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Seattle City Light

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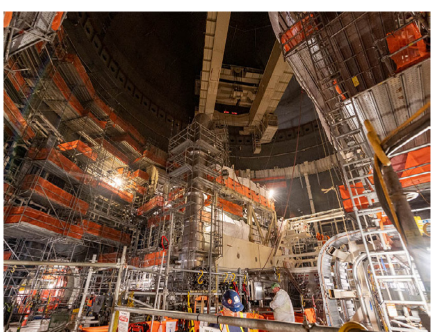
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The Virginia governor could switch parties in an election Nov. 4, but Dominion CEO Robert Blue argued the CVOW project is necessary for data center demand and to support key naval facilities in Virginia, so it should avoid any negative actions from the federal government regardless of the election's outcomes.

In this week's issue

Connecticut's Regulatory Drama Keeps Exploding

By Bryson Hull

Bryson Hull

One of the foundational lessons of journalism holding the powerful to account is the downfall of President Richard Nixon, who resigned rather than face impeachment after reporting uncovered evidence he'd lied about Watergate. No one ever called Nixon "probably the best president."

Yet after Connecticut's chief utility regulator, Marissa Gillett, resigned while facing an impeachment hearing, we are reading fans of her advocacy calling her "probably the best regulator in the country."

Gillett's exit tracks President Nixon's — and the lesson that the cover-up is worse than the lie is being proven again because certain journalists are doing their job.

The *hagiography* of Gillett as a superior, ground-breaking regulator flies in the face of the circumstances of her exit, and unfolding evidence that the Public Utilities Regulatory Authority (PURA) under Gillett hid public records that would have proved clear bias in an agency that is quasi-judicial in mission and by statute.

Here are the facts. Gillett, a lawyer, denied under oath before the Connecticut General Assembly that she restricted her fellow commissioners' access to PURA staff. Stunningly, a printed color copy of an email laying out those restrictions appeared in *The Hartford Courant*, which had requested it under Connecticut's Freedom of Information Act.

This prompted a call for her impeachment by the Republican minority, and agreement by the Democratic Speaker of the House to entertain that request for what would have been the first such hearing in Connecticut in two decades.

House Minority Leader Vincent Candelora wrote *in his letter* seeking an impeachment inquiry that "in direct contradiction to Ms. Gillett's sworn testimony during her confirmation hearing, she did in fact issue a directive to the other commissioners of the Authority that restricted access to support staff."

I was aware from PURA sources over a year ago that the email and directive existed, yet it was not produced by the agency until there was no choice. Unfortunately for PURA's leadership, a sitting commissioner had kept *a hard copy* — who handed it over to the attorney general's office.

Marissa Gillett | *Connecticut Executive and Legislative Nominations Committee*

Prior Coverage

Bryson Hull's opinion piece was prompted by an RTO Insider article published Sept. 24. (See *Escalating Conflict with Utilities Leads to Resignation of Top Conn. Regulator*.)

What followed was stunning sequence of events: The attorney general's office, defending PURA in a lawsuit over two rate cases filed by two of the state's natural gas utilities, *capitulated* and offered to give the utilities the legal relief they sought by sending the cases back to PURA with Gillett recused.

Subsequently, the presiding judge *admonished* both PURA's general counsel and the attorney general's office for failing to produce the documents they knew existed. PURA on Oct. 27, in another attempt to settle the case, *admitted* Gillett violated the law.

At the center of this case was the utilities' assertion that Gillett was biased, which arose from a previous scandal in which Gillett denied authoring an opinion article signed by the chairs of Connecticut's Energy and Technology Committee, PURA's committee of jurisdiction.

Months of litigation over two utilities' rate cases had come to hinge on whether Gillett was involved in writing a December 2024 *op-ed* under the names of two legislators to whom she is inarguably close. The litigation revealed more cover-up attempts in apparent contravention of state law, such as her decision in November 2023 to *set her phone* to auto-delete text messages after just 30 days.

The opinion article accused Connecticut's utilities of paying credit ratings agencies to lower their credit ratings — after all five of them had their ratings slashed because of PURA's aggressive, erratic cuts to rate requests. This prompted Bank of America *to say* Connecticut had "probably" the "worst regulatory environment in the country" and Moody's to *declare it* "the least credit supportive utility regulatory environment" in the U.S.

The opinion article is an example of inartful blame-shifting, because its premise is utterly absurd to anyone with even a passing understanding of how federally regulated credit ratings agencies work — never mind the Enron-level legal exposure both the ratings agency and the company involved would face.

None of this came about because of some "escalating conflict" with utilities: all of it was the unforced error of Gillett and a few high-ranking PURA officials, combined with their later attempts to lie and cover it up. By turning regulation away from collaboration and into an adversarial process, the regulated companies have no choice but to press their case.

There is likely to be no let-up on that front, especially in light of new allegations of a cover-up. PURA's executive secretary wrote a letter Oct. 6 outlining orders he'd been given by PURA's general counsel *to deny* that adverse public records existed. PURA declined to comment because of an ongoing personnel investigation, a Oct. 28 report in *The Hartford Courant* says.

Alas, Gillett — emboldened by her allies in the legislature and the governor's office — which for six years refused to appoint PURA's statutorily required five commissioners lest Gillett's power be diluted — acted with perceived impunity and got caught because of journalistic vigilance.

Seeking a fresh start without the embarrassment of an actual investigation, Gov. Ned Lamont (D) on Oct. 20 *appointed* four new PURA commissioners and named Thomas Wiehl, formerly of the Connecticut Office of Consumer Counsel, as chair. With PURA at a full complement of five commissioners with diverse expertise, Wiehl signaled in *his first press conference* that he will emphasize collaboration and return PURA to its traditional role as a professional, impartial regulator.

For PURA to succeed, an honest, thorough accounting of the Gillett era is required. Since collaboration is at the core of smoothly functioning regulation, trust with the regulated companies and the ultimate end users — the people of the state of Connecticut bearing some of the nation's highest retail electricity rates — must be rebuilt.

This is not just to ensure that Connecticut's regulation is proper, reasonable and working in the interest of the people, but to ensure that PURA's record under Gillett is not portrayed as a model of propriety or best practices in the national conversation about the future of regulation.

The facts speak otherwise, thanks to good, old-fashioned journalism that uncovered a record riddled with deceptions. If Gillett is the nation's best regulator, the U.S. is in real trouble. Let Connecticut's embarrassing regulatory saga be a lesson for other jurisdictions on what not to do. ■

— Bryson Hull, Consumer Energy Alliance's deputy Northeast director, is a former journalist who has written about energy issues since being hired to cover Enron Corp. a year before its then-record bankruptcy.

Demand Growth's Impact on Markets Probed at Nodal Trader Conference

By James Downing

From left: NERC Senior Vice President Mark Lauby; Wish Bakshi, Arcus Power lead data and AI consultant; Abram Klein, managing partner at Appian Way; Concentric Energy Advisors CEO Danielle Powers; and Ken Irvin, partner at Sidley Austin, at S&P Global's Nodal Trader Conference | © RTO Insider

WASHINGTON — Uncertainty in load forecasts presents competitive firms and regulated utilities with polar opposite incentives, NRG Vice President of Regulatory Affairs Travis Kavulla said at S&P Global's Nodal Trader Conference on Oct. 24.

"Data centers and the consequences of unbelievable load forecasts are really not good," Kavulla said. "On the power generation side, it could actually, paradoxically, lead to underinvestment in power generation that relies on market forwards. Investors and companies like mine might just throw up their hands and say, 'This is so unbelievable. We're standing pat. We don't want to overbuild.'"

While companies that operate purely in the markets might wait to see how much demand actually shows up — which could prove overly cautious — utilities have different incentives, he said.

"It might induce overspending and overbuild because of the moral hazards and financial incentives that are present on that side of the industry," Kavulla said. For "people who, unlike merchant generation, don't have to wear the risk of the spending that they include in rate base and have a captured base of customers, there will always be someone there to pay for it, even if data center growth doesn't materialize."

The situation also can induce a crisis for politicians, which risks laws being passed that compound the problems facing the industry, he added.

"What PJM is really asking the community for generation to do is to add more than the amount of generation — about 40,000 MW — that was added during the entire turnover of the shale revolution, of coal to gas, in a shorter period of time than that generation got online when supply chains were less challenged," Kavulla said.

Why This Matters

Demand growth and the uncertain load forecasts accompanying it are posing problems for markets and regulators across the U.S.

Other markets like ERCOT also have huge projections for future demand, but forward prices remain low. Forward prices in PJM shot up right after the RTO released its first load forecasts that included booming demand from data centers and other large loads, but they fell shortly after.

Capacity prices have shot up in PJM over the past two auctions, but the price impact of new load coming onto the system is absent in energy forwards, Kavulla said.

"We also have ERCOT, which shows similar activities," Kavulla said. "No capacity market here to remove some of the pressure of trading off load growth. Instead, you would expect, certainly, given what we saw in the previous projection of demand growth well exceeding supply additions, for the market to be significantly impacted, and that's just not the case."

The situation has many explanations, but three of them stand out for Kavulla, including that load growth is fake. But even a fraction of the projections becoming a reality should push forward prices up given how tight many markets are and the well documented issues getting new supply on the grid.

Another option is expecting politics to intervene rather than letting prices rise enough to incent a market response to add more supplies, he said.

"There will be some *deus ex machina* of policy that could either be 'bring your own generation' that causes entry to happen outside of the energy price fundamentals," Kavulla said. "There could just be a price cap on energy. There could be government funding or rate-regulated entry of generation. Something will happen that causes the energy markets not to be doing the lift associated with the load growth projections."

The other issue is that the markets themselves do not lead to deals that far in the future with competitive retail contracts lasting one to five years.

"There might be a lot of people wanting to sell you something on a longer daily basis, but not a lot of people willing to buy something on a longer daily basis," Kavulla said. "All things being equal, that ends up working to the counter effect of incremental demand outpacing incremental supply."

All three can be true at the same time, and Kavulla argued the situation can be fixed with more of a top-down approach to large loads.

Data center developers and others currently bring plans to utilities, which collect them and are aggregated across ISO/RTO markets. But Kavulla said it would work better for markets to publicly announce available headroom and then request large loads apply to use it. The Alberta Electric System Operator has put that idea into practice.

"We are going to say we have X megawatts of capacity available in the Alberta market today, and we are going to tender that out and have data centers who are interested in developing quickly in this province subscribe it," Kavulla said. "In a series of literally three stakeholder meetings in the Alberta regulatory process, they kind of rolled out this design."

The approach is similar to how the natural gas industry gets customers to sign up for new pipelines, which shows FERC in its regulatory process that there is a need for new capacity, he added.

Capacity markets worked reasonably well at incenting new generation in the past, but they need some reforms to deal with the current paradigm, Concentric Energy Advisors CEO Danielle Powers said during a panel Oct. 23.

"When we deregulated, we lacked the planning function — period," Powers said. "It used to be that the utilities plan, and they planned for the right mix at the right time, and that was all left to market forces, largely. And so, I think you can have both."

Regulators and ISO/RTOs instead have focused on "nibbling around the edges." While resource accreditation is important, it is vital that the grid get the right mix of resources online so it can operate reliably, she said.

The markets have been adding supply but not enough generation that also can provide key grid balancing services, said NERC Senior Vice President Mark Lauby.

"We have solar panels, but they don't always provide the kind of meat and potatoes of frequency and mass that we expect," Lauby said. "So how are we going to supplement that?"

NERC has been studying large loads for 18 months, and their proliferation has major implications for how the grid will be operated in the future, Lauby said. The grid always has been operated so it can absorb losing a large generator and, in some cases, large loads going offline instantly.

"Now we're talking about losing the city of San Francisco at one time," Lauby said. "So how do we manage that? What are some of the adjustments we need to make in the system? What are the interconnection requirements so we can make sure that the system remains reliable?"

NERC is considering new standards to ensure the system can be operated reliably, and in its stakeholder-driven mandatory standards process, that could involve the large loads helping to develop new rules.

NRG Vice President of Regulatory Affairs Travis Kavulla gives a speech at S&P Global's Nodal Trader Conference. | © *RTO Insider*

Part of the issue is misaligned timing: If a regulated utility had gone to a state commission and asked to build a couple of gigawatts on speculation just two and a half years ago, they would have been laughed out of the room, said Abram Klein, managing partner at Appian Way.

"We're at a little intermediate period where the markets have gotten a little bit tighter," Klein said. "But there's a lot of positive sides. I mean, the solar plus wind plus batteries is working much better than expected."

One area that could stand improvement is the demand side, with studies from Duke University's Tyler Norris and Goldman Sachs saying that could help the grid meet rising demand from large loads. But that needs to be priced into the market, as opposed to the DR in PJM that suppresses energy prices whenever it is called on, Klein said.

Traditional DR will not work with data centers because of the "rebound event," where if 4 GW of data center load is asked to go offline peak, it will just create a new net peak whenever it is allowed back on the grid, said Arcus Power's Wish Bakshi, lead data and AI consultant.

Data centers can offer flexibility, but it would work better to "underclock" chips, which Bakshi compared to operating a V12 like a much less powerful V4 engine.

"You turn it down, so it keeps running and training, and at 8 p.m. or 9 p.m., they basically kick back up, so you don't have that crazy spike, and you're basically ramping up very slowly," Bakshi said. "That's kind of how you do it with these AI data centers."

The other option is just to pay high power prices to keep the data center running, which can make economic sense given that its owners invested tens of billions of dollars just in the high-end Nvidia chips that make it work, Bakshi said.

Another option is shifting compute load to another data center, but that comes with its own limits.

"There's only so much fiber optic cable that go across the country that can actually do that," Bakshi said. "Is it possible? Yes. But only the big shops can do that. Google's already working on it." ■

U.S., Westinghouse Partner for $80B in Nuclear Construction

Agreement is Part of Trump's Push for Energy Dominance, Nuclear Renaissance

By John Cropley

The U.S. has entered a strategic partnership to pursue construction of at least $80 billion worth of Westinghouse nuclear reactors nationwide.

Cameco Corp. and Brookfield Asset Management, the two owners of Westinghouse Electric Co., announced the agreement Oct. 28.

The company announcements were missing some specifics, and the Trump administration did not make its own announcement. But piecing together the information available, it appears the U.S. has agreed to use tools at its disposal to facilitate construction of reactors and then help pay for them, possibly with Japanese investments, in return for a share of profits and a potential ownership share.

The partnership provides for the U.S. government to arrange financing and facilitate the permitting and approvals for new Westinghouse reactors to be built in the U.S., including near-term financing of long lead-time items.

Among many other things in his *series of nuclear executive orders* May 23, President Donald Trump ordered that *10 new large reactors* be designed and under construction by 2030.

The 1.1-GW Westinghouse AP1000 reactor at the center of the Oct. 28 announcement would fit the bill, as it is a proven design intended for modular construction and is being used in multiple projects under way worldwide.

But the company announcement did not specifically say the $80 billion or more would be directed to AP1000 construction or say where the money would come from.

The containment for the Unit 3 Westinghouse AP1000 reactor at Plant Vogtle is shown under construction in August 2021. | *Georgia Power*

Why This Matters

The agreement puts the weight of U.S. policy and finance behind nuclear power development.

The *Brookfield* announcement said:

"The partnership contains profit sharing mechanisms that provide for all parties, including the American people, once certain thresholds are met, to participate in the long-term financial and strategic value that will be created within Westinghouse by the growth of nuclear energy and advancement of investment into AI capabilities in the United States."

This sentence was omitted from the *Cameco announcement*, which contained much more specific information:

"Under the new strategic partnership, the U.S. government will be granted a participation interest which, once vested, will entitle it to receive 20% of any cash distributions in excess of $17.5 billion made by Westinghouse after the granting of the participation interest. For the participation interest to vest, the U.S. government must make a final investment decision and enter into definitive agreements to complete the construction of new Westinghouse nuclear reactors in the U.S. with an aggregate value of at least $80 billion.

"Additionally, in recognition of the anticipated acceleration of long-term value creation that the U.S. government is expected to help unlock by deploying its financial, regulatory, policy and diplomatic tools to support the objectives of the partnership, if, on or prior to January 2029 the participation interest has vested, and if the valuation in an initial public offering (IPO) of Westinghouse is expected to be $30 billion or more at that time, the U.S. government will be entitled to require an IPO.

"Immediately prior to, or in connection

with the IPO, the participation interest will directly or indirectly convert into a warrant, with a five-year term, to purchase equity securities equivalent to 20% of the public value of the IPO entity at the time of exercise after deducting $17.5 billion from the public value."

Support from Japan Investment

The details of the binding term sheet announced Oct. 28 are expected to be replaced with definitive agreements reached through negotiation, Cameco said.

The Brookfield announcement quoted U.S. Energy Secretary Chris Wright and U.S. Commerce Secretary Howard Lutnick cheering the strategic agreement. But neither Energy nor Commerce made any announcement or offered any detail about the agreement.

The White House *offered the clearest insight* into the finances later Oct. 28, with an announcement from Trump's ongoing diplomatic tour of Asia, saying that as part of its July agreement to invest $550 billion in the U.S., Japan now has agreed to invest up to $332 billion in critical U.S. energy infrastructure, including Westinghouse AP1000 reactors, GE Vernova small modular reactors and several other types of equipment from other companies.

All of this would fit with Trump's push for U.S. energy dominance, in part with a massive increase in nuclear generating capacity, and his vision of a revitalized U.S. industrial base.

Until recently, U.S. nuclear energy development had stalled because of the high cost and long timeline for construction. Part of the problem was there have been so many different designs in the U.S. and so few new plants were being built that economies of scale and institutional knowledge were not being developed for construction.

The Plant Vogtle units 3 and 4 expansion in Georgia, for example, was completed years behind schedule and vastly over-budget and helped run Westinghouse into bankruptcy court in 2017.

But Plant Vogtle was the first of its kind in a generation — subsequent efforts are expected to proceed more smoothly. Even Vogtle Unit 4 was faster to completion than Unit 3.

A *U.S. Department of Energy report* in June noted that the second series of AP1000 reactor construction in China is reaching milestones much more quickly than the first series and predicted that time and cost savings also would accrue in the U.S. if a steady stream of AP1000 reactors was built.

As the demand for nuclear power grows nationwide and worldwide, Westinghouse is presenting the AP1000 as the solution to these first-of-a-kind challenges, offering modular construction in a shorter time frame with simpler design, fewer components, smaller amounts of material and a compacted footprint.

Two AP1000s are in operation at Plant Vogtle and four in China, *Westinghouse reports*, and 32 are contracted or under construction worldwide.

The AP1000 is not one of the cutting-edge Gen IV reactors in the midst of intense research and design, but rather an advanced evolution of traditional models — a Gen III+, as Westinghouse calls it. ■

Load Growth Requires Holistic Interconnection Reform, Experts Say

By Jon Lamson

Holistic reform to interconnection barriers is essential to meeting rapidly growing power demand across the country, experts emphasized in a recent webinar.

Panelists at the Resources for the Future webinar on Oct. 27 discussed underlying challenges of interconnection, along with reform efforts underway throughout the U.S.

As demand for new generation accelerates, "we need all hands on deck," said Sarah Toth Kotwis, senior associate at the nonprofit think tank RMI.

"We are in a really crucial time," said Joe Rand, energy policy researcher at the Lawrence Berkeley National Laboratory. "If we don't have transmission and headroom to connect that new supply, we're simply not going to be able to do it."

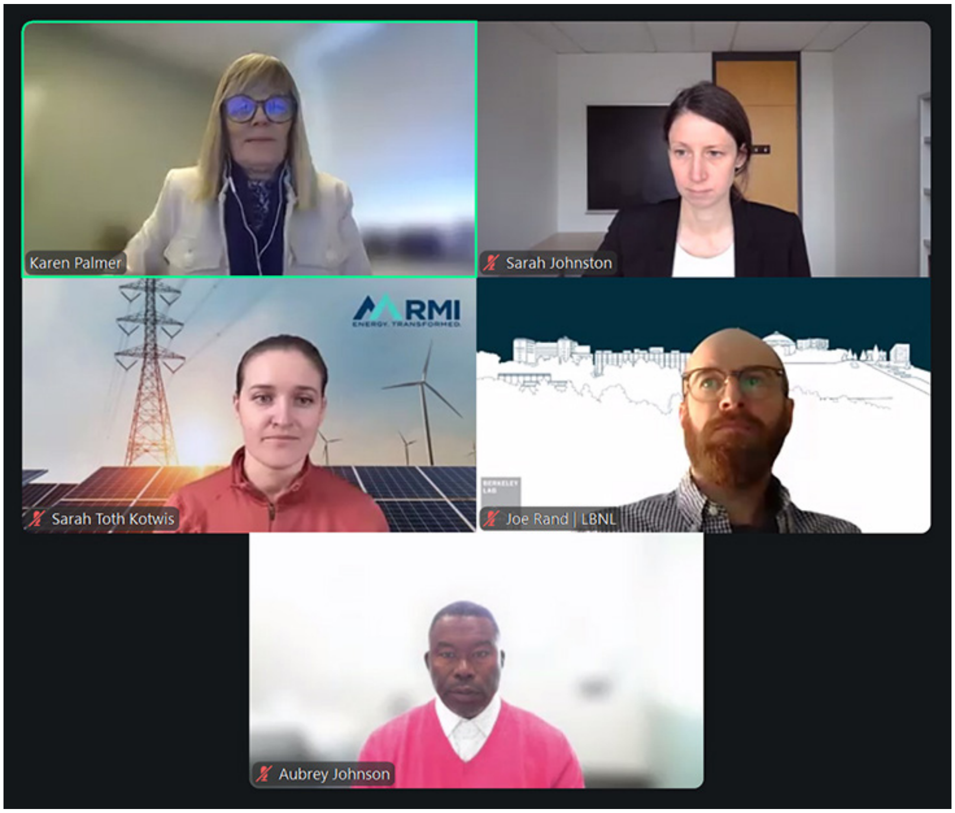
Rand said queue backlogs ballooned in recent years, though some declines in queue capacity occurred between 2023 and 2024. He noted that interconnection requests generally have low completion rates; Berkeley Lab data indicate that only about 13% of the capacity entering interconnection queues achieves commercial operation.

The core issues of interconnection are long wait times and high costs, Toth Kotwis said. To address these issues in the short-term, grid operators should focus on process changes to connect projects as quickly and cheaply as possible, while focusing long-term efforts on "proactive transmission planning that optimizes planning throughout the system."

Aubrey Johnson, vice president of system planning and competitive transmission at MISO, said the RTO's queue saw major growth starting in 2021. He said MISO has been actively pursuing interconnection improvements to keep up with increasing interconnection requests.

Why This Matters

Grid operators across the country are forecasting major demand increases associated with data center development and electrification.



Panel clockwise from top left: Karen Palmer, RFF; Sarah Johnston, University of Calgary; Joe Rand, Lawrence Berkeley National Laboratory; Aubrey Johnson, MISO; Sarah Toth Kotwis, RMI; | *Resources for the Future*

"A lot of what FERC Order 2023 has done, MISO had already been in the process of doing," Johnson said. "We've been doing [cluster studies] since back in 2019."

FERC Order 2023 directs grid operators to adopt first-ready, first-served cluster study processes and require generators to meet significant site control and financial requirements.

"What we've found out from the cluster study is: it has the ability for us to be faster, but it actually does not necessarily get us to be faster because of all the restudies that end up happening," he noted.

