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PJM

Eddystone Ordered to Remain Operational for PJM 90 More Days

Constellation

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CAISO/WEST

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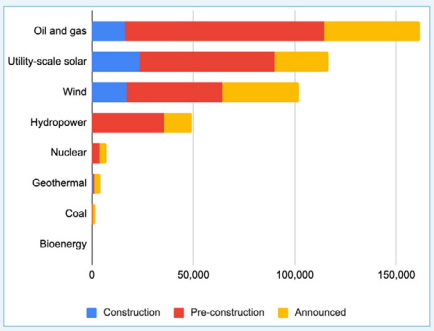

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In this week's issue

Political Intermittency is Now the Biggest Threat to the Grid

By Dej Knuckey


Dej Knuckey

When a government's word is no longer its bond, investors get nervous, and investors in clean energy generation plants in the United States are very nervous indeed. For good reason: The administration is threatening wind and solar generation projects with tactics ranging from revoking permits to trimming tax credits to reneging on grants.

Capriciousness is the Market's Kryptonite

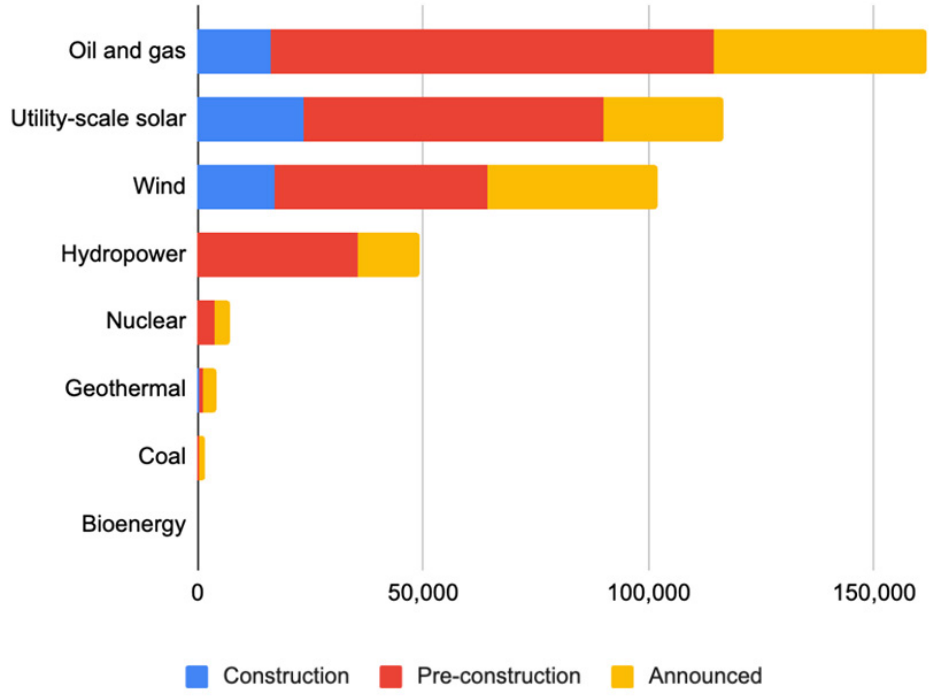
Project developers are, by nature and necessity, risk averse. There's no reward if a project gets derailed by a desert tortoise after years of planning, permitting and perfecting the capital stack to fund its construction. But how can the industry do due diligence when a political wild card can be dealt at the last minute?

A recent example, where the Bureau of Ocean Energy Management halted the *Revolution Wind offshore project* for belated and questionable "national security concerns," is the wildest wild card yet. After all, if this can happen to an 80% complete project that underwent more than a decade of studies and hearings to obtain permission, no project seems safe.

As Nancy Sopko, vice president of external affairs for a U.S. Wind project off the coast of Delaware, another *project under threat*, said, the permits the administration is threatening to revoke for that project were "secured after a multi-year and rigorous public review process" and were legally sound. But a drawn-out legal battle, even if the project team prevails, is just another cost that will make a project difficult to pencil out.

The market is becoming increasingly cautious about investing in clean energy generation and is re-evaluating projects already in the planning stage. Already