effective for the 2026/27 base period (May 2026-April 2027) for determining loads' GA charges.

The *C-PPA framework* allows participants in the Industrial Conservation Initiative (ICI) to sign "virtual" power purchase agreements with renewable generators — defined as wind, water, biomass, biogas, biofuel, solar or geothermal — located anywhere in Ontario.

Before the June rule change by the Ministry of Energy and Mines (*Regulation 429/04*), the ICI program allowed only on-site PPAs, in which electricity is generated and consumed at the same location, behind the meter. ICI is designed to reduce large electricity users' consumption during peak hours.

### What's Next

IESO plans to post final documents on the program by January before opening the C-PPA submission window Feb. 1.

The revised regulation will help large consumers reduce their electricity costs and meet clean energy goals, while providing an additional revenue source for generators and supporting new generation investment, IESO said in an *engagement session* outlining the program Nov. 4.

### Potential Global Adjustment Savings

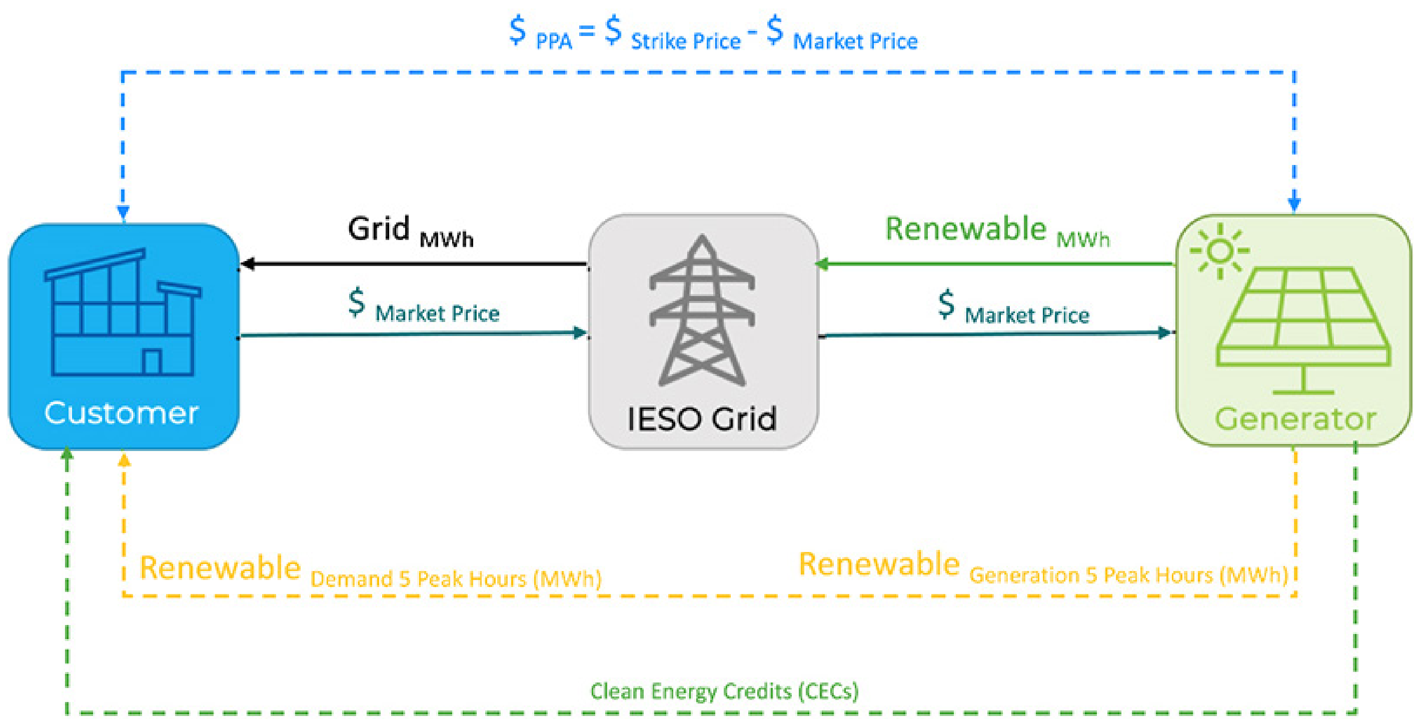
C-PPAs handle financial settlements separately from the physical delivery of electricity, with the generator's output offsetting the consumer's demand during peak periods.

ICI participants that cut their usage during the top five peak hours over a 12-month base period (the *peak demand factor*) can significantly reduce their GA charges. The GA funds new grid infrastructure as well as maintenance and conservation programs.

### Eligible Loads

ICI participants, called "Class A" customers, include:

- manufacturing and industrial loads, including greenhouses, with an average monthly maximum hourly demand between 500 kW and 1 MW;
- customers with an average monthly maximum hourly demand between 1 and 5 MW, which can opt in to the program; and
- customers with an average monthly maximum hourly demand greater than 5 MW, which are automatically entered into the ICI program unless they opt out.




C-PPA contracts will enable electricity to flow through the IESO grid and be settled at the applicable market price. The customer and generator each settle the market price through the IESO and separately settle the difference between the strike price and market price. | *IESO*

### Generator Eligibility

The program allows participation by generators and customers that are distribution-connected if they are registered as a market participant and settled in the IESO market.

New generation facilities are eligible to participate if they have a municipal resolution of support and are not located on Prime Agricultural Land.

C-PPA transactions must be settled through the IESO market.

### 'Stacking' OK

The new rules allow generating facilities and customers to "stack" multiple PPAs. But they limit the "eligible" electricity under the program to that which has not already been paid for or committed ("compensated" electricity), such as that procured through IESO contracts.

"The fundamental principle is that the regulation does not permit double recovery," IESO's Keigan Buck said. "A given unit of electricity can be either eligible electricity or compensated electricity. [It] cannot be both."


IESO's Keigan Buck (left) and Greg Moore | *IESO*

### 'Eligible' Electricity

Generators must deliver to the IESO grid or distribution system "*some volume*" of eligible electricity in each hour of the base period without using temporary storage.

"Based on the IESO's current interpretation, we understand the regulation's requirement for generators to deliver … any non-zero amount of energy — essentially any volume above 0 MWh," IESO spokesman Michael Dodsworth said.

The rules provide exceptions to the delivery requirement for facility outages, insufficient wind or sunlight, compliance with IESO dispatch instructions or circumstances beyond the generator's control, such as delivery constraints.

### Next Steps

IESO is accepting *feedback* until Nov. 18 at *engagement@ieso.ca*. It plans to post final documents on the program in December or January.

The C-PPA submission window opens Feb. 1, 2026, and closes March 30. Submissions must be sent by email to *corporateppa@ieso.ca*.

"We strongly encourage submitting early within the window, because some of the timelines are quite tight for approval of the documents, and it may require some back and forth between proponents and the IESO," the ISO's Greg Moore said. ■

# ISO-NE Forecasts Minimal Shortfall Risk for Upcoming Winter

*By Jon Lamson*

ISO-NE's probabilistic modeling indicates there is minimal risk of shortfall in the upcoming winter, COO Vamsi Chadalavada told the NEPOOL Participants Committee on Nov. 6.

The risk levels identified by ISO-NE's Probabilistic Energy Adequacy Tool are well below the duration and magnitude metrics recently established by the RTO in its Regional Energy Shortfall Threshold (REST). (See *ISO-NE Proceeding with Shortfall Threshold After Positive Feedback*.)

The REST shortfall metrics are calculated based on the 0.25%, 21-day model cases with the greatest shortfall risk. These extreme model cases averaged a 0.1% shortfall magnitude and a 0.7-hour shortfall duration for the upcoming winter, well shy of the 3% magnitude and 18-hours criteria that would need to be exceeded to violate the REST.

Chadalavada said ISO-NE is confident it can maintain grid reliability even in the worst-case scenarios.

"The worst-case 21-day energy shortfall quantities result from a low probability combination of several uncertainties," including low LNG and fuel oil inventories, low import levels and high levels of unexpected outages, Chadalavada said.

"In the worst cases, energy shortfall begins on Day 14 or later, thus allowing time for additional actions," he said. "ISO expects that in the event of a forecasted energy shortfall, market-based incentives will encourage relief in the form of market response, including additional fuel replenishment."

If ISO-NE's 21-day forecast indicates a shortfall is likely, the RTO would have access to other emergency measures, including limiting exports, scheduling imports, seeking waivers to air permit limits and conservation appeals, he said.

Seasonal weather forecasting shows a 33 to 40% probability of above-average temperatures for southern New England, and equal changes for above average and below average temperatures in northern New England, Chadalavada said.

He said ISO-NE anticipates the tanks at the Saint John LNG terminal being full, and he added that generators with large fuel oil storage capabilities have indicated "that pre-winter replenishment is underway and supply chains are expected to be strong with adequate supply available."

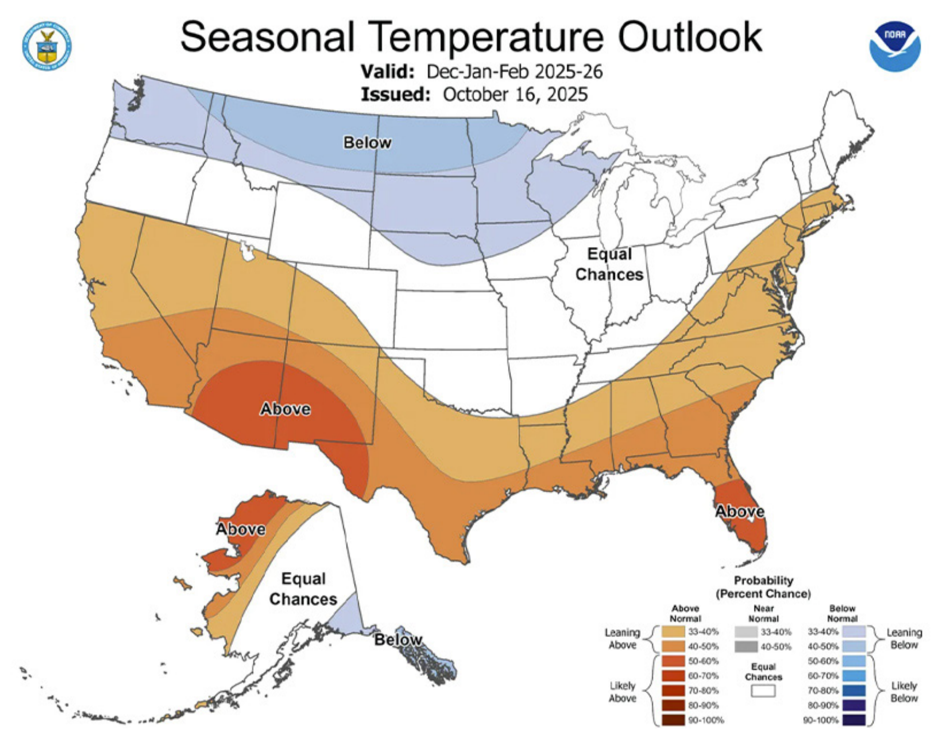
## Operations Report

Energy market value totaled $429 million in October, up significantly from $350 million in October 2024, ISO-NE reported. Ancillary market value totaled nearly $17 million, more than double the $8 million total in the prior October.

ISO-NE recorded its first monthly net export in 13 years in October, Chadalavada noted.

The low import levels appear to be driven by continued *drought* conditions and low reservoir levels in Québec and also may be affected by Hydro-Québec's looming baseload export commitments associated with the New England Clean Energy Connect and Champlain Hudson Power Express transmission projects.

Hydro-Québec has said it is managing its reservoir levels to ensure it will have enough power to meet these commitments. ISO-NE expects NECEC to be in service this upcoming winter. (See *Drought, Climate Drive Uncertainty on New England Imports from Québec*.) ■




NOAA 2025 seasonal temperature outlook | *NOAA*

### Also at the Meeting

ISO-NE recorded its first monthly net export in 13 years in October, which likely was driven by drought conditions and low reservoir levels in Québec, and may have been affected Hydro-Québec's looming baseload export commitments to the U.S.

# Incoming ISO-NE CEO Chadalavada Outlines Multiyear Road Map


ISO-NE board Chair Cheryl LaFleur speaking at the public board meeting Nov. 5. | © *RTO Insider*

*By Jon Lamson*

BOSTON — Incoming ISO-NE CEO Vamsi Chadalavada emphasized the importance of innovation and a forward-looking approach to prepare for the future grid in his remarks at the RTO's annual open board meeting Nov. 5.

Discussing the RTO's 2027-2030 road map, Chadalavada said ISO-NE must continue to lay the groundwork for the incorporation of increasing amounts of inverter-based generation, storage, retail demand resources, grid-enhancing technologies and increasingly advanced software.

## Why This Matters

Chadalavada's remarks may give some indication of how he plans to lead the RTO when he takes over as CEO in 2026.

"It's really important for the ISO not to be a barrier" for the incorporation of new technologies on the grid, said Chadalavada, who has served as COO since 2008. He added that he remains "very mindful that our core mission is to maintain reliability through efficient wholesale markets."

Chadalavada, who will replace Gordon van Welie as CEO in 2026, joined ISO-NE in 2005. (See *Retiring ISO-NE CEO van Welie Reflects on 25 Years at the RTO*.) The change in leadership comes at a critical point for the RTO, which faces the simultaneous, interrelated challenges of accelerating load growth and increasing levels of intermittent renewable generation.

With both demand and supply likely to become increasingly variable, ISO-NE is working to develop "a foundation of new probabilistic forecasts to manage grid uncertainties," he noted.

Earlier this year, ISO-NE *announced* its plans to develop a "dynamic, real-time probabilistic forecast of the system's energy ramping needs," which could be used to determine how much reserves the RTO procures on a given day. These changes are aimed at more efficiently managing operational uncertainties, ISO-NE has said.

"Everything we do has to make sure that the existing grid is optimized to the greatest extent possible," Chadalavada said. "We don't want to wait for the day when we have 25 GW of inverter-based resources; we want to lay the groundwork now."

Chadalavada also said ISO-NE will likely increase its investment in artificial intelligence to help speed up the development of several initiatives. Citing one example, he said ISO-NE operating guides can take an "extraordinary amount of time" to develop, and the RTO hopes to put "innovation and AI to great use" to expedite these processes.

He said speeding up markets or operations projects at ISO-NE should have a positive effect on innovation within the wholesale markets. He also stressed the importance of integrating the RTO's internal models, studies and processes.

"To address operational uncertainties over the coming years, ISO markets and operations initiatives will be tightly interwoven, in practice and purpose," he said.

Also speaking at the meeting, van Welie reflected on his long tenure leading the RTO. He said the implementation of wholesale markets has had widespread positive effects, including attracting more investment, reducing consumer costs and lowering emissions.

"One of the big points of these markets was to have the risk of investments stay with investors, rather than be passed onto consumers," he said.

He also said the region has benefited significantly from forward-looking transmission investments that enabled gas generators to replace dirtier and less efficient coal and oil resources, and ultimately "gave us the foundation for introducing the first grid-scale renewables onto the fleet."

He expressed optimism that ISO-NE's ongoing Longer-term Transmission Planning procurement "is going to help us open a path into Maine, where there is a lot of land-based wind potential."

Van Welie said he is disappointed that demand-side resources have not advanced as quickly as he hoped but said these resources will be a critical component of the future grid.

Several members of the public spoke at the meeting, emphasizing the urgency of decarbonizing to minimize the effects of manmade climate change and urging the RTO to take bolder steps to help cut emissions.

Community organizer Mireille Bejjani addresses the ISO-NE Board of Directors. | © *RTO Insider*

"The window for preventing the worst climate outcomes is rapidly closing," said Lilly Worthley, a member of Fix the Grid.

The group, which is supported by many climate and environmental organizations in the region, distributed a statement that included a series of recommendations aimed at increasing ISO-NE's accountability to the public. It called on the RTO to:

- improve its community engagement processes;
- add state representation to the Board of Directors;
- increase opportunities for public participation; and
- add climate and affordability priorities to its mission statement.

Activists applauded some of the steps taken in recent years by ISO-NE, including the establishment of the annual open board meeting, the creation of a community affairs policy adviser position and the RTO's advocacy for offshore wind at the federal level.

But more work needs to be done to increase transparency, accessibility and accountability, Fix the Grid wrote in its statement.

"We believe the upcoming leadership transition provides a real opportunity for a new chapter at ISO-NE, to steer the region toward a cleaner, more just energy future," the group said. ■

# Load Growth Outpacing Distributed Generation, Eversource Says

By Jon Lamson

Weather-normalized electricity demand has increased by about 2% this year in Eversource Energy's service territories in New England, in part due to heating and transportation electrification, CEO Joe Nolan said during the company's third-quarter earnings call.

Nolan expressed optimism about new transmission opportunities to meet this load growth, along with the potential for a more favorable regulatory environment in Connecticut in the wake of the resignation of Connecticut Public Utilities Regulatory Authority (PURA) Chair Marissa Gillett. (See *Escalating Conflict with Utilities Leads to Resignation of Top Conn. Regulator*.)

## Why This Matters

After years of relatively stagnant power demand in New England, the load growth experienced in Eversource's service territories could mark the start of a steady increase in region-wide demand anticipated by ISO-NE.

"Load growth in our service territory has started outpacing the impacts of distributed generation such as rooftop solar," Nolan said on the Nov. 5 call, adding that the company experienced a peak load of more than 12 GW during the summer, its highest peak since 2013. The company's service territory covers parts of Massachusetts, New Hampshire and Connecticut.

The increasing demand has been "driven primarily by electrification of transportation and heating, decarbonization initiatives from both the public and private sectors, and economic expansion across

| *Eversource Energy*

manufacturing and commercial sectors," Nolan said.

The observed load growth may be part of a larger trend that experts expect to accelerate into the 2030s. By 2034, ISO-NE forecasts New England's average annual net load increasing by more than 11% and the average summer peak load increasing by more than 8%, or about 2 GW.

The RTO experienced its highest peak load since 2013 in June 2025, though net load (not normalized to account for weather effects) over the first nine months of 2025 was about equal to 2024 net load over the same period. (See *Extreme Heat Triggers Capacity Deficiency in New England*.)

"The evolving electric landscape presents a need for numerous transmission projects, such as upgrades linking onshore and offshore wind to load centers, interconnections improving regional reliability and addressing congestion as the generation mix for our region evolves," Nolan said.

Nolan added that the company expects to spend nearly $2 billion on its electric distribution business and about $1.4 billion on its transmission business in 2025.

A large portion of the company's transmission spending is associated with asset upgrades, a major concern for New England states and consumer advocates in recent years. According to data *published* by ISO-NE, Eversource plans to spend about $774 million on asset condition projects expected to come online in 2025. (See *More Oversight Needed on Local Transmission Spending in NE, Panel Says*.)

Nolan indicated that Eversource responded to ISO-NE's first longer-term transmission planning (LTTP) solicitation and that LTTP solicitations and land acquisitions at strategic interconnection points could create opportunities to add "billions of dollars to our future investment plans."

"Each project that we are considering not only supports our growth trajectory, but also deepens our value proposition as a grid innovator," Nolan said.

ISO-NE's LTTP solicitation is the first to be run under its new process, which aims to procure transmission solutions to needs identified in long-term planning studies. The first procurement is focused on reducing transmission constraints in Maine and enabling the interconnection of onshore wind in the state.

ISO-NE received six qualified proposals prior to the submission deadline at the end of September, ranging in cost from about $1 billion to $4 billion. (See *ISO-NE Reveals 1st Details of Long-term Transmission Proposals*.) ISO-NE has not announced which companies submitted proposals.

Regarding the company's business in Connecticut, Nolan appeared cautiously optimistic about financial opportunities in the state after Gillett resigned in September amid mounting political and legal battles with utilities and Republicans in the state.

"We're seeing a constructive shift in Connecticut's regulatory landscape," Nolan said. "A transparent regulatory process is going to benefit all stakeholders, including our customers, and we are looking forward to getting back to work on Connecticut's energy goals."

Also on Nov. 5, PURA *approved* a rate increase for the Yankee Gas Co., an Eversource subsidiary. The decision authorized a higher revenue requirement for the company than initially outlined in a draft decision authored during Gillett's tenure.

In the prior week, PURA similarly *approved* a higher revenue requirement in a United Illuminating rate case relative to a draft decision issued under Gillett's leadership.

Connecticut Gov. Ned Lamont (D) has nominated four new commissioners to PURA, bringing the total number on the commission to five. However, both decisions were issued by the two remaining active commissioners at the authority, one of whom worked as a lobbyist for United Illuminating as recently as 2024.

While the final decisions appear more favorable to the utilities than the draft decisions, only one of the two commissioners who ruled on these cases is set to be part of the full incoming commission, and the rulings may not give much indication about the regulatory approach of the full incoming commission.

Asked whether the new commission will lead to an improvement in Eversource's credit rating, Eversource CFO John Moreira said credit rating agencies are "in a wait-and-see mode."

"They want to see some constructive regulatory outcomes," Moreira said, adding, "we think that this new commission is focused on working collaboratively with all the utilities." ■

# More Oversight Needed on Local Transmission Spending in NE, Panel Says

By Jon Lamson

Despite recent transparency improvements, broader efforts are needed to address underlying concerns about a lack of regulatory oversight of local transmission costs in New England, according to panelists on a recent webinar held by Advanced Energy United.

Speakers at the Nov. 4 webinar emphasized the need to address the "regulatory gap" that allows most transmission spending in the region to avoid scrutiny.

The regulatory gap is a "consumer confidence issue," said Jackie Bihrle, managing attorney at the Massachusetts Attorney General's Office. "Consumers should be able to have confidence that utility spending is the least-cost, most effective solution, and that has dwindled with this gap."

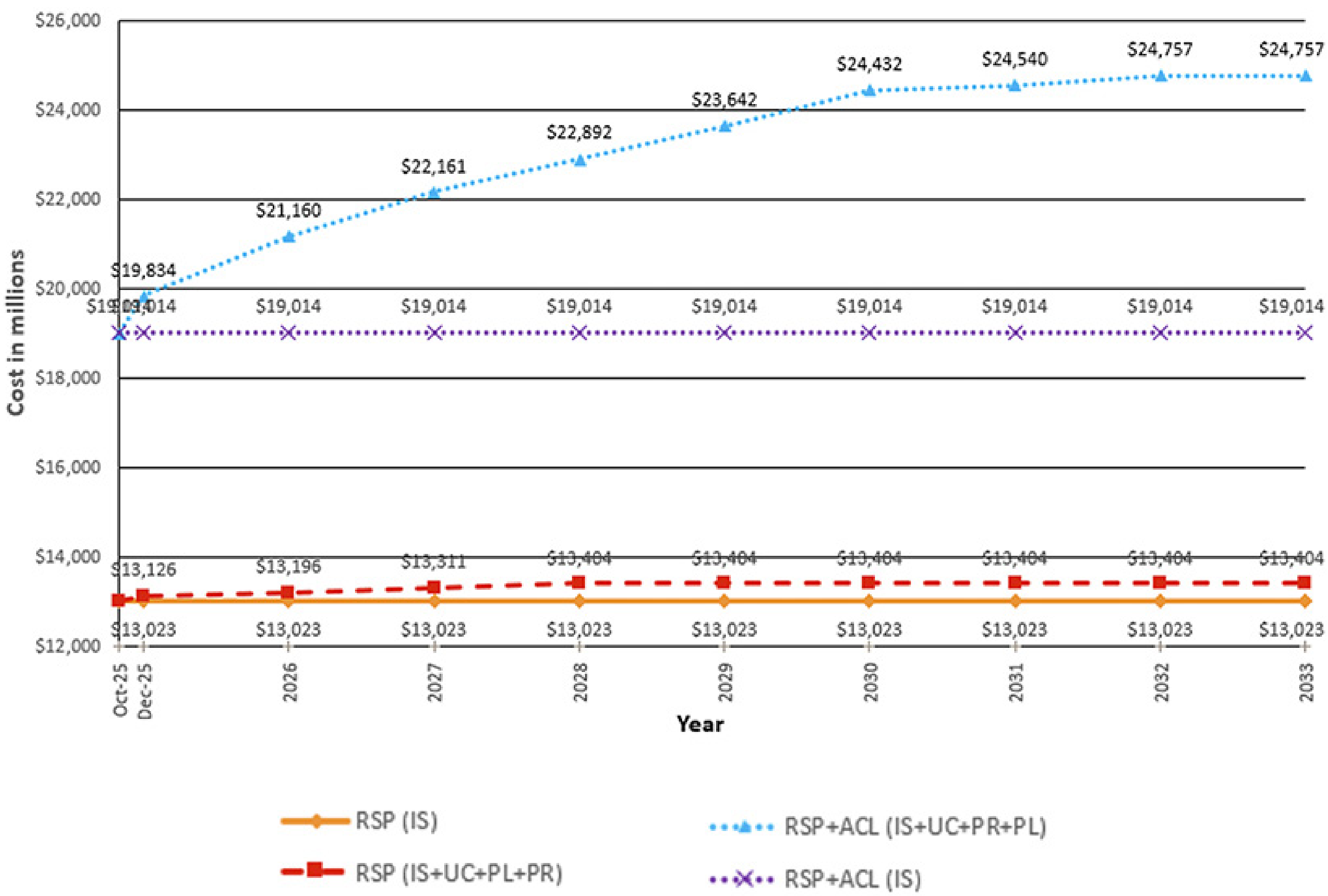
Local transmission projects, known as asset-condition projects (ACPs) in New England, are typically upgrades of existing assets deemed to be aging or deteriorating. The projects are not subject to competitive bidding processes or regional planning processes, and the transmission owners recover costs through FERC formula rates.

Asset-condition costs have risen significantly in New England in recent years. The region's transmission owners *reported* nearly $4 billion in ACPs placed in service between 2020 and 2024, and the companies forecast spending in 2025 to total nearly $1.5 billion.

## Why This Matters

Right-sizing asset-condition projects could help cost-effectively increase transmission capacity in New England, but the region does not yet have a structure in place to enable this to happen.

While substantial spending is necessary to maintain the region's grid, more safeguards are needed to ensure this spending is as cost effective as possible, the panelists agreed.




Cumulative spending on planned asset-condition and Regional System Plan projects in ISO-NE through 2033 (IS: In Service, UC: Under Construction, PL: Planned, PR: Proposed) | *ISO-NE*

Local transmission spending is subject to "the lightest touch review possible" at the federal level, and projects generally face minimal scrutiny from state-level permitting processes, said Matthew Christiansen, partner at Wilson Sonsini Goodrich & Rosati and former FERC general counsel.

He said there is clear evidence that transmission spending has been concentrated in recent years on projects that are not subject to regional planning or competitive solicitation processes. Along with increased spending on local projects, "you actually see the same thing with regional projects that are exempted from competition," he said.

Christiansen added that formula rate procedures at FERC have created structural difficulties for stakeholders seeking to challenge the prudency of costs. Instead of requiring TOs to prove the prudency of investments, formula rates shift the burden of proof to third parties contesting the prudency of the spending.

"It really does change the playing field in terms of what has to be proven, in a way that makes it much more likely that costs will ultimately be passed through to ratepayers," Christiansen said, adding that consumer advocates' ability to challenge costs is typically minimized by limited resources and "informational asymmetries" between them and TOs.

In June, ISO-NE agreed to take on a non-regulatory "asset condition reviewer" role to provide increased transparency into project spending. In a recent update, the RTO said the role is "envisioned to provide an independent review and opinion of asset-condition projects submitted for review by the TOs," which could help inform formula rate challenges with FERC. (See *ISO-NE Gives Update on Asset Condition Reviewer Role*.)

"It will help, I think, on the transparency issue," Bihrle said. "This isn't going to completely solve the underlying problem, but we think it's a really important step in the right direction."

The insight and "objective opinions" provided by ISO-NE could "provide some information upon which interested stakeholders could challenge asset-condition spending at FERC," Bihrle added.

Discussing potential solutions to the broader issue, Christiansen said it is easier to diagnose the problems than it is to provide answers that would not have unintended consequences.

He said FERC could establish a dedicated "technical office" to perform targeted audits of local projects; this could provide a good starting point for identifying issues or trends.

Claire Wayner, senior associate at RMI, emphasized the importance of coordinating local and regional transmission projects and looking for opportunities to right-size projects to maximize potential benefits.

She said coordination and right-sizing discussions need to occur early in the planning process, as it can be hard to address these questions by the time projects reach state permitting proceedings.

"This cannot be solved alone by increased state-level oversight," Wayner said. "We need to see regions do more regional-first planning." ■

# Michigan PSC Approves Special Data Center Rate Terms for Consumers Energy

By Amanda Durish Cook

Shutterstock

The Michigan Public Service Commission has approved tailored rate provisions between Consumers Energy and energy-intensive load customers.

Clean energy groups commended the commission's efforts to protect consumers but were critical of the Nov. 6 ruling's lack of directives that large loads meet Michigan's clean energy standard of 80% by 2035 and 100% by 2040.

The new provisions apply to customers with loads of at least 100 MW. Contracts would contain a five-year ramp-up period to full service and a 15-year term thereafter. The contract's minimum billing demand requirement would have customers paying for on-peak demand, transmission demand and maximum demand charges based on 80% of their contracted capacity, regardless of actual usage. If customers want to exit the contract early, they must pay a fee equal to their minimum billing demand multiplied by the number of remaining months in the contract (*U-21859*).

The PSC said its decision attempts to simultaneously take advantage of economic opportunities while making sure large load customers cover the costs required to serve them. It said it believed its order would ensure "adequate guardrails" to avoid socializing data center costs and would prevent other customers from picking up the tab on stranded costs if anticipated loads fail to materialize.

Contracts would extend automatically in five-year increments and require four years' notice to terminate.

The order requires prospective customers to pay an administrative fee to Consumers for man hours spent studying and drawing up plans to serve the customer.

"These requirements are meant to ensure large load customers remain in service long enough that they will contribute significantly to new and embedded costs while also giving Consumers time to plan for unprecedented changes to its overall load," the PSC said in a press release accompanying the order.

The new terms allow a large load customer to seek a one-time capacity reduction of no more than 10%, with a four-year written notice. Requests for reductions larger than 10% will have to go through commission approval. Consumers can suspend service to the customer if its usage begins to exceed contracted capacity by 1 MW or more.

However, the commission did not prescribe a specific rate design, leaving that for future rate cases Consumers brings forward. Instead, the PSC directed Consumers to propose six different cost-of-service study and rate design proposals "meant to analyze large load customers' impact on rates and their contribution to interconnection costs, which will be used to set the rate for these customers going forward," the PSC said.

The commissioners said large load customers can expect to be categorized under a separate rate class using a different cost allocation. They told Consumers to file *ex parte* cases for each large load customer to show that costs wrought by them aren't bankrolled by other customers.

Consumers is further obliged to make annual reports to the commission containing data on large loads, their demand and energy use, changes in their capacity requirements and possible exit fees.

Finally, the commission held off on ordering further stipulations to mitigate large load customers' effect on integrated resource planning and the state's renewable and clean energy standards. The PSC said those matters were best handled in separate, ongoing proceedings before it.

## Why This Matters

The latest ruling from the Michigan Public Service Commission aims to shield ratepayers from shouldering costs to power data centers. Environmental groups were disappointed in the decision's silence on using clean energy.

Prior to the PSC's order, Consumers had only its general primary demand (GPD) rate as its default terms of service, with the largest customer under the GPD at 28 MW. The original GPD uses a minimum on-peak billing demand of 60% based on previous summer use with a one-year minimum contract.

Consumers currently serves just one customer larger than 100 MW through a special rate established by the state legislature.

In testimony, Jim Dauphinais, counsel for the Association of Businesses Advocating Tariff Equity, said Consumers has received inquiries for new data center projects totaling 15 GW, with a half dozen of the inquiries for 900 MW or more for an individual customer. Dauphinais said discovery in the commission's proceeding showed that Consumers contacted a local transmission owner over a 2.65-GW addition and was told the needed transmission investment to accommodate the extra demand would range from $730 million to $780 million.

Dauphinais testified that Consumers risked entangling its existing customers in subsidizing large loads unless it was held to strict consumer protections and annual reporting.

Consumers' peak total demand is 7 GW. It announced in late July that it had reached an agreement to supply power to a data center of up to 1 GW for an unnamed developer.

Environmental advocates said that while the commission addressed the threat of higher bills, it didn't shut down the possibility that data centers would undercut Michigan's clean energy goals.

"This ruling is an important first step towards protecting Michiganders from the energy costs of data centers and the speculative rush that's threatening to drive up our already high costs of electricity and deplete our water supply. We cannot afford to continue building high-cost gas or running expensive, dirty and old coal plants just to feed the data center rush. We expect regulators and our utilities to prioritize the use of cleaner, cheaper renewable energy to benefit all Michiganders," Elayne Coleman, director of the Sierra Club's Michigan chapter, said in a statement following the ruling.

The Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan intervened in the case, arguing for 90% capacity payments instead of 80% under the new service terms. The group was represented by Earthjustice and Troposphere Legal.

"When data centers arrive, they typically bring the threat of higher utility bills and too often the undermining of clean energy goals. Today's ruling is an important step towards reducing the risk of the former but, unfortunately, fails to address the latter," said Shannon Fisk, director of state power sector advocacy at Earthjustice.

Fisk said she was encouraged that the commission protected consumers against stranded asset costs and vowed to continue fighting to ensure that data centers are supplied by clean energy "rather than dirty fossil fuels."

Derrell Slaughter, a Michigan-based policy director at the NRDC, said that while the PSC's order "makes strides on customer protection," it fell short of compliance with Michigan's clean energy standards.

"Without guardrails from the Public Service Commission order, it creates uncertainty about whether these large new customers will be powered by clean energy and ultimately help Michigan meet its clean energy goals," Slaughter said. ■

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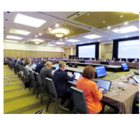
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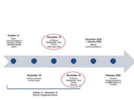
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# MISO Installs Former Bonneville Executive to Board

*By Amanda Durish Cook*

MISO is adding Bonneville Power Administration's former chief operating officer to its Board of Directors and welcoming back two term-limited directors in 2026 after collecting membership votes.

Joel Cook | *Bonneville Power Administration*

MISO members approved three-year terms for board incumbents Todd Raba and Barbara Krumsiek alongside Joel Cook, BPA's former COO and senior vice president of transmission services. (See *MISO Board Set to Add Bonneville Power Exec, Keep 2 Existing Members*.) New terms begin Jan. 1, 2026.

Cook departed Bonneville in February when he took up the federal Office of Personnel Management's buyout offer.

Incumbents Raba and Krumsiek are relying on a special waiver of MISO's rules that allows them to serve a fourth, three-year term. Ordinarily, MISO board members are limited to three terms. This year, MISO's Nominating Committee — composed of three board members not up for re-election and two MISO stakeholders — recommended the use of waivers to prevent a potential 33% turnover on the board. MISO's board is composed of nine independent directors and MISO CEO John Bear.

Longtime board member H.B. "Trip" Doggett is vacating the seat Cook will take over. Doggett's final official duties will be during MISO Board Week in December.

MISO membership voted electronically throughout October on the trio of candidates. MISO's board elections require preselected candidates to receive a majority of votes in support among membership. MISO members can vote for, against or abstain from selecting any of the candidates.

Twenty-five percent of MISO membership (39 members in 2025) must vote in order to establish a quorum. MISO will release more details concerning the vote at its annual meeting Dec. 11, part of Board Week in Indianapolis.

"As MISO faces growing complexities and dynamic changes, the continuity of directors Raba and Krumsiek provides a source of strategic leadership and momentum that is critically important," MISO CEO John Bear said in a press release. "We also welcome the new insights and perspectives from Director-elect Cook. His experience in the electric power industry will be beneficial to MISO and its members."

Board Chair Raba thanked Doggett for his service. "His deep experience, insights and professionalism have been immeasurable during a period of extensive transformation," Raba said. ■

The MISO Board of Directors meets in September in Detroit. | © *RTO Insider*

# 43 Expedited Tx Projects Line up for MISO 2026 Planning Cycle

By Amanda Durish Cook

With its 2025 cycle of transmission projects not yet final and approved, MISO already is working through 43 expedited project requests ahead of its 2026 cycle to support almost 14 GW of new load.

Since June, MISO has fielded 43 expedited project *requests* for the 2026 MISO Transmission Expansion Plan (MTEP 26). Many of the project proposals deal with large load additions; together, they represent 13.765 GW of new load.

At a Nov. 4 teleconference of the Expedited Project Review Technical Studies Task Force, Expansion Planning Manager Zheng Zhou said that over the past two years, large load interconnection projects have "increasingly utilized" MISO's expedited review process for projects that cannot wait until end-of-the-year approval through the RTO's annual MTEP process.

MISO fielded five project requests in June and approved two. Of the remaining three, two are under study and one was recommended for approval at the Nov. 4 meeting.

Of the 15 requests in August, MISO has approved five and recommended six more for approval Nov. 4, with four under study, including Entergy Louisiana's Mount Olive-to-Cargas 500-kV line and substation work to support a new Meta data center in Richland Parish.

In October, MISO received 23 expedited requests and has recommended two for approval. Those two are smaller, age- and condition-based upgrades in Louisiana for 1803 Electric Cooperative, which joined MISO in June. MISO staff said 1803 is trying to get a jump on securing long-lead equipment for a "like-for-like replacement with no topological change."

MISO has pivoted to a bimonthly processing approach to handle its growing number of transmission projects submitted by members for expedited treatment.

The grid operator now opens an acceptance window every other month for expedited project requests, with the next one in December. It has said the new cadence should be less cumbersome for staff than its previous ad-hoc approach. Until mid-2025, MISO evaluated requests as it received them. (See *MISO Starting from Scratch on New Schedule for Reviewing Expedited Tx Projects*.)

MISO studies smaller expedited projects in batches while larger, more complex projects receive individual assessments. It has a goal of a 30-day study turnaround for more straightforward projects. The RTO also schedules a single, monthly Technical Study Task Force meeting to discuss expedited projects instead of holding piecemeal, short task force meetings every time a request pops up.

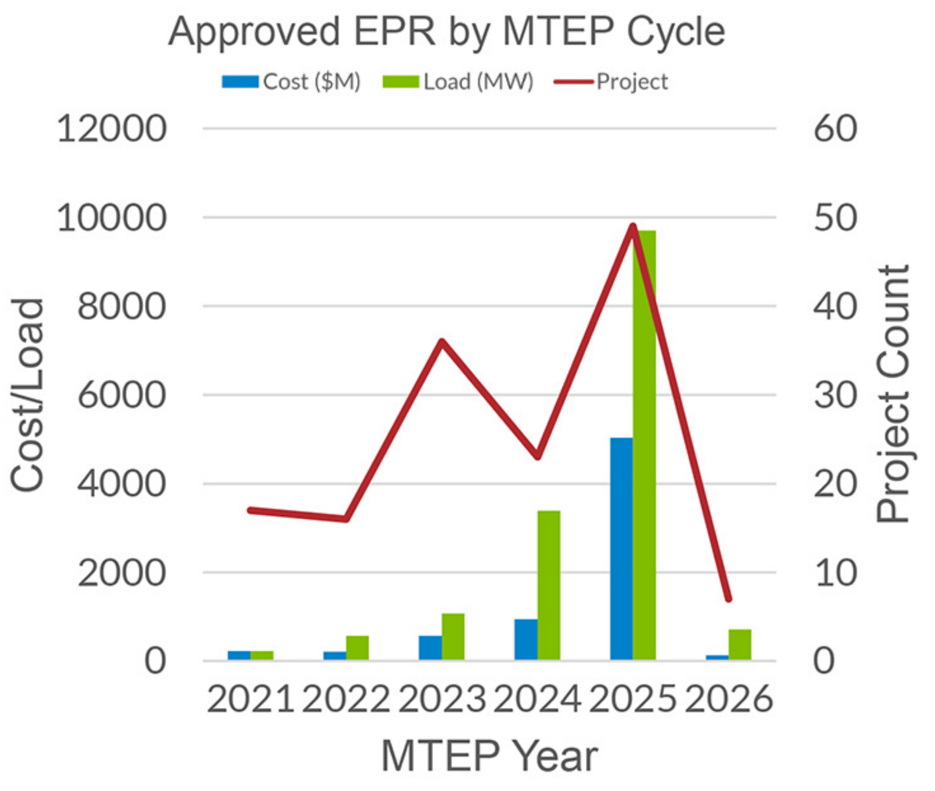
MISO has experienced a runaway volume of expedited requests in recent years as load growth surges. The RTO said it used to process an average of six expedited requests annually before 2021. MTEP 25 contains 49 expedited transmission projects. The projects themselves are becoming larger and more complex.

MTEP 25's more than $4 billion in expedited investment eclipses MTEP 24's $896 million worth of expedited requests and MTEP 23's $684 million. MISO said expedited projects are responsible for most of the 11.6 GW of large load additions that MTEP 25 will support.

Some stakeholders have asked MISO to consider adopting a load interconnection queue similar to its generator interconnection queue because of the snowballing expedited requests. ■

## Why This Matters

There are 49 expedited transmission projects in MTEP 25. Ahead of MTEP 26, MISO transmission owners have already submitted 43 urgent projects, with more on the way. Unprecedented load growth is the culprit.




Approved expedited project requests in the last five years | MISO

# Permits for Trump-favored Gas Pipeline Approved by N.Y. and N.J.

By Vincent Gabrielle

ALBANY — The state of New York has reversed course and issued a *critical* water-quality permit for a proposed natural gas pipeline off the coast of New York City.

The New York Department of Environmental Conservation's approval Nov. 7 reverses the state's three previous denials. Hours later, New Jersey's Department of Environmental Protection *issued* water quality and other environmental certifications for the same project.

The permit approvals come after public fights over offshore wind, gas pipelines and congestion pricing between Gov. Kathy Hochul (D) and President Donald Trump.

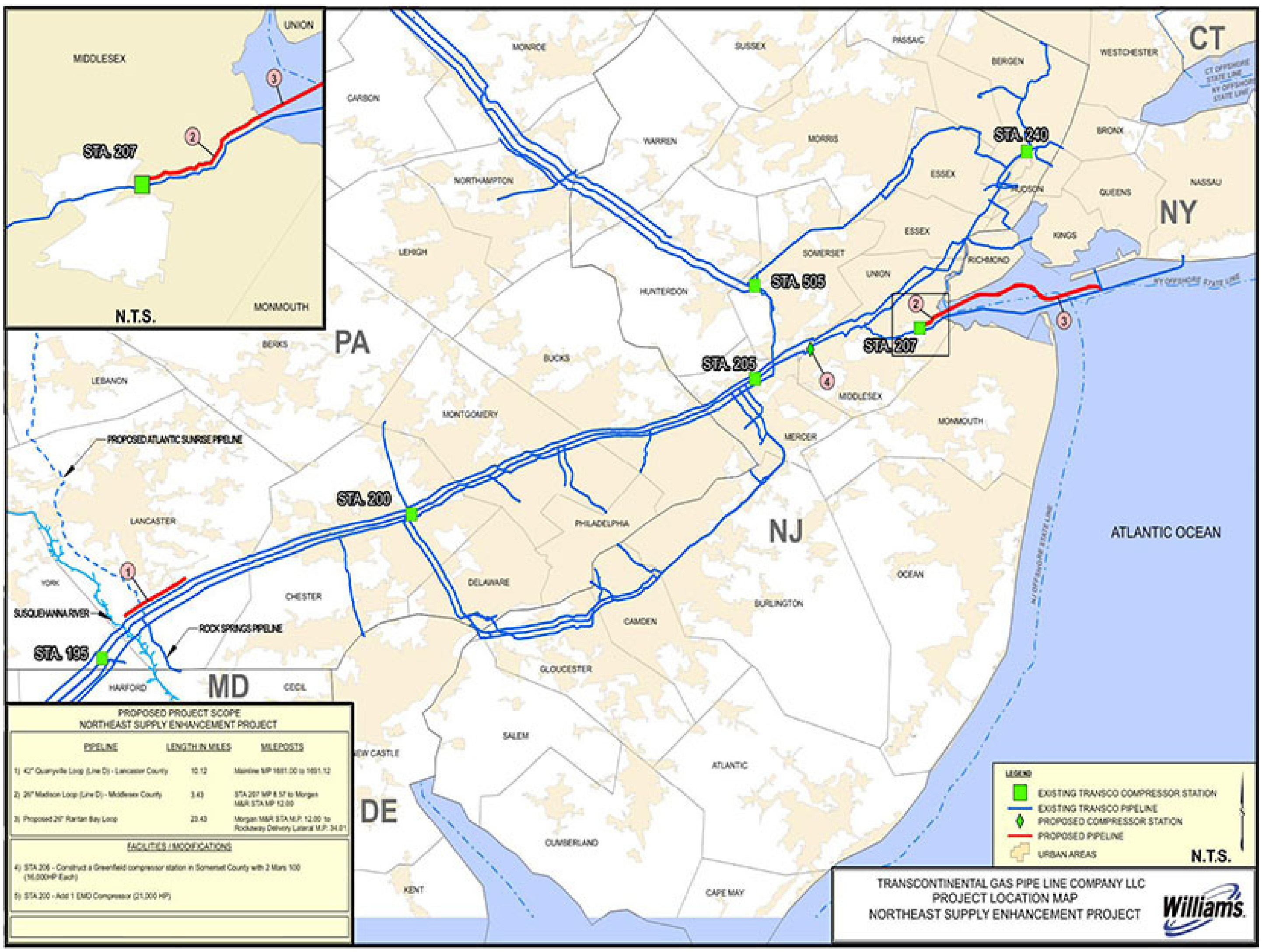
"Today's decision is a complete reversal from their previous determinations to reject the exact same pipeline over threats to New York's water quality," said Mark Izeman, senior attorney for the Natural Resources Defense Council. "The proposal is the same. The law is the same. The only thing that's changed is the politics."

In an emailed statement, Hochul said she stood by the DEC's decision.

"While I have expressed an openness to natural gas, I have also been crystal clear that all proposed projects must be reviewed impartially by the required

## Why This Matters

The Northeast Supply Enhancement pipeline had been denied permits multiple times in New York and New Jersey due to environmental impact issues. NESE was favored by the Trump administration. These new rulings reverse previous denials.




NESE project map | *Williams Co.'s*

agencies to determine compliance with state and federal laws," Hochul wrote. "I am comfortable that in approving the permits, including a water quality certification, for the NESE application, the DEC did just that."

The Northeast Supply Enhancement (NESE) project would carry natural gas 24 miles from New Jersey into New York City and Long Island across Raritan Bay. It is an expansion of Williams Cos.' massive, nationwide gas pipeline system operated by the Transcontinental Gas Pipeline Co.

In the permit approval announcement, DEC said another project, the 124-mile Constitution Pipeline, would not move ahead. The department said Constitution Pipeline Co. withdrew its application for permits. The Constitution Pipeline was planned to cross New York into New England and was controversial with locals and many New York elected officials.

Chad Zamarin, CEO of Williams, *told POLITICO* the company was "proud" NESE was moving forward and that the company planned continue working on the Constitution project. The company revived both pipelines after receiving public support from the Trump administration.

"As governor, a top priority is making sure the lights and heat stay on for all New Yorkers as we face potential energy shortages downstate as soon as next summer," Hochul said in an emailed statement. "We need to govern in reality."

Trump took to *Truth Social* days earlier to support NESE and Constitution.

"Gov. Kathy Hochul of New York state is killing the entire region with energy prices that are out of control and expected to triple because she can't get an upstate and separately Long Island pipeline built," Trump wrote before condemning New York City's congestion pricing tolls.

Earlier in 2025, the president publicly feuded with the governor over the denial of pipeline permits and offshore wind. The president moved to stop construction on Empire Wind 1 but reversed course after claiming to reach a deal with Hochul in May. (See *BOEM Lifts Stop-work Order on Empire Wind*.) The White House claims Hochul "*caved*" on natural gas while the governor's office denies any deal was reached.

Anshul Gupta, policy and research director for New Yorkers for Clean Power, said in an emailed statement that shortly after Trump and Hochul reached an agreement, the New York State Public Service Commission found a reliability need for the NESE.

"The reasons that the PSC gave in its rushed determination of NESE's reliability need are transparently concocted to justify the project," Gupta wrote. "It's a remarkable coincidence that this so-called reliability need happens to exactly meet the 400,000 Dt/day capacity of a project that was proposed more than five years ago."

The Independent Power Producers of New York praised the decision, saying it affirmed that natural gas is a crucial resource in maintaining the reliability and safety of the New York grid. IPPNY noted that 90% of electricity generated in the city is from natural gas and oil.

"I commend the DEC for recognizing that natural gas will continue to play a key role in the state's energy future," IPPNY CEO Gavin Donohue said in an emailed statement. "Until zero-emissions dispatchable resources … have been identified and developed, natural gas will remain a necessary transitional component of New York's fuel mix."

Izeman said he's preparing to fight the permit in court. The NRDC, Earthjustice and other groups had challenged FERC's greenlighting of the pipeline in federal appeals court at the end of October. In an emailed statement, Earthjustice called the approval "shameful." ■

# NYISO Meeting Briefs

## Operating Committee

NYISO presented the results of Phase 1 of the *2024 Cluster Study* process at a special Operating Committee meeting Nov. 4.

The vast majority of the projects in the study are energy storage systems throughout New York. Of the 202 projects in the study, only three were found to be physically infeasible and barred from transitioning to Phase 2 of the cluster study process.

Three projects were examined for the 2025 *Expedited Deliverability Study*. Only one project, Empire Generating Units 1 and 2, was found to be able to satisfy the NYISO Deliverability Interconnection Standard at its requested capacity resource interconnection service level without system upgrades.

The committee unanimously approved both studies, with one abstention.

## ICAP Working Group

The Installed Capacity Working Group received a presentation on the *impact* on consumers from NYISO's planned implementation of FERC Order 2222.

NYISO found that reliability would improve from more participation of suppliers in the operating reserves program and that ancillary services prices for 30-minute reserves would increase slightly. No measurable impact was found on the capacity market. The order was also found to increase the price signals of new technologies.

The ISO also *presented* an update on the Improved Duct Firing Model project. It has identified elements of the model's design that are incompatible with its current software. The ISO is exploring options, including possible tariff revisions, to implement the FERC-approved model design. ■

| © RTO Insider

*— Vincent Gabrielle*

# N.J. Backs Clean Energy Democrat for Governor

## Congresswoman Mikie Sherrill Plans to 'Freeze' Electricity Rates

*By Hugh R. Morley*

New Jersey Governor-elect Mikie Sherrill (D) | *Mikie Sherrill for New Jersey*

New Jersey voters resoundingly backed Democrat Mikie Sherrill in the state's gubernatorial race, sweeping into power a clean energy advocate who says she will freeze utility rates immediately and "*massively build* out cheaper and cleaner power generation."

Sherrill, who is serving her fourth term in the state's 11th Congressional District in the northern part of the state, trounced Republican Jack Ciattarelli 56% to 42%.

Statewide election results Nov. 4 in Virginia and Georgia also held implications for energy policy. (See related story *Democrats Win the Races for Virginia Governor and Georgia PSC Seats*)

Sherrill's campaign focused on "affordability" for New Jersey residents, with a promise that on her first day in office, she would address the state's dramatically rising electricity costs by declaring a "state of emergency" on utility costs, and freezing rates.

"I intend to move quickly and actively, and not passively," she said in a Nov. 5 interview on "Morning Joe," explaining her successful message to voters. "I intend to really address these key things immediately."

Sherrill, a mother of four, is a former Navy helicopter pilot and assistant U.S. Attorney and is considered a moderate Democrat. She succeeds two-term Democratic Gov. Phil Murphy, who pursued an aggressive clean energy agenda — including an 11-GW offshore wind program — but is prevented from running again by New Jersey law.

### Why This Matters

New Jersey ratepayers saw a 20% hike in electricity bills in June, and the state expects a shortfall in electricity supply as data centers proliferate. Sherrill's pledge to freeze electricity rates drew some skepticism from analysts, who wondered if the governor will have the power to make such a move.

Ciattarelli, in his third race for governor, received the endorsement of President Donald Trump and tied himself to the president. In an Oct. 8 debate, he gave Trump's second-term performance an "A" rating and said, "I think he's right about everything he's doing."

Ciattarelli pledged to pull the state out of the Regional Greenhouse Gas Initiative, saying it adds costs to state ratepayers by forcing the state to use out-of-state power. He pledged to expand natural gas-fueled generation and would ban offshore wind.

### Confronting PJM

Anjuli Ramos-Busot, New Jersey Chapter director of the Sierra Club, which endorsed Sherrill, said she expects the governor-elect to broadly follow Murphy's clean energy policies but be more focused on the costs and impact on ratepayers. That's in large part shaped by the state's difficult energy situation, Ramos-Busot said.

"Her approach to clean energy is definitely focused on affordability," Ramos-Busot said. "She wants to develop more clean energy and also would sustain the generation that is carbon-based," she added, noting that Sherrill wants to maintain natural gas plants and make them more efficient, so they continue running.

Ramos-Busot said she believed Sherrill is open about her support for clean energy and the fact that she won with such a strong majority shows the public accepts that position.

New Jersey ratepayers' average electricity bill increased 20% in June, and the state expects to face a dramatic shortfall

*Continued on page 38*

# Democrats Win the Races for Virginia Governor and Georgia PSC Seats

*By James Downing*

Democrats won off-cycle elections around the country Nov. 4, with races in Georgia, New Jersey and Virginia holding implications for energy policy.

In *Virginia*, Gov.-elect Abigail Spanberger (D) cruised to victory over Lt. Gov. Winsome Earle-Sears (R) in a race where energy was less of a focus than in New Jersey. (See related story *N.J. Backs Clean Energy Democrat for Governor*.)

Democrats' strong performance in Virginia was evident downballot, where they won all the statewide offices and added to their majority in the House of Delegates (state senators were not up for re-election).

"Virginians voted for a pragmatic leader who gets results, because we're in the midst of a growing energy affordability crisis, and she will need to lead from Day 1," Advanced Energy United Virginia Director Jim Purekal said in a statement. "Gov.-elect Spanberger has a clear mandate to make energy more affordable and reliable by making it easier to build low-cost clean energy and fixing the bottlenecks that slow progress."

Environmental group Clean Virginia congratulated Spanberger and downballot Democrats in a statement.

"Virginians have made history," Clean Virginia Executive Director Brennan Gilmore said. "For the first time, every statewide office and the majority of the House of Delegates will be held by leaders who do not accept money from Virginia's monopoly utilities. That marks a sea change in Virginia politics and a clear rejection of the pay-to-play system that has dominated Richmond for decades."

As home to the largest data center market in the world, which is growing fast, Virginia has had to contend with large load customers' impact on the grid. Spanberger has *said* the data centers should pay for their fair share of grid impacts.

In 2025, a number of bills were introduced in the legislature that would have responded to data center growth. Most failed to make it through to law with a split government. That will not be an issue once Spanberger and newly elected legislators take office. (See *Virginia Legislators Introduce Bills to Deal with Data Center Growth*.)

One area of concern, which equity research firm Jeffries said is "hanging above all else," is whether the change in governors will spell trouble for Dominion Energy's Coastal Virginia Offshore Wind (CVOW) project.

Incumbent Gov. Glenn Youngkin (R) was term-limited, and the question is whether the Trump administration will leave the project alone, as it has so far. Roadblocks have been thrown up against offshore wind projects in Democratic-run states to Virginia's north.

Dominion CEO Robert Blue addressed that issue on the firm's earnings call a few days before the election, arguing that CVOW's electrons were needed to meet growing demand from data centers and to power facilities vital to the U.S. Navy in southeast Virginia, so it should move forward with its planned completion in late 2026. (See *Dominion Reports on CVOW Progress, Data Center Growth in Q3 Earnings*.)

Virgina State Capitol in Richmond, Va. | *Virginia Department of Historic Resources*

## Why This Matters

Democrats will have complete control of Virginia's state government, while the party also notched victories in Georgia PSC elections that had been dominated by Republicans for decades.

In *Georgia*, Democrats flipped two seats on the Public Service Commission as Alicia Johnson and Peter Hubbard handily defeated incumbent Republicans Tim Echols and Fitz Johnson. Echols has been on the PSC since 2011, while Fitz Johnson joined it in 2021.

Alicia Johnson has a background in health care, and her website calls her "a lifelong community advocate," while Hubbard has 15 years of energy experience and has been active before the PSC via a nonprofit he founded in 2019: the Georgia Center for Energy Solutions. Both Democrats said cutting consumers' power bills was a priority.

In a post-election note, Jeffries analyst Julien Dumoulin-Smith noted that Southern Co.'s Georgia Power has "top-tier authorized rates of return," and the incoming commissioners' election promises around affordability make the outcome of its next rate case, for deliveries starting in 2029, less certain.

In New Jersey, Democrat Mikie Sherrill campaigned on "affordability" for residents of the state, with a promise that on her first day in office, she would address the state's dramatically rising electricity costs by declaring a "state of emergency" on utility costs, and freezing rates. Sherrill trounced Republican Jack Ciattarelli 56% to 42%. ■

# PJM Winter Outlook Finds Tightening Reserve Margins

*By Devin Leith-Yessian*

PJM's winter *outlook* found the RTO should have enough resources to meet the forecast peak load of 145,700 MW, although the reserve margin continues to decline as new resource development lags. If the forecast is reached, it would surpass the previous winter's record-setting peak of 143,700 MW. (See *PJM Sets Record Winter Peak Load*.)

Load growth has continued to erode PJM's reserve margin, which stands at 7.5 GW in the forecast, down from 8.7 GW in the previous year. About 4.8 GW of new nameplate generation was included in the modeling. Much of that is solar, however, and amounts to just 1 GW of capacity. (See *PJM OC Briefs: Oct. 10, 2024*.)

"The grid is set up to keep the power flowing reliably this winter under forecast conditions, but the tightening of our margins will begin to impact us in the next few years if it continues," said Aftab Khan, PJM executive vice president of operations, planning and security, in an announcement of the winter outlook. "PJM is working on multiple levels with all of our stakeholders to reverse this trend of demand growing faster than we can add generation."

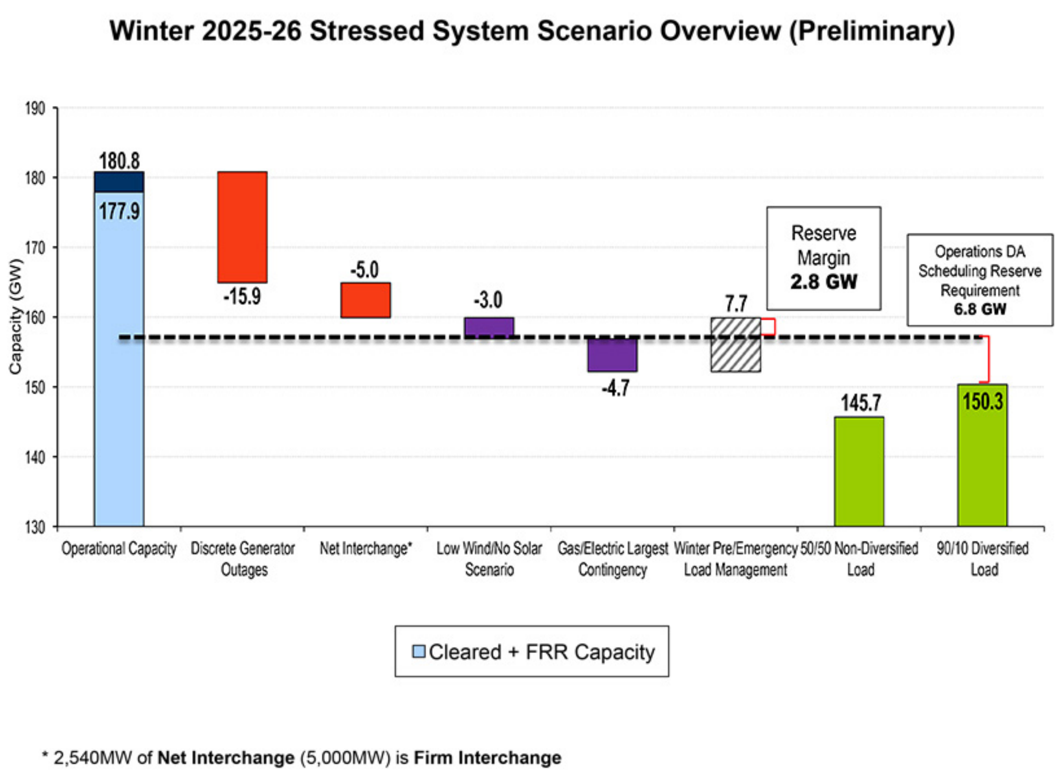
The analysis shows 180.8 GW of operational capacity, which includes 177.9 GW with commitments in the capacity market, as well as resources anticipated to be available. An additional 7.7 GW of load management will be available. Of those resources, 15.9 GW is expected to be on outage during periods of system strain, and 5 GW of exports were included.

The reserve margin measures the amount of operational capacity above the 90/10 diversified load forecast plus the 6.8-GW day-ahead scheduling reserve requirement.

The amount of operational capacity reflects improvements in resource performance observed since the December 2022 Winter Storm Elliott. After that storm, PJM made several changes to its emergency procedures, nonperformance penalties and advance commitment practices. The announcement says the margin could become tighter if those improvements do not continue.

"Generator performance will be critical to maintaining reliability this winter," said Mike Bryson, PJM senior vice president of operations. "We are encouraged by the work we have seen by generation owners to fortify their units for winter operations, and we will continue to focus on communication and coordination that help us understand how PJM can help to mitigate gas scheduling challenges or other generator limitations."

*Presenting* the outlook during the Nov. 3 Operating Committee meeting, PJM's Akash Patel outlined the preliminary results of scenarios exploring how low renewable generation or the largest gas contingency could affect the reserve margin. If wind and solar output were to be 3 GW lower than expected, there would be 200 MW of operational capacity available before load management would be required. The largest gas contingency would take 4.7 GW off the system, shrinking the reserve margin to 5.8 GW; pairing the two scenarios would leave a 2.8-GW margin.




A PJM graphic shows a scenario in which low renewable output and the largest gas contingency could impact the reserve margin for the 2025/26 winter. | *PJM*

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned why PJM included 5 GW of exports in the analysis, stating that PJM's governing documents require that nonfirm ties to other regions be curtailed if it falls into a reserve shortage.

PJM Director of Operations Planning Dave Souder said the 5 GW is the historical value PJM has exported over peaks. The study results indicate with that level of exports PJM would be deficient and would begin implementing procedures to curtail off-system sales.

The announcement of the outlook says PJM and ReliabilityFirst intend to double the number of site visits they will conduct at 30 generators to share best practices on winterization. PJM also will conduct unannounced tests of generators that have not run in the weeks ahead of the winter season. ■

# GridLab: More Renewables Could Have Saved Billions in PJM Auction

*By James Downing*

If just 10% of the land-based renewables in PJM's generator interconnection queue had been developed, the total cost of the RTO's 2026/27 capacity auction would have been reduced by $3.5 billion, according to an analysis GridLab commissioned by Aurora Energy Research.

The queue has 130 GW of nameplate capacity that entered before 2024, and just a fraction of the solar, wind and batteries in it would have cut 2026/27 capacity costs down to $12.6 billion from the $16.1 billion in actual costs.

"I think part of my frustration with the narrative coming out of PJM was they're sort of blaming state policy for the reason that the auction has gone up so much. They say, 'State policy is forcing plants to retire,'" GridLab Executive Director Ric O'Connell said in an interview. "And I just don't think it's true. I think the reason that the auction has gone up is because PJM basically has taken a very long time — the longest of all the RTOs — to get new capacity online."

The only state policy actually requiring plants to retire is in Illinois, and that does not kick in for 10 years, O'Connell noted. A lot of retirements have happened in Ohio, which does not have the same stringent clean energy policies as more liberal states, he said.

Renewables have less of a capacity value than their nameplate, but the analysis used the same effective load-carrying capability values as the RTO.

"Wind actually has a really high capacity value because the risk periods are in the winter," O'Connell said. "And the reason the risk periods in PJM were in the winter is because gas heavily underperformed in Winter Storm Elliott."

The last time PJM's grid faced major reliability issues was during that storm in December 2022, and the main culprit was natural gas. (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

The auction's high prices signaled that supply and demand conditions in PJM are tight. As demand increases, the reserve margin gets narrower — making the timely connection of new resources increasingly critical to avoid high prices and threats to reliability.

## Why This Matters

The analysis shows that while renewables have fairly low capacity values, more of them would significantly lower capacity prices in PJM.

PJM said in a statement that it agrees it needs to remove obstacles for all types of generation resources coming online.

"We are committed to connecting new generation to the grid as quickly as possible," the RTO said. "PJM has processed about 160 GW of proposed generation resources, mostly renewables or batteries, since 2023. There are about 46 GW of new resources that will be processed by the end of 2026. We are currently working on multiple fronts, including our partnership with Google/Tapestry, to further streamline our processes by leveraging AI." (See *PJM, Alphabet Partnering on AI Tools to Speed Interconnection*.)

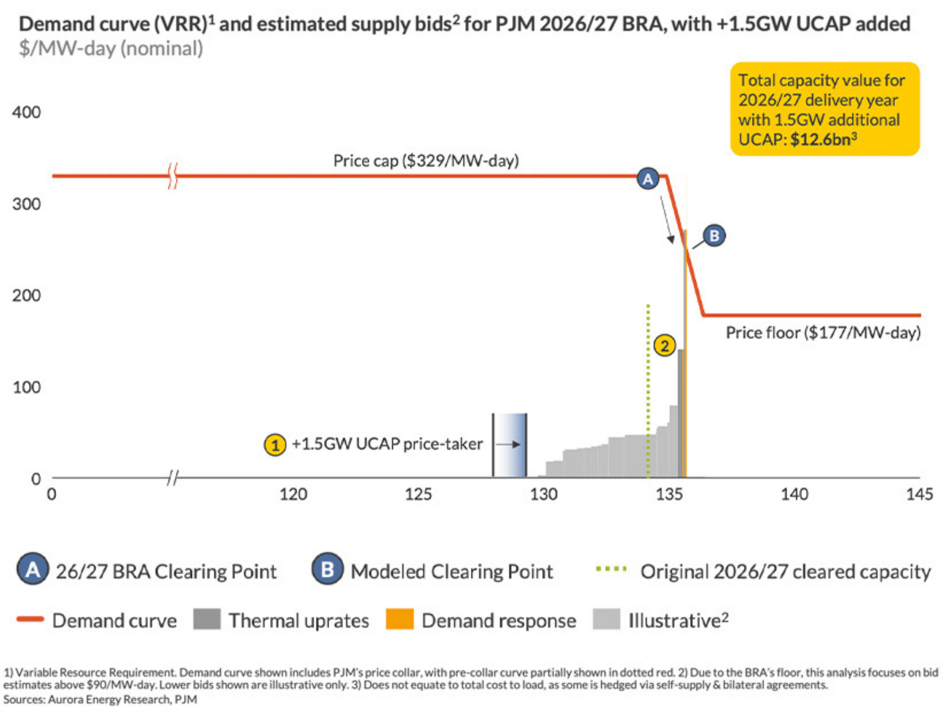
As of October, about 60 GW of capacity had cleared the queue and either had signed interconnection agreements or were offered such deals, meaning that they should be ready to move forward on construction, PJM said.

But they are not getting built.

Both PJM and the GridLab study point to issues outside the RTO's control, such as permitting, the supply chain and financing as slowing construction.

"We have called on policymakers to advance policies that will help keep existing supply and bring new supply to the power grid," PJM said. "We also ask that they analyze any state/local permitting challenges to the deployment of new generation resources and electricity infrastructure and enact policies to facilitate construction."

O'Connell argued that PJM should have been ready for a wave of interconnection requests from renewable power projects because that same wave washed over




GridLab's report found that 1.5 GW of renewable capacity could have saved $3.5 billion in the last PJM capacity auction. | *GridLab* other markets earlier and gummed up queues in the process.

"CAISO sort of got this wave of interconnection applications in the mid- to late 2000s, and so they developed the cluster study process, and they really thought through how to address the issue," O'Connell said. "MISO got it earlier because there was a lot of wind development."

Up until the mid-2010s, PJM was seeing some renewables, but not enough to slow down the queue that was initially developed with natural gas and other traditional generation in mind. Then, between 2017 and 2021, the wave came and queue entry rose by 293%, according to the analysis. The RTO then announced it would not be able to study projects again until 2026, and queue entry declined rapidly.

"They should have read the room, and they should have looked around and said, 'Oh, this happened in CAISO; this happened in MISO; this happened in SPP. It's going to happen to us; we should get ready,'" O'Connell said.

The issue with many projects making it through the queue and not being ready to start construction also can be tied to the delayed queue, he said: Projects faced yearslong delays that compounded the issues they were facing.

"They applied for interconnection in 2018, and now they're trying to build that project that they had envisioned in 2018 and the world's totally different," O'Connell said. "Prices have gone way up. Maybe their permits expired."

The analysis suggests PJM should adopt new software to help speed up interconnection studies. It could pair large loads with capacity meant to meet the demand and expedite it through the queue, or it could adopt something like SPP's Consolidated Planning Process, in which generator interconnection and transmission planning are handled at once.

Another major improvement would be changing PJM's governance process and giving states a bigger role, which is an idea supported by most of the governors in the RTO, O'Connell said. (See *Governors Call for More State Authority in PJM*.)

"The primary problem with PJM is its governance structure," O'Connell said. "It's kind of owned and run by incumbent transmission owners and generation owners. And in some sense, they don't want competition. They don't want these new resources online. And so, I think that's why you're seeing PJM sort of drag its feet, because the incumbent gas generators are doing just fine. They're making lots of money as capacity prices go up. They're getting windfall profits." ■

# N.J. Backs Clean Energy Democrat for Governor

*Continued from page 34*

in electricity supply as more data centers are developed in the PJM region.

Sherrill's pledge to freeze electricity rates drew some skepticism from analysts, who wondered if the governor had the power to make such a move. Electricity rates are set by the basic generation services auction, and the prices are passed on to ratepayers through the utilities. Those rates are heavily influenced by the PJM capacity auction: In the July 2024 auction, rates increased 10-fold.

PJM officials say the increase is the result of the dramatic rise in demand due to the expected data center load and the closure of fossil fuel plants more rapidly than new plants — mainly clean energy plants — have come online.

Sherrill, on her campaign website, has said she will "require more transparency from our utility companies, including PSE&G, JCP&L, Atlantic City Electric and Rockland Electric and our grid operator PJM." She said PJM has "really screwed up the market" by creating delays in the connection of clean energy resources to the grid, helping to create the shortfall. She has said she expects the attorney general will seek to force PJM to connect clean energy sources to the grid.

In an October debate, Sherrill said she is "going to drive in an energy arsenal of power as we drive costs down over time, making sure we build out our solar, our battery storage, improve our gas generation in the state and then develop nuclear power."

She also pledged to *modernize and make more efficient* gas-fueled plants in the state and make permitting easier for new projects, including solar and battery storage projects.

During the campaign, Sherrill made little mention of the state's offshore wind sector, which mostly has stalled amid economic challenges and opposition from the Trump administration. The state has no offshore wind project in progress since Atlantic Shores withdrew its plans in June. (See *Developer Shelves Atlantic Shores, Seeks to Cancel ORECs*.)

But prior to the campaign, she was a strong wind advocate. In a September 2024 op-ed, she wrote that the state is "perfectly positioned to shape the future by becoming a global leader in the renewable offshore wind space," adding that the state "cannot let this opportunity go to waste."

Sherrill, *during the primary* election, said she would expand community solar projects on warehouses and commercial space and put "solar fields on landfills, brownfields, parking lots and quarries."

She also said she would focus on energy efficiency and incentivizing customers to reduce energy use during peak hours. She also advocated for the development of "more and faster electric vehicle chargers, which work with the grid, so people can feel secure making their next car purchase an electric vehicle."

As a member of Congress, she supported the *Infrastructure Investment and Jobs Act*, the *Inflation Reduction Act* and the Chips & Science Act. ■

# Constellation Proposes up to 1,500 MW of New Capacity in Md.

## Batteries and Gas Peakers Could be Followed by New Nuclear Capacity

*By John Cropley*

Constellation Energy is proposing 714 MW of new gas-fired peaker capacity and up to 800 MW of storage in response to a Maryland solicitation.

Constellation also said it could provide additional gigawatts of power with a combination of new nuclear generation and extension or expansion of existing nuclear facilities in Maryland.

Constellation's *Nov. 4 announcement* contains caveats: Some policymakers argue against building the additional natural gas infrastructure that the peakers would require; Maryland legislators need to provide clear direction and enabling legislation; and local utilities need to provide faster connections to the grid.

Meanwhile, Constellation and other major stakeholders are *pressing for reforms* in the PJM market. (See *PJM Drops Non-capacity Backed Load, Shifts Focus to Resource Queue, PRD*.)

Maryland Gov. Wes Moore (D) signed the Next Generation Energy Act (*SB0937*/*HB1035*) into law May 20.

In response, the Public Service Commission on Sept. 30 initiated *Docket PC74* and issued a solicitation for dispatchable generation and large-capacity energy resources through an expedited certification of public convenience and necessity (CPCN) process.

The dispatchable generation must have an effective load carrying capability of at least 65% as determined by PJM's most recent ELCC rating and must have a lower greenhouse gas emissions profile than coal- or oil-fired generation.

### Why This Matters

Like other states in PJM, Maryland is pursuing generation aggressively to meet the expected increase in demand from data centers and other large loads.

The energy resource must be a generating station or energy storage system that has applied for or been approved for PJM interconnection and must have a capacity rating of at least 20 MW after accounting for ELCC.

There were four responses by the Oct. 31 deadline:

A civil engineering firm submitted a confidential document; a group of environmental and community activists advocated in favor of solar, storage and wind but against natural gas; Alpha Generation requested a dispatchable resource CPCN for the 35-MW uprate it's pursuing for its 766-MW gas-fired Keys Energy Center; and Constellation submitted its two gas and one storage projects for consideration as dispatchable generation resources.

The 150-MW and 564-MW gas projects would use turbines that Constellation owns and would relocate to the project sites, which are adjacent to existing, undisclosed power stations. Anticipated annual run times were not disclosed. Constellation expects to submit service requests to PJM before April 27, 2026, as part of the Cycle 1 interconnection process.

Constellation said it has submitted a new gas service request to Baltimore Gas and Electric for the two projects. Securing firm supply in the highly constrained Mid-Atlantic pipeline system is challenging, so it is working with BGE to determine availability and will continue discussions with other parties as needed to secure firm gas to the sites.

Constellation warned that if the two gas plants are to be built, policymakers must work with gas utilities to facilitate gas supply improvements expeditiously; include appropriate cost recovery for gas infrastructure investments; and potentially authorize a special contract between the gas utility and generator to ensure firm supply at predictable rates.

Constellation's storage proposal would entail up to 800 MW of four-hour battery energy storage systems on up to four, 12.5-acre parcels owned by Constellation at undisclosed locations.

Constellation Energy is offering the possibility of extending the operational life and increasing the output of its Calvert Cliffs nuclear plant in Maryland, and says it could potentially co-locate new advanced nuclear generation there. | *Constellation*

They would export electricity for sale in PJM real-time and day-ahead energy wholesale markets, fast-start ancillary services and capacity markets.

The anticipated ELCC rate would be 58%, which Constellation acknowledges falls short of the 65% minimum specified by the PSC. But it argues in its proposal that the anticipated unforced capacity — as much as 464 MW — would be a significant addition to PJM's resource-constrained BGE Zone, and it would be emissions-free.

Constellation anticipates submitting this project as well in PJM's Cycle 1 interconnection process.

Constellation's potential increases in nuclear capacity are in earlier stages. They entail: Relicensing the two reactors at Calvert Cliffs to operate an additional 20 years beyond their current retirement dates, 2034 and 2036; investing in uprates to increase the Calvert Cliffs output by 10%, or 190 MW; and exploring construction of 2,000 MW of next-generation nuclear reactors beside Calvert Cliffs.

Together, these would equal 4,000 MW of emissions-free generation capacity added or not removed from the grid.

"Constellation could bring all — or any combination — of these new projects forward to meet Maryland's energy generation needs at the lowest possible cost to consumers," the company said, "provided we have clear direction and enabling legislation from Maryland's policymakers." ■

# PJM Presents Shortlist of RTEP Projects

*By Devin Leith-Yessian*

VALLEY FORGE, Pa. — PJM *presented* its shortlist of projects for inclusion in the first window of its 2025 Regional Transmission Expansion Plan (RTEP), which includes need for increased west-to-east transfer capability to supply rising data center load in Northern Virginia and the PPL region.

The projects were sorted into four regions: the PPL region of the MAAC zone, the overall MAAC zone, a southern cluster focused on resolving transmission violations and a western cluster centered around Columbus, Ohio. PJM expects to present its recommendations to the Transmission Expansion Advisory Committee during its Dec. 2 meeting.

The need in PPL is being driven by load growth increasing by about 5 GW between the 2024 and 2025 load forecasts, which is driven predominantly by data centers. The removal of 7.5 GW expected from offshore wind projects in New Jersey also caused five 500-kV lines to overload, increasing the need for more transmission into the Mid-Atlantic.

PJM added scenarios removing the offshore wind generation to reflect the New Jersey Board of Public Utilities canceling solicitations for development and postponing construction of transmission and other infrastructure. (See *N.J. Puts on Hold Remaining Pieces of $1.07B OSW Transmission Project*.)

PJM has shortlisted a single portfolio from PPL, which would make several upgrades to transmission around the Susquehanna nuclear generator for $565 million. The package includes building a new Kelayres 500-kV substation, extending the Susquehanna-Sunbury 500-kV line to cut into Kelayres and rebuilding the Juniata-Sunbury 500-kV line.

PJM Director of Transmission Planning Sami Abdulsalam said this is the first time a transmission owner has submitted a complete competitive RTEP portfolio with a fixed cost cap. He said there is strong confidence the utility's forecast will increase again next year, creating the need for upgrades of this magnitude.

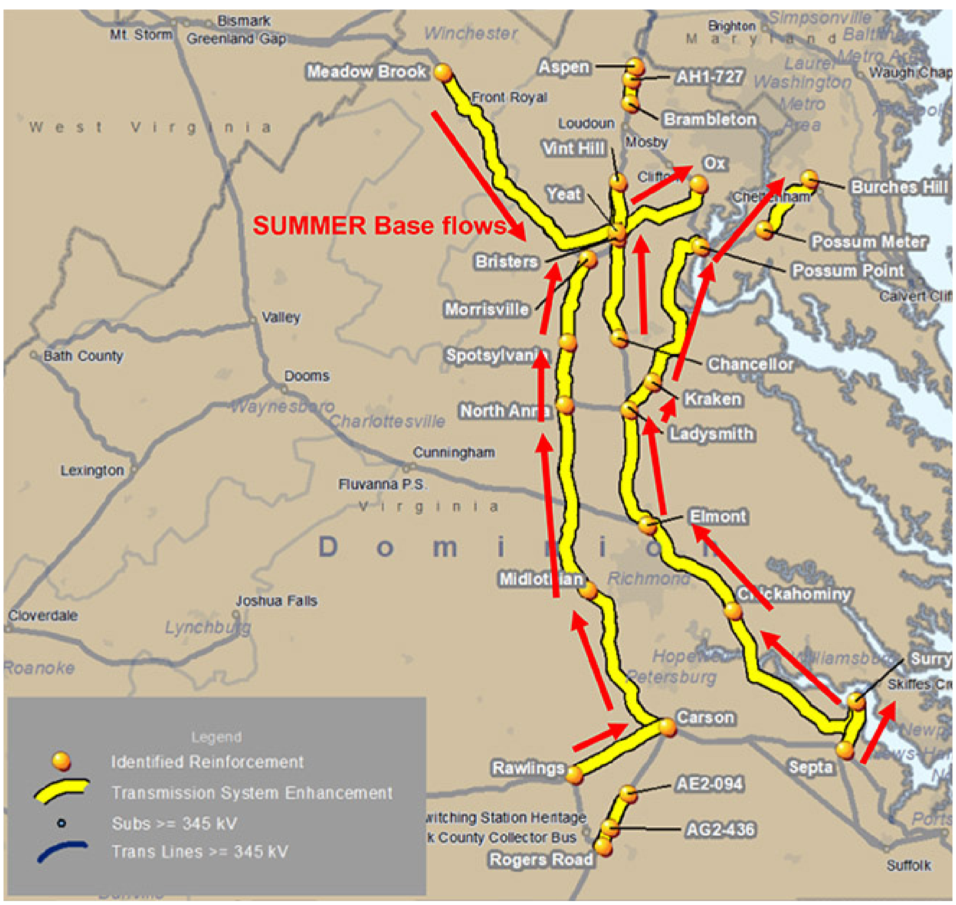
Increased transfer capability into the larger MAAC region is being prompted by data center growth in PPL, with three portfolios shortlisted and a fourth under consideration. A joint FirstEnergy and MAIT project would build two 500-kV lines between the Keystone and Susquehanna substations for $1.16 billion; a NextEra and Exelon package would build a 765-kV line from Kammer to Juniata, with two new 765/500-kV substations along the corridor for $1.74 billion; and a proposal from NextEra, Exelon and MAIT would build the Kammer-Juniata 765-kV line, plus a 500-kV line from Keystone to Susquehanna, for $2.82 billion.

New generation in southern Dominion paired with load growth in Northern Virginia is expected to cause multiple overloads on 500-kV lines between the two regions in 2032. Three packages were shortlisted: a high-voltage DC line from the Heritage substation to Mosby paired with a 500-kV line between Elmont and Kraken sponsored by Dominion for $4.82 billion; a pair of 765-kV lines from Heritage to Vontay and between Joshua Falls and Morrisville, passing through Cunningham brought by Transource for $1.97 billion; and two 500-kV lines between Heritage and Morrisville and from Finneywood to Cunningham and ending at Morrisville proposed by Dominion for $1.99 billion.

Several residents voiced support for the HVDC line, noting it would be underground and mostly follow existing transmission corridors. Many of the comments also called for more underground HVDC options. PJM staff responded that they're limited to the solutions presented by project sponsors.

Abdulsalam said there are several benefits to underground HVDC beyond aesthetics, including easier expansion capability and reduced injection of short circuit. But he cautioned that it's not a given the transfer capability is greater than overhead 765 kV.

The western cluster aims to address load growth in Ohio near Columbus and Melissa, as well as regional power flows




A PJM graphic shows power flows driving transmission violations identified in the 2025 Regional Transmission Expansion Plan. | *PJM* shifting toward the eastern and southern regions of PJM. Transource submitted a $2.78 billion project including several upgrades to the 765-kV and 500-kV networks around Columbus, including a 765-kV line from Greentown mostly using greenfield right-of-way; a $2.92 billion project from NextEra and Exelon to construct a greenfield 765-kV ring from Gwynneville and looping around Columbus; and $1.49 billion to build a 765-kV line from Belmont in West Virginia to Vassell and upgrade several lines to the southwest of Columbus.

## Supplemental Projects

FirstEnergy *presented* a $50 million project in the APS zone to replace 93 wood H-frames with steel structures and reconductor 12.72 miles along the Carroll-Mount Airy 230-kV line. The utility said the wood poles show signs of accelerated decay and woodpecker damage. The project is in the conceptual phase with a projected in-service date of June 30, 2029.

The utility also presented a $36.8 million project to serve a new customer requesting 230-kV service near the Doubs substation by constructing a 230-kV substation along the Doubs-Sage 230-kV line. The facility would feature 10 breakers and have a breaker-and-a-half (BAAH) configuration. The scope also includes reconductoring 2.9 miles of the Doubs-Sage line. The project is in the conceptual phase with a projected in-service date of Feb. 18, 2032.

FirstEnergy *presented* a $30 million project in the Penelec zone to rebuild 6.7 miles of the Johnstown-Seward 230-kV line to resolve deteriorating wood structures and insulator bells. The project is in the conceptual phase with an in-service date of June 15, 2027.

AEP *presented* a need to make repairs along 74 miles of its Hanna-Tanners Creek 345-kV line, which has experienced damage to structure legs, insulator assemblies and conductor strands. Brackets holding suspension insulator strings also are wearing out on 87% of the structures inspected, creating increased risk that a conductor could fall from the towers. There have been five momentary and two permanent outages on the line in the past five years.

PECO *presented* a $176.6 million project to serve a new customer seeking to bring 600 MW of load near Fairless Hills, Pa., by 2028. The project's first phase would install two temporary 230-kV lines tapping into the double-circuit Ford Mill-Emilie line, followed by the construction of a 230-kV BAAH substation, named Sinter, with 11 breakers and two customer feeds. The line segment between Sinter and Emilie would be rebuilt, and terminal equipment at Emilie would be upgraded.

Two new service requests were presented for 750 MW near Limerick, Pa., by 2032 and another for 500 MW of load in Philadelphia expected to come online by 2029.

## Planning Committee Examines Spare Equipment Philosophy

PJM has expanded its *guidance* on spare equipment for transmission owners, increasing the document from a single page to eight in an effort to consider equipment likely to fail during extreme weather.

The Planning Committee requested that the Transmission & Substation Subcommittee re-evaluate the document, including the possibility of a "targeted return to service" when determining the adequate supply of spare parts, as well as the logistics to deliver that equipment. (See "PJM Seeks Stakeholder Attention on Spare Equipment Requests," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

The new language lists several major types of equipment that may be difficult to procure or transport after a failure, such as transformers, reactors, circuit breakers, tower components and conductors, and it gives high-level guidance on spare equipment storage and typical replacement timelines.

"Spare equipment is critical to the continued integrity of the bulk electric system (BES)," the document reads." Failure to maintain adequate spare equipment can lead to unnecessary higher operating costs and unnecessarily long outage times, consequently compromising transmission and overall system reliability.

"Interconnected transmission owners (ITOs) need to be able to support any local interconnection agreements. The purpose of this philosophy is to ensure that thought is given to maintaining adequate spare equipment for the BES. Any new facility connecting to the bulk electric system should observe this philosophy." ■

# FERC Rejects Kentucky Complaint Against AEP's Tx Cost Allocation

*By James Downing*

FERC *rejected* a complaint that the Kentucky Public Service Commission and attorney general filed against American Electric Power over a cost-allocation dispute involving the AEP East Operating Cos.' transmission agreement (*EL25-67*).

AEP East provides transmission service to its utilities in PJM and some transmission-only affiliates in the region in an arrangement that started in 1984, predating the utility's membership in the RTO, which began in 2004. The allocation of transmission costs for lines of 69 kV and above is shared among its utilities in Kentucky, Indiana, Michigan, Ohio, Virginia and West Virginia under a deal approved by FERC in 2010.

The deal covers all PJM projects, even "supplemental" transmission that transmission owners use to plan for their own, local needs. Under its Attachment M-3, PJM allocates the cost of supplemental projects only to the utilities that build them, but the 2010 Transmission Agreement allocates them across AEP's utilities in the region.

Kentucky complained that setup is not fair because its residents do not benefit from supplemental transmission investments made in other states.

"Since 2019, AEP East has added $3.4 billion in AEP East Attachment M-3 Projects to rate base, of which more than $75 million has been allocated to Kentucky electricity consumers," the order said. "Complainants aver that few, if any, of those AEP East Attachment M-3 Projects have any relationship to serving Kentucky Power retail or wholesale customers."

## Why This Matters

FERC upheld a principle that even if a utility is not the initial driver of a project, it can be allocated costs if it received benefits from the project.

The transmission agreement has been around since 1984 and in addition to joining the RTO, AEP stopped centrally planning its generation, the latter of which was a key part of FERC's reasoning for approving the arrangement in the first place.

AEP argued that Kentucky consumers still use all of the AEP East transmission system and the benefits they get are roughly commensurate with the costs they paid. The utility holding company approaches local planning as if the AEP East utilities were a fully integrated system.

"AEP East states that this means making transmission investments at the local level with the purpose and effect of benefiting the entire AEP East transmission system, as reflected in AEP East's transmission planning guidelines, and asserts that the AEP East transmission system was developed to be, and remains, a system within a system," the order said.

FERC found that the complaint failed to prove the 2010 Transmission Agreement's rules for allocating supplemental projects were unjust and unreasonable. Commission rules require that consumers pay for transmission that benefits them and allocations are done in way "at least roughly commensurate with benefits."

Cost allocations do not have to be done with "exacting provision," but FERC needs a plausible reason for why they are roughly commensurate with assigned costs. The commission previously explained it has a strong policy of requiring rolled-in costs when any degree of integration has been shown.

"Complainants point to a selection of 26 AEP East Attachment M-3 Projects that they argue do not provide benefits to Kentucky customers that are commensurate with the approximately $15 million per year in costs allocated to Kentucky customers for those projects," FERC said. "As discussed above, providing a selection of projects as evidence that a cost-allocation framework is no longer just and reasonable is not sufficient to overturn a cost-allocation framework approved by the commission."

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It still makes sense to allocate supplemental projects across all of AEP's operating companies in PJM because while different utilities might have created the need for the upgrades, to the extent another firm benefits from them — it can be said to have "caused" part of the costs.

"Complainants focus on which entities drive the initial need for a transmission project, but that is not the end of the cost-causation analysis — rather, the cost-causation principle requires that the costs for a transmission project be allocated to those who benefit from the project," FERC said.

"As discussed above, the commission has rejected challenges to cost allocations for specific transmission facilities where those facilities formed part of the integrated transmission system. Kentucky Power's system is part of AEP East's integrated transmission network. Thus, it is reasonable to conclude that Kentucky Power's customers benefit from the AEP East Attachment M-3 Projects that become a part of that transmission network." ■

# PJM Stakeholders Endorse Rules for DER Participation

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The PJM Market Implementation Committee *endorsed* by acclamation revisions to Manual 18 to define how distributed energy resources will participate in the 2028/29 capacity auction in accordance with PJM's Order 2222 compliance filing.

The Independent Market Monitor had *proposed* revising the language to address a possible issue where resources could bypass market power mitigation by offering into an auction as an aggregation of demand response resources, which are not subject to market power mitigation rules, but then include generation during the delivery year by classifying the resource as heterogeneous.

The recommended language would have sorted DERs into either homogenous distributed generation, homogeneous demand response or heterogeneous resources. If a resource failed to abide by its classification in the delivery year it would fail to meet its capacity commitment. It was not included as an amendment to PJM's language.

Deputy Monitor Catherine Tyler said a resource with a DER plan should be required to supply the same type of aggregation that it offered into a Base Residual Auction. An aggregation composed of a combination of generation and DR that changed the concentration of one or the other would not be affected by the proposal, she said.

Questioned how PJM would handle such an issue today, PJM's Pete Langbein said the information collected about market participants would make it clear how a resource is being offered into the market. If there appears to be an effort to exercise market power, PJM would reach out to the participant and potentially refer them to the Monitor or FERC's Office of Enforcement. He said it likely would be rare for a DER to solely be composed of DR, but if such a resource was offered into an auction and then installed a significant amount of generation, that would raise red flags to PJM staff.

Aaron Breidenbaugh, senior director of regulatory affairs at CPower Energy Management, said it can be difficult to anticipate the future three years in advance. A DR participant might decide to install storage or solar and then be unable to do so, which could create compliance risks for customers interested in aggregation. Adding onerous limits would discourage participants and possibly punish participants who had no adverse impact on market power.

"It's a harsh solution in search of a potential problem," he said.

Monitor Joe Bowring responded that if an entity believes they may participate in the capacity auction as a more advanced resource, they should offer as such.

"It is ineffective to substitute red flags and potential referrals for good market rules. Good market rules are not punishment unless participants attempt to exercise market power," Bowring said.

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The Manual 18 revisions also reflect changes to how DR is offered into the market, removing the availability window to model DR as being dispatchable in all hours and changing the calculation of participants' winter peak load to be based on the 9 a.m. coincident peak, rather than each DR site's individual peak. (See *PJM Stakeholders Endorse More Detailed Demand Response Modeling*.)

## PJM Update on Regulation Market Redesign

PJM's Michael Olaleye *presented* an update on the implementation of PJM's redesign of the regulation market, which went live Oct. 1. The changes shifted the market from two bidirectional signals to one, shortened clearing and commitment to 30 minutes, and established the tracking ramp limited desired parameter. (See "PJM Presents Regulation Market Rework," *PJM MRC/MC Briefs: Dec. 20, 2023*.)

Since the go-live date, there have been more days with high clearing prices, with Oct. 3 seeing two intervals at $33,897/MWh and $29,636/MWh. There were 11 intervals where the clearing price exceeded $5,000/MWh. Despite performance scoring being tightened to consider only the precision of a resource's response — accuracy and delay were eliminated as criteria — Olaleye said average scores have remained largely the same.

A handful of market participants said the lost opportunity costs seen during October were shocking and questioned whether this is likely to be the norm.

Rebecca Stadelmeyer, Gabel Associates vice president of wholesale power and market services, said it was not expected that clearing prices would be in the thousands and that participants are working to figure out how to price load deals for auctions in deregulated states and ensure customers are protected. She suggested PJM hold education sessions on the results of the market changes, adding that past discussions relied on theory about how the redesign might play out. ■

# PJM Monitor Presents Spin Event Performance

## October Metrics also Presented to Operating Committee

The PJM Independent Market Monitor *found* that modeling issues were the largest cause of synchronized reserve underperformance during a July 22 spin event, in which about 80% of assigned reserves responded.

The Monitor has been reaching out to resource owners whose units underperform during reserve deployments, focusing on events longer than 10 minutes. It also has inquired with the owners of overperforming resources, but the small sample size limited the amount that could be shared.

The effort has become more important since PJM instituted a 30% adder on the synchronized and primary reserve requirement in May 2023 to counteract a low response rate.

The 10-minute-32-second event had 2,764 MW of generation and 548 MW of demand response assigned, with a 78.8% response rate. (See "July Operating Metrics," *July Heat Wave Update, PJM OC Briefs: Aug. 7, 2025*.)

Joel Romero Luna, a market analyst with the Monitor, said PJM's modeling of the amount of time needed to bring equipment into service or change output is accounting for a rising share of reserve underperformance. That constituted the largest cause July 22, at 178.8 MW of the 523 MW for which a cause was attributed.

Issues with software and hardware, such as mechanical failures or errors in programs that dispatch units, were the second-highest rationale for underperformance, followed by outdated or inaccurate resource parameters.

Luna told the Operating Committee on Nov. 3 that communication between PJM and resource operators has improved significantly. However, operators sometimes still do not know what is required of them during a spin event.

Personnel error and communications issues accounted for 12% of the shortfall for which a cause could be attributed. PJM has reworked how reserve deployments are sent to resource operators to convey instructions through unit basepoints. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

## October Operating Metrics

PJM's load forecast accuracy improved for a fourth consecutive month, PJM's Marcus Smith said while *presenting* the monthly operating metrics. The average hourly forecast error was 1.02%, while the rate for peak hours was 1.30%.

Three days exceeded the RTO's 3% peak-hour error benchmark due to unpredicted weather conditions. The peak Oct. 4 was 3.05% under forecast due to high temperatures in the east causing increased load. Oct. 7 was over forecast by 3.12% due to storms across the footprint pushing temperatures down, and Oct. 8 was over forecast by 3.59% due to lower temperatures and variations in cloud coverage.

Joel Romero Luna, Monitoring Analytics | © RTO Insider

There was one shared reserve event and one geomagnetic disturbance warning, and there were 24 post-contingency local load relief warnings. Two shortage cases were approved Oct. 3 due to low generation during the afternoon ramp; another was issued Oct. 17 at 10:20 a.m. due to a unit tripping offline.

A spin event was declared Oct. 15 at 4:52 p.m.; it lasted 5 minutes and 21 seconds. There was 2,804 MW of generation assigned, of which 57% responded.

Another event Oct. 17 was initiated at 8:13 p.m. and lasted 11 minutes and 7 seconds. There was 1,743 MW of generation assigned, of which 74% responded, and 644 MW of demand response assigned, of which 92% responded.

The Oct. 17 deployment is the second in PJM's three-event rolling average used to determine whether it will reduce a 30% adder on the synchronized and primary reserve requirement. Paired with an event Sept. 25 with 77% performance, the average is 78%. Performance across three consecutive events must be above 75% for the adder to be reduced by 10%, and a larger reduction is possible if performance is higher. (See *PJM OC Briefs: March 6, 2025*.)

A third October spin event was declared Oct. 28, but the data had not been processed before the Operating Committee meeting.

## Manual 14D Revisions Endorsed

Stakeholders endorsed by acclamation a slate of *revisions* to Manual 14D: Generation Operational Requirements drafted through the document's periodic review.

The changes require that generation owners notify PJM of start-up issues that may affect their units during a cold weather advisory and added sections detailing cold weather operating limit data requests and the cold weather advisory drill. They also detail how data about resources is used in PJM's Gen Model to produce load flow, short circuit and dynamics modeling for planning staff. ■

*— Devin Leith-Yessian*

# SPP Board Approves 2025 ITP with 4 765-kV Projects

*By Tom Kleckner*

## The Bottom Line

The SPP board has approved the RTO's 2025 Integrated Transmission Plan that includes four 765-kV projects, but not without addressing concerns about affordability. The grid operator has agreed to several cost-containment measures to help utilities with their consumers.

LITTLE ROCK, Ark. — It took almost two months of stakeholder meetings, outreach and education, working group discussions, staff modeling and everyone's consternation over affordability before SPP's Board of Directors approved a 2025 Integrated Transmission Plan (ITP) designed to keep pace with accelerating load growth and ensure grid reliability.

The ITP's portfolio includes four 765-kV projects that total 949 miles and are part of a planned 765-kV backbone, along with 46 other proposals approved for construction permits. It also comes with an $8.6 billion price tag, eclipsing the record 2024 ITP that had SPP's first 765-kV project and a $7.65 billion cost. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

SPP says the *10-year ITP assessment* shows the portfolio is necessary to ensure the grid is ready for future demand, citing industrial electrification, manufacturing onshoring and economic development forecasts that show the grid at its limits. The grid operator is projecting a 25% increase in demand by 2030 for its 14-state footprint and a near doubling of its peak load (56 GW) in 10 years.

The portfolio has regional benefit-to-cost ratios between 12:1 and 18:1, the highest in the RTO's planning history.

Still, with memories fresh over a recent cost-estimate increase for SPP's first 765-kV project, members expressed concerns over the portfolio's expense. The board in September approved a revised cost estimate of $3.62 billion, up from an original projection of $1.69 billion in February, for Southwestern Public Service's 765-kV project in the 2024 ITP. (See *SPP Board Approves 765-kV Project's Increased Cost*.)

"It's really hard for us at a local level to talk about affordability when the metrics in the report are region-wide. The only thing our customers see in their [bills] is their rates going up," Evergy's Denise Buffington said during the Nov. 4 discussion.

"We have the job over the next 12 months, probably 10 months, to go to our legislature and our governor and our customers and explain to them why 765 is important," she added, asking for "a little grace" and time to advocate about why the 2025 ITP is the right long-term solution. "We have to get the metrics down to a local level."

Buffington's message and those of other members were received by the board.

"As a board, we recognize that we're making decisions that will significantly impact every homeowner and business in SPP," board Chair Ray Hepper said as the meeting ground on through the lunch hour. "Reliability and affordability are a really delicate balance, and we strive to do our best in making that balance, thinking like every dollar we are approving is our own dollar. We also recognize that economic development for this region and attracting new loads that can serve our national interests is a key driver for a cost-effective system that will support growth in this critical time."

### SPP Mitigation Measures

To help ease concerns, SPP staff filed a *memo* with the board and the Members Committee outlining their measures to mitigate risks related to the viability and cost of 765-kV projects in the 2025 ITP. The measures will apply to 765-kV projects that receive a conditional construction permit or a request for proposals. They include SPP's commitment to analyze the proposed 765-kV overlay analysis within the 2026 ITP assessment.

Hepper then added his own requirements for SPP so the board can fulfill its oversight responsibility and help "assure that only appropriate costs for new transmission are incurred."

"Our goal is a reliable, cost-effective transmission system that will serve the region for years to come," he said.

Hepper directed staff to file quarterly


NextEra Energy Resources' Matt Pawlowski lays out the case for action on the 2025 ITP. | *© RTO Insider* reports with the board should there be any changes that could affect approved projects in the 2025 ITP or any future assessments. He earned a commitment from COO Antoine Lucas to work through the stakeholder process and complete the 765-kV overlay analysis as part of the 2026 ITP and determine whether further mitigation actions or changes are needed.

Finally, he ordered staff to bring to the February board meeting a plan to expedite and improve the competitive project process, including a plan to improve the evaluation of RFPs.

"You've created a set of off-ramps and on-ramps for projects, which makes a lot of sense because things change relative to forecasts," director Steve Wright said.

The Members Committee's advisory vote passed 17-3, with three abstentions. Electric Cooperatives of Arkansas, Nebraska Public Power District and Omaha Public Power District voted against the measure.

The portfolio the board approved began as an $18.1 billion package of projects that staff identified to meet 10-year reliability and economic needs. It was whittled down by deferring about $7 billion in projects without near-term needs or that could be "further optimized" within the 2026 ITP, and again by deferring two economic 765-kV projects and their $2.6 billion costs, reducing the package to its final total.

The 2025 ITP does not include another $1 billion in zonal planning criteria projects submitted for study by members.

Most deferred projects will be further evaluated in the 2026 ITP as SPP continues to study a 765-kV backbone. It says a single 765-kV line can carry four times the power of a 345-kV line, using less land and losing less energy over long distances. That makes 765 kV a more efficient, cost-effective and forward-looking solution for a growing grid, staff said.

Name tents pop up as discussion begins on the 2025 ITP. | © *RTO Insider*

"We're building today for the demands of tomorrow," said Casey Cathey, the RTO's engineering vice president.

Stacey Burbure, American Electric Power's lead for transmission business development and joint ventures, applauded SPP's decision to move forward with its 765-kV overlay. She noted AEP's service territory includes some of the poorest parts of Appalachia, where the company has some of its more than *2,000 miles of 765-kV infrastructure*.

"It's our baby. This was the most efficient and effective way for us to serve our customers, and it remains a very effective tool in the bucket for every RTO," Burbure said. "This is a tool that folks are turning to to solve the issues that confront us, regardless of which RTO you're in. Is this the right outcome for SPP as a region? I think the answer is obvious. It's yes."

Matt Pawlowski, vice president of development for NextEra Energy Transmission, pointed out that the portfolio includes two 765-kV legs on either side of the footprint, but no road connecting the two highways. While NextEra supports the $8.6 billion ITP, it would have preferred the $11.1 billion package, he said.

"Without a connector, the systems on either side of those lines are going to be overloaded," Pawlowksi said. "We are going to have reliability issues. If we don't address it with the two economic projects, I think we're really missing out."

He said if the two economic projects are again deferred, SPP will face the danger of getting behind an "entire queue of projects in the supply chain."

"If you defer these projects, you are totally kidding yourself. You are not going to build these projects by 2030 plus, 2035 probably at best," Pawlowski said. "So what is preventing us from looking at those two projects and improving them as a region when staff has already said that they're needed?"

The discussion will continue in February when the board gathers again in Little Rock for its first quarterly meeting of 2026. Hepper, who prefers to have people around the table debating issues, has canceled the original virtual scheduled meeting to further discuss in person 765-kV lines and the competitive project process.

Board Chair Ray Hepper (center) explains next steps as SPP CEO Lanny Nickell (left) and director Stuart Solomon listen. | © *RTO Insider*

"We are going to have some very significant decisions to talk over," he said.

## SPP Introduces CARE Team

SPP has introduced another acronym to its lexicon with the creation of the Cost Control and Allocation Review and Evaluation (CARE) Team. The cross-functional body will review, evaluate, assess and recommend refinements or alternatives to current transmission cost controls and cost-allocation methodology.

Wright and Kayla Hahn, the Missouri Public Service Commission's chair, will co-chair the 15-person team and have already met once to discuss CARE's scope. It has been asked to deliver a final report in August 2026.

Other members will include independent director Stuart Solomon, commissioners Chuck Hutchinson (Nebraska), Justin Tate (Arkansas) and Kathleen Jackson (Texas), and state regulatory staffers Jon Thurber (South Dakota), Jason Chaplin (Oklahoma) and Justin Grady (Kansas). Members from the Members Committee and the Strategic Planning Committee will be added later.

"The idea was, 'Let's get this conversation happening. Let's have a conversation between the groups within SPP that have the organizational responsibility for allocation and cost control,'" said New Mexico Commissioner Pat O'Connell, the Regional State Committee's president.

"So, to me, just getting all those folks together to have this conversation by itself is valuable," he said. "I am also confident that SPP works to deliver good results, so that the recommendations will be also valuable and impactful." ■

# SPP Awards 8th Competitive Project, 3rd in 2025

## RTO Board Approves Reduced Admin Fee, Golden Spread Appeal

*By Tom Kleckner*

LITTLE ROCK, Ark. — SPP's Board of Directors has awarded its eighth competitive project and third in 2025 under FERC Order 1000, a 345-kV upgrade in the Texas Panhandle.

A panel of industry experts designated Transource Oklahoma and Southwestern Public Service as the transmission owners for the project, on a 150-mile line from Beckham County, Okla., to Potter County, Texas.

NextEra Energy Transmission Southwest was the only other bidder on the project in what the panel said were two high-quality proposals.

"Both proposals were from highly qualified, experienced entities with a successful history in the design, build and operation of similar and relevant projects," said Tom Bozeman, chair of the industry expert panel (IEP).

That was apparent in the *IEP's scoring*. The panel saw less than 3 points of difference between the two proposals, with NEET Southwest's bid getting a slightly higher score than the Transource-SPS proposal: 1,088.54 to 1,086. However, Transource and SPS submitted a lower cost, or "present value requirement," to customers: $248.68 million to $269.53 million.

IEP Chair Tom Bozeman explains the scoring behind SPP's latest competitive project. | © *RTO Insider*

Bozeman said the panel questioned the results but agreed the small difference between the bids was "reflective of two highly qualified respondents with very similar proposals."

"We found [the Transource-SPS proposal's] cost to customers' savings of almost $21 million to be a distinguishing package," he said.

SPP staff has given the project an estimated $429.73 million price tag and a projected November 2029 in-service date.

The Transource-SPS bid was the only one to offer a cap on the annual transmission revenue requirement. That also played a part in the IEP's unanimous decision.

During questions by the board, the IEP said its requirements did not include information on cost caps and how to deal with them. Director Irene Dimitry, who leads an Order 1000 *Strategic Review Task Force* that is trying to improve the selection process' effectiveness and reduce the cycle time, agreed more information and analysis is needed.

"There's this need to make sure we're getting all the information we need to make an informed decision," she said. "We have work to do, especially in thinking about the projects that are coming out of the 2025 ITP. What can we do differently moving forward, so that the information is gathered from the bidders and that guidance is given to whoever's doing the evaluation to deliver the analysis that we need?"

Dimitry said the task force is weighing the use of outside consultants to augment the IEPs and provide additional expertise to ensure they can handle the volume of projects coming out of the 2025 assessment.

"We're presuming there will be some big projects coming in, including an expectation of our first [competitive] 765[-kV] projects," she said.

The Members Committee unanimously endorsed the IEP's recommendation with its advisory vote. The Advanced Power Alliance and Basin Electric Power Cooperative abstained.

### Why This Matters

SPP continues to show awarding competitive projects under FERC Order 1000 can be done with its third successful bid of 2025. The RTO will only get more opportunities with several more competitive projects expected to come out of the 2025 transmission plan.

The Beckham-Potter project was one of four competitive upgrades that were approved out of the 2024 Integrated Transmission Plan. It is a companion to SPS' 765-kV Potter County-Crossroads-Phantom project, which also came out of the same ITP assessment but does not directly address any 2024 needs by itself.

Transource and SPS were both involved in the last two winning bids handed out by the IEP. Transource won the 38-mile Mathewson-Redbud project in Oklahoma in May, and SPS was awarded a 20-mile, 115-kV proposal in August. (See *SPP Approves 6th Competitive Transmission Project* and *SPP Board of Directors/Members Committee Briefs: Aug. 5, 2025*.)

### Admin Fee Reduced in 2026

"We're going back to the future as it relates to administrative fees," CFO David Kelley said, unveiling a 2026-2027 budget that includes a nearly 5% reduction in the effective administrative fee (EAF) that members and customers pay for the RTO's services.

The EAF will drop to 45.7 cents/MWh from 47.9 cents/MWh, effective Jan. 1, 2026, thanks to a net revenue requirement (NRR) of $216.5 million boosted by the RTO's expansion into the Western Interconnection. The 2025 NRR was budgeted at $204 million, but SPP expects the expansion to add about $16 million of positive NRR in 2026.

Kelley said the Western RTO participants will bring in slightly more than 40 TWh of transmission billing units, about a 9.3% increase, when the market goes live April 1, 2026. That will help offset an 8.7% increase in budgeted operating expenses, from $273.9 million in 2025 to $297.7 million.

The board approved the budget following the MC's unanimous endorsement. The board also approved a $27.6 million capital allocation to invest in artificial intelligence and associated hardware.

"We are investing in technology to make the organization more efficient and to limit future increases to our administrative fees," Kelley said, "both from a staffing headcount perspective and outside services and future technology."

The rate schedules that go into effect Jan. 1 are calculated by the NRR and the billing determinants for each schedule.

"What I've seen is the sophistication of our financial planning has increased over the seven years that I've been with SPP," Director Susan Certoma said. "The complexity of the financials has increased also, but David, his team and all those involved in the budget process have been able to translate the complexity into clear and powerful messages, which provide all stakeholders with a clear understanding of the budget."

### Capacity Assessment Appeal

Board members approved Golden Spread Electric Cooperative's appeal of a rejected tariff change (*RR642*) that would enable transmission customers and host TOs to access load-hosting capacity assessment in determining the amount of load the existing system can handle without requiring additional network upgrades.

Golden Spread's Mike Wise brought the same appeal to the Markets and Operations Policy Committee in October, when it received only 29.51% approval. SPP's TO members united to vote against the change, citing concerns over reliability issues with sharing load-hosting capacity and creating operational risks. (See *Golden Spread to Appeal Rejection of Capacity Assessment Change to Board*.)

Staff drafted the proposed change to tariff Attachment AQ's screening process following a recommendation from the Holistic Integrated Tariff Team's (HITT) *2019 report*. It would allow SPP to proactively perform analysis to determine load capacity at each node on the system without incremental investment. Information gathered from the load-hosting capacity assessment would determine whether transmission customers would be required to go through an AQ delivery point network study.

The retiring Bruce Rew reacts to applause from the board and members. | © RTO Insider

"It's my understanding that nobody opposes the tool, necessarily; that it's a point in time where you have potential, available capacity," Evergy's Denise Buffington said. "The challenge we had was it should not replace the study, the need for a study, right? The hosting capacity is like a heat map at a point in time, but if you're actually going to use it to connect something to the system, then the study needs to be performed. It's not good enough just to rely on this tool."

"This tool, as laid out, does not bypass the transmission owners' right to ask for the study. It's their prerogative," Wise said. "This is not removing that decision."

SPP staff said they would continue their work on the tool with the Transmission Working Group. They offered to gather technical feedback, fix the tool and come back to the board with another recommendation.

Members endorsed the successful appeal 21-1, with one abstention. Liberty Utilities voted against the measure.

### Change to LTCR Market

The board approved a proposed tariff change (*RR697*) modifying the language to allow netting of flows in the long-term congestion rights (LTCR) allocation, giving more opportunities to all participants to receive the rights.

The revision request formalizes a policy approved by the Regional State Committee in February and completes one of the last remaining recommendations from the HITT. (See "RA, Congestion-hedging Recs Pass," *SPP Board/Regional State Committee Briefs: Feb. 3-4, 2025* and *SPP Board Approves HITT's Recommendations*.)

"We've spent a lot of time trying to figure out how to improve our congestion-hedging process. I think this is just another step on that way," SPP CEO Lanny Nickell said.

Eligible entities can nominate up to 50% of each path under the change and hold any awarded LTCRs for five years. All current awarded LTCRs will remain under the current rules and can be released yearly, if desired.

The MC endorsed the proposal 17-4, with two abstentions. Basin Electric, Nebraska Public Power District, Oklahoma Gas & Electric and Omaha Public Power District all opposed the measure, as did their state utility commissions (Nebraska, North Dakota and Oklahoma) during the RSC meeting.

The board approved three other revision requests that received a single dissenting vote between the RSC and MC:

- *RR655* establishes clear outage-submission requirements, including definitions, data standards, timelines and rules for submission, extension and updates. Market participants will be required to provide accurate timely outage and capability information; transmission providers will review and potentially deny noncompliant submissions.

- *RR707* incentivizes on-site fuel storage by applying a unique class average for resources that provide the capability. Newly constructed thermal resources and those that undergo a primary fuel conversion will be applied with a 0% equivalent forced outage factor (EFOF) for the first winter season; non-NERC registered resources will use class average EFOF for the 2022/23 and 2023/24 winter seasons.
- *RR719* aligns cost allocation for deliverability by allowing network resource interconnection service's delivery portion before the Consolidated Planning Process is deployed to also be eligible for base-plan funding.

## Rew, Osburn, Ross Honored

Dave Osburn, OMPA | © RTO Insider

Stakeholders celebrated SPP's Bruce Rew and Oklahoma Municipal Power Authority's Dave Osburn, who are both retiring, with several standing ovations.

Nickell presented official resolutions to Osburn and Rew, one of SPP's original 14 employees. Rew announced his retirement in April after 35 years with the RTO. Osburn is stepping away from the MC but plans to continue participating in the Resource Energy and Adequacy Leadership Team through February 2026.

"One of the things that's always impressed me when I came here and got involved with SPP is while we sometimes have different business goals when it came to the organization and what's best for the power pool in general, people kind of came together, found a way to collaborate and reach consensus," Osburn said. "And I just always appreciated what takes place at SPP and how we try to figure out a good solution for everybody, not just our system."

"When I reflect back, a lot of things have changed, but a lot of things have stayed the same," Rew said. "One of those things are meetings like this, where the members are passionately committed to making a difference for SPP and setting the future for SPP. Shortly after I started, SPP celebrated 50 years and a short 15 years from now, it will be 100 years for SPP. So I do want an invitation to the 100-year anniversary so I can see what difference this organization has made in the next 15 years while I'm gone."

Nickell also called out American Electric Power's Richard Ross, who is giving up the Market Working Group's chair after 21 years in the seat.

"I want to call [Ross] a super chair because a lot of work was done under his leadership," he said. "I remember what our Market Working Group secretary said about Richard: 'You have guided the MWG with a boot, a gavel, a steady hand, sharp insight and a collaborative, feisty spirit that has left an undeniable mark on this group and on SPP's market evolution.'"

"That's the truth," muttered an SPP staffer in the audience.

Nickell said he wanted to give Ross one of the Gold Stars that he hands out for work well done, except for one small problem: "I've just never been awarded one."

## Bastone, Hepper, Wright Re-elected to Board

Members re-elected independent Directors Bronwen Bastone, Ray Hepper and Steve Wright to new three-year terms on the board during the Annual Meeting of Members.

Bastone, Wright and Hepper were first elected in 2020, 2022 and 2023, respectively. Hepper, the board's chair, said Stuart Solomon has agreed to serve as vice chair, effective immediately.

Members also elected four new members and six incumbents to the MC, which acts as a sounding board and provides input to the directors. The four new members and the sectors they represent are:

- Brad Hans, Municipal Energy Agency of Nebraska, and Paul Mahlberg, Kansas Municipal Energy Agency (Municipal);
- Chris Matos, Google Energy (Large Retail); and
- Ken Miller, OG&E (Investor-owned Utility).

The re-elected incumbents are:

- Buddy Hasten, Arkansas Electric Cooperative Corp., and Jeremy Severson, Basin Electric (Cooperative);
- Brett White, Pine Gate Renewables (Independent Power Producer/Marketer);
- Bleau LaFave, NorthWestern Energy, and Stacey Burbure, Public Service Company of Oklahoma (Investor-owned Utility); and
- C. Patrick Woods, ITC Great Plains (Independent Transmission Company).

The nominations were brought forward by the Corporate Governance Committee. Each member will serve two-year terms.

## Competitive Project Proceeds

His seat at the table not yet warm, OG&E's Miller pulled from the consent agenda a working group's recommendation to make no changes to a construction permit for the 345-kV Sooner-Wekiwa competitive upgrade.

The Project Cost Working Group analyzed the project, awarded to Transource Oklahoma in 2020, but determined it couldn't make a ruling on a reported cost increase that exceeded commitments because Transource included a confidential obligation in the proposal.

Miller said he had concerns about SPP's competitive process but that his complaint was about not being able to see the cost overruns.

"We don't know whether they're reasonable and should be recoverable. We can't see that," he said. "I have concerns about the competitive process, but I also have concerns we are signaling to FERC that these cost overruns are reasonable."

SPP assured the board and members that staff will continue to review the project and address any issues. The project has a Nov. 17 in-service date.

Miller abstained from the vote on the motion, which passed the MC 19-0, with three other abstentions.

The consent agenda, passed in a voice vote, included the *violation relaxation limit analysis report*; CGC's nominations of Miller to the Strategic Planning Committee, and Western Farmers Electric Cooperative's Rodney Palesano and OG&E's Brad Cochran to the Human Resources Committee; and *RR706*. The tariff change adds the federal service exemption transfer point as a qualifying source for candidate LCTRs and auction revenue rights.

The agenda also included recommendations to accept new cost estimates for five projects as reasonable, nine out-of-cycle re-evaluations and two withdrawals. ■

# SPP State Regulators Affirm Use of Highway/Byway Cost Allocation

## RSC Elects New Leaders

*By Tom Kleckner*

LITTLE ROCK, Ark. — SPP state regulators have approved several motions related to FERC Order 1920's mandate for long-term, scenario-based planning to ensure the system can meet future needs and be fairly compensated.

The Regional State Committee endorsed the continued use of SPP's highway/byway cost allocation for long-term regional projects during its Nov. 3 quarterly meeting. It also approved the Cost Allocation Working Group's recommendation to allocate long-term projects with public policy benefits to the state they benefit.

Under the grid operator's highway/byway methodology, one-third of the cost of byway projects — lines rated at 100 to 300 kV — are allocated to the RTO's full footprint, with customers in the transmission pricing zone in which the project is built being allocated the rest. "Highway" projects, those larger than 300 kV, are allocated RTO-wide.

The RSC offered several amendments to the motions brought forward by a CAWG sub-group, but both failed. Both would have established a $150 million threshold for projects to be cost allocated, provided that a simple majority of affected committee members vote to initiate the process.

However, separate votes to require alternative *ex post* cost allocation methodology be approved by either a two-thirds or simple majority both failed with deadlocked ballots.

John Krajewski, a consultant for the Nebraska Power Review Board who led the CAWG sub-group, said SPP has never identified a project or issued a notification to construct (NTC) out of a 20-year study.

"So, in some respects, this was an academic exercise," he said, "but I also think it was important because we're required to do it under Order 1920, and it's possible in the future this may be an issue."

Order 1920 requires transmission providers to plan for at least 20 years, create at least three different long-term scenarios

SPP CEO Lanny Nickell delivers the president's report as Minnesota's John Tuma listens. | © *RTO Insider*

to identify future needs and evaluate potential solutions for cost-effectiveness. The order also incorporates a landowner bill of rights, tribal impact reports and engagement plans with environmental justice communities. The compliance filing is due in June.

### Nickell Recaps 'Transformational' Year

SPP CEO Lanny Nickell thanked the RSC for the "key role" it played in helping the grid operator move initiatives related to resource adequacy and cost allocation that made 2025 a "transformational" year.

Nickell name-checked the one-time expedited resource adequacy study (ERAS) to fast-track qualified projects and a provisional load process, both approved recently by FERC. He also mentioned the Consolidated Planning Process that would combine transmission planning and generator interconnection studies; it was *filed* with FERC on Nov. 3.

"That, in and of itself, is going to be revolutionary," he said of the CPP.

Nickell said SPP received 36 submissions as part of the ERAS process, totaling 13.2 GW of capacity. About 73% of that is gas generation, with solar and batteries accounting for the rest. Generator interconnection agreements will be made during the first quarter of 2026, he said.

"That's the kind of generation we're going to need to help us with our accreditation and to help load-serving entities meet their requirements," he said.

The RTO expansion into the Western Interconnection remains on track, Nickell said, with a Dec. 2 go/no go date fast approaching to determine whether to open the transmission congestion rights market in the West on Jan. 1, 2026. The next key decision comes Feb. 2, he said, when SPP will decide whether or not to stick with the April 1 go-live date.

The grid operator's other Western market, Markets+, has 41 entities that have committed to fund the development of the market's systems development and hardware. SPP is still targeting a go-live date in late 2027.

"We're in a time of change, and I think it's just important to realize and to show and to demonstrate what can be done when you put your heart to it and put your mind to it," Nickell said.

### JTIQ Funds Remain in Limbo

General Counsel Paul Suskie told the committee that SPP still has yet to receive "official word" about the status of the U.S. Department of Energy's $464 million grant for the grid operator's *Joint Targeted Interconnection Queue* initiative with MISO.

"Fingers are crossed that the funds will still be there," Suskie said. "I'm personally an optimistic person. I'm optimistic the current administration will see the value that JTIQ will have for the region to get new generation online."

The DOE loan under its Grid Resilience and Innovation Partnerships (GRIP) program would account for more than 27% of the $1.7 billion portfolio, comprising five 345-kV projects along SPP's northern seam with MISO. Each grid operator is responsible for two projects in its footprint, and they share the fifth.

The funds were *awarded in 2023* to the Minnesota Department of Commerce, the lead applicant in the JTIQ initiative that also involves the Great Plains Institute and the two RTOs. However, the department in early October included the $464 million grant on a list of projects that it intended to terminate. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

Suskie said conversations continue between DOE and parties to the initiative. NTCs have been awarded to *Omaha Public Power District* and *Evergy* for the JITQ projects, he said, giving them the obligation to move forward with their portions of the projects and making them eligible for cost recovery.

FERC has approved the RTOs' request to allocate the portfolio's costs 100% to interconnecting generation assessed on a per-megawatt basis. In doing so, it cited the GRIP funding as one of the "unique set of facts and circumstances of the proposed JTIQ framework." (See *FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism*.)

### RSC Selects New Leadership

The RSC approved the Nominating Committee's slate of officers for the 2026 term, with Nebraska's Chuck Hutchinson succeeding New Mexico's Patrick O'Connell as president.

Oklahoma's Kim David will serve as the RSC's vice president, while Arkansas' Justin Tate and Missouri's Kayla Hahn will take the secretary and treasurer positions, respectively.

O'Connell said it was an honor to have led the committee and its differing points of view.

"We work together to try to get to consensus and focus on the region first," he said. "That's not always true in daily life in general, especially these days. This isn't just professionally a great experience; it's also kind of a respite from the real world sometimes. I really, on a personal level, really appreciate how the RSC works together, and then I appreciate that SPP allows us to work together in that way.

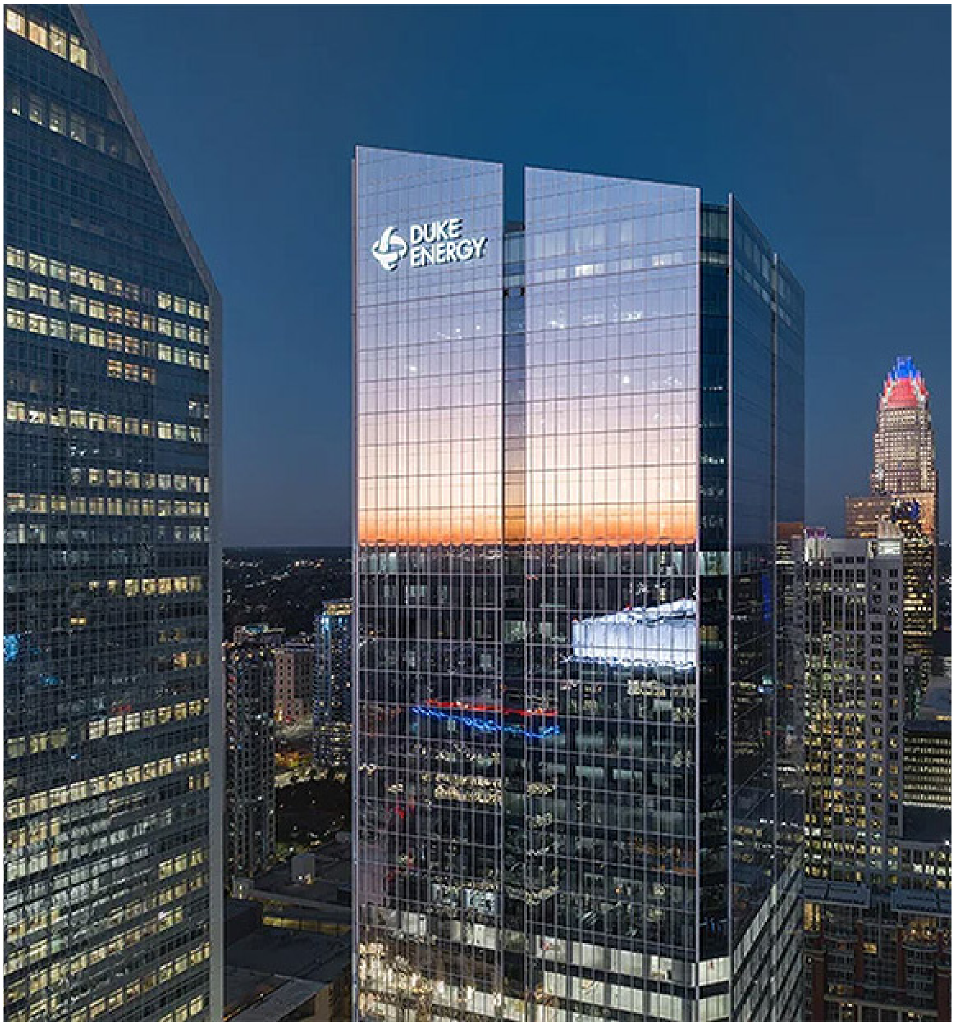
"So, thank you all for that," O'Connell said. "Dry your eyes, OK?"

Randy Pinocci, Montana PSC | *© RTO Insider*

The RSC's roster grew to 13 with the addition of Montana's Randy Pinocci. Observing from the audience were Wyoming Public Service Commission Chair Mike Robinson, another potential new member, and New Mexico's Greg Nibert, who will replace O'Connell on the RSC in 2026. ■

# Duke Reports Growing Investment Plans on Increased Earnings

*By James Downing*




| Duke Energy

Duke Energy reported third-quarter earnings of $1.4 billion ($1.81/share), up from 2024 on higher retail sales volume and new rates.

"We approach 2026 with momentum as our company converts large load economic development prospects into tangible projects with signed electric service agreements, and we are already turning dirt on projects to meet this load and grow," CEO Harry Sideris said on an earnings call held Nov. 7. "We're carrying out an ambitious generation bill that will add more than 13 GW of capacity to our system in the next five years."

Duke expects its new five-year capital plan for 2026 to 2030 to be between $95 billion and $105 billion, up from the $87 billion that was planned for 2025 to 2029. The spending will help Duke modernize its system and bring new large load customers like data centers online, Sideris said.

"The step up is primarily related to investments in new generation that will drive earnings-based growth of more than 8.5% through 2030," Sideris said.

While investments are accelerating, Sideris said that Duke was also keeping affordability in mind for its customers, both large industrials competing in global markets and households trying to manage their budgets.

"We continue to leverage AI and pursue a technology-enabled industry leading cost structure as we invest in our system," Sideris said. "Other tools we are utilizing to keep rates as low as possible include the combination of the Duke Energy Carolinas and Duke Energy Progress utilities, which, if approved, would save retail customers more than $1 billion through 2038."

Other activities on affordability include storm cost securitization, which Sideris said would cut the impact to bills by 18% compared to traditional mechanisms, and new tariffs and contract provisions for large load customers looking to take service from its utilities, he added.

"These are just a few of the many solutions we use to ensure our 10 million customers receive the service they count on at a fair price," Sideris said. "We recognize that our work to provide affordable energy for customers is never done, but we are proud that average rate changes have paced below the rate of inflation over the last decade, and that our rates are well below the national average."

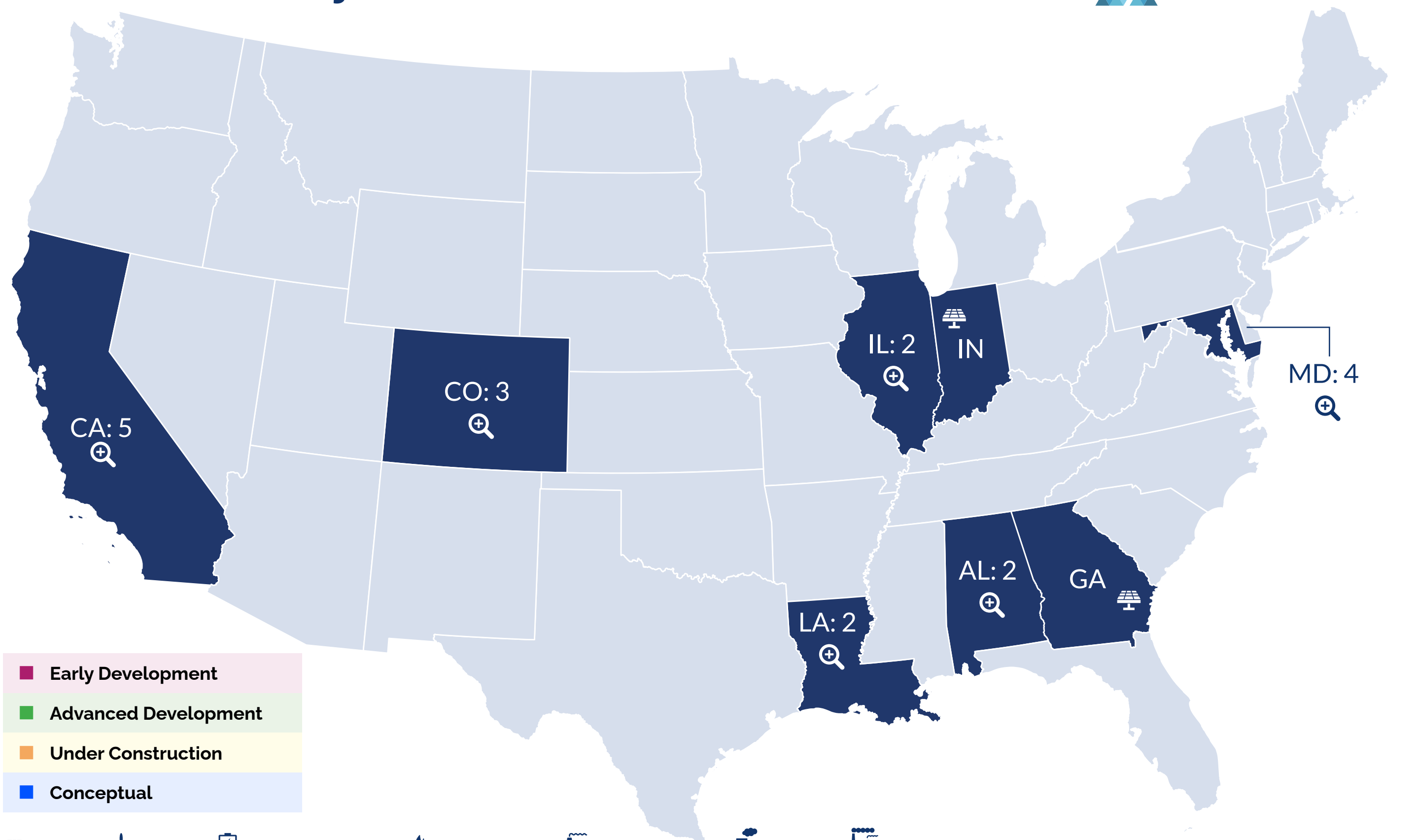
Duke is building 8.5 GW of new dispatchable generation across its footprint over the next five years, which includes 1 GW of uprates. The rest is new natural gas plants.

The company is also considering new nuclear plants, both small modular reactors and, after a request from the North Carolina Utilities Commission, traditional nuclear.

"We feel nuclear is a very important part of the future," Sideris said. "With that said, there's a lot of things that we have to determine and figure out before we move forward. We're encouraged to see the government and some of the partnerships with Westinghouse that were recently announced leaning into this and addressing supply chain concerns, which is one of the items that we have on our list. We still need to figure out what we're going to do with cost overrun protection and how we're going to protect our investors and our customers from overruns on those projects, as well as how we're going to protect the balance sheet if we move forward with nuclear, so we're working to resolve those working with government officials as well as some of the tech customers." ■

# Generation Projects Added in the Past Week

YES ENERGY




Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Coal

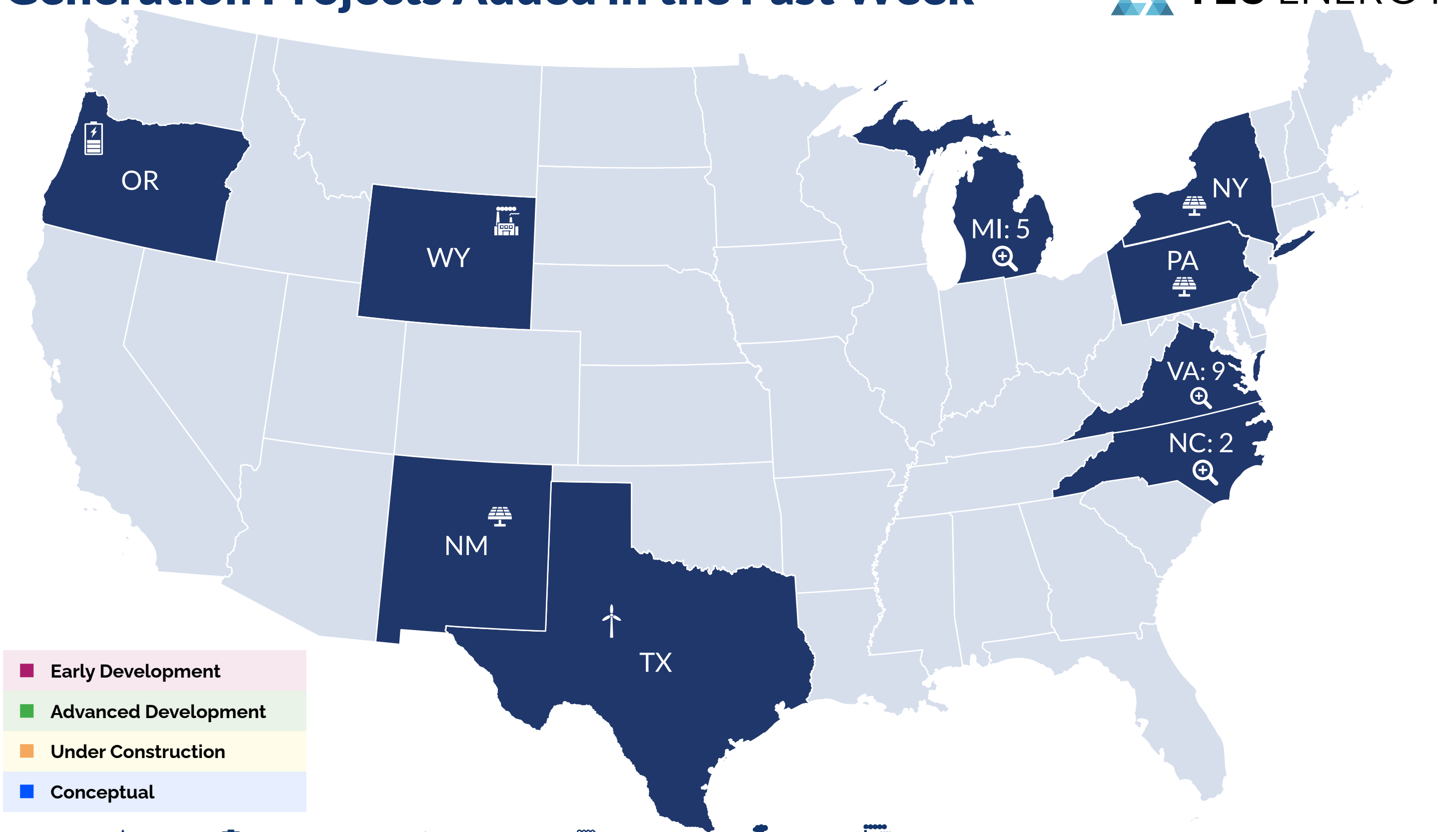
Data from Yes Energy

| | Project or Unit Name | Holding Company or Parent Organization | Intermediate Subsidiary or Utility | State or Province | Capacity (MW) | In Service Year |
|---|---|---|---|---|---|---|
| | **TOP Solar** | Renewable Properties, LLC | | AL | 1 | 2026 |
| | **LNT Solar** | Renewable Properties LLC | | AL | 2 | 2026 |
| | **Adventist Health Delano Solar** | ENGIE | | CA | 2 | 2026 |
| | **Yucaipa Valley Water District Filtration Solar (Oak Glen Road Solar)** | ENGIE | | CA | 3 | 2026 |
| | **Yucaipa Valley Water District Recycling Facility Solar** | ENGIE | | CA | 3 | 2026 |
| | **Westlands VI** | Westside Holdings, LLC | | CA | 250 | 2028 |
| | **Westlands VI BESS** | Westside Holdings, LLC | | CA | 110 | 2028 |
| | **City of Fort Morgan Solar** | Sandhills Energy LLC | | CO | 2 | 2026 |
| | **Waterton Community Solar Garden (CSG)** | Ownership Undisclosed | | CO | 8 | 2027 |
| | **City of Yuma Solar** | Sandhills Energy LLC | | CO | 3 | 2026 |
| | **Prologis Portside 2509 - slsav502** | Prologis Logistics Services Inc | | GA | 2 | 2025 |
| | **USS Swank Solar** | United States Solar Corporation | | IL | 1 | 2026 |
| | **6225 E Minooka Solar Project** | Wunder Power | | IL | 5 | 2026 |
| | **Honey Creek Solar, Phase 1** | Omers | Leeward Renewable Energy, LLC | IN | 180 | 2028 |
| | **Fort Polk - Chaffee East Solar** | Blackstone Group | Onyx Renewable Partners | LA | 5 | 2026 |
| | **Fort Polk - Chaffee West Solar** | Blackstone Group | Onyx Renewable Partners | LA | 4 | 2026 |
| | **Kent Point Road Solar** | Lodestar Energy Group | | MD | 3 | 2027 |
| | **Conowingo Creek Solar** | Halo Energy LLC | | MD | 2 | 2026 |
| | **Lambs Knoll Solar** | Chaberton Energy Inc | | MD | 5 | 2029 |
| | **Woodside Solar** | EQT Partners | New Leaf Energy | MD | 5 | 2027 |

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

# Generation Projects Added in the Past Week

YES ENERGY




Solar Wind Energy Stoarage Natural Gas Geothermal Nuclear Coal

Data from Yes Energy

| | Project or Unit Name | Holding Company or Parent Organization | Intermediate Subsidiary or Utility | State or Province | Capacity (MW) | In Service Year |
|---|---|---|---|---|---|---|
| | **Gratiot-Findlay Neighborhood Solar** | Lightstar Renewables LLC | | MI | 11 | 2027 |
| | **Houston Whittier/Hayes Neighborhood Solar** | Lightstar Renewables LLC | | MI | | 2027 |
| | **State Fair Neighborhood Solar** | Lightstar Renewables LLC | | MI | | 2027 |
| | **Greenfield Park Neighborhood Solar** | DTE Electric Company | | MI | 10 | 2027 |
| | **Van Dyke/Lynch Neighborhood Solar** | DTE Energy | | MI | 10 | 2026 |
| | **Old Liberty Solar** | Renewable Energy Services | | NC | 44 | 2029 |
| | **Allen-3 BESS** | Duke Energy | Duke Energy Carolinas, LLC | NC | 199 | 2029 |
| | **Pluma Solar Las Vegas (Pluma - Pino)** | Brookfield Asset Management | Standard Solar | NM | 5 | 2026 |
| | **Herkimer Solar (NY)** | Greenvolt Power Renewables | | NY | 3 | 2026 |
| | **PDX Data Center BESS** | Blackrock Inc | Aligned Data Centers, LLC | OR | 31 | 2026 |
| | **Hampden CSG 1** | Dimension Renewable Energy | Dimension Energy LLC | PA | 2 | 2026 |
| | **Buffalo Gap Wind Farm Repower** | AES Corp. | | TX | 527 | 2030 |
| | **SynerGen Duffield Community Solar 1** | Synergen Solar LLC | | VA | 5 | 2026 |
| | **VMEA Harrisonburg BESS** | VA Municipal Electric Association No 1 | | VA | 7 | 2027 |
| | **VMEA Manassas BESS** | VA Municipal Electric Association No 1 | | VA | 7 | 2027 |
| | **Meadow Creek VA BESS 1** | Ownership Undisclosed | | VA | 4 | 2026 |
| | **Salem VA BESS 1** | Ownership Undisclosed | | VA | 4 | 2026 |
| | **Campion Solar** | Oneenergy Development LLC | | VA | 5 | 2100 |
| | **Colleen VA BESS 1** | Lightshift Energy | | VA | 4 | 2026 |
| | **Piney River VA BESS 1** | Lightshift Energy | | VA | 4 | 2026 |
| | **Railroad Energy Center** | Equinor | East Point Energy | VA | 40 | 2027 |
| | **Dry Fork Station Unit 2** | Basin Electric Power Coop | | WY | | 2030 |

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

# Company Briefs

## Qcells Furloughs 1,000 Workers at U.S. Solar Factories

Qcells last week said it would furlough 1,000 workers at its Georgia factories because shipments of components it needs from overseas are being routinely stalled by U.S. customs officials.

Qcells has implemented temporary reduced hours and furloughs for about half of its manufacturing employees at plants in Cartersville and Dalton. It has also cut about 300 staffing agency workers.

The announcement comes months after the company said some of its shipments of solar cells had been detained at U.S. ports under a 2021 law banning imports from China's Xinjiang region due to concerns about forced labor. The detained shipments have been clearing customs, but the delays have forced the company to curtail production.

More: *Reuters*

## Renewable Developer Norris to Join Google

Tyler Norris, a renewable energy developer who authored a paper on data center flexibility and was named to TIME's Most Influential Climate Leaders of 2025, announced he has joined Google as its head of market innovation on the Advanced Energy Team.

Norris said he will be focused on identifying and advancing innovations to better enable electricity markets to accommodate AI-driven demand and clean energy technologies.

More: *X*; *TIME*

## Pine Gate Renewables Files for Bankruptcy

U.S. solar and storage developer Pine Gate Renewables filed for Chapter 11 bankruptcy protection to facilitate a court-supervised sale of all its assets and businesses.

Pine Gate has more than 30 GW of projects in its development pipeline and operates a fleet of 2 GW of solar and storage assets.

Pine Gate expects to complete the marketing and sales process in about 45 days.

More: *Renewables Now*

## Nuclear Startup Raises $130M for Fission Reactors

Valar Atomics, a nuclear startup aiming to build thousands of nuclear fission reactors within a decade, has raised $130 million from investors.

The company began construction in September on its first reactor and says it's on track to demonstrate it can produce 100 kW of energy by July 4, 2026. Eventually, the company plans to mass manufacture small modular reactors and cluster them at gigasites where they will help power artificial intelligence data centers, industrial manufacturers and other customers.

More: *Financial Post*



# Federal Briefs

## Trump Taps Former Rep. Pearce to Lead BLM

President Donald Trump last week nominated former Rep. Steve Pearce (R-N.M.) to lead the Bureau of Land Management.

Pearce unsuccessfully ran for New Mexico governor in 2018. He served on the House Natural Resources committee, which oversees the agency he may now run.

Pearce's nomination comes several months after Trump's initial pick for the role, Kathleen Sgamma, withdrew from consideration.

More: *The Hill*

## White House Picks Weaver for NRC Role

The Trump administration last week nominated Douglas Weaver for a commissioner seat on the Nuclear Regulatory Commission.

If confirmed, Weaver would fill the seat vacated by Annie Caputo, who resigned in July. He would finish the remainder of Caputo's term, which expires June 30, 2026.

More: *Nuclear Newswire*

## Judge: Trump Admin Can Reconsider SouthCoast Wind Permit

Judge Tanya S. Chutkan of the U.S. District Court for the District of Columbia last week ruled the Trump administration may reconsider the Biden-era approval of SouthCoast Wind, a wind farm planned off the coast of Nantucket, Mass.

Chutkan wrote the project developers would not "suffer immediate and significant hardship" if the administration were allowed to reconsider the permit. The decision would effectively allow the Bureau of Ocean Energy Management to re-evaluate its approval of the project's construction and operations plan. The agency approved the plan on Jan. 17, three days before Trump's second term began.

As proposed, SouthCoast Wind would include 141 turbines in federal waters about 23 miles south of Nantucket.

More: *The New York Times*

# State Briefs

## ARIZONA

### SRP Board Approves Converting Springerville Unit 4 to Natural Gas

The SRP Board of Directors last week approved converting the coal-fired Springerville Generating Station Unit 4 to natural gas.

The board said it was the lowest cost option to preserve the plant's 400-MW capacity and is expected to save customers about $45 million compared to building a new facility.

More: *SRP*

### TEP Unveils State's Largest Storage System

Tucson Electric Power last week unveiled its 200-MW Roadrunner Reserve I storage system – the company's largest battery storage system.

A second, 200-MW phase is under construction and is expected to be completed by summer 2026.

More: *KVOA*

## CALIFORNIA

### Kern County Solar Project Becomes Operational

Clearway Energy Group last week announced its 140-MW Rosamond South 1 project in Kern County has reached commercial operations.

The project also contains 117 MW of storage and has long-term contracts with MCE, the University of California, Rancho Cucamonga Municipal Utility, Eastside Power Authority, City of Moreno Valley and Constellation Energy.

More: *Solar Power World*

### Regulators Hold off on Approving PGE's Diablo Plan

The Coastal Commission last week held off on approving Pacific Gas and Electric's plan to continue operating its Diablo Canyon nuclear plant, saying the utility must first dedicate thousands of acres of land to conservation to mitigate its cooling system's impacts on the ocean.

PG&E applied for a coastal development permit to run the power plant until 2030, as requested by the Legislature in Senate Bill 846. The permit would require PG&E to dedicate thousands of acres of land surrounding the plant to conservation to offset the negative environmental impacts of the once-through cooling system, but PG&E and the commission haven't yet agreed on how much land should be set aside, when it should happen and what the process should be.

PG&E and commission staff are expected to present an updated mitigation package in December. The commissioners will then decide whether to issue the permit.

More: *The Tribune*

## COLORADO

### Xcel Energy Nears Completion of Marshall Fire Settlements

A lawyer representing Xcel Energy told a Boulder County District Court judge last week that the utility has executed or reached settlements with more than 2,000 plaintiffs in the lawsuit over the 2021 Marshall Fire.

More than 4,000 plaintiffs filed claims alleging Xcel was responsible for one of two fires that merged on Dec. 30, 2021. In September, Xcel and two telecommunications companies agreed to pay $640 million to settle lawsuits related to the disaster.

More: *Boulder Reporting Lab*

## KANSAS

### Regulators Approve Large Load Tariff

The Corporation Commission last week unanimously approved a large load tariff that will subject large energy users to additional costs and restrictions.

The tariff affects new businesses using more than 75 MW of peak load energy per month. Existing businesses that increase their usage by 75 MW/month will also come under the tariff.

The order sets multiple requirements for large load users, including a minimum contract term of 12 years, plus an optional five-year period as the company ramps up. It also requires those customers to pay a minimum of 80% of their contract and post collateral for two years of minimum bills.

More: *Kansas Reflector*

## MASSACHUSETTS

### Wind Turbine Blade Breaks off in Plymouth, Lands in Cranberry Bog

A blade broke off a wind turbine last week and landed in a cranberry bog in Plymouth.

Video showed the blade lying on the ground in the bog, surrounded by debris. The part of the turbine that holds the blade in place appeared to be charred at the top of the tower.

An investigation is underway.

More: *CBS Boston*

## MINNESOTA

### Xcel Asks PUC to Double Battery Capacity

Xcel Energy recently asked the Public Utilities Commission for permission to double its planned battery capacity at its Sherco Energy Hub while adding a 200-MW fourth phase of solar and deploying about 136 MW of batteries at a separate site southwest of Minneapolis.

If the PUC approves the proposal, Sherco would host 910 MW of solar and 600 MW of battery capacity by the end of the decade.

Xcel expects to break ground on the Sherco and Blue Lake battery installations next year and have them become operational in 2027. It aims to commission the Sherco solar project by 2029.

More: *Canary Media*

## NEVADA

### NV Energy Overcharged Customers $65.4M

NV Energy estimated it overcharged customers $65.4 million from 2002 through 2024, the company reported in response to an investigation by the Public Utilities Commission.

The utility initially acknowledged overcharging some 60,000 customers by roughly $17 million in May, but an audit later found it had overcharged another 20,000 "previously unidentified 'multi-family accounts' for an undisclosed amount." The overcharging began in 2002 when the company began to charge different rates to single-family residential customers than those in multi-family units. The overcharges were primarily assessed to ratepayers in multi-family developments who were misclassified and charged the higher, single-family rate.

It is unknown how much of the money has been paid back.

More: *Nevada Current*

## OREGON

### Utilities Halt Service Cutoffs for Vulnerable Customers

Portland General Electric and Pacific Power last week announced they will halt service disconnections for qualified low-income and medically vulnerable customers until the end of the year.

Data from the Public Utility Commission shows more than 28,000 customers of the two utilities had their service disconnected in the first half of 2025.

More: *The Oregonian*

## RHODE ISLAND

### Siting Board OKs SouthCoast Wind Tx Line Plan

The Energy Facility Siting Board last week approved SouthCoast Wind's plan to run power lines from its 141-turbine offshore wind project up the Sakonnet River and across Portsmouth to Mount Hope Bay.

The license for the transmission lines is conditioned upon securing other state and federal permits, and financing agreements with utility suppliers. If the developers do not secure the approvals and complete a project within five years, the cable license lapses.

More: *Rhode Island Current*

## WISCONSIN

### MGE Seeks Approval to Add More Solar, Battery Storage

Madison Gas and Electric last week said it is seeking Public Service Commission approval to add more than 85 MW of solar capacity and 18 MW of battery storage.

The investments include shares in five large-scale solar facilities, one of which includes battery storage. The projects, developed in partnership with WEC Energy Group, would bring more than 1,000 MW of solar energy and battery storage to the state.

More: *MGE*