More projects joining the queue has caused queue cycles to take longer, causing delays to the start of subsequent queue cycles, Johnson said. He added that MISO has struggled with high dropout rates, with only about 20% of the projects that enter MISO's queue signing generator interconnection agreements.

"Time will tell" how the increased cost requirements and withdrawal penalties mandated by Order 2023 will affect completion rates, but these reforms should affect the volume of projects entering queues, Johnson said.

Johnson added that forward-looking transmission planning efforts, such as MISO's Long-Range Transmission Planning initiative and MISO and SPP's Joint Targeted Interconnection Queue process, should help lower interconnection costs and increase project viability.

Rand of the Berkeley Lab said the requirements of Order 2023 should reduce the number of speculative projects in the queue.

"In 2024, we did see just unprecedented levels of withdrawals," Rand said. "I think a lot of older, nonviable projects are really starting to pull the plug as they see these reforms being implemented."

While reducing the number of nonviable projects should help, developers have a different perspective on so-called speculative projects, Rand said.

"I think they would say that none of their projects are speculative per se; they would happily build any of these if the interconnection costs were reasonable to them, and, of course, if the other factors like permitting and offtake agreements lined up," he said.

Rand said the Order 2023 reforms have not solved the fundamental issue of price transparency that motivates developers to submit a high volume of requests.

"From a developer standpoint, they don't have another way to identify what the interconnection cost requirements are going to be for that particular project until they get in the queue," he said.

In PJM, projects with network upgrade costs higher than $100,000/MW "are over 50% more likely to drop out before the third study than projects that don't have that," said Sarah Johnston, associate professor at the University of Calgary.

"Presumably this is new information, because otherwise they wouldn't want to plan the project and go through the process," Johnston said. "And so, it does speak to how having this up-front certainty could help in getting some generators out of the queue."

Speakers emphasized that resource development challenges are not limited to interconnection barriers, and noted that permitting, supply chain and contracting issues frequently prevent development after resources sign interconnection agreements.

Toth Kotwis said some of the issues projects face after achieving an interconnection agreement can be attributed to how long the study process takes.

"Projects that are connecting now, in 2025, to PJM's grid have been waiting in the queues for eight years on average," Toth Kotwis said. "So much has changed in the last eight years … of course it's a struggle to get built, because we're in a new reality of supply chain constraints and global geopolitics making everything more difficult."

Johnson of MISO said he's confident RTOs across the country are making significant progress toward addressing interconnection barriers, but that the industry should "be giving the same level of attention" to helping projects with signed interconnection agreements reach commercial operation.

He said there are more than 60 GW of projects with signed agreements in MISO alone, more than half of which have been delayed beyond their planned in-service date.

"Across the organized markets, there's over 260 GW of signed [generator interconnection agreements] today that know what their upgrade costs are, that supposedly would be viable projects, but most often are not getting built," Johnson said. ■

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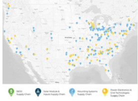
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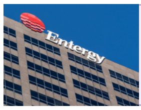
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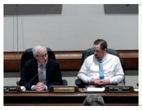
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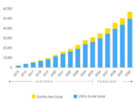
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Now a Mature Industry, Batteries Face a More Certain Future

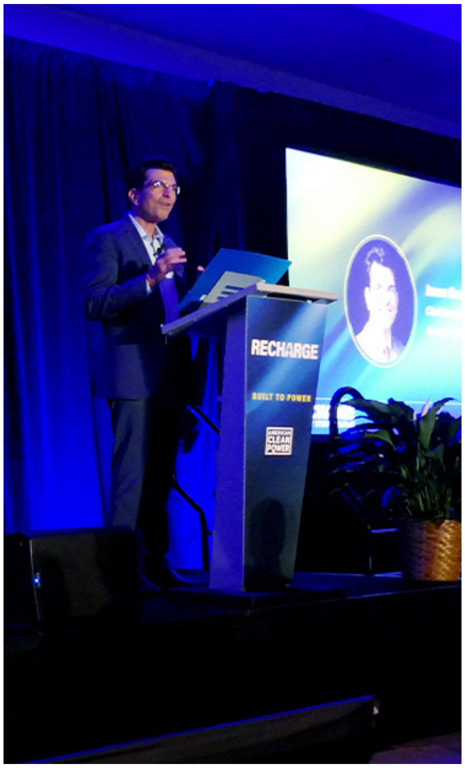
ACP's Energy Storage Summit Highlights Resource's Growth in Texas

By Tom Kleckner

AUSTIN, Texas — Reports of the energy storage industry's demise are greatly exaggerated, experts said during the American Clean Power Association's annual Energy Storage Summit.

Laura Beane, chair of ACP's board and CEO of Vestas North America, welcomed attendees to Texas, a state "now increasingly at the forefront of the energy storage future." She recalled her comments from ACP's CLEANPOWER conference, held May 19-22 in Phoenix, where she laid out the challenges facing the industry.

"The noise, the shifting policy landscape, the disinformation, the conflicting narratives," Beane told an estimated 750 attendees during the Oct. 27-29 conference's opener. "Yes, there's still a lot of noise. There are regulatory hurdles; there's a tremendous amount of uncertainty, and we're working hard every day to cut through that noise, but our job, individually and collectively, every day, is to also drown out the noise.



ACP CEO Jason Grumet kicks off the RECHARGE Energy Storage Summit in Austin, Texas. | © *RTO Insider*

"When we cut away the distractions, what do we see? We see an industry that, like most mature industries, is driven by demand and supply, and right now, we are standing on the edge of the greatest energy expansion this country has ever seen," she added. "Energy storage has truly come of age. It's no longer a concept on the horizon. It's here. It's real; it's essential."

A *recent report* from BloombergNEF bears this out. (See *BNEF Sees Short-term Pain, Longer-term Rebound for Renewables*.) The report says the U.S. is expected to add 204 GW over the next decade, a sharp increase from the 31 GW installed through 2024. The projections are 25% higher than those BNEF shared after the One Big Beautiful Bill Act, which slammed wind and solar energy, was signed into law in July.

BNEF's Isshu Kikuma, one of the report's authors and a summit panelist, said storage is faring better than renewables because the full value of its tax credits is good through 2033. The credits drop to 75% in 2034 and 50% in 2035.

ACP CEO Jason Grumet followed Beane on the stage and compared storage to a good neighbor or friend.

"Storage is the friend who shows up on moving day with a truck and snacks. Storage is the person who picks you up at the airport at 11:30 at night," he said. "We are warm. We are relatable.

"But look, 99% of Americans and virtually all policymakers do not know much about storage," Grumet went on. "We live in a moment where electrons and molecules are seen to have political affiliation, but storage so far is kind of like hanging out in that kind of quiet, independent voice."

But there are risks for the industry, both foreign and domestic, he said.

"The supply chain is a huge challenge for us. The concentration of critical mineral processing in China is an economic risk," Grumet said. "The most imminent risk we face domestically is not technology; it's political uncertainty."

Why This Matters

Battery storage is faring better than renewable energy since July's reconciliation bill because it retains the full value of its tax credits through 2033. The result is a mature industry, driven by demand and supply, standing on the edge of a massive energy expansion.

Storage Proves Value in ERCOT

ERCOT CEO Pablo Vegas sat down with Grumet for a fireside chat and said that despite meeting near-record summer demand with a fuel mix that includes energy storage and renewables and their resulting low prices, managing the Texas grid is not easy.

"We are special — I will start with that — but it's a challenge every day. It's a challenge because things are constantly changing," Vegas told Grumet.

When he was named ERCOT's CEO in 2022, he said, there was less than 2 GW of storage on the system. "It has doubled every single year that I have been here," he said, noting the grid operator's installed storage capacity has grown to 15 GW. The *interconnection queue* includes an additional 178 GW of standalone and co-located storage.

Texas Public Utility Commission Chair Thomas Gleeson said he runs into the same political headwinds. He said the joke in his office is that when he testifies in legislative hearings, "it seems like the Democrats on the committee agreed with me more than the than the Republicans."

"I believe batteries are a dispatchable technology," Gleeson said. "We need more gas plants in the state. I think it would be hard to deny that. But I would say often when posed the question, 'What do you do with unreliable, intermittent resources?' And I was quick to tell folks, 'I don't believe that they're unreliable.' They're variable, which causes its own kind of challenge. But gas plants break.

"The goal, again, is to have such an expansive portfolio that they all work well together in balance," Gleeson said. "And so, I do view batteries as dispatchable. I think everyone should."

Robb: Batteries Help Grid Reliability

NERC CEO Jim Robb agreed with Gleeson, saying his organization has been "really clear" on storage's reliability contributions to the grid.

Storage "mitigates the variability that you're always going to have with wind and solar production. Clouds fly over, wind stops for a few minutes, so it helps deal with those issues," he said.

Robb said the bigger issue comes during the late afternoons, when solar production begins to ramp down. ERCOT credits storage in Texas for compensating for the loss of solar in the evening hours. The grid operator has now gone two summers without serious reliability concerns. (See *Texas RE: ESRs to Boost ERCOT During Summer*.)

"We see enormous benefits from having battery storage combined with [solar]," he said. "You look at California, you look at Texas, in particular. Texas is probably the most interesting market because it's isolated whereas California is integrated with the rest of the West."

Nickell Sees Storage's Growth in SPP

While Texas and California are awash with solar and storage facilities, SPP isn't. ERCOT's neighbor had 172 MW of accredited summer *battery storage capacity* in 2025 and 548 MW of operational solar as of June 2025.

However, the RTO's interconnection queue lists 48.4 GW and 34.6 GW of storage and solar capacity requests, respectively. That accounts for almost two-thirds of the queue's requested capacity.

ACP's Maurice Moss (left) and SPP CEO Lanny Nickell | © *RTO Insider*

"We see a lot of interest. We're not seeing a lot of it get built yet," SPP CEO Lanny Nickell said. "What we've heard when we talk to a lot of our customers, developers and the market is that markets in California and in Texas are more lucrative. And the reason for that is because, not only are the prices on average higher in those markets … but also, particularly for storage in those markets, there's a lot more volatility. You want to be able to charge when prices are low, and you want to be able to discharge when prices are high, and when that gap exists almost on a daily basis, that's attractive."

Nickell is buoyed when he looks at the requests for storage and solar in the generator interconnection queue. "We know solar is coming, and we think solar will bring more storage … over the next two [to] four years," he said.

SPP filed a proposed *tariff change* with FERC in October following the board's approval of a high-impact large-load service proposal that Nickell said would make the footprint much more attractive to those loads. (See "Large Load Integration OK'd," *SPP Board Approves 765-kV Project's Increased Cost*.)

FERC Chairs Like Batteries' Value

Former FERC Chairs Rich Glick and Willie Phillips appeared as a two-person panel and reminded the audience that reliability remains the No. 1 challenge for any leader of the commission.

"We didn't experience the great load growth that we're now talking about today," Glick said. "It's amazing to me, like night and day from when I was at the commission until today, [that California and Texas] added a significant amount of storage that's helped keep prices down, but it also helped keep the lights on during some very, very difficult weather conditions. Obviously, storage provides some of the essential reliability services and does it in a very quick way, much quicker than some other technologies."

Phillips said that when he succeeded Glick as FERC's chair, he found that meetings with industry executives consumed much of his day.

"It helped highlight just how much demand forecasts were beginning to change. I started hearing from CEO after CEO, leader after leader, that they were having a doubling of the expected demand for energy coming on to their system, depending on the particular region," he said. "That crystallized for me … that if we don't get this moment right, there could be some reliability, some resource adequacy, some type of crisis that we face." ■

This article has been edited for length.
Click here for the full version.

WRAP Wins Commitments from 16 Entities

Final Group Consists Heavily of Future Markets+ Participants

By Robert Mullin

Sixteen entities have committed to participating in the Western Resource Adequacy Program's first financially "binding" season covering winter 2027/28, the Western Power Pool said Oct. 31 — the deadline for participants to commit to the program.

"As of the deadline, there are 16 current participants that will remain in the program for binding operations, including five in addition to the 11 who sent a commitment letter last month, and we expect more companies to join in the future," WPP said in a notice posted on its website.

The committed participants include:

- Arizona Public Service
- Avista Corp.
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- Clatskanie People's Utility District
- Constellation
- PUD No. 2 of Grant County
- Idaho Power
- NorthWestern Energy
- Powerex Corp.
- Puget Sound Energy
- Salt River Project Agricultural Improvement and Power District
- Seattle City Light
- Tacoma Power
- The Energy Authority
- Tucson Electric Power

WPP said the participants "bring significant load (over 58,000 MW in peak load) and resources and a large, diverse geographic footprint, making WRAP one of the largest RA programs in the country and giving us critical mass for a binding program."

New commitments after the initial 11 include Constellation, Grant County, Idaho Power, Seattle City Light and The Energy Authority. WPP noted the full group "includes members committed to or leaning toward" either CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+, "as well as some who have not indicated they will join a day-ahead market." SPP is operating the WRAP on behalf of the WPP and its Markets+ day-ahead platform, which requires members to participate in the program.

Why This Matters

The final WRAP commitments show how much the program has been divided along the line of participants in CAISO's EDAM and SPP's Markets+.

The Oct. 31 announcement marks the conclusion of a tumultuous October for the WRAP. The month began with PacifiCorp asking the WPP's board of directors to delay the program's binding phase by at least one year to deal with uncertainties around the program, followed by a similar request from Portland General Electric (PGE). (See *PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date*.)

Early October also brought news of NV Energy's intent to withdraw from the WRAP, a move the utility explained to the Public Utilities Commission of Nevada in an Aug. 29 filing that didn't come to light until the regulator resolved issues with its website. (See *NV Energy to Withdraw from WRAP*.)

Then came the development, revealed by NV Energy, that future EDAM participants already have begun discussions about developing an alternative to WRAP. (See *EDAM Participants Exploring Potential New Western RA Program*.)

Just ahead of the deadline, NV Energy, PacifiCorp and PGE issued letters notifying WPP of their withdrawal, along with Calpine, Eugene Water & Electric Board (EWEB) and Public Service Company of New Mexico (PNM). (See related stories *4 Entities Join NV Energy in Exiting WRAP, While Idaho Power Commits* and *PacifiCorp Next to Leave WRAP After Raising Concerns*.)

Among the five utilities withdrawing from the WRAP, four (NV Energy, PacifiCorp, PGE and PNM) have committed to joining the EDAM, while EWEB will be participating in Markets+ by virtue of its location with the Bonneville Power Administration's balancing authority area.

Of the 16 committing to the first binding season, 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.

In an Oct. 30 *letter* affirming SCL's commitment to WRAP, utility Power Supply Officer Siobhan Doherty called the program "a cornerstone for enhancing reliability and coordination across the Western Interconnection" and said the SCL's participation already has "provided tangible benefits for Seattle and the broader region."

But Doherty raised a concern shared by some withdrawing participants, saying SCL "continues to closely monitor developments related to planning reserve margin (PRM) volatility in the shoulder months, particularly June and September. We recognize this as an area that could materially affect program outcomes and merits continued refinement."

California Dreamin'?

The WRAP withdrawals have generated speculation in the Western electric sector about what kind of RA alternative could take shape in the region, including the potential for a program that might include California utilities — and CAISO.

In an email to *RTO Insider*, the ISO said it recognized that some EDAM participants are exploring WRAP alternatives and acknowledged that "several have approached CAISO with preliminary questions regarding our technical capabilities in this area, and we remain open to those discussions as stakeholder needs evolve.

"Ultimately, decisions about participation in WRAP and any alternative approaches rest with the utilities, their regulators and stakeholders. As with WRAP, any new resource adequacy program will not alter the CAISO Balancing Authority's existing resource adequacy requirements." ■

PacifiCorp Next to Leave WRAP After Raising Concerns

Utility Joins 5 Others in Exiting Program

By Henrik Nilsson

PacifiCorp joins other utilities leaving the Western Power Pool's Western Resource Adequacy Program just before the deadline to commit to the program's first binding phase.

PacifiCorp *submitted its withdrawal notice* on Oct. 30. Michael Wilding, the utility's vice president of energy supply management, signed the letter and addressed it to WPP Chief Strategy Officer Rebecca Sexton.

WRAP participants had until Oct. 31 to commit to WRAP's first financially binding phase in winter 2027/28.

PacifiCorp's withdrawal goes into effect before Nov. 1, 2027, and the utility will be subject to the requirements of WRAP's tariff during the two-year withdrawal period, according to the letter.

Wilding did not shut the door entirely on rejoining the program, saying PacifiCorp "will continue to engage with the program for the duration of the withdrawal period."

"Should circumstances change, the company can reenter the program by September 2026 to join other participants in the first financially binding program season in November 2027," he added.

In an email to *RTO Insider*, PacifiCorp spokesperson Omar Granados said, "We appreciate the Western Power Pool and its leadership in addressing resource adequacy across the region. PacifiCorp remains committed to providing safe, reliable power, and we believe collaborating with our regional partners is the best way to develop long-term solutions for our customers."

WRAP has stated it secured enough participants for the program to enter the first binding phase after 11 utilities reaffirmed their commitment in late September. (See *WRAP 'Binding' Phase Set for Winter 2027/28 After Utilities Affirm Commitment*.)

Why This Matters

PacifiCorp marks another exit before a looming deadline for withdrawing from the program.

| Shutterstock

"The vast majority of our participants are remaining in the program," Dave Zvareck, WRAP director, told *RTO Insider*. "We have received some exit notices this week, which was expected, as well as renewed commitment to the program, and we will move forward with binding operations in winter 2027/2028."

PacifiCorp's withdrawal comes after it asked WPP's Board of Directors to allow WRAP participants to defer their decisions to commit to the program's binding phase by at least one year after raising concerns about WRAP's design, planning reserve margins, charges and its ability to adapt to the emergence of day-ahead markets in the West. (See *PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date*.)

Other entities exiting the program have highlighted the challenges of navigating WRAP's requirements when most of the West will be split into two day-ahead markets: SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

All load-serving entities in Markets+ must participate in WRAP, which is being operated by SPP on behalf of WPP. By contrast, EDAM doesn't require participation in an organized resource adequacy program, instead leaving members the option of choosing their own RA programs. But EDAM will use a resource sufficiency evaluation to ensure participants' RA going into the day-ahead and real-time time frames.

PacifiCorp joined Calpine, Eugene Water & Electric Board, Portland General Electric, Public Service Company of New Mexico and NV Energy in exiting WRAP. Out of those six entities, only EWEB will participate in Markets+ because it sits within the Bonneville Power Administration's balancing authority area. (See related story *4 Entities Join NV Energy in Exiting WRAP, While Idaho Power Commits*.)

Under WRAP's forward-showing requirement, participants must demonstrate they have secured their share of regional capacity needed for the upcoming season. Once WRAP enters its binding phase, participants with surplus capacity must help those with a deficit in the hours of highest need.

The binding phase also includes penalties for participants that enter a binding season with capacity deficiencies compared with their forward showing of resources promised for that season. ■

PGE to Explore Alternatives After Withdrawing from WRAP

Utility Signals Intent in Letter to Oregon PUC Explaining Withdrawal

By Robert Mullin

Portland General Electric is exploring an alternative to the Western Power Pool's Western Resource Adequacy Program (WRAP) that better suits its upcoming participation in CAISO's Extended Day-Ahead Market, the utility has told Oregon regulators.

PGE expressed its intention in an Oct. 29 *letter* to the Oregon Public Utility Commission explaining why the utility was withdrawing from the WRAP ahead of the Oct. 31 deadline to commit to the program's first "binding" — or penalty — phase covering winter 2027/28. Oregon rules require the state's investor-owned utilities to participate in either a program such as WRAP or a state-run RA program.

The tone of the letter suggests PGE is likely closing the door on future participation in WRAP as developments point to an alternative program taking shape in the West.

"We are pursuing alternatives to WRAP that better align with the EDAM market to maximize the value to customers," Sujata Pagedar, PGE senior director of regulatory and governance, told OPUC in the letter. "By maintaining open dialogue and focusing on shared objectives, we believe we can collectively build a framework that delivers lasting benefits for the region."

The Oregon-based utility was one of five WRAP participants to notify WPP of their withdrawal by Oct. 29. (See related story, *4 Entities Join NV Energy in Exiting WRAP, While Idaho Power Commits*.)

Why This Matters

PGE's letter suggests the utility will turn to an alternative Western RA program rather than revisiting WRAP participation in the future.

Even before NV Energy conveyed its formal notice of withdrawal on Oct. 27, utility officials told Nevada regulators they were already in discussion with other future EDAM participants about developing an alternative to WRAP. (See *EDAM Participants Exploring Potential New Western RA Program*.)

Asked whether PGE was participating in those discussions, utility spokesperson Drew Hanson told *RTO Insider*: "It is less about a specific new RA program and more about remaining committed to regional collaboration and actively exploring alternative resource adequacy solutions."

'Unwavering' Commitment

In the letter to OPUC, Pagedar said PGE's "decision was not made lightly" but reflected "the fact that there are significant unresolved uncertainties in the program design, reliability metrics, technology readiness and governance — with no clear timeline for resolving these issues and implementing necessary changes in time for PGE to adequately prepare the March 31, 2027, forward showing submittal for the first binding season, effective Nov. 1, 2027."

She noted that PGE was a "foundational member" of WRAP, "worked diligently" to move to binding operations as quickly as possible and was the first participant to receive a "passing" score on the operations program report during the "non-binding" phase.

Still, PGE had identified critical shortcomings.

Among those was WPP's proposed realignment of the WRAP's operation subregions with CAISO's EDAM and SPP's Markets+ (compared with the previous Northwest/Southwest breakdown), which Pagedar said was necessary for a "robust" RA framework but posed too much risk without postponing the first binding season.

She said such "a complete realignment in such a compressed timeline creates substantial risk regarding how these metrics will be recalibrated and how those changes will impact participants' capacity demonstration and financial exposure" during the first winter binding season.

Portland General Electric's operations center in Tualatin, Ore. | *Portland General Electric*

Pagedar said PGE was concerned also about the outcome of efforts by the WRAP's Planning Reserve Margin Task Force to evaluate new methodologies for setting planning reserve margins for program participants.

"These changes directly impact deficiency charge calculations and the risk profile for participants. The changes to the PRM methodology and timeline could directly impact the calculation of resource capacity contributions," she wrote.

PGE also expressed concern about the "technical readiness" of WRAP, which is being operated on behalf of WPP by SPP, saying the forward showing and operations platforms appear to "lack the technical stability and responsiveness needed for a binding adequacy program" and that user interface and system issues that "raise doubts about the operator's ability to implement changes in time for market participants to adjust their IT systems."

Pagedar concluded that PGE has an "unwavering" commitment to collaborating on regional RA.

"We will continue to work with partners across the West to advance solutions that strengthen reliability, affordability and resilience for all customers," she wrote. ■

‘Aggressive’ EDAM Schedule ‘Going Smoothly’ for PacifiCorp, PGE

CAISO Working on Congestion Revenue Allocation Challenges

By David Krause

PacifiCorp and Portland General Electric remain on track to join CAISO’s Extended Day-Ahead Market (EDAM) on their planned entry dates, although the schedule remains “very tight and very aggressive,” CAISO executives said during a stakeholder meeting.

“Things are going very smoothly,” CAISO Chief Information and Technology Officer Khaled Abdul-Rahman said during the Oct. 27 Western Energy Markets Regional Issues Forum (RIF) meeting. “We are going to be in market simulation for [PacifiCorp] until mid-January 2026, and our go-live is scheduled for May 1, 2026.”

PacifiCorp’s systems are being tested in EDAM’s market simulation phase, which is a critical step to ensure market features, rule changes and system upgrades are working as designed, CAISO said in a *document* on the subject.

CAISO in 2025 has held workshops to show how more complicated parts of EDAM will work, such as scheduling at interties, Abdul-Rahman said, and the ISO plans to hold more elaborate workshops on the subject in November.

“We have to make sure our existing market participants are comfortable with the changes,” Abdul-Rahman said. “And in terms of post-market implementation, the main challenge is preparing settlement data … this is the area that we are focusing on a lot because there are a lot of changes.”

CAISO is working specifically on implementation challenges associated with congestion revenue allocation, although these challenges are “not impacting our plan” to begin EDAM in 2026, Abdul-Rahman said. (See *CAISO’s EDAM Scores Simultaneous Wins at FERC*.)

While EDAM’s market simulation phase continues, PacifiCorp is transitioning from a five-day per week operation to a seven-day per week operation, Paul Wood, PacifiCorp director of portfolio optimization, said at the meeting.

“The big thing to stress is that there has to be a lot of continuous training, testing and development,” Wood said. “Getting employees trained to participate in the EDAM market while continuing to perform daily jobs is [important]. There’s been a lot of training for employees to get their tools ready for a total change on May 1.”

Ensuring vendors and consultants are involved early helps clear up assumptions before they become problems, Wood added. And flexibility through the transition to EDAM is key, since market rules and designs will shift, he said.

PGE is on track to begin its EDAM market simulation phase in March 2026, complete the phase by June 2026, and then enter the EDAM on Oct. 1, 2026.

RIF Transition Update

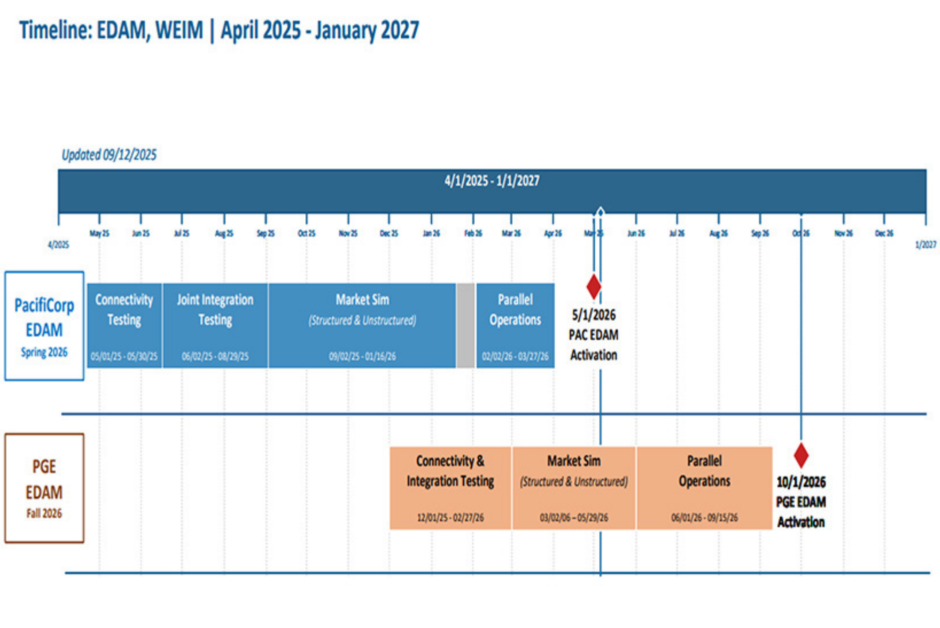
RIF committee members proposed to move forward with the transition of the RIF into the Stakeholder Representatives Committee (SRC) to be established for the Regional Organization for Western Energy being developed by the West-Wide Governance Pathways Initiative, which eventually will assume governance of the EDAM and Western Energy Imbalance Market (WEIM). (See related story, *Pathways Co-chair Maps out ‘Enhanced’ Stakeholder Process for Western Markets*.)

The timing and implementation approach for the transition need to be determined, and existing functions of the RIF need to continue in the meantime, committee members said. (See *Pathways Initiative Clarifies Near-term Division of Labor with CAISO*.)

One stakeholder asked the RIF committee to discuss the advantages of starting the SRC directly after ending the RIF, rather than including a transitional phase, so that “folks can stand up and walk from one room to the other.”

Lindsey Schlekeway, NV Energy market policy manager and WEIM entity sector liaison, said many RIF stakeholders are the same stakeholders who will be in the SRC, so if “we can’t find a clear method for the transition, a lot of duplicative work would occur.”

“This is going to be a huge effort in order to stand up this new stakeholder committee, so we are just trying to find the most efficient and streamlined path,” Schlekeway said. ■



Current EDAM implementation timeline for PacifiCorp and PGE | *CAISO*

4 Entities Join NV Energy in Exiting WRAP, While Idaho Power Commits

PNM Says Evolution of Day-ahead Markets 1 Reason for Leaving

By Henrik Nilsson and Robert Mullin

Why This Matters

The WRAP developments come just ahead of a looming deadline for withdrawing from the program, and show the fissure between participants joining either EDAM or Markets+ — with one notable exception.

Calpine, Eugene Water & Electric Board, Portland General Electric and Public Service Company of New Mexico have joined NV Energy in leaving the Western Resource Adequacy Program, while Idaho Power signaled its continued commitment, reflecting the complexity surrounding the emergence of day-ahead markets in the West.

PNM, PGE, EWEB and Calpine announced their intent to withdraw from the Western Power Pool's WRAP in four separate letters posted on WPP's website Oct. 29. NV Energy informed the Public Utilities Commission of Nevada about its plans earlier in 2025, but its formal withdrawal *notice* was published on WPP's website Oct. 27. (See *NV Energy to Withdraw from WRAP*.)

PNM, PGE and EWEB each cited different reasons for leaving WRAP, while Calpine offered no details about its departure.

PNM's Senior Vice President Laurie Williams *said* the decision to withdraw followed "careful consideration of several factors, most notably the emergence of two day-ahead markets in the West: the CAISO Extended Day-Ahead Market (EDAM) and SPP Markets+."

All load-serving entities in Markets+ must participate in WRAP. By contrast, EDAM won't require participation in an organized resource adequacy program. Instead, it will use a resource sufficiency evaluation to ensure participants' RA going into the day-ahead and real-time time frames to meet their own needs without depending on others.

But some EDAM participants have discussed launching a separate RA program. NV Energy and the Imperial Irrigation District, both of which have committed to joining EDAM, have said they are discussing the potential for a new Western RA program. (See *EDAM Participants Exploring Potential New Western RA Program*.)

PNM's withdrawal notice provided fodder for this idea, with Williams writing that the utility "believes it is prudent to pursue resource adequacy programs aligned with each market, consistent with practices in other ISO/RTOs."

Williams also commended WPP's efforts to address concerns with day-ahead markets, planning reserve margins and deficiency charges. She noted that WPP has created task forces aimed at tackling those issues but said "these initiatives remain preliminary and require further development, and as such, PNM is unable to make a binding commitment to the program in its current state."

"PNM remains committed to resource adequacy in the West and will continue to engage with WRAP and participate in [Resource Adequacy Participants Committee] during our transition over the next two years," Williams wrote. "We remain confident that the foundational work of WRAP entities will support future efforts to coordinate across evolving market structures."

PGE CEO Maria Pope *said* the utility would exit WRAP before the Oct. 31 deadline, citing "continued uncertainty regarding program design, technical readiness, and alignment with evolving market structures."

Just like the other participants that submitted their exit notices, Pope expressed appreciation for WPP's efforts, saying PGE "remains committed to working collaboratively with the Western Power Pool and regional partners to strengthen WRAP. We remain a member in good standing of the WRAP in a non-binding status with all the privileges and requirements of a member."

NV Energy kept its formal withdrawal notice brief, stating it "appreciates the collaborative efforts of the WRAP community and looks forward to future opportunities for regional coordination."

NV Energy announced its plans to leave WRAP in filings with the Public Utilities Commission of Nevada. The utility cited five "critical issues," including "steep penalties for capacity deficiencies identified seven months before the compliance season," and potential disadvantages for EDAM participants.

Calpine's withdrawal *letter* was similarly brief, with Senior Vice President Neil Bresnan providing no explanation for the move. The independent power producer operates about 27 GW of resources across the U.S., with most of its Western plants concentrated in California, along with one combined cycle gas plant each in Arizona and Oregon.

'Strong Supporter'

Of the five entities notifying WPP of their withdrawal from the WRAP, EWEB is possibly the only one seriously leaving the door open for future participation.

In its *letter*, the Oregon-based municipal utility, which sits within the Bonneville Power Administration's balancing authority area, said its decision "is based on our need to align future participation in the Binding Program phase with the start of our next Bonneville Power Administration (BPA) Power and Transmission contracts, which take effect October 2028," noting that BPA serves as the utility's "primary energy/transmission supplier."

"This notice reflects EWEB's specific operational and contractual circumstances and should not be interpreted as a criticism of WRAP or its objectives," EWEB CEO Frank Lawson wrote in the letter. "EWEB remains a strong supporter of the development of regional resource adequacy standards and recognizes the vital role WRAP plays in advancing reliability across the Western Interconnection. We value the opportunity to have participated in the program's formation and remain committed to advocating for WRAP's continued success."

Lawson said the utility would seek to meet with WPP staff "to discuss the appropriate steps, timing and obligations associated with our participation during the notice and withdrawal period" and to ascertain "available options for fulfilling any residual obligations under the tariff during this time."

EWEB spokesperson Aaron Orlowski told *RTO Insider* the views set out in the utility's letter "weren't just words" but genuinely reflected its position on the WRAP, including its continued support for the program. He said the financial risks of participating in the program's penalty phase ahead of securing the BPA contracts prevented EWEB from committing at this point, but that it looked forward to joining in the future.

'Continued Refinement'

Idaho Power was the clear standout in announcing its intention to remain in the WRAP, especially given that the Boise-based utility has signaled its intent to join EDAM rather than Markets+ — although it may be better positioned than most to avoid penalties. (See *WRAP Participants Find Value in Program's Nonbinding Phase*.)

In its letter, CEO Lisa Grow lauded the "dedication and hard work" of WPP staff and stakeholders in developing the WRAP but also pointed to "several key areas that warrant continued attention and improvement," including issues related to the "ongoing volatility and variability" of planning reserve margins, day-ahead markets and deficiency penalties.

On the evolving markets in the West, Grow wrote that "it is essential that WRAP continues to evolve in a way that equitably accommodates participants across different market structures — or those not in a market at all — to ensure broad and sustained participation."

Grow noted also that the utility supports the WRAP's recently approved deficiency charge deferral resolution and the "continued refinement" of deficiency charge provisions.

"This provision is especially critical for entities like Idaho Power that are making substantial investments in new generation and transmission infrastructure over the next five years," she wrote.

Grow said also that while Idaho Power is prepared for the first binding season, the utility thinks "it will be important to evaluate program and entity readiness between now and then," pointing out that the WRAP tariff allows for potential delay in binding operations.

Looming Deadline

The withdrawal notices came as an Oct. 31 deadline loomed for participants to commit to the WRAP's first binding phase in winter 2027/28. Of the 11 members that have so far committed to the program's first binding season, all but one are expected to join Markets+.

Carrie Simpson, SPP vice president of markets, told *RTO Insider* "Markets+ continues to move forward with strong participant commitment. While some entities have provided notice of their intent to exit WRAP, it does not impact the viability of Markets+."

PacifiCorp had requested additional time before committing to the program's binding phase. (See *PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date*.) PacifiCorp later joined the four companies in leaving the WRAP. (See related story, *PacifiCorp Next to Leave WRAP After Raising Concerns*.)

PacifiCorp and PGE are slated to become EDAM's first participants in 2026.

In response letters to PacifiCorp and PGE, WPP board Chair Bill Drummond said delaying the binding phase "would have a detrimental effect on reliability for the region, including undermining confidence in WRAP data and modeling, limiting program compliance and preventing us from unlocking the full benefits of the program." ■

PNM headquarters in Albuquerque, N.M. | *Camerafiend, CC BY-SA-3.0 via Wikimedia Commons*

Pathways Initiative Exploring Funding Options, Issues RFP to Staff ROWE

By Henrik Nilsson

The West-Wide Governance Pathways Initiative's Launch Committee will hire an executive staffing firm and is considering funding sources as it advances to the next phases of building the independent organization that will govern CAISO's energy markets.

The committee is seeking $7 million to $8 million in start-up costs for the Regional Organization for Western Energy (ROWE). The money will cover costs from 2026 to 2027, Jim Shetler, general manager of the Balancing Authority of Northern California, said at Pathways' monthly stakeholder meeting Oct. 31.

"We're in the process of refining and making sure we covered the necessary costs," Shetler said. "We currently are looking at three main tranches of funding."

The funding alternatives include stakeholder contributions, grants and debt financing.

Pathways received a commitment under former President Joe Biden's administration to underwrite the committee's efforts to establish ROWE to oversee CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). (See *Feds Pause $1M Pathways Initiative Funding, Group Leader Says*.)

However, Shetler said, "it's rather doubtful that we will get that federal grant."

"We are starting to outreach to other entities, to look at private sector entities who may be willing to provide grant funds for this effort, and [we] have had some initial conversations around that," Shetler added.

On Oct. 29, the Launch Committee *issued a request for proposals* to pay $420,000 for an executive staffing firm to assist in seating ROWE's independent board and hiring of initial key staff.

The RFP notes that because of "funding limitations," the committee is considering two options for support: basic support, including assisting in scheduling candidate interviews and preparing agendas; or routine support, which would include tasks such as vetting potential candidates and coordinating interviews.

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Why This Matters

After the successful passage of AB 825, the Pathways Initiative's next challenge appears to be funding the next phases of the effort to shift governance of CAISO's energy markets to a new regional organization.

The independent board will initially have five members, with two additional members to be added after tariff changes are approved by FERC.

"The board selection process will begin in January, so the nominating committee will begin to really meet in earnest the beginning of next year. The goal is to find five board members to be seated by or around July of 2026," said Kathleen Staks, executive director of Western Freedom and co-chair of the Launch Committee.

California Gov. Gavin Newsom signed AB 825 into law on Sept. 19, allowing CAISO and investor-owned utilities to participate in ROWE. (See *Newsom Signs Calif. Pathways Bill into Law*.)

One goal in establishing the organization was to remove what some see as a barrier to wider participation in CAISO-run markets by ensuring they are not governed solely by officials and stakeholders in California. Another goal is to continue to "add additional market services that are voluntary for any Western stakeholders who want them," Staks said.

"So being able to go from just overseeing the EIM and EDAM to adding additional services as Western stakeholders demand them is a really critical function," Staks said. "This is not just independent governance over these energy markets. It is independent governance over all of the functions and offerings that go beyond that." ■

Pathways Co-chair Maps out 'Enhanced' Stakeholder Process for Western Markets

By Henrik Nilsson

The West-Wide Governance Pathways Initiative's Launch Committee Co-Chair Pam Sporborg said the stakeholder process of the new regional organization that will oversee CAISO's energy markets is an evolution of the ISO's Regional Issues Forum (RIF).

The RIF is a space for the power industry to discuss issues related to the ISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). However, following the passage of AB 825 in California, CAISO will hand over responsibility for the markets to the independent Regional Organization for Western Energy (ROWE), which is being designed by the Pathways Initiative's Launch Committee. The handover is scheduled for early 2028. (See *Newsom Signs Calif. Pathways Bill into Law*.)

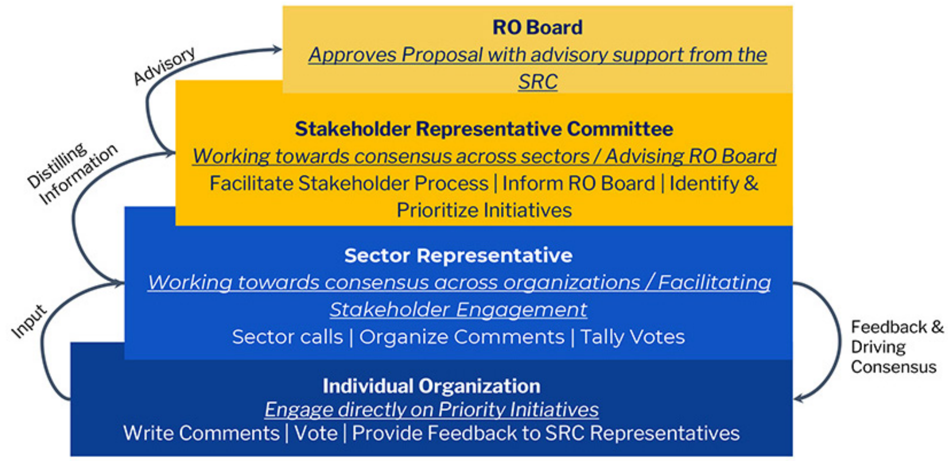
Speaking at *the RIF* on Oct. 27, Sporborg, director of transmission and markets at Portland General Electric, said the Pathways Initiative's Stakeholder Representatives Committee (SRC), which will provide advisory support to ROWE's board, builds on the RIF's success, praising the forum as enabling "more in-depth dialog on the stakeholder process and the evolution of the market."

"We … see the Stakeholder Representatives Committee as this incremental evolution beyond the RIF sector liaison role with an expanded number of sectors that I think add some granularity and new voices into the process," Sporborg said.

"We have more of an opportunity to really have additional engagement in each of the policy development processes,"

Why This Matters

With ROWE set to assume responsibility for CAISO's energy markets, more details are coming out on how governance of the markets will play out.



The Pathways Initiative's Launch Committee envisions that future policy development of CAISO's markets will be driven by significant stakeholder input. | *CAISO*

Sporborg said. She added that there is an "opportunity to bring … members of each sector into that policy development process to ensure that as the market evolves, it's really evolving at the direction of stakeholders."

She noted the sectors will be involved in market development by providing SRC members with more say on proposals through an enhanced voting process, comment engagement, analysis and other opportunities.

Sporborg explained the enhanced voting approach, saying stakeholders will submit indicative votes throughout the policymaking process to ensure concerns are being addressed and to provide more analysis on proposals rather than SRC members simply voting "support, oppose or neutral."

The Launch Committee is considering a remand process to allow entities to refine unpopular proposals. This would apply to final proposals prior to an initiative being sent to the ROWE board.

"We want to enhance the way these votes get shared with the board, so that there would be some opportunity to identify … more analytics behind that support, oppose or neutral vote to help the board understand if there's opposition in a particular sector," Sporborg said. "For example, do all small utilities oppose a proposal, or does this have significant opposition in the IPP sector? We want to be able to have that kind of analytic show through the tabulated voting."

Already, the Launch Committee has announced that representatives from nine sectors will advise on the nomination of members to ROWE's initial board. (See *Pathways to Engage Broad Set of Stakeholders to Select Independent RO Board*.)

Those entities include:

- EDAM entities
- WEIM entities
- ISO-participating transmission owners
- Non-IOU load-serving entities serving load from WEIM or EDAM
- Public interest organizations
- Independent power producers, independent transmission developers and marketers
- Consumer advocates
- Large commercial and industrial customers
- Distributed energy resources

Sporborg said the Launch Committee envisions a "hybrid structure" that brings together staff expertise and stakeholder input, "where you get the ability to execute quickly and to drive forward through a staff-driven process. But by bringing more of the voice of the stakeholder into that process, we can have more of a stakeholder-driven policy evolution." ■

Analysis Finds 'Material' Parallel Flow Effects in CAISO from PacifiCorp BAA Transactions

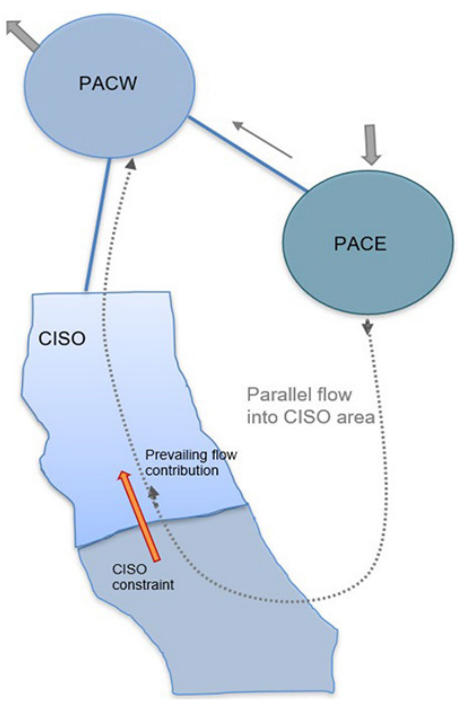
ISO Begins 3-stage Analysis on Issue

By David Krause

In an ongoing high-stakes analysis, CAISO has determined that transactions between PacifiCorp's two balancing authority areas can "materially" affect parallel flows on certain CAISO transmission constraints, an ISO representative told market officials and stakeholders.

The finding is part of CAISO's analysis of congestion revenue allocation during parallel flow situations within the ISO's Extended Day-Ahead Market (EDAM). EDAM is to begin operation next year, with PacifiCorp as an initial participant.

The subject of how to allocate congestion revenues under parallel — or loop — flows took priority at CAISO in February after Powerex argued the EDAM model contains a "design flaw" with potentially $1 billion in unjustifiable charges at stake. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)



Transactions with flows in the same direction increase congestion rents. | *CAISO*

CAISO then began months of work to address the concern, culminating in June, when it approved a new method for allocating certain congestion revenues in EDAM during parallel flow times, a design FERC later accepted. (See *CAISO Approves New EDAM Congestion Revenue Allocation Design*.)

The newly approved method, however, could create unintended market incentives, said Guillermo Alderete, CAISO director of market performance and advanced analytics, at an Oct. 29 joint meeting of CAISO's Board of Governors and the Western Energy Markets Governing Body. CAISO's Market Surveillance Committee (MSC) in a June *memo* also said it is concerned about the new method's potential to create self-scheduling incentives.

To address those concerns, CAISO and its Department of Market Monitor (DMM) developed three stages of analysis, starting with a study of congestion revenue and parallel flow data in the Western Energy Imbalance Market between January 2024 and August 2025.

In this first stage, CAISO found transactions between PacifiCorp areas can "materially impact" parallel flow on some major transmission constraints in CAISO's region, Alderete said.

CAISO specifically found that about 145 congested constraints — about 96% of the total constraints— were in the ISO. Of these constraints, about 21% were affected by parallel flows generated by transactions between the PacifiCorp East and West areas, Alderete said.

Constraints on Path 26 — which consists of three 500-kV lines between Pacific Gas and Electric's and Southern California Edison's territories — can see up to 40% flow impacts from transactions between the PacifiCorp East and West regions, he said.

However, the direction of transaction flow determines whether congestion revenue rents increase or decrease. If a transaction in PacifiCorp's region flows in the same direction as transaction constraints on CAISO's system, then congestion revenue rents will increase, Alderete said. On the other hand, if a transaction in PacifiCorp's region flows in the opposite direction as transaction constraints on CAISO's system, then rents will decrease, he said.

> **Why This Matters**
>
> CAISO has released initial findings regarding possible issues associated with a new method to calculate congestion revenues stemming from parallel flows in EDAM.

"Based on what you've seen so far, are you seeing anything that would indicate that we have a red flag that we should be looking at or reassessing anything?" WEM Governing Body member Robert Kondziolka asked at the meeting.

"No, at this time we don't see any reason to take any dramatic action to change our proposal," said Anna McKenna, CAISO vice president of market design and analysis. "But the analysis thus far does indicate and confirm some of the differences in parallel flows, and this is not a surprise."

In general, congestion across all areas is concentrated during solar hours and increases during evening peak hours in the summer, Alderete said. Transactions in CAISO's region have "de minimis" parallel flow impacts on constraints in PacifiCorp's areas, Alderete said.

The second stage of analysis will use EDAM market simulations to analyze whether problematic incentives appear in the EDAM under the new congestion revenue calculation method.

The third stage will occur after the EDAM begins in 2026 and will include analysis of actual congestion revenue allocations under parallel flows in the EDAM. ■

CAISO Board Approves 2 Key RA Program Proposals

WEIM Produces $412M in Benefits in Q3

By David Krause

CAISO's Board of Governors approved two proposals intended to improve how the ISO calculates resource adequacy values and tracks RA supply.

Some stakeholders asked the ISO to delay implementing the proposals while the California Public Utilities Commission works on similar RA updates.

The approved RA proposals are part of CAISO's Resource Adequacy Modeling and Program Design initiative, which began in 2023 to reform RA rules, requirements and processes. The ISO board approved both proposals at its Oct. 30 general session.

The first proposal — known as Track 1 — updates CAISO's default qualifying capacity (QC) and planning reserve margin calculation methods. Under existing practice, energy capacity portfolios must meet the industry standard reliability statistics of a 0.1 loss of load expectation, which is equal to one loss-of-load event every 10 years.

The new QC calculation method more accurately reflects the "reliability contribution of each resource type" and is "well suited to account for the ISO balancing authority area's diverse resource mix, historical reliability risks and anticipated future trends," CAISO Vice President of Market Design and Analysis Anna McKenna said in an Oct. 22 *memo*.

Under the new method, wind and solar resource QCs will be calculated using a resource's average effective load-carrying capability (ELCC) during net peak periods. ELCC shows the reliability contribution of a resource as a percentage of its maximum capacity. Under CAISO's existing rules, wind and solar QCs are calculated based on a resource's average monthly historic performance from noon to 6 p.m. over three years.

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For nuclear, dispatchable thermal and hydroelectric resources, the new QC calculation will be based on an unforced capacity approach, which calculates QC using historic forced outage rates during the at-risk hours for the system over the past three years. The previous QC method for these resources was based on "net dependable capacity" defined by NERC's Generating Availability Data System information (GADS).

The CPUC is also developing its own UCAP design for storage and thermal resource QC purposes, CAISO staff said in a *document*. CAISO management "remains committed to collaboration and will seek opportunities to align inputs and assumptions where appropriate," the ISO said.

The Alliance for Retail Energy Markets (AReM) wants CAISO to wait one year to implement the Track 1 proposal to allow coordination between the CPUC and the ISO, AReM representatives said in the document.

The new QC and PRM methods apply only where Local Regulatory Authorities (LRAs) have not established their own methods for CAISO's RA program. Currently, when an LRA has not defined its own QC and PRM criteria, CAISO applies a default PRM of 15% and a default QC, McKenna said in her memo.

CAISO's Department of Market Monitoring supported the Track 1 proposal but cautioned that the new QC method does not change certain aspects of existing RA calculation methods. Those methods can still "lead to capacity accounting differences across LRAs," DMM Executive Director Eric Hildebrandt said in an Oct. 22 *memo*.

There are also "several unaddressed issues" that need to be revisited for default values and modeling processes, Hildebrandt said. These include the seasonality of default values and unforced capacity, the resource adequacy availability incentive mechanism and the capacity procurement mechanism, he said in the memo.

> **Why This Matters**
>
> Some of CAISO's default RA rules have not been revisited or significantly updated for more than 20 years.

RA Data Requirements

The second RA program change, Track 3, updates RA reporting policies to require all RA-eligible capacity in CAISO's territory to submit annual and monthly reports.

The revision will improve grid reliability by giving the ISO a "more complete view of the status of all RA-eligible capacity and identifying capacity that may be available for backstop procurement," McKenna said in an Oct. 22 *memo*.

In addition to strengthening reliability, the increased data visibility can "improve policy and modeling for the CAISO system," Hildebrandt said.

"Additional visibility into RA resources internal to the CAISO balancing authority area would improve a systemwide understanding of recent trends in the capacity procurement mechanism and competitive solicitation process," Hildebrandt said.

WEIM Q3 Benefits

Separately, the Western Energy Imbalance Market produced about $412 million in benefits for market participants in Q3 2025. WEIM has produced about $7.82 billion since beginning operations in 2014.

NV Energy received the most of all participants — about $104 million for the quarter.

"These numbers are another reminder of the tremendous economic and reliability value of the Western Energy Imbalance Market," CAISO CEO Elliot Mainzer said in a *press release*. "Now, more than ever, we should be looking for ways to come together to preserve and enhance these benefits for Western electricity ratepayers." ■

FERC Approves Incentives, Tariff for SWIP-North

LS Power Successfully Argues for Previously Rejected Incentives

By Elaine Goodman

FERC has granted Great Basin Transmission's request for incentives and a transmission owner tariff for its Southwest Intertie Project-North line — rejecting arguments that the project no longer makes sense with the cancellation of the Lava Ridge wind farm.

In an Oct. 31 order (*ER25-2025*), FERC accepted Great Basin's proposed transmission owner tariff and formula rate for the project, also known as SWIP-North.

SWIP-North is a 285-mile, 500-kV line being developed by LS Power subsidiary Great Basin Transmission at an estimated cost of $1 billion. It will run from eastern Nevada near Ely to Idaho Power's Midpoint Substation near Twin Falls, providing a bi-directional energy pathway between the Desert Southwest and the Pacific Northwest.

Great Basin's transmission owner tariff includes the terms and conditions to participate as a Participating Transmission Owner (PTO) in CAISO. The PTO model allows lines outside of California to join the ISO while avoiding financial risks. (See *CAISO Wins FERC Approval for Subscriber-funded Tx Plan*.)

Great Basin said its tariff is consistent with other PTO tariffs on file at FERC, including those of affiliates DesertLink and LS Power Grid California.

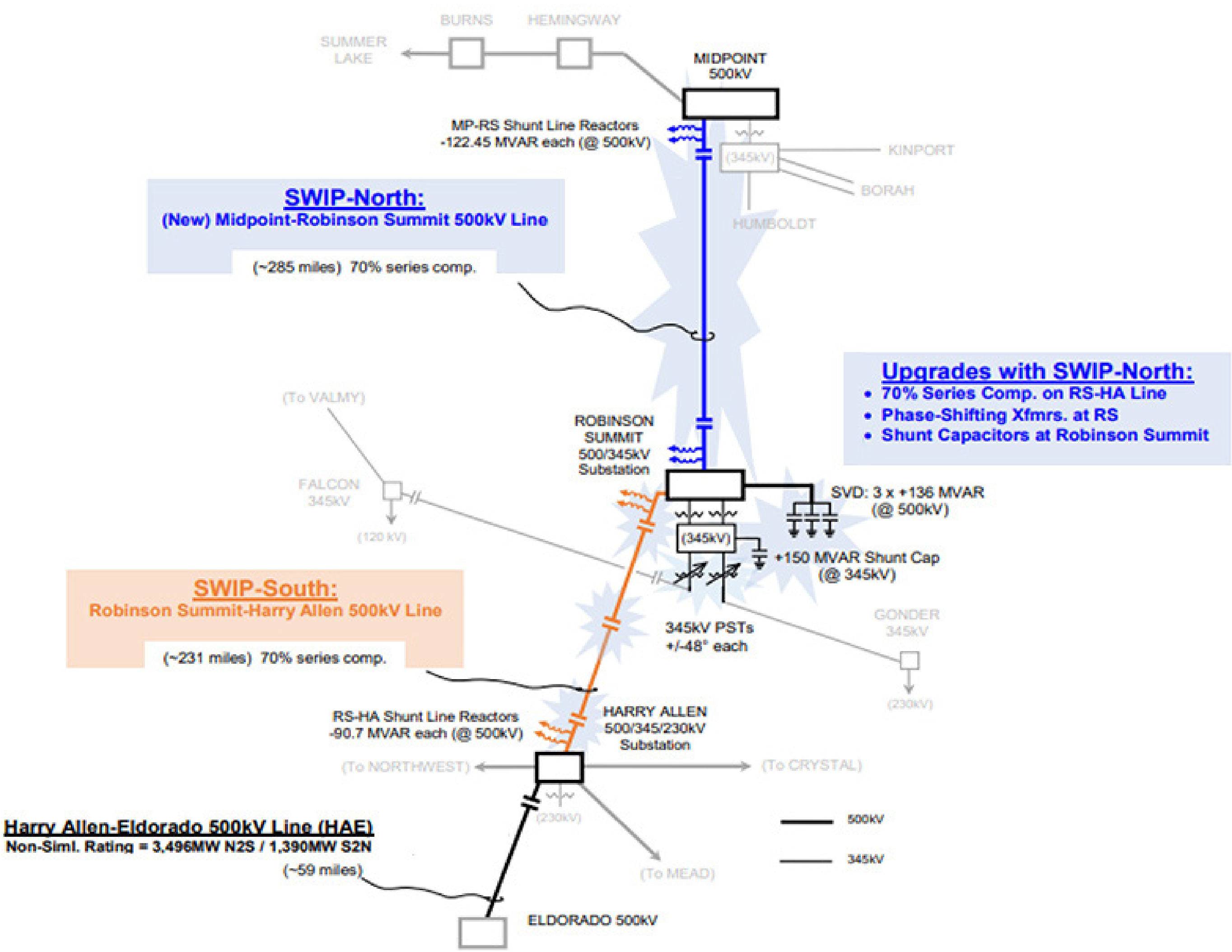
FERC also granted Great Basin's request for several transmission-development incentives.

Why This Matters

SWIP-North will allow Idaho Power, which has an ownership stake in the project, to import energy from the Desert Southwest to meet winter peak loads.

The abandoned plant incentive will allow the company to recover its costs if the project is abandoned due to events beyond its control.

In addition, the commission granted



SWIP-North is a 500-kV line that will run from eastern Nevada near Ely to Idaho Power's Midpoint Substation near Twin Falls. | *CAISO*

Great Basin's request for a regulatory asset incentive, which allows deferred recovery of prudently incurred pre-commercial costs through the creation of a regulatory asset. And FERC approved an RTO adder for SWIP-North, which will take effect when Great Basin joins CAISO and turns over operational control of the transmission line.

FERC Chair Laura Swett and Commissioner David LaCerte did not participate in the decision.

Reducing Congestion Costs

FERC's approval of the abandoned-plant and regulatory-asset incentives is a reversal from the commission's previous denial of Great Basin's request. (See *FERC Denies LS Power's Bid for SWIP-N Incentives*.)

In a Feb. 20 *order*, the commission found that the company failed to meet the criteria of FERC Order 679, which requires transmission incentive applicants to show that a project will ensure reliability or reduce costs associated with transmission congestion.

The incentive request was denied without prejudice. In its new request, filed April 23, Great Basin supplied an economic study by Hitachi Energy that showed annual congestion costs for the California-Oregon Intertie Corridor (COI corridor) would drop by about $38.6 million a year, to $156.7 million, with SWIP-North in place.

In addition, Great Basin argued, SWIP-North would give Idaho Power access to the Desert Southwest market, improving reliability during extreme cold weather events. By alleviating congestion constraints between the Pacific Northwest and Desert Southwest, the project would reduce the cost of delivered power, the company said.

And CAISO identified reliability benefits of the project, including resource diversity and the addition of a parallel path with the COI Corridor. Those could be important factors during wildfires or extreme weather.

A group called Stop Lava Ridge argued that recent policy changes reduce the chances of the development of the 1,000 MW of Idaho wind that Great Basin relies on in its application. The group noted the Department of the Interior's cancellation Aug. 5 of the 1,000-MW Lava Ridge wind project. (See *Interior Reverses Approval of Lava Ridge Wind Project*.)

But Great Basin responded that SWIP-North's congestion relief benefits are not tied to Lava Ridge wind.

"Whether the source is from nuclear generation, gas generation, hydro generation, geothermal generation or other nonwind resources, and regardless of the state of origin (i.e., Idaho, Oregon, Wyoming, Washington, etc.) of such generation, the addition of SWIP-North would still provide COI congestion relief benefits," Jinxiang Zhu of Hitachi Energy said in a filing.

In fact, SWIP-North would relieve even more congestion without Idaho wind generation, Zhu said, reducing congestion costs by $47.2 million and further reducing the number of COI corridor congestion hours. ■

ISO-NE Talks Order 2023 Updates at NEPOOL Transmission Committee

By Jon Lamson

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Proposed tariff changes, intended to update how ISO-NE assigns capacity rights to resources not subject to its interconnection processes, were introduced at the NEPOOL Transmission Committee meeting Oct. 28.

Alex Rost, director of transmission services, said ISO-NE proposes to "formalize the concept of equivalent capacity network resource capability (CNRC) and address how equivalent CNRC is established, managed and reduced."

CNRC values define the capacity interconnection rights of resources that are subject to ISO-NE's interconnection procedures. Before FERC Order 2023, resources established CNRC by obtaining capacity supply obligations (CSOs). In the new interconnection framework, those resources gain CIRs via the cluster study processes.

The Order 2023 changes have created a need "to clarify how equivalent CNRC is assigned, managed and reduced" under the new interconnection framework, Rost said.

Resources not subject to the RTO's interconnection procedures that could receive equivalent CNRC values include those connected to the distribution system, aggregations of distributed resources and active demand resources, he noted.

"For consistency with resources subject to the ISO interconnection procedures, the process to establish equivalent CNRC … should be supported by clear and trackable commitments related to a resource achieving commercial operation," Rost said.

To establish equivalent CNRC, resources would need to prove their deliverability in an "all-or-nothing deliverability analysis screen," which would be coordinated with the similar deliverability analyses performed in ISO-NE interconnection cluster studies.

Deliverability analyses for resources seeking equivalent CNRC would be performed "right after the conclusion of a cluster study" and would be adjusted "as needed" following cluster restudies, Rost said.

After proving deliverability, resources could achieve equivalent CNRC by obtaining a CSO or by "locking-in" equivalent CNRC prior to participating in a capacity auction, Rost said.

The rules for the CSO pathway to achieving equivalent CNRC would be "very similar to the pre-Order No. 2023 approach used to establish CNRC," Rost noted. CNRC values would "equal the highest amount of CSO obtained in a capacity market activity," with seasonal adjustments to account for varying winter or summer capabilities.

To achieve equivalent CNRC prior to auction participation, developers would need a commercial operations date within the following two years and would need to demonstrate adequate financial commitment to the resource.

For resources following this path, ISO-NE would rely on winter and summer qualified capacity estimates "consistent with capacity market qualification."

"'Locked-in' equivalent CNRC must be assigned to a specific project and will be withdrawn if the specific project has its interconnection agreement (or equivalent) terminated or fails to achieve commercial operation within two years from the date that equivalent CNRC is requested," Rost said.

ISO-NE plans to maintain its existing methods for reducing or retiring equivalent CNRC; resources could request deactivation or would be automatically retired if they are inactive for three years.

Rost said the RTO plans to implement the changes prior to the 2026 interim Reconfiguration Auction qualification process. ISO-NE will discuss the proposal with stakeholders in the coming months and is targeting a TC vote in January. ■

MISO Members Grapple with Large Load Implications

By Amanda Durish Cook

MISO members debated how their system could change under the weight of large load additions and scheduled a future discussion in front of the RTO's board of directors.

MISO Advisory Committee members considered the co-location of large loads at generating facilities at their Oct. 28 teleconference and planned a discussion slot on large loads at the Dec. 10 meeting held in front of the MISO Board of Directors.

Union of Concerned Scientists' Sam Gomberg said there's a "timing mismatch" between the rapid development of data centers and the slower-moving processes to "responsibly" get generation and transmission online. On top of that, Gomberg said vacillating federal policy is worsening uncertainty in planning for rising demand.

"People know they should be running, but they're not exactly sure which direction to be running in," Gomberg said.

Clean Grid Alliance Executive Director Beth Soholt said in MISO, load forecasts, generation planning, interconnection queues and transmission planning "aren't totally synced up." Soholt added there's an "opaqueness" regarding how much large load customers are required to pay, with each state outlining its own cost responsibilities.

Illinois Commerce Commissioner Michael Carrigan joked that no one can get through a day without debating "AI, data centers, shifting load or increasing load from manufacturing." He said he's particularly concerned about an undersized grid expansion.

"We're going to grow into practically anything you build," Carrigan said.

But Kavita Maini, representing MISO industrial customers, asked what would happen to all newly built generation if AI processing became more efficient and didn't need as much generation as anticipated.

"In my head, that's one of the biggest challenges," Maini said.

Maini said large loads should cover the costs they incur. Gomberg agreed he was concerned consumers could end up financing grid upgrades through increased power bills.

"The minute we start talking about subsidies and discounts, the whole system becomes inefficient," Maini said.

Wisconsin Public Service Commissioner Marcus Hawkins said the timing of when cost recovery begins on large loads is vital because existing customers typically are the only ones paying leading up to energizing the large load facility.

Gomberg said it's probably worth it for MISO to expand participation rules for energy storage and hybrid resources to get online quickly and reliably handle new load. He said storage can absorb or transmit power in a "matter of milliseconds" to keep load and energy balanced.

The MISO Advisory Committee meets in September 2025 in Detroit. | *© RTO Insider*

Why This Matters

MISO members are apprehensive over who ultimately incurs costs when data centers and large load customers need grid expansion.

Gomberg and Soholt said it's probably time to dust off NextEra Energy's 2024 proposal that MISO create a dedicated study and registration process for new generation contingent on large loads. (See "NextEra Makes 2nd Overture for Bundled Studies," *MISO Previews Future Projects to Improve System Planning*.)

Soholt called for more consolidated planning across MISO in general that ties together load estimates, annual and long-term transmission planning, and the interconnection queue and associated fast lane.

"We still have very siloed planning," Soholt said.

Gomberg said he is "very curious" what happens when concentrated large loads cause congestion issues on the MISO system. Xcel Energy's Susan Rossi, representing MISO Transmission Owners, said she likewise has questions around the potential for added reliability costs and uplift payments that could be induced by large loads.

John Wolfram, also representing MISO TOs, said he wondered what ensues when a co-located power plant goes offline but the large load it was built to serve tries to keep humming. Wolfram said that kind of "post-contingency thinking" could be helpful.

NextEra Energy's Erin Murphy said members' conversations are especially germane since the Department of Energy recently directed FERC to initiate a rulemaking to speed up the interconnection of large load additions, including data centers and manufacturing facilities. Also, FERC in 2024 initiated proceedings to explore the upshots of co-locating large loads near generating facilities (AD24-11). ■

J.H. Campbell Tab Rises to $80M on DOE's Stay Open Orders

By Amanda Durish Cook

The J.H. Campbell coal plant in Michigan has racked up $80 million in net costs since late May to stay online, per emergency orders from the U.S. Department of Energy.

Plant owner Consumers Energy reported in an Oct. 30 *filing* to the U.S. Securities and Exchange Commission that from May 23 through Sept. 30, the costs of keeping the 1,420-MW plant online were about $164 million, with the utility offsetting $84 million with revenue from selling the plant's output in the MISO markets.

J.H. Campell now costs more than $615,000 per day to operate since DOE issued its first emergency order to prevent the plant's retirement as scheduled May 31. The plant now is operating under a second emergency order that expires Nov. 19. (See *DOE Orders Mich. Coal Plant to Remain Available Another 90 Days*.)

Consumers Energy divided the costs of running the plant into the two timespans of the emergency orders. From May 20 to Aug. 20, costs swelled to $120 million, with $67 million in revenues, leaving $53 million to be paid. From Aug. 21 through Sept. 30, costs reached $44 million, with power sales covering $17 million, leaving $27 million unpaid.

Consumers Energy will detail the remaining costs associated with the second DOE order in its next quarterly filing, due to the SEC in late January 2026.

The Bottom Line

Consumers Energy's latest filing to the U.S. Securities and Exchange Commission shows the coal plant cost $164 million to run in a little more than four months and made $84 million selling its output to MISO. That leaves an $80 million bill for ratepayers across MISO Midwest.

Earthjustice senior attorney Michael Lenoff said DOE's orders that the Campbell plant remain accessible are "extremely expensive."

Earthjustice, the Sierra Club, Michigan Attorney General Dana Nessel and others are suing DOE, arguing separately that ratepayers are unfairly expected to pay for the plant's expenses. (See *Opponents Take DOE to Court over J.H. Campbell Retirement Delay*.)

"Forcing this unnecessary coal plant to keep operating is bilking consumers for the benefit of the coal industry. Earthjustice is in court now to stop the administration from harming consumers, trampling markets and unlawfully usurping the authority of states and regulators to make decisions in the public interest," Lenoff said in a statement.

Numbers from EPA's Clean Air Markets Program Data show that J.H. Campbell's three units were not consistently generating from July to September, when Unit 1 did not produce power on 25 of the 92 days; Unit 2 was dormant 74 of 92 days; and Unit 3 did not produce power 29 of 92 days.

Several organizations continue to argue that DOE's pair of orders remain unnecessary.

In a September rehearing request challenging the second DOE order, Earthjustice and several other public interest groups argued that even on June 23, MISO's tightest reserve margin day of the summer, the RTO had 3.3 GW of offers above what it needed to meet its 119-GW peak demand, with an additional 7 GW of emergency headroom from resources on standby. The groups argued that the "primary actors in the electric industry already protect resource adequacy without intrusion" from DOE (*202-25-7*).

The cost of operating the plant is set to be paid by ratepayers across MISO Midwest. (See *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States*.)

Minnesota Public Utilities Commissioner Joseph Sullivan said DOE is infringing on state jurisdiction by ordering the plant to be kept online in rolling, 90-day increments. Sullivan told the MISO Board of Directors Sept. 18 that Consumers Energy, the state of Michigan, MISO and the MISO Independent Market Monitor all agree that J.H. Campbell was "properly planned for retirement and not needed for reliability."

Consumers Energy's J.H. Campbell coal plant | *Consumers Energy*

DOE claims it's directing not states but MISO and FERC to keep the plant open. Sullivan said DOE relied on MISO's previous warnings that resource adequacy was in peril despite the 2025/26 capacity auction clearing sufficient resources.

"We need to be careful with our narrative," Sullivan said. He warned MISO against assuming retiring generation won't be replaced or presuming that new load would be brought onto the system without the resources to support it.

The Michigan Public Service Commission in late August accepted annual capacity demonstrations from Michigan's electric utilities, indicating that each has enough capacity to meet customer needs four years into the future (*U-21775*). ■

MISO Predicts 103-GW Peak for Winter

By Amanda Durish Cook

MISO said even a 109-GW peak this winter shouldn't prove problematic, though the RTO said a more probable scenario would deliver a 103-GW peak in January.

MISO's coincident peak forecast from members estimates a 102.6-GW winter peak in January. However, MISO said there's potential for a 108.9-GW peak using a non-coincident peak forecast.

MISO attracted 123.1 GW worth of offers in its winter capacity auction, with 120.2 GW ultimately clearing. The grid operator also has about 11 GW in load-modifying resources that can assist in an emergency during the season.

At an Oct. 29 Winter Readiness Workshop, MISO Senior Resource Adequacy Engineer Gurman Kaur said MISO believes it has more than enough supply to get through the winter.

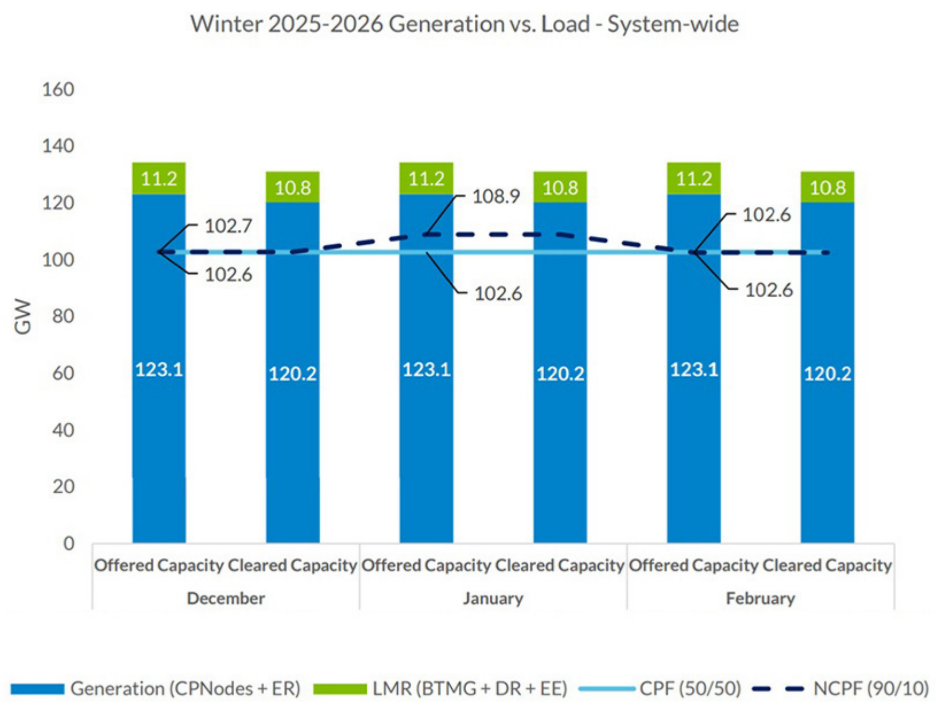
However, MISO Director of Operations Risk Management Jason Howard said ongoing fleet change coupled with increasing demand and extreme weather could make for thorny operations.

"The combination of load growth, resource flexibility needs during the riskiest times of the day and the ever-present possibility of larger winter storms is our new reality," Howard said in a press release. "In response to this complex risk environment, MISO is enhancing our forecasting capabilities, dynamic reserves and outage coordination processes to ensure MISO maintains reliability for the 45 million people we serve."

Howard said MISO would rely on its Forward Reliability Assessment and Commitment system tool, which looks six days ahead to make unit commitments, and would issue grid notices and warnings days in advance when it notices reserves are poised to shrink.

MISO reminded stakeholders that it and its members "reliably and efficiently navigated several significant weather events last winter," including an arctic 6.5-degrees Fahrenheit average footprint-wide temperature Jan. 20-22, that sent systemwide peak demand shooting to 108 GW, with a record-high 33 GW of that from MISO South. (See *MISO South Hit Record, 33-GW Winter Peak in Jan. Storm*.)

MISO Manager of Operations Risk Assessment Matthew Campbell said during last winter's trio of storms, MISO maintained consistent communications with members, conducted daily risk assessments and produced net uncertainty forecasts to guide unit commitments.



MISO wintertime generation supply versus monthly peak load estimates for winter 2025/26 | *MISO*

What's Next

MISO said its grid is primed for either a 103-GW peak or a less probable 109-GW peak this winter, which could deliver repeat blasts of cold in the footprint by way of a weaker La Niña weather pattern.

Campbell noted that the U.S. Energy Information Administration expects coal inventories at power plants to be lower than last winter and "on the lower end of the five-year average." He likewise said natural gas storage is projected to be lower than a five-year average every month of winter.

MISO said winter 2024/25 — which was colder than usual due to periods of "durable" cold air — is the top comparison to draw on to predict winter 2025/26.

Ella Dankanics, a senior at Purdue University and a meteorological risk analyst for MISO, said the National Oceanic and Atmospheric Administration expects equal chances for MISO Midwest to have a colder- or warmer-than-normal winter. MISO interprets the equal opportunity could mean temperature swings.

Dankanics said warm and cold air could "battle" throughout the season, bringing a greater risk of equipment icing.

NOAA, meanwhile, anticipates above normal temperatures in MISO South. The agency also predicts active storm patterns and higher-than-average precipitation in the Great Lakes region with a drier season near the Gulf of Mexico.

Dankanics said there's potential for a weaker La Niña weather pattern this winter that creates more opportunities for deep freezes, reinforced by weaker stratospheric winds.

Dankanics said in historical winters with a weak La Niña trend, MISO's systemwide peak load consistently reached the 95th percentile, or about 97 GW. ■

MISO Requests Nearly $450M Budget for 2026

By Amanda Durish Cook

The Bottom Line

MISO's annual budgets have climbed from almost $300 million in 2017 to nearly $450 million for 2026.

DETROIT — MISO said its 2026 budget requires an increase of more than 11% over 2025's.

MISO plans to allot itself $448.4 million in operating expenses and project investments in 2026, *up* 11.2% from 2025's $403.3 million budget, CFO Melissa Brown told the Board of Directors' Audit and Finance Committee on Oct. 29.

The RTO said it would increase its administrative fee from 51 cents/MWh in 2025 to 54 cents/MWh in 2026.

Brown told the committee that modern systems are more expensive to implement and maintain, and MISO needs to spend more to complete the switch from its legacy software to newer technology.

"That's kind of the balancing act we're in right now," Brown said.

The committee voted unanimously to recommend the budget. The full board will vote on whether to approve the draft 2026 spending amounts at its year-end meeting Dec. 11 in Indianapolis.

Brown said the budget may be reduced by that time, with MISO shedding about $2 million to $3 million in project investments.

MISO now experiences more volatility in its financial estimates for its major projects, Brown said, including evolving design work on new initiatives such as planning for large loads, rolling out ambient-adjusted ratings for transmission lines, working on the interconnection queue fast lane and getting the regular queue down to a single-year process.

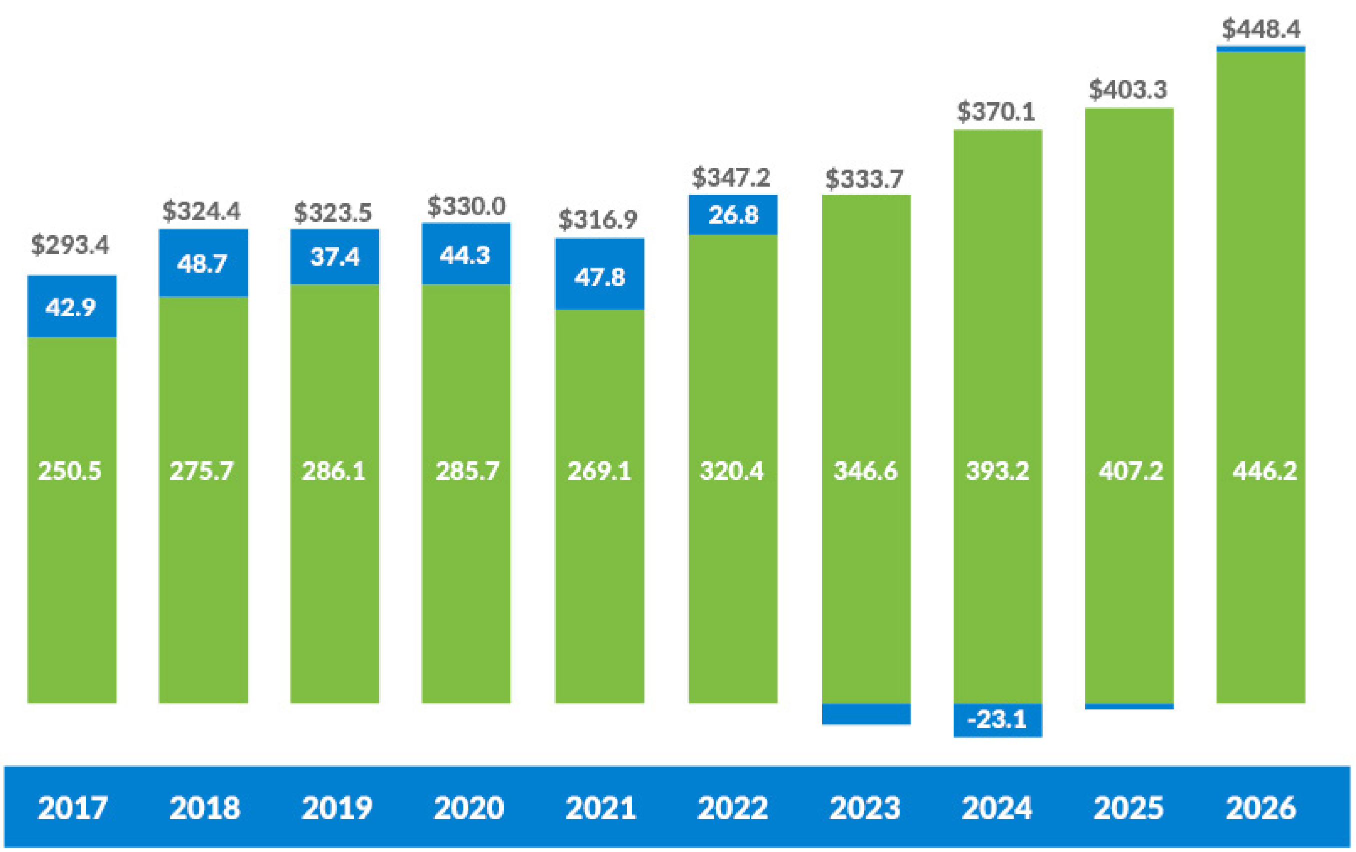
The RTO also plans to hire 28 staff members for new positions in 2026, spread across operations, planning and cybersecurity.

Brown said MISO's capital investments will jump to $32.4 million in 2026 — up $2 million — mainly from an upgrade to its headquarters-based control room in Carmel, Ind. Brown said the control room hasn't had an overhaul since its inception.

"To say that it is overdue is probably an understatement," Brown said during MISO's last Board Week in Detroit in September.

The stakeholder-led Finance Subcommittee has endorsed the budget.

"MISO has taken a conversative approach with the budget and not yet factored potential load growth from data centers and other new load activity, which could reduce MISO rates," subcommittee Chair Mitch Myhre, of Alliant Energy, said of the RTO's 2026 financial plans at the Advisory Committee's meeting Oct. 28. If MISO collects more from members because of more load being served, it could lower the rate it charges members. But Myhre said the "dynamic environment" today means no one quite knows how much load upsurge to expect. ■



MISO annual expenses since 2017 | *MISO*

MISO Advisory Committee Switches Leadership After Freeman Exit

By Amanda Durish Cook

MISO's Advisory Committee will continue to be led by its vice chair through the end of 2025 after the departure of Sarah Freeman from Indiana's regulatory agency.

At an Oct. 28 meeting, acting chair and vice chair Brian Drumm, of ITC, agreed to helm the Advisory Committee's remaining meeting during MISO's quarterly Board Week in early December in Indianapolis.

Former Advisory Committee chair Freeman *exited* the Indiana Utility Regulatory Commission — and thus MISO — Oct. 10 to join the Regulatory Assistance Project (RAP), a global nongovernmental organization that helps policymakers tackle the clean energy transition. Freeman concluded 28 years of service to the state of Indiana to become a principal with RAP.

Chris Norton, of MISO's Transmission-Dependent Utilities sector, proposed Drumm's extension as acting chair. No committee member objected. Drumm previously led the Sept. 17 Advisory Committee meeting in Detroit as part of MISO Board Week.

Former Indiana Utility Regulatory Commissioner Sarah Freeman listens as she presides over a MISO Advisory Committee meeting in March. | © *RTO Insider*

At the Organization of MISO States' annual meeting Oct. 21, OMS President and Minnesota Public Utilities Commissioner Joseph Sullivan said he would miss Freeman and her ability to work toward a goal and "ride over" noise in the industry. He said Freeman was one of the most active listeners he's ever encountered and that he viewed her as a mentor through her demeanor and conduct.

MISO's Advisory Committee is pulling together a committee of its members to consider nominations and select new leadership in 2026.

OMS intends to nominate Michigan Public Service Commission Chair Dan Scripps for committee consideration as the next Advisory Committee chair. Sullivan said Scripps is "well suited to be a neutral voice" and potentially replace Freeman's leadership on the Advisory Committee.

Separately, IURC Chairman Jim Huston took over Freeman's representation on OMS until his retirement in early 2026. Huston plans to step down from the commission sometime in January, retiring after more than a decade on the job. ■

Wanted: N.Y. Community Eager to Host Nuclear Reactor

New York Power Authority Seeking Partners for Advanced Nuclear Build

By John Cropley

Here's something you don't see every day: a state asking communities to raise their hand and explain why they should be the site of a next-generation nuclear reactor.

The New York Power Authority has begun to *sound out developers* on how they would go about building a gigawatt or more of advanced nuclear generating capacity and *sound out communities* on why they would be the right place to do it.

The requests for information NYPA issued Oct. 30 will not result in a contract award or siting designation, but they will help shape the process by which those decisions are made.

Faced with the prospect of increasing power demand in New York state, the statutory requirement to reduce emissions and the slow pace of renewable energy development, Gov. Kathy Hochul (D) in June ordered NYPA to develop at least 1 GW of advanced nuclear capacity. (See *N.Y. Pursuing Development of 1-GW Advanced Nuclear Facility*.)

Caveats: It must be sited in a community that welcomes it and must be developed in partnership with the private sector.

So NYPA is looking for a site and is trying to line up potential private-sector partners with a track record of developing, constructing, operating and/or servicing nuclear energy facilities.

It defines advanced nuclear as large-scale or small modular reactors employing Gen III+ or Gen IV technologies. Microreactors are not under consideration.

NYPA requires that the project start construction before 2033 and enter operation by 2040.

NYPA is steering clear of first-of-a-kind projects, which can carry elevated risk of delay, technical hurdles and cost overrun, but it is not being strict about this — it asks merely that the first concrete have been poured for at least one similar project somewhere else in North America by early 2030.

Host Community

The host communities RFI defines "community" as anything from a village to a county to a multicounty region.

New York City, Long Island and all but one Hudson Valley county are excluded from consideration — NYPA is looking toward the less densely populated parts of upstate, and away from the crowded downstate areas where many viewed the now-closed Indian Point nuclear plant unfavorably.

Constellation Energy's FitzPatrick and Nine Mile Point nuclear plants in Oswego County, N.Y. | *Constellation Energy*

> **Why This Matters**
>
> New York is laying the groundwork for a public-private partnership on nuclear reactor construction.

NYPA seeks a site that has a clear path toward construction of nuclear generation, is large enough, has water access, is protected from hazards and has demonstrated support from key stakeholders within the community.

Respondents should describe their community's high-level vision for nuclear and how it would advance the community's goals.

NYPA wants to know about factors including the area workforce and workforce development programs; local supply chain; supportive institutions such as labor unions and community leaders; infrastructure; power-intensive industries the community hosts or is trying to attract; framework for local approvals; and development incentives that would attract and retain nuclear supply chain businesses.

Also important are details such as interconnection potential, transportation access suitable for heavy cargo, environmental issues and any efforts taken to gauge popular support.

Interest has been expressed already. *Officials in Oswego County*, home to three of the state's four operating commercial reactors, say additional reactors would be a nice fit there. Many in the *lakeside city of Dunkirk*, which suffered economically with the shutdown of NRG Energy's coal-fired power plant, are *lobbying for that site* to host the state's next reactor.

Development Partner

In the RFI issued to developers, NYPA seeks details about the technology they would use, siting considerations, cost and timeline assumptions, and potential ownership/partnership structures they see with NYPA.

And of course NYPA is looking for a demonstrated credible path to adding at least 1 GW of fission generation to New York's grid as soon as possible.

NYPA asks respondents what experience they have with nuclear or other large-scale capital project construction and operation, details about those projects, their track record in securing state and federal funding, partnerships they would develop, what manufacturer and technology they would use in New York, supply chain considerations, fuel and waste management, design modularity and anticipated challenges.

NYPA also wants to know which site the respondents would propose for their project or know how they would identify a site if they have not already.

And it asks some questions that point to the central challenges of nuclear power development: describe your licensing strategy; provide your anticipated timeline up to commercial operation date; detail high-level levelized cost of electricity and overnight costs assumption; and give a directional level of maturity on those cost and time estimates, and on the assumptions underlying them.

Then there are the questions of equity, which New York retains as a guiding principle: Discuss your approach to workforce development; highlight your partnerships with labor unions and community organizations; and describe how your strategy supports job quality, equitable access for workers from disadvantaged communities and a skilled regional workforce.

The response deadline for both RFIs is Dec. 11. Participation is not a prerequisite for consideration in the future solicitation process.

Underlying Need

New York is likely to miss its statutory goal of 70% renewable energy in 2030, perhaps by a wide margin. As of 2023, its power mix was only 23.2% renewables, and increasing that percentage is only going to get more difficult during Trump 2.0.

Meanwhile, the existing fossil generation is aging, and new fossil generation may be needed to replace it if emissions-free resources cannot be brought online in time. So the state has embraced nuclear as a firm resource to complement intermittent wind and solar.

New York's four commercial reactors are a crucial piece of the state energy portfolio, providing 22.2% of the electricity generated in the state in 2023 and nearly half of its emissions-free electricity. Despite their age, they are running at a capacity factor in the mid-90% range.

They have received $3.69 billion in the first seven years of New York's zero emissions credit program, begun in 2017 to prevent their retirement for economic reasons.

The state is considering extending the ZEC program to 2049 to prevent retirement of the three oldest reactors, which began operating in 1960, 1970 and 1975 and are coming up on license renewals. (See *N.Y. Makes Case for Extending Nuclear Subsidies to 2049*.)

All four reactors are owned by Constellation Energy. In January, New York state joined Constellation in a proposal for a federal grant to support Constellation's early site permit request for one or more advanced nuclear reactors to be co-located with two of the existing reactors in Oswego County. ■

NYISO Management Committee Passes Comprehensive Reliability Plan

By Vincent Gabrielle

The NYISO Management Committee voted to approve the ISO's 2025-2034 Comprehensive Reliability Plan, though stakeholders and the Market Monitoring Unit again voiced concerns with how it is structuring its planning.

The Natural Resources Defense Council voted against the plan at the committee's meeting Oct. 29, while Energy Spectrum, the New York Utility Intervention Unit, Multiple Intervenors and New York City abstained.

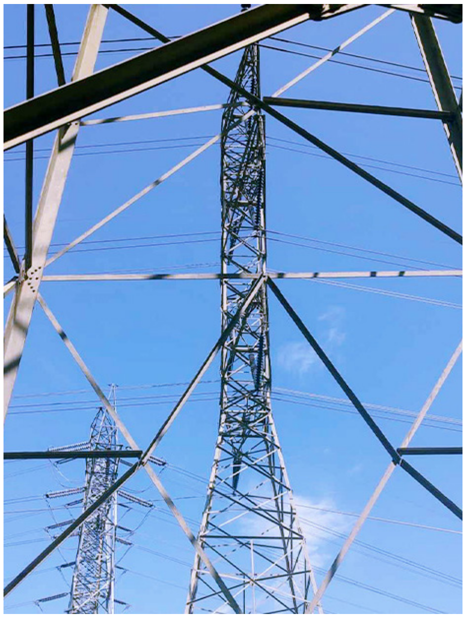
The biennial CRP looks ahead 10 years to plan for long-term reliability. The latest plan did not identify a specific actionable reliability need but said that "New York's electrical system faces an era of profound reliability challenges" and called for several thousand megawatts of additional dispatchable generation. (See *NYISO Reliability Plan Calls for 'New Dispatchable Generation'*.)

It calls for looking at a wider range of scenarios for transmission planning and relying less on emergency measures for maintaining resource adequacy. Ross Altman, senior manager of reliability planning for NYISO, said implementing the plan could require manual and tariff changes.

"You want to consider a range of potential forecasts coupled with your ability to go ahead and procure through solicitation resources to meet whatever potential gap is in necessary resources," said Howard Fromer, director of regulatory affairs for Bayonne Energy Center. "What do you propose to do about aligning our markets so that they are going out and procuring resources that are consistent with your reliability needs through your planning process?"

"I don't have anything for you today because this is the beginning of the road," Altman said. "What we actually plan for requires additional conversations in the next months."

Altman said staff took Fromer's point very seriously and that aligning markets with reliability planning was something the ISO was actively working on.



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"My expectation is that you would want to conduct the [upcoming] Reliability Needs Assessment [RNA] with the new structure," said Doreen Saia, chair of the energy and natural resources practice for Greenberg Traurig. She said this would require very fast action from NYISO and its stakeholder committees and asked the ISO to create a public schedule quickly. "Transparency is important. Notice is important."

Zach Smith, NYISO vice president of system and resource planning, thanked Saia for pointing this out but cautioned that the ISO was not sure that tariff revisions were needed. If they were, the ISO would need to be mindful of the tight timeline to get revisions filed before the next RNA.

"I want to push back on the idea that we can commence the RNA without understanding how NYISO is going to determine actionable reliability," the NRDC's Chris Casey said. "The assumption that the ISO is planning to use different scenarios gets colored differently if those scenarios are informational *versus* actionable."

"I actually fully agree with you," Altman replied. He said the broad range of scenarios the ISO had previously shown was intended to illustrate what it had to account for. "The actual implementation of that, and the assumptions that will go into the RNA, will be very detailed."

Casey pointed to a graph in the CRP that showed the state hitting a 4,000-MW shortfall and compared it to a more detailed slice of the same data. He said the ISO was overemphasizing the worst-case scenarios and that those scenarios did not have a sufficient basis to justify centering them.

Altman said these weren't actually the worst cases and that staff actually excluded several outliers that assumed nuclear plants would not get relicensed. As the process continued, stakeholder feedback would be used to "find the balance."

A representative from Earthjustice said that amid all the discussion of schedules and changes to the markets, they had not heard any evidence from NYISO that the changes it was presenting were necessary. They asked if the ISO had called in independent consultants to look at the changes to the reliability planning process to see if they made sense.

"I would strongly encourage the consideration of this before there's this dramatic shift in the way the markets are planned and the way that reliability planning occurs," they said.

The MMU said it was concerned that there is a growing gap between planning and the markets.

"We've been seeing that open up in the past couple of years, and I think it's a concern because it's going to provide the wrong incentive," said Pallas LeeVanSchaick, vice president of Potomac Economics. He said that gap undermines the market's ability to maintain reliability. It could also result in the ISO keeping more capacity than is needed to meet the needs of the system.

The CRP now goes before the Board of Directors, which is expected to pass it before the end of November. Discussions over the proposed planning process changes would then begin in December. ■

Nvidia, Emerald AI, EPRI and PJM Announce Flexible Data Center Project

By James Downing

The artificial intelligence industry and power industry are working together to develop the first "power-flexible AI factory" at a 96-MW facility in Manassas, Va.

Nvidia, Emerald AI, the Electric Power Research Institute, Digital Realty and PJM are working to test the flexible capabilities of the Aurora AI Factory, which was designed from the bottom up to provide services to the grid. The power-flexible design, if adopted across the country, could unlock 100 GW of capacity on the grid, based on a study from Duke University. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

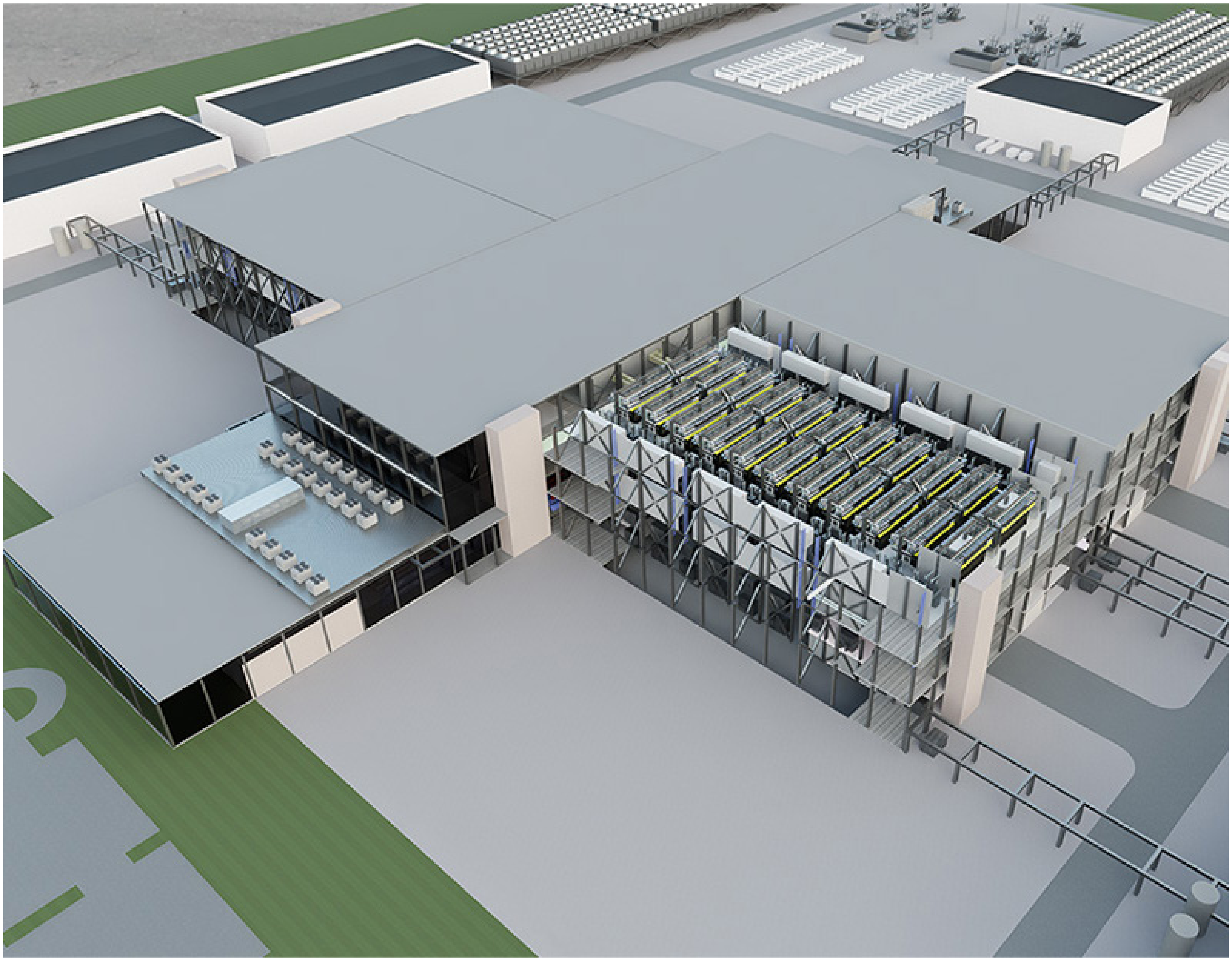
Why This Matters

The Aurora AI Factory is being designed with flexibility in mind, which could help data centers get to market much sooner than waiting for the grid to be expanded so they can get 24/7 service.

Emerald is a startup that has been working on the data center flexibility project with Nvidia, the largest company by market capitalization in the world because of its advanced chips that have fueled the rise of AI. The project is meant to help show the system can work, which would increase speed to market for data centers and take pressure off the grid, Emerald Chief Scientist Ayse Coskun said in an interview.

"AI data centers are facing a lot of wait time," Coskun said. "In Virginia, we hear about five- to seven-year wait times for data centers to get connected."

Load flexibility on the part of data centers means they can plug into the grid much



A digital rendering of the Aurora AI Factory from Nvidia | *Nvidia* more quickly because they can get offline when the system is stressed.

Nvidia not only provides the chips, but it also offers control services for the project. EPRI is involved with its "DCFlex Initiative," and the data center will bid services into PJM's wholesale markets. (See *EPRI Launches DCFlex Initiative to Help Integrate Data Centers onto the Grid*.)

Data centers have varying levels of flexibility, from little to none at customer-facing facilities that make up the bulk of the facilities in Northern Virginia's Data Center Alley, to cryptomining facilities that fall off the grid as soon as prices make their production unprofitable. AI data centers can be somewhere in the middle.

"A key ingredient in our technology is to make sure we meet these quality-of-service or priority constraints of customers," Coskun said. "Some AI workloads fall into this category of being urgent and therefore not being flexible, but there's a lot of other AI workloads."

Some of the computing processes can be slowed down or delayed for the few hours at a time when the grid would need to count on demand response from data centers, she added.

"Overall, when you look into the performance impact for this kind of actions, it's minuscule," Coskun said. "And in some cases, it's not even noticeable."

With ample benefits from speed-to-market concerns and little impact on AI data centers' operations, flexibility makes sense, but it is still early days of the concept for the customer class.

"Emerald AI is positioning itself to be this interface layer between the data centers and the power grid," Coskun said. "Traditionally, there wasn't a ton of communication between the power grids and the data centers, but as we design our data centers in a smarter and more flexible way, we believe there's going to be this communication and programs may evolve. … There's a ton of mechanisms that are existing in power markets that are not heavily used by data centers."

The exciting thing about the Aurora facility is that it is being developed from the ground up for flexibility, which is normally an afterthought for data centers, EPRI Emerging Technologies Executive Anuja Ratnayake said in an interview.

EPRI's DCFlex initiative was started to help the power industry meet the fast-growing demand for electricity from their expansion. The program is also working on real-world demonstrations at data centers in North Carolina and Arizona, the latter of which also includes Emerald.

"The major challenge for the industry is powering the data centers that are coming up at the moment, and the challenge comes from the scale and the pace of the growth in the data center sector," Ratnayake said. "For the last 20-plus years … data centers grew up for enterprise purposes and for social media purposes and then for cloud purposes. What we are seeing happening in the last about two years is there is sort of a new type of a data center, which is what Nvidia is terming the AI factories."

Data centers used to be five or 10 MW on the large side, but now with AI's need for computing power and the energy to run all those Nvidia chips, it is seeing requests for 500 MW or even 1 GW, which is the size of a major city, she said.

"Think about the grid that is planned around these little loads that come together in the form of a city versus a single point in the grid that represents that same load," Ratnayake said. "That's new, and what that means … is the grid has to do a whole host of new investments, both potentially on the generation side and on the grid side."

It can take up to a decade or more to build new generation and wires, but the data centers want to connect in a year or two, she noted. If data centers can respond and cut the amount of energy pulled from the grid, they can get connected while the grid is being expanded.

"This is that seven- to 10-plus-year period," Ratnayake said. "During that period, if you're able to be flexible, we can potentially connect you faster. That's where the flexibility piece becomes important."

One of the questions EPRI is studying is how much flexibility data centers might continue to provide to the grid once it has been expanded.

"It will be tied closer to business models more than really the technology viability," Ratnayake said. "The technology viability will exist forever, but it will be up to the data center operators to really embrace which business model makes the best sense." ■

PJM Asks FERC to Deny Demand Response Metering Data Complaint

By James Downing

PJM told FERC that a complaint seeking to use statistics to estimate customers' demand response when accessing meter data is not practical (*EL26-4*).

Curtailment service providers Voltus and Mission:data filed the complaint against PJM, but the issues are all tied to state regulators — or relevant electric retail regulatory authorities (RERRAs) — who have the authority over end-use customers' smart meters and the data they use, the RTO told FERC on Oct. 28.

"There is considerable history behind why RERRAs put limitations on the release of customer data without customer consent, and those restrictions are embedded in many cases in state law or state regulations as a consumer protection measure given widespread evidence of the misuse of customer data," PJM said. "Complainants ask this commission to circumvent all of those state laws and regulations by instead amending PJM's tariff to decrease the accuracy associated with the accounting of and compensation for residential customer demand response data."

Fixing the state-level issue through a degradation of the information PJM gets on DR shows that FERC is not the proper venue to deal with the issue, the RTO argued, especially as Voltus and Mission:data have not exhausted the options available to them in state regulatory proceedings.

"The complainants effectively ask this commission to circumvent the states' jurisdiction over retail data access issues by requiring PJM to allow for less accurate data for interval metered residential demand response customers without even showing any attempt to work with the RERRAs on this issue," the RTO told FERC.

FERC examined the issue in 2023, when it rejected a similar complaint from CPower over lack of evidence that customer data were not widely available. Voltus and Mission:data offered some specific information on how difficult it was to get data from mass market customers at specific utilities. (See *Voltus, Mission:data Seek Changes to PJM Data Requirements for DR*.) PJM rules require actual meter data in all cases except when a residential customer does not have an installed interval meter.

"For residential customers that do not already have interval meters installed to measure their actual use as it changes by interval, the CSP may rely on a statistical estimate derived from sampling the usage of customers that do have interval metering," PJM said. "This reduces the barriers to entry for such residential customers to participate as demand response in PJM's markets, as it allows CSPs to facilitate their participation while only incurring the cost of installing interval meters for a representative sample of residential customers without interval metering."

None of the evidence offered about difficulties at specific utilities shows that Voltus and Mission:data tried to get rules changed in state proceedings, PJM said. It is also unclear how the RTO could enforce the standard that statistical modeling is allowed when metering data is difficult to obtain, it argued.

"It is reasonable that CSPs may have to conduct some level of administrative work in registering residential demand response customers, and the complaint offers no clear criterion by which PJM could determine whether interval metered data is 'not reasonably available,'" the RTO said.

Granting the complaint would lead to widespread use of statistical modeling, which is less accurate than the actual metering data required today, PJM said.

PJM's Independent Market Monitor also took issue with the complainants' proposed remedy.

"Using statistical sampling when actual interval meter data is available would unjustly and unreasonably degrade PJM's ability to accurately measure the megawatts of capacity actually available and the actual performance of that capacity and therefore degrade PJM's ability to maintain resource adequacy and to correctly determine efficient capacity market prices through supply and demand in the market," the Monitor told FERC. "In addition, such treatment would introduce undue discrimination in favor of the demand response resources that do not use available meter data, which is what all other capacity resources are required to use."

DR has to be timely and verifiable because knowing exactly when and how much load is cut is critical to reliably operating the grid and accurately compensating, the Monitor argued.

"If load reductions are only measured on coarse intervals or through statistical sampling, it is not possible to verify that the defined reduction can occur and did occur when dispatched and thereby to count on it for reliability and compensate it appropriately," it said. "The public interest in system reliability and efficiency justifies the metering requirement for participants seeking to sell demand response."

Exelon argued that the complaint misconstrues utility data practices, which are required by state regulations.

The company's utilities "adhere to state laws and regulations to safeguard customer data, including complying with critical energy/electric infrastructure information (CEII), which includes sensitive grid and infrastructure data," Exelon told FERC. "Furthermore, where the complaint objects to CSPs' limited access to tools available for licensed retail electric suppliers, the complaint is in fact taking issue with state laws, regulations and fundamental elements of restructuring that require such limitations."

Voltus and Mission:data were not without their supporters, which included CPower.

"PJM's present rules have erected an impenetrable barrier to curtailment service providers seeking to enroll residential customers in demand response programs," the company said. "CPower has experienced identical unreasonable barriers, both before and since CPower filed a similar unsuccessful complaint in 2023." ■

N.J. Forum Explores Solutions to Looming Energy Shortfall

By Hugh R. Morley

FRANKLIN TOWNSHIP, N.J. — New Jersey will need to overcome a raft of permitting, funding and policy issues as it seeks to remake its energy strategy to confront the sudden, data center-fueled rise in energy demand on the horizon, speakers told an energy forum organized by the state's largest business group.

Perhaps the most urgent need is a clear-eyed look, coupled with some tough decisions, at what energy sources the state is going to pursue, keynote speaker Zenon Christodoulou, a commissioner on the Board of Public Utilities, said at the New Jersey Business & Industry Association's annual Energy and Environmental Policy Forum, held Oct. 28-29.

As the state emerges from a vigorous, Democratic-led pursuit of offshore wind, Christodoulou warned against accepting the "agnostic" view of energy in which all sources are valid, commonly described as the "all of the above" approach.

"I know it sounds impartial and democratic," but the word "agnostic" also "conveys a sense of ignorance and lack of knowledge," and the state needs a more defined strategy, he said.

"We need to take some educated guesses here," he said. "We need to find the best-of-the-above approach, not an old approach. And while we're at it, maybe we can look at some below-the-surface approaches, like geothermal and hydrogen."

The conference took place amid the final stages of the gubernatorial election to pick the successor to Gov. Phil Murphy (D), who aggressively pursued a clean energy strategy, the largest part of which — 11 GW of offshore wind — has largely stalled under unfavorable economic conditions and President Donald Trump's opposition.

Energy issues have taken center stage in the state in large part from a predicted electricity shortfall and the impact on ratepayers. New Jersey ratepayers' average electric bill rose 20% in June.

As one of the 13 states served by PJM, New Jersey faces a dramatic surge in demand, mainly because of the expected development of heavy electricity-using data centers. Analysts say the expected shortfall was also triggered by rapid closures of aging fossil fuel plants as new plants, mainly clean, have come online more slowly.

New Jersey BPU Commissioner Zenon Christodoulou speaks at the NJBIA Energy and Environmental Policy Forum on Oct. 28 | © RTO Insider

Importer or Exporter?

Former Gov. Chris Christie (R), a keynote speaker at the forum, said the state generated enough electricity that it was exporting power when he handed the reins to Murphy. He blamed the incumbent's "hyper focus" on clean energy for the state's current predicament and its swing to become an energy importer, rather than being self-sufficient.

"What he's done is deter any baseload generation, and that begins the part of the problem," Christie said. He added that the next governor will have to "bite the bullet" and develop natural gas plants.

"Their first step, in my view, if they asked [me], would be to sit down with utilities and say, 'What do we need to do to get you to open two or three new natural gas generation plants as quickly as possible?'" he said.

But Brian O. Lipman, director of the New Jersey Division of Rate Counsel, told a panel on rates that the state has been a net importer of electricity since 1990, and that's not a problem.


New Jersey Rate Counsel Brian O. Lipman | © RTO Insider LLC

"We're not an exporting state," he said. "The whole point of PJM is that we could bring in cheaper electricity from other states. Generation is expensive to build, and it's cheaper to build it, quite frankly, in Pennsylvania, in the middle of nowhere, than it is anywhere in New Jersey.

"We can talk about whether we should be an importer, and how much we should be, whether it's economic to build in New Jersey at this time," he said. "But the reality is, when it's economic to build outside the state and bring electricity in, that's what we should be doing."

If New Jersey wants to generate its own power, then it needs to streamline and speed up the permitting process, he said. "We can do things with permitting where we can override the NIMBY issues that a lot of these projects are going to have," he said.

He suggested the state could protect itself from bearing the burden and infrastructure costs of excessive data center demand by requiring such facilities to bring their own generation sources. But he also expressed caution.

"If you legislate too much, the data center is just going to go to another state," he said. "And if the data center goes to Pennsylvania, we still have the same demand issues that we would have if they were in New Jersey. We just aren't going to get any of the economic benefits that we would get if they were built in New Jersey."

Backing Nuclear

With wind and solar largely an afterthought at the forum, the panelists more frequently focused on nuclear and gas to resolve the state's looming power shortage.

Erick A. Ford, New Jersey Energy Policy Coalition | *© RTO Insider LLC*

Erick A. Ford, president of the New Jersey Energy Policy Coalition, which advocates for a "balanced" energy strategy, said the state is "uniquely positioned" to lead the move into nuclear, with an experienced workforce and a history of managing nuclear plants, including Public Service Enterprise Group's three existing facilities in Salem and the now-defunct Oyster Creek plant.

Speakers on a panel titled "Nuclear Power – Is it in NJ's Future?" cited several recent announcements that suggest nuclear power is increasingly viable. They included the U.S. government's announcement on the same date as the conference that it had forged a partnership with the Canadian owners of Westinghouse Electric to spend at least $80 billion on nuclear reactors. In a separate announcement, NextEra Energy said it plans to restart the 50-year-old Duane Arnold Energy Center. (See related stories, *U.S., Westinghouse Partner for $80B in Nuclear Construction* and *NextEra, Google Announce Nuclear Collaboration*.)

Matthew Leggett, K&L Gates (left), and Timothy Fox, ClearView Energy Partners | *© RTO Insider LLC*

New Jersey is home to a 50-acre technology center in Camden, run by Holtec International, which is restarting Michigan's Palisades nuclear plant and plans to build two small modular reactors beside it. (See *Holtec Announces SMR Plans at Palisades Nuclear Plant*.)

The company also is decommissioning the Oyster Creek facility. Holtec CEO Krishna Singh told New Jersey legislators in August that the company is looking at whether four of its SMR-300 reactors could be sited in Oyster Creek, generating 1,300 MW of power.

Feasibility Challenges

Whether New Jersey is a contender for future reactors is unclear. The U.S. Nuclear Regulatory Commission in 2016 issued PSEG an early site permit for the Salem site that currently houses the three reactors it operates, but the company has yet to announce any plans for the site.

To host other facilities, the state would have to meet the needs of developers or their clients.

Ray Fakhoury, energy policy manager for Amazon Web Services, told the forum that nuclear projects will be critical to the company's Net Zero by 2040 plan. Amazon on *Oct. 16 outlined* plans to build up to 12 SMRs and generate 5 GW of nuclear power by 2039.

In looking for sites to put a data center served by a nuclear project, the company's first priority is access to a transmission line to "create the promise that there will be future growth opportunities to that potential area," he said.

"The challenge is a one-off facility might not be so useful for Amazon because we can't capture those economies of scale," he said. In addition, having a site with a pre-application submitted, "early site works being done and permitting kind of being set forward are all really critical to building, and all of that is wrapped up in this nice bundle of policy certainty."

Other challenges to developing nuclear sites in the state will be finding trained workers and overcoming the lack of a supply chain. On top of those challenges is the fact that nuclear plants take longer and cost more to build than other generating sources and so can't meet the state's urgent shorter-term needs.

Yet the NRC has reduced the 5-mile emergency management zone perimeter for nuclear plants, shrinking the footprint needed, which is helpful to densely populated states such as New Jersey. And nuclear plants last much longer than other plants. ■

This article has been edited for length.
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FERC Rejects Tri-State's 'High Impact Load Tariff' Aimed at Data Centers

Commission Finds Proposed Rules Fall Outside its Jurisdiction

By Robert Mullin

FERC has rejected Tri-State Generation and Transmission's proposed tariff designed to manage the projected massive growth in data center load confronting its Mountain West member utilities over the next decade (*ER25-3316*).

The commission's Oct. 27 decision could call into question a growing push among utilities to develop such rulesets to insulate ratepayers from the financial and reliability risks stemming from the heavy energy demands of new data centers. (See *Large-load Tariffs Touted as Alternative to 'Side Deals'*.)

Modeled on similar tariffs filed by other U.S. utilities, Tri-State's High Impact Load Tariff would have established a biennial planning cycle for customer loads rated at 45 MW or higher, with the aim of weeding out speculative projects.

In its filing, the Colorado-based cooperative wrote that a "separate HIL planning cycle process is necessary because HILs are of a size that require significant generation capacity additions or procurement of long-term [power purchase agreements], which necessitates proper planning" to prevent ratepayers from bearing the financial burden of grid projects being completed "only for a HIL to not materialize."

The proposed rules would have required Tri-State members and developers of HIL projects to undergo an evaluation process that included providing evidence that a developer had 90% site control of its project location and submitting an executed member-customer high-impact load (MCHIL) agreement and high-impact load agreement (HILA) to be executed between the utility member and Tri-State.

Developers of projects under 80 MW would also have been required to pay an evaluation fee starting at $35,000 plus $1,000/MW, with the fee increasing to $150,000 for projects between 80 and 200 MW and $250,000 for projects above 200 MW — levels Tri-Sate said were consistent with deposit thresholds under its large generator interconnection process.

The HILA also would have required a HIL customer to provide a minimum security deposit of $2.7 million/MW to offset the risk that the customer "begins commercial operations late [or] ceases operations before the expiration of the HILA term or the HIL does not operate at the expected level (or at all)."

'A Job for the States Alone'

In rejecting the proposed rules, the commission largely agreed with protests by Data Center Coalition and infrastructure developer Eolian Energy, finding that "certain aspects" of Tri-State's proposed tariff "appear to present an impermissible intrusion on retail rate regulation," which falls under the purview of states and is not subject to FERC's jurisdictional authority under the Federal Power Act.

"We find that several provisions of the HIL Tariff require specific terms and conditions of service by a utility member to an end-use HIL customer (i.e., a retail service) and make the MCHIL a condition of Tri-State's agreement to provide wholesale service to its utility members to facilitate their retail service of large loads," the commission wrote.

The commission noted the protesters' argument that Tri-State was proposing to use a FERC-jurisdictional tariff to set the terms of retail sales by "dictating" the minimum amount of energy a large load customer must purchase at retail.

"For example, Data Center Coalition argues that mandating HIL customers enter into contracts with utility members that contain minimum monthly demand and energy requirements are terms of retail service that are beyond the commission's authority to regulate. Eolian argues that the MCHIL is a retail agreement, and Tri-State's failure to explain how the commission can approve a tariff provision that dictates the terms of retail service is a deficiency in Tri-State's filing," the commission wrote.

Tri-State did not provide "a sufficient basis" for FERC finding the proposal did not regulate the terms and conditions of a HIL customer's retail service "in ways that are beyond the commission's authority,"

Why This Matters

The commission's decision could call into question a growing strategy among utilities to develop tariffs designed to insulate ratepayers from the risks stemming from the heavy energy demands of new artificial intelligence data centers.

Tri-State's proposed High Impact Load Tariff was designed to help the co-op and its utility members manage an expected boom in data center development in the Mountain West region. | *NOVVA Data Centers* it said, pointing specifically to the HILA provision that requires a Tri-State utility member to enter into an MCHIL that sets the terms for energy sales from the member to its retail customer.

The commission also disagreed with Tri-State's contention that FERC has authority to assert jurisdiction over the proposed HILT and HILA, "which condition Tri-State's service to its utility members on those utility members' HIL customers complying with certain terms and conditions of retail service."

"We note that the plain language of the FPA bars the commission from regulating retail sales, and the Supreme Court has been clear: Specification of terms of sale at retail 'is a job for the states alone.'"

The commission also rejected Tri-State's argument that it should accept the HIL program because it is similar to the co-op's FERC-approved demand response program in laying out key terms for utility member participation.

"We disagree because Tri-State's demand response program does not place the terms and conditions on the retail sale of electricity; instead, it sets forth the technical requirements that a utility member's demand response resources must meet in order for the utility member to qualify for incentive payments from Tri-State's demand response programs," the commission wrote.

Guidance for 2nd Attempt

But the commission left open the door for Tri-State to file a modified version of the HILT that does not infringe on retail rate regulation, outlining a handful of "concerns" about the tariff the co-op should address, including:

- insufficient evidence that the proposed security deposits are "appropriately sized to mitigate the risks Tri-State identifies";
- insufficient explanation justifying why Tri-State should be able to terminate a utility member's HILA for reasons beyond the member's control, potentially after the member has already incurred construction costs to help serve the new load; and
- lack of justification for the "degree of discretion" Tri-State proposed to give itself in implementing various parts of the HILT, such as the evaluation criteria.

The commission also found that the tariff did not provide sufficient detail about the "interactions" between the proposed reliability and transmission criteria in the evaluation.

"We also note that Tri-State's metrics for assessing the reliability criteria lack the necessary details for the commission to evaluate their effectiveness and whether they ensure not unduly discriminatory treatment across projects," it wrote.

Reached for comment, a Tri-State spokesperson told *RTO Insider*: "While this is a disappointing result, FERC provided guidance to Tri-State that we can use to move forward toward our goal of creating a repeatable and fair process to bring high-impact loads to Tri-State and our members, while providing data centers and other large loads a transparent and fair process.

"We still are reviewing the order and determining our next steps, but there may be an opportunity to modify the tariff to address FERC's comments and deliver the consistency our members seek, in responding to requests for service from heavy energy users." ■

NextEra, Google Announce Nuclear Collaboration

Restart of Duane Arnold Planned, New Nuclear Construction Explored

By John Cropley

NextEra Energy plans to recommission the Duane Arnold nuclear plant in Iowa in collaboration with Google. | *NextEra Energy*

NextEra Energy plans to restart the 50-year-old Iowa nuclear power plant it shut down in 2020 and sell some of its output to Google for data center operations.

The target date for resumed operation of the 615-MW Duane Arnold Energy Center is the first quarter of 2029.

NextEra and Google announced the 25-year power purchase agreement late Oct. 27, and NextEra elaborated in its *third-quarter earnings report* Oct. 28.

Central Iowa Power Cooperative and Corn Belt Power Cooperative will surrender their 30% ownership stake in the facility to NextEra in return for NextEra assuming their liability for decommissioning.

Central Iowa and Google will purchase the full output of the plant on equal terms, which were not disclosed but which are expected to contribute annually an adjusted 16 cents on average to NextEra's earnings per share for the first 10 years of the agreement.

NextEra CEO John Ketchum said the company is not ready to disclose the expected cost of recommissioning.

For comparison, Constellation estimates a $1.6 billion price tag to restart the former Three Mile Island Unit 1, a pressurized-water reactor commissioned and retired at roughly the same time as the Duane Arnold reactor, which is smaller and uses the less complex boiling water design.

Why This Matters

The small number of retired but not disassembled U.S. nuclear plants has become a potentially valuable commodity, able to come back online at a fraction of the cost in time and money of a comparable new facility.

Ketchum said the same team that has been doing the decommissioning will bring the facility back to operational status, and some of the employees who formerly operated Duane Arnold are expected to be rehired.

NextEra announced plans to shut down the facility in 2018, in an era when multiple U.S. nuclear plants had become uneconomical due to their high cost of operation and were being retired.

Duane Arnold ceased operation even sooner than planned when an August 2020 windstorm damaged its cooling towers.

Not even five years later, the nuclear power landscape began to change dramatically as demand for power — particularly the emissions-free baseload power provided by atomic fission — began to rise.

The very small number of retired but not disassembled U.S. nuclear plants have become a potentially valuable commodity, able to come back online at a fraction of the cost in time and money of a comparable new facility.

Two other retired nuclear power plants have begun recommissioning processes; the operational lives of existing reactors are being extended rather than cut short; construction may resume on a half-built, two-reactor facility mothballed eight years ago; uprating is planned for existing plants; and corporate offtake agreements are being signed for existing reactors as well as for advanced nuclear technologies that have not even reached prototype testing.

In this environment, NextEra considers the Duane Arnold restart a good move. The company still needs regulatory approvals but has begun the process of obtaining them. (See *NextEra Closer to Recommissioning Duane Arnold with FERC Waivers*.)

"Because we carefully and methodically went through the decommissioning process, we have confidence in the investment required to restart it," Ketchum said. NextEra expects the recommissioned facility to qualify for the full range of available federal tax credits, he said.

The first quarter of 2029 is the latest the restart would be expected, Ketchum said. It could be as soon as the fourth quarter of 2028.

NextEra and Google also announced an agreement to explore development of new nuclear generation across the United States.

Counting Duane Arnold, the two companies have executed more than 3.5 GW of energy projects nationwide.

NextEra Energy *reported GAAP earnings* of $2.44 billion or $1.18/share on revenue of $7.97 billion in the third quarter of 2025, up from $1.85 billion, $0.90/share and $7.57 billion in the same quarter a year earlier. ■

Dominion Reports on CVOW Progress, Data Center Growth in Q3 Earnings

By James Downing

Dominion Energy reported $1 billion in net income in the third quarter, which saw it remain on track with its offshore wind project while its pipeline of data center customers grew yet again.

The Coastal Virginia Offshore Wind (CVOW) project should see its first turbine installed later in November, with the first power delivery expected in the first quarter of 2026, Dominion CEO Robert Blue told analysts during a conference call held Oct. 31. Additional strings of turbines will be installed until the project's completion target near the end of 2026.

"The project is now two-thirds complete and just a few months away from delivering much needed electricity to our customers," Blue said.

While the project's progress is on schedule now, analysts wondered if the upcoming gubernatorial election could throw it off. Gov. Glenn Youngkin (R) is term limited, and U.S. Rep. Abigail Spanberger (D) is leading in polls ahead of Election Day on Nov. 4.

All the candidates running for statewide office support CVOW, but one analyst asked what risk the project faced with a Democrat likely to become governor given how the Trump administration has treated offshore wind and other energy projects in Democratic-led states.

"It's the fastest way to get 2.6 GW on the grid that's going to serve AI and technology companies, defense security installations," Blue said. "It's critical to important infrastructure upgrades at the Oceana Naval Air Station. And if you stop it now, it causes energy inflation. So, it's not surprising that we're seeing bipartisan support at all levels of government, and we expect that to continue after the election."

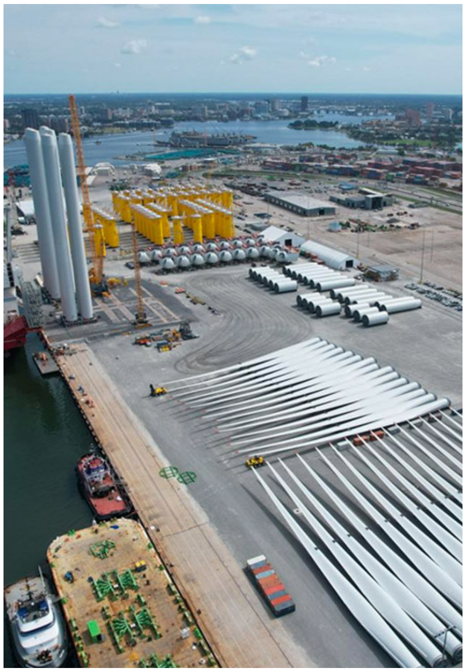
Dominion is also facing some delays in getting the ship it had built to install many of the wind plant's components — the *Charybdis* — to work. The vessel is compliant with the Jones Act, which requires U.S.-owned and crewed vessels when sailing domestically, and was meant to "derisk" construction.

"This is the first Jones Act-compliant wind turbine insulation vessel to be built in the U.S. and subject to U.S. regulatory oversight," Blue said. "It's a big ship. It's 472 feet long. It's 184 feet wide. It weighs 27,000 tons. It's got some complex systems on it. It's got a 2,200-ton capacity crane. It's got a jacking system that's capable of creating a 40-meter air gap under the hull when the ship is jacked up."

It was delivered to Portsmouth, Va., in October. Regulators there identified some issues that needed to be fixed before it can get to work. Regulators had concerns with the electrical systems, which Dominion's workers are painstakingly reviewing, and some documentation issues, Blue said.

"To date, we've done over 4,000 inspections across 69 electrical systems, including 1,400 cable inspections," Blue said. "We've got 200 people working around the clock. Of that original 200 punch-list items, we've closed out about 120, so it's important to know not all those items are created equal. Some punch-list items are a little more complex and will take longer to resolve, but the progress has been really good."

While for now Dominion expects CVOW to be fully installed by the end of 2026, the *Charybdis*' issues could push that back to early 2027, Blue said.



A picture from October of CVOW components being staged in Portsmouth, Va., which Dominion shared in its earnings presentation. | *Dominion Energy*

Dominion now has 47 GW of data centers at various levels of development in its pipeline, which is up from 40 GW at the end of 2024, Blue said. The biggest chunk of those, 28.2 GW, is in the least-certain category, defined as only asking for an engineering study from the utility.

An additional 9 GW have signed a construction letter of authorization, which means Dominion can start work on upgrading infrastructure and the data center has to pay even if it walks away. And 9.8 GW have signed an electric service agreement, which defines how the data center will take service and lays out cost recovery.

"We welcome these customers to our system and recognize the vital contribution data centers make to national, state and community success," Blue said. "We're developing resources across distribution, transmission and generation to ensure we meet this critical need on a timely basis, while also taking active steps to safeguard all of our customers from the risk of paying more than their fair share for reliable and affordable electric service." ■

Why This Matters

Control of the Virginia governor's office could switch parties in the election Nov. 4, but Dominion CEO Robert Blue argued the CVOW project is necessary for data center demand and to support key naval facilities in Virginia, so it should avoid any negative actions from the federal government regardless of the election's outcomes.

Southern Co.: Data Centers Continue to Power Growth

By Holden Mann

During Southern Co.'s quarterly earnings call Oct. 30, CEO Chris Womack assured investors that the company "continues to perform exceptionally well [with] an incredibly bright future ahead."

Southern's net income for the third quarter stood at $1.71 billion ($1.55/share), up from $1.54 billion ($1.40/share) in the same period in 2024. Year-to-date income was $3.93 billion ($3.56/share), up from $3.87 billion ($3.53/share) in the same period the year before.

Operating revenue for the quarter came to $7.82 billion, a $549 million increase from the third quarter of 2024, while year-to-date revenue also rose by $2.19 billion over the same period in 2024, to $22.57 billion. Operating expenses for the third quarter rose to $5.23 billion from $4.91 billion for the third quarter of 2024, and from $14.37 billion to $16.2 billion year-to-date.

Adjusted earnings per share came to $1.60, CFO David Poroch said, 17 cents higher than the same period last year and 10 cents above the company's estimate. He attributed the growth to investment in state-regulated utilities and increased usage by customers, offset by milder-than-expected weather, higher depreciation and amortization, and higher interest costs. Southern is predicting adjusted earnings per share of 54 cents for the fourth quarter and $4.30 for the full year.

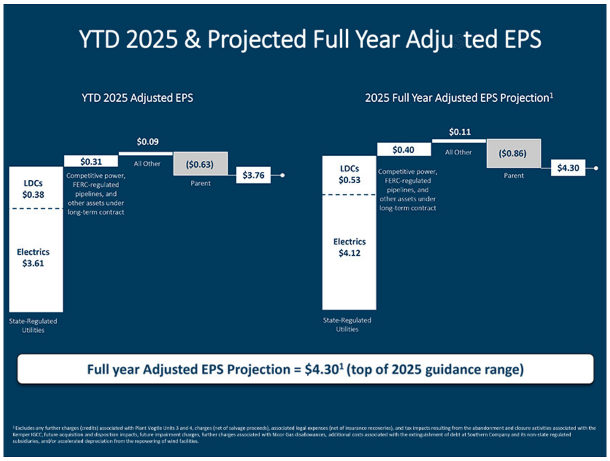
Weather-normal retail electricity sales were up 1.8% from the first three quarters of 2024, Poroch said, on track for the highest annual increase since 2010 excluding the COVID-19 pandemic. The biggest change was in commercial customers, which grew 2.6%. Next came the industrial sector with 1.6% growth, and then residential with 1.2%. Sales to other sectors fell 2.5%.

For the third quarter alone, total weather-adjusted retail electricity sales grew 2.6%, again led by the commercial sector with growth of 3.5%. Residential sales were up 2.7%, while industrial sales rose 1.5% and others grew 1.9%.

Poroch attributed the growth in the commercial sector to increased sales to existing and new customers, including a 17% increase in electricity usage by data centers from the previous year. Overall economic growth across the company's service territory "remains robust," Poroch said, citing announcements in the third quarter by 22 companies to either establish or expand operations in the Southeast, resulting in an expected 5,000 new jobs and capital investments of about $2.8 billion.

Womack said the company has "made great progress with signing new large-load contracts," with 23 projects totaling 7 GW of demand having already broken ground with construction expected to conclude by 2029. Additional contracted projects are expected to bring this total to 8 GW by the mid-2030s, Poroch said.

Southern is also working to build the generation capacity to meet this demand, Womack added, pointing to the ongoing construction of natural gas and battery storage facilities in Georgia and Alabama totaling about 2.5 GW and expected to come online over the next two years.



Southern Co.'s year-to-date and projected full-year adjusted earnings per share | *Southern Co.*

Reviewing Southern's financing activities, Poroch said the company issued $4 billion in long-term debt across its subsidiaries, crediting "the quality and credit strength" of the company for drawing "robust investor interest," which in turn will lead to lower interest costs and long-term benefits to customers. He said the debt issues, combined with those of the first half of the year, "fully satisfied" each subsidiary's long-term debt financing needs for 2025.

Why This Matters

Southern saw 17% higher electricity usage from data centers in the third quarter of 2025 than in the same period the prior year, reflecting the strong ongoing demand from these customers fueling the company's revenues.

Southern has also raised about $7 billion of the $9 billion in equity needed to fund its long-term $76 billion capital investment plan, with $1.8 billion of that total raised since the company's July earnings call, Poroch said. (See *Southern Expects Large Load Growth to Continue*.)

Asked about his reaction to the federal government's recently announced agreement with Westinghouse to build at least $80 billion of the company's nuclear reactors nationwide, Womack said he was "incredibly excited" about the news and that the commitment represented an important step toward meeting the country's growing electricity demand. (See related story, *U.S., Westinghouse Partner for $80B in Nuclear Construction*.)

However, he said the company had not made any decisions about pursuing new nuclear construction after the completion of Plant Vogtle Units 3 and 4 in Georgia, the first new nuclear plants in a generation whose construction ran years behind schedule and vastly overbudget.

"We want to make sure that all risks are mitigated before we make that kind of decision," Womack said. "I'm excited about all the activity that's occurring around the country with considerations about new nuclear, [and] we're going to continue to work with the administration [and] other government agencies to talk about the … role that new nuclear can play in meeting this growing demand, but … we're not in a position to make that decision at this point." ■

NIPSCO's 1st GenCo Endeavor to Feature Gas, Cost $6B or More

By Amanda Durish Cook

Northern Indiana Public Service Co.'s leadership plan to test their new GenCo spinoff business with a $6 billion to $7 billion grid investment from a large, yet unnamed customer.

NIPSCO secured approval in September from the Indiana Utility Regulatory Commission (IURC) to launch its business model dedicated to building generation quickly to serve data centers and other large loads.

Lloyd Yates, CEO of parent company NiSource, said NIPSCO in September struck its first GenCo agreement with a "large, investment-grade data center customer" that would require two 1,300-MW GE Vernova natural gas turbines, 400 MW of new battery storage and transmission upgrades in northern Indiana.

NIPSCO's contract with the customer stipulates an initial 15-year term. The utility plans to start constructing generation in 2027 and be able to meet the project's full demand by 2032.

Yates said GenCo's first, potential $7 billion investment will allow $1 billion in savings to flow back to existing customers. He said NiSource has "capitalized on emerging data center opportunities" in Indiana.

"The IURC's approval of GenCo unlocks a unique business model designed to protect existing customers, serve new customers with speed and flexibility and maintain the financial integrity of NIPSCO," Yates told shareholders during an Oct. 29 earnings call. "The GenCo strategy goes beyond simply providing power. It establishes a framework that strengthens our system, supports local communities and drives long-term sustainable growth for all stakeholders,"

The Bottom Line

NIPSCO said it will need two 1,300-MW natural gas turbines, 400 MW of new battery storage and transmission upgrades to serve an unnamed large-load customer under the first contract of its GenCo spinoff.

NiSource reported $1.27 billion ($0.19/share) in revenue for the third quarter of 2025.

Yates emphasized NiSource is committed to keeping energy costs "reasonable and predictable" for the rest of its ratepayers.

NiSource Executive Vice President Michael Luhrs said NiSource plans to submit a special contract agreement to the IURC for review before the end of 2025. He said the utility expects a decision in the first half of 2026.

GenCo is exempt from many regulatory reviews typically required to build new generation in Indiana. Instead of the usual public proceeding, IURC would review the proposed contracts and power purchase agreements between NIPSCO and large loads on a case-by-case basis.

Multiple groups argue GenCo's framework is flawed and is ripe for misconduct.

Clean Grid Alliance *said* GenCo would enjoy regulatory shortcuts while essentially maintaining the status of an unregulated independent power producer backed by a regulated monopoly. That one-sidedness would distort market competition and also could impede the clean energy transition, the nonprofit argued. It asked why NIPSCO didn't simply create a new pricing tariff for data center load.

Watchdog group Citizens Action Coalition similarly *argued* GenCo would benefit shareholders over the public. It also said GenCo's setup can't fully isolate large-load investments because if the spinoff business were to lose money, it could affect NiSource's credit rating.

The Citizens Action Coalition and the Indiana Office of Utility Consumer Counselor have alerted the IURC they plan to appeal its authorization of GenCo.

NIPSCO continues to claim GenCo will sequester investments stemming from large loads from being rolled into its rate base.

Northern Indiana Public Service Co

On the earnings call, Luhrs said NiSource is limited in the details it can share and called the deal a "breakthrough infrastructure agreement."

Luhrs said the agreement will require consistent capacity payments of the customer, the "pass-through treatment of certain costs" and termination protections to mitigate risks posed by an early exit of the customer. He said NIPSCO's proposed generation project and transmission upgrades were "carefully structured" to prioritize affordability "so that growth does not come at the expense of existing customers."

Luhrs stressed that the contract ensures NIPSCO retail customers won't be responsible for the infrastructure costs associated with serving the large load. He added NIPSCO would complete the project with "minimal interruption" to existing operations.

"We continue to see strong momentum from large-load customers," Luhrs said, indicating GenCo will attract more customers.

Minutes after announcing the gas generation additions under GenCo, Yates said NIPSCO remains committed to the energy transition and would close its R.M. Schahfer and Michigan City coal plants by the end of 2025 and at the end of 2028, respectively. NIPSCO has announced plans to build a $644 million natural gas peaker plant at the Schahfer site to supply more demand tied to data center growth. ■

Xcel Energy, AEP Plan to Invest $132B Through 2030

By Tom Kleckner

Xcel Energy and American Electric Power said during their quarterly earnings calls that they have increased their capital investment spend to meet increasing demand from large loads.

Xcel told financial analysts Oct. 30 that it plans to invest $60 billion over the next five years to strengthen its infrastructure because of 11% annual rate base growth.

CEO Bob Frenzel said he expects the updated five-year plan to deliver 7,500 MW of zero-carbon renewable generation, 3,000 MW of gas-fired generation and almost 2,000 MW of energy storage to ensure system reliability, and 1,500 miles of HV transmission line miles to support demand growth. He said Xcel has safe-harbored all renewable and storage projects in the base capital plan.

The Minneapolis-based company says it has 19 turbines on order, taking advantage of its scale to meet the demand from oil and gas electrification in the Permian Basin.

"The growth you see in the Permian is probably a function of two things," Frenzel said. "One is continued strength in mining in the Permian Basin. So just more wells, more infrastructure, more fields being open. The second is a trend toward electrification of those fields and of existing fields."

Xcel said it recorded a $290 million ($0.36/share) charge in reaching a settlement with plaintiffs in the 2021 Marshall wildfire in Colorado. The amount has been excluded from quarterly and year-to-date ongoing earnings. The company expects to pay about $640 million related to these settlements, with about $353 million expected to be reimbursed to Public Service of Colorado by remaining insurance coverage.

"Xcel Energy does not admit any fault or wrongdoing in disputes that our equipment caused the second ignition," CFO Brian Van Abel said. "We believe this provides a positive outcome for our communities and our investors."

The company *reported* earnings of $524 million ($0.88/share) during the quarter, compared to $682 million ($1.21/share) for the same period in 2024.

Xcel reaffirmed its 2025 earnings guidance of $3.75-$3.85/share. Frenzel said he's confident the company can deliver on earnings guidance for the 21st year in a row.

The company's stock price closed at $81.59 Oct. 30, up 50 cents from its open.

AEP: $72B Capex Plan

AEP told financial analysts Oct. 29 that it's revised its five-year capital plan to $72 billion and that it is supported by an expected $10% annual growth rate in its rate base. System demand is projected to surge to 65 GW by 2030, up from a current peak of 37 GW. Company executives said they will invest $30 billion in transmission, $20 billion in generation, $17 billion in distribution and $5 billion in other spending.

"Electricity demand growth is happening, and we are seeing it play out across the country in real time," CEO Bill Fehrman told analysts. "Regions with concentrated data center and industrial development, including AEP's footprint, are emerging as clear winners. Large annual capital budgets from hyperscalers totaling hundreds of billions of dollars reinforce the conviction, strength and staying power of this demand growth."

The Columbus, Ohio-based company said its 28 GW of contract data center load all have financial commitments associated with them.

"That's why we have so much confidence in the 28 GW," CFO Trevor Mihalik said.

AEP reported third-quarter earnings of $972 million ($1.82/share), slightly above 2024's performance of $960 million ($1.80/share) for the same period. The company reaffirmed its 2025 operating earnings guidance range of $5.75-$5.95/share, saying it expects to be in the upper half of the spread.

AEP's stock price closed at $121.89 Oct. 30, up $6.79 (5.9%) from its Oct. 29 open. ■

Xcel Energy's CEO Bob Frenzel | © *RTO Insider*

New APS Gas Plant Will Offer Large-user Subscriptions

Desert Sun Power Plant Will Help Meet Data Center Demand

By Elaine Goodman

Arizona Public Service is planning to build an up-to-2-GW natural gas power plant that would be paid for in part by large-load subscribers such as data centers.

The Desert Sun Power Plant would be built west of Gila Bend, Ariz., in two phases, APS announced Oct. 30.

Phase 1 would serve APS' existing customers and "business as usual" growth. It would be paid for by ratepayers. In contrast, Phase 2 would be paid for by the extra-large customers who would use its output through a subscription model. APS defines extra-large customers as those needing 25 MW or more.

Extra-large users would sign long-term contracts covering capital costs and assuming development risks. APS calls the strategy "growth pays for growth."

"Additional natural gas generation is essential to support our existing customers and to begin addressing unprecedented requests from extra-large energy users, such as data centers," said Jacob Tetlow, APS executive vice president and chief operating officer.

APS has nearly 4.5 GW of committed extra high load factor customer demand, Ted Geisler, CEO of APS parent company Pinnacle West, said during a second-quarter earnings call in August.

In addition, there is almost 20 GW of uncommitted demand from customers that have "expressed serious interest in new projects within our system," Geisler said.

Tetlow called the load growth "unprecedented." And large-load customers seem interested in the Desert Sun project.

"We've had a good response," Tetlow told *RTO Insider* in an interview.

Desert Sun's Phase 2 customers would buy into a portfolio containing the new gas plant and other resources such as solar, storage or wind, Tetlow said. Phase 2 contracts would go to the Arizona Corporation Commission, most likely in a package, for approval.

The capacity of the two phases combined could be as much as 2 GW, though the amount in each phase isn't yet known. Project costs are still being worked out.

Phase 1 would include transmission upgrades, whose costs would be incorporated into base rates, Tetlow said. Phase 2 will come with additional transmission upgrades that the extra-large load subscribers would fund.

APS now offers an extra-high load factor tariff for large customers. The subscription model would be an alternative, Tetlow said.

APS is seeking to expand its gas-fueled power plant portfolio, which now includes the Ocotillo facility in Tempe, with the Desert Sun Power Plant near Gila Bend. | *APS*

Why This Matters

At a time of unprecedented demand growth, APS' large-customer subscriber model may help the company accelerate new resource development.

Because customers using the subscription model would help pay to build new resources, they could get service sooner. The model would also provide cost certainty to the large customers, while preventing cost shifts to smaller customers, Tetlow said.

Phase 1 of the power plant is scheduled to begin operations by late 2030. Phase 2's operation date will be determined through discussions with the extra-large customers.

The new plant will come with advanced emissions controls to meet federal and county air quality standards. Using hydrogen as fuel for the new plant or deploying carbon capture may be considered in the future, Tetlow said.

APS intends to supply the plant with natural gas via the proposed Transwestern Pipeline's Desert Southwest expansion project.

APS plans to add nearly 7,300 MW of new resources by 2028, to meet rising demand due to Arizona's rapid growth. Natural gas complements APS' renewable resources, while nuclear energy and coal make the system resilient, the company said.

Although APS had planned to exit the coal-fired Four Corners Power Plant in 2031, the company is now reserving the option to continue using Four Corners through 2038.

Tetlow noted the importance of reliability in Arizona's climate.

"It's 118 degrees sometimes," he said. "[Desert Sun] is a resource to ensure reliability in the desert." ■

DTE Energy Lands 1.4-GW Hyperscaler Agreement

New Energy Storage Planned but no Additional Generation Needed to Serve Load

By John Cropley

DTE Energy plans to retire its coal-fired Monroe Power Plant and replace its output with a combined-cycle gas turbine. | *Shutterstock*

DTE Energy has secured its first hyperscaler agreement and says it has enough excess capacity to power the 1.4-GW data center load without new construction.

The Michigan utility said it does plan to add 1 GW of storage capacity in connection with the hyperscaler project in a peak-shaving role, but the customer will cover the cost.

However, if DTE secures the other data center agreements it is negotiating, it will need to add capacity.

In its *third-quarter earnings report* Oct. 30, DTE said it is boosting its five-year capital investment plan from $30 billion to $36.5 billion and allocating almost all of the additional $6.5 billion to its electric business to support data center development and the transition to cleaner power generation.

CEO Joi Harris said during an earnings call with financial analysts that DTE is in late-stage negotiations with other hyperscalers for about 3 GW of new load and it has potentially 3 to 4 GW in other data center opportunities further down in the pipeline.

DTE is looking at new gas-fired generation for some of this load.

Harris said DTE already is in the manufacturing queue for a combined-cycle gas turbine to replace the coal-fired Monroe Power Plant, which is slated for retirement as DTE works toward a complete exit from coal by 2032. The new gas facility will cost about $2.5 billion, or $2,500/kW, she said.

Additional combined-cycle gas turbines will be needed for new gigawatt-scale data centers, Harris said, but new demand from smaller data centers could be met with a mix of renewable and fossil generation and storage.

Why This Matters

DTE says the deal boosts its business while protecting ratepayers.

The wait time now is three to four years for a new combined-cycle gas turbine, she said, but less for smaller-scale gas generation equipment.

DTE expects to have a better picture of what mix of generation it needs once it firms up negotiations with some of the other potential large-load customers and knows what their anticipated ramp rates are. It plans to provide more details in its next integrated resource plan.

But the utility does anticipate the need for greater generation capacity — the 1.4-GW hyperscaler project alone will result in a 25% increase in load as it ramps up over the next two to three years, Harris said.

DTE will submit the hyperscaler contract for regulatory approval Oct. 31. It includes a 19-year power-supply agreement with minimum monthly charges.

The hyperscaler also will pay for the new energy storage through a 15-year contract. Two-thirds of the new storage capacity will be met with construction to start in 2026; the remainder will be met through tolling agreements.

Nationally, hyperscaler proposals drawing as much power as a small city have consumer advocates fretting over the impact on electric rates.

But Harris presented DTE's 1.4-GW data center deal as a win for existing ratepayers, as they won't have to pay for infrastructure up front or face the prospect of paying for stranded assets down the road.

"We don't have to build anything substantial to support the load," she said. "We're using our excess capacity to support the load and building batteries on top of it, just for peak-shaving purposes. And the customers get that full benefit, so it will show up in the form of a lower ask over our next rate case cycle."

The 1.4-GW agreement also will help drive 6 to 8% annual growth in earnings per share through 2030, Harris said.

DTE reported third-quarter 2025 net earnings of $419 million or $2.01/share on revenue of $3.53 billion, compared with $477 million, $2.30/share and $2.91 billion in the third quarter of 2024. ■

CPower's 2025 VPP Dispatches Already More Than Double 2024 Levels

By James Downing

Rising demand and extreme weather led to a huge spike in dispatches across CPower Energy's Virtual Power Plant (VPP) portfolio as customers it aggregated delivered 38 GWh of load relief over the first nine months of 2025, more than doubling the total from 2024.

"DR and VPPs are having a bit of a moment in the market," CPower CEO Michael Smith said in an interview Nov. 3. "They're extremely important flexibility provided to a market that's growing in terms of demand, that's experiencing more severe and more frequent weather incursions, and we continue to be an extremely important part of the energy transition in that regard."

In 2024, CPower's aggregated customers delivered just 16 GWh to the grid all year, which means for the first three quarters of 2025, they've already provided 137% more. That shows VPPs consistently answer the call for grid support and the resources can be relied on in the future, Smith said.

This summer had extreme heat in June that drove dispatches in PJM and ISO-NE, he added.

"You're seeing, you know, two phenomena," Smith said. "More customers seeking to access the opportunity represented by these markets. And … weather driving more dispatch."

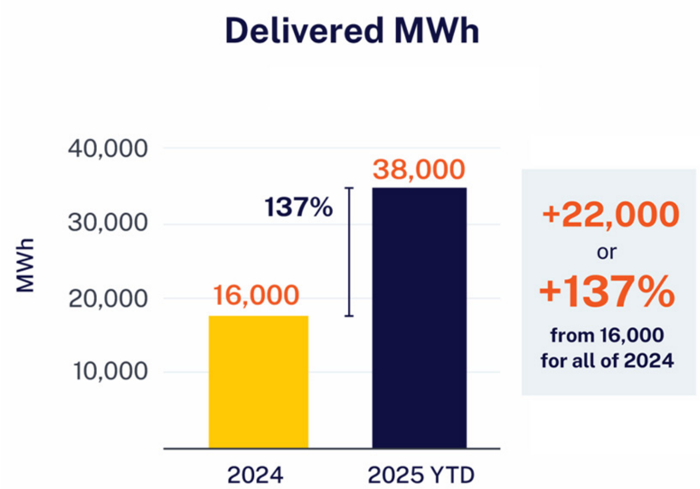
CPower also sees increased interest from large loads like data centers that want to be plugged into the grid quickly. Flexibility is going to be vital for the data center industry in the near term as a major goal for them is speed to market.

"Let's call it three, five, seven years. Generation and transmission build is not going to catch up to the needs of the grid created by extreme demand growth," Smith said. "So, we're going to need the shock absorber provided by demand response and VPP providers."

Once generation and transmission development catch up to the growth and can serve large loads at peak times without issue, some data centers still will want to earn money.

"Customers have inherent flexibility, and they get paid for it," Smith said. "I think that continuing to go back to that fundamental principle would dictate that you're always going to have this be part of the market, even when you do get supply/demand, generation/demand balanced."

One issue CPower and other aggregators always have to balance is ensuring that customers who provide DR do not get burned out by being called upon constantly to balance the grid.



The amount of DR that was called on in the first nine months of this year compared to all of 2024. | *CPower*

"We work with all of our customers to ensure that they're comfortable with the commitment they're making to an evolving market," Smith said. "Some customers decide they want to commit less because they think they're going to get dispatched more."

Another factor they must compete against is large customers engaging in their own peak shaving to lower their bills, which has been a phenomenon since the markets launched.

Why This Matters

Dispatches of CPower's virtual power plants already are more than double that of 2024, which the firm said shows the resource can be a reliable shock absorber as demand growth continues.

"I would say those conversations, particularly after the dispatches of the summer of 2025, are more acute in our business," Smith said. "But we're not seeing customers fleeing these markets. Customers are in these markets. They're participating. They're getting compensated well for their participation in these markets."

While large loads are driving changes and dominating the broader power industry's attention in general, the biggest market potential for demand response remains residential and small commercial customers.

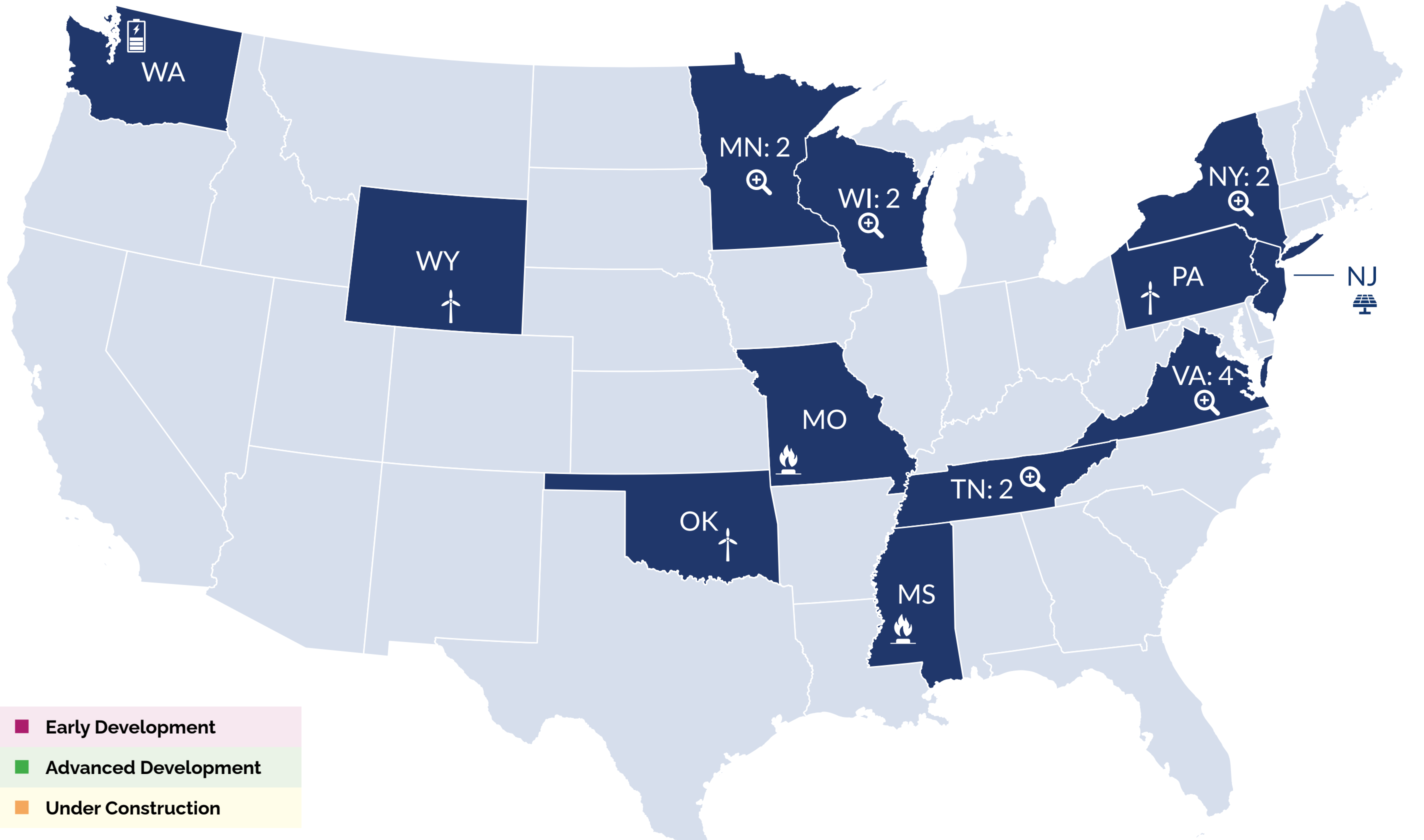
CPower supports a pending complaint from Voltus at FERC, which would allow for statistical modeling of their demand response to be used more widely in PJM due to difficulty in obtaining actual smart-meter data. (See *Voltus, Mission:data Seek Changes to PJM Data Requirements for DR*.)

The states control the rules around releasing data from smart meters to third parties such as DR/VPP aggregators due in part to concerns around data security, which can be overcome, Smith said.

"That's traditionally been very hard for state commissions to get their heads around," he added. "Collectively, think about going back to the opening of the retail power markets and retail energy providers not being able to get that same kind of data. So, we're having those same discussions again. We're seeing some movement at the state commission levels, but it's going to take some time to get that right." ■

Generation Projects Added in the Past Week

YES ENERGY



Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Distillate Fuel Oil

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
	Redwood Sun	Sunshare		MN	5	2100
	USS Coin Solar	US Solar		MN	1	2026
	State Line Combined Cycle Addition	Algonquin Power and Utilities	Liberty Utilities	MO	250	2030
	Vicksburg Advanced Power Station	Enetergy	Entergy Mississippi	MS	754	2028
	Vineland Solar (Aggreko)	AETS OpCo Holdings	Aggreko Energy Transition Solutions	NJ	10	2026
	Norbut Solar Farms - NSF Marshall Site 1, 2 & 3	Brookfield Asset Management	Luminance	NY	5	2025
	Westmoreland Solar	EDP Group	EDP Renewables North America	NY	5	2025
	Prairie Wolf Wind	RWE	RWE Clean Energy	OK	239	2100
	Sugar Maple Wind (PA)	RWE	RWE Clean Energy	PA	81	2026
	Lagoon Creek Energy Complex	Tennessee Valley Authority	Tennessee Valley Authority	TN	350	2100
	Allen Aeroderivative Combustion Turbine Project	Tennessee Valley Authority	Tennessee Valley Authority	TN	200	2026
	Houston Lane Solar 1	Ownership Undisclosed		VA	5	2027
	PEVA 6, 7, & 15 Solar	Ownership Undisclosed		VA	2	2100
	Rogers Road Solar 3	Ownership Undisclosed		VA	5	2027
	Ebenezer Road Solar 1	New Leaf Energy		VA	5	2027
	Goldeneye BESS (WA)	Tenaska		WA	200	2026
	Port Washington Generating Station Turbine Upgrade Project	WEC Energy Group, Inc.	WE Energies	WI	172	2028
	MISO Project S1034	Alliant Energy	Wisconsin Power And Light Company	WI	25	2028
	Two Rivers Wind 2	DIF Capital Partners	Bluearth Renewables US LLC	WY	280	2027

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

Company Briefs

GM to Lay off 3,400 at Detroit Plant, Other EV Sites

General Motors last week announced it will lay off 3,400 workers who build EVs and batteries.

Employees at GM's Detroit-area all-electric Factory Zero assembly plant will be hit the hardest, with 1,200 jobs cut as the company downsizes to a single shift in response to the slowing U.S. market. The company will also cut 550 jobs at its Ultium Cells battery cell plant in Ohio, with an additional 850 slated for temporary layoff. The Ultium Cells plant in Tennessee will temporarily lay off 700 workers. Nearly 120 others at plants that make other EV parts also face temporary layoffs.

Despite the hit to EVs, GM upped its expected yearly net profits to between $12 billion and $13 billion.

More: *The Detroit News*

Meta, Treaty Oak Sign Solar PPAs

Independent power producer Treaty Oak Clean Energy last week announced it has signed long-term power purchase agreements with Meta Platforms for two utility-scale solar projects in Louisiana.

They will be the 185-MW Beekman Solar project in Morehouse Parish and the 200-MW Hollis Creek Solar project in Sabine Parish. Both projects are expected to be operational in the third quarter of 2027.

Under these agreements, Meta will acquire the environmental attributes generated by the projects to support its clean energy and sustainability objectives while the energy produced will be supplied to the local grid.

More: *Power Technology*

Shell Quits Atlantic Shores OSW Joint Venture with EDF

Shell last week announced it has withdrawn from the Atlantic Shores offshore wind joint venture, a partnership with EDF power solutions that was created to develop projects off New Jersey and New York.

Shell paused its involvement in Atlantic Shores in early 2025 after booking close to $1 billion in impairments in its 2024 fourth-quarter results, mainly related to its renewable energy assets in North America.

More: *Renewables Now*

Federal Briefs

All Operational U.S. LNG Terminals Have Violated Pollution Limits

Every fully operational LNG terminal in the U.S. has violated federal pollution limits in recent years, according to analysis of data from the EPA and state governments.

According to the report, between October 2022 and July 2025, all seven export terminals have been in noncompliance with the Clean Air Act for at least one quarter. Some plants were in violation more often than others. The most frequent offenders, the Sabine Pass and Calcasieu Pass terminals in Louisiana, have been out of compliance with certain air pollution standards under the Clean Air Act since 2022. Five terminals have also been in noncompliance with the Clean Water Act, with four breaching the regulation for at least two quarters between April 2022 and July 2025.

The U.S. has been the world's largest LNG exporter since 2023.

More: *The Guardian*

FERC Grants Extension for Completion of LNG Project

FERC last week granted Commonwealth's request for a four-year extension to construct its LNG export terminal in Louisiana.

The approval gives the company until Dec. 31, 2031, to complete the project.

The extension comes days after a Louisiana judge vacated a state permit for the project after a coalition of environmental groups challenged whether the authorization should have been issued in the first place.

More: *Upstream*

DOE Cancels EPRI Grant to Study How OSW Affects Bats

Last month, the Electric Power Research Institute (EPRI) received a letter from the DOE abruptly canceling its $1.6 million grant to study bat behavior in California waters earmarked for offshore wind development.

The researchers had been two years into a study of bats in the territory California plans to use for floating offshore wind turbines in the future. A study last year estimated onshore wind farms killed nearly 800,000 bats every year in Canada, Germany, the U.K. and the U.S.

The bat project is one of 351 individual DOE awards, totaling nearly $16 billion in funding, that in early October appeared on a leaked list of potential grant terminations.

More: *Canary Media*

State Briefs

CONECTICUT

PURA Approves $66M Rate Hike for United Illuminating

The Public Utilities Regulatory Authority last week approved a $66 million (17%) rate hike for United Illuminating, effective Nov. 1.

While the additional $66 million is less than the original $105 million increase the company sought, it's also a sharp increase from the $28.6 million increase recommended by PURA before former Chair Marissa Gillett stepped down in October.

According to estimates, the increase will raise the average electric bill by about $10/month.

More: *CT Mirror*

IDAHO

PUC Develops Process for Utilities to Submit Wildfire Mitigation Plans

The Public Utilities Commission approved a process for utilities to submit wildfire mitigation plans to the state.

A law passed by the Legislature earlier this year that went into effect July 1 requires investor-owned utilities to adopt and submit wildfire mitigation plans to the PUC for approval every year.

Along with developing the submission process, the PUC also developed a rolling filing for utilities to submit their plans over the next six months. Once the plans are submitted, the commission's staff has up to six months to evaluate and then approve or deny the plans.

More: *Idaho Capital Sun*

INDIANA

Duke Energy Gets URC Approval for Gas Plants

Duke Energy last week received Utility Regulatory Commission approval for two new natural gas units at its Cayuga Station in Vermillion County.

The two natural gas units will add 1,476 MW to the grid.

The Office of Utility Consumer Counselor recommended the state deny the utility's petition on the grounds of affordability, but the URC's final ruling found that Duke's proposal satisfied the state's five pillars of energy policy.

More: *Indianapolis Star*

KENTUCKY

PSC Grants LG&E/KU Permission to Build Plants for Data Centers

The Public Service Commission last week granted Louisville Gas and Electric and Kentucky Utilities permission to spend $3 billion to build two 645-MW natural gas plants.

The utilities say the plants are mostly needed to meet the future power demands of data centers they expect to be built in the state in the future.

LG&E/KU were also cleared to extend the life of the Ghent Generating Station — which they previously requested to retire — with upgrades allowing it to operate year-round, but the PSC did not approve a request to keep a coal unit open past its 2027 retirement date in Louisville.

More: *Kentucky Public Radio*; *Lexington Herald-Leader*

MONTANA

Consumer Counsel Urges PSC to Reject NorthWestern Rate Increase

The state's Consumer Counsel last week filed a briefing with the Public Service Commission, asking the PSC to reject NorthWestern Energy's $48 million rate increase request to recover costs associated with building the Yellowstone County Generating Station.

The counsel argued the "substantial" overruns stem from "unnecessary development risks" NorthWestern took to build the plant. The plant, built without preapproval from the PSC, was estimated to have cost $320 million in August 2024. NorthWestern originally estimated total construction costs at $256 million in 2022, according to the counsel.

NorthWestern argues the cost overruns, or "construction change orders," weren't its fault.

More: *Daily Montanan*

NEW YORK

Hecate Energy Scraps Battery Storage System Plans

Hecate Energy filed a notice with the Department of Public Service to terminate its plans to construct a $300 million battery energy storage system in Staten Island.

No reason for the termination was given. Hecate missed the deadline to submit legally required plans by more than 200 days and sought an extension from the Public Service Commission before being denied. The company first announced intentions for the project in 2023.

More: *Staten Island Advance*

PENNSYLVANIA

Talen Energy Reports Automatic Shutdown at Nuclear Plant

One of two nuclear reactors at the Susquehanna Steam Electric Station shut down automatically last week at the same time firefighters were dispatched to the plant, Talen Energy reported to the Nuclear Regulatory Commission.

A company spokesperson said an incident occurred when workers were filling a hydrogen tank and a cloud of the flammable gas unexpectedly ignited, triggering the shutdown. According to Talen's report, the plant's Unit 2 reactor was operating at 100% power when it shut down in a safety procedure known as a SCRAM. The NRC defines a SCRAM as the sudden shutdown of a reactor by the rapid insertion of control rods that halt the nuclear reaction. Talen said all systems performed as expected.

Talen has 60 days to investigate and report its findings to the NRC along with steps taken to correct the issue. The Unit 2 reactor may resume operation before a follow-up report is submitted, but the NRC has inspectors assigned to the plant who will verify it is safe to restart.

More: *Pennsylvania Capital-Star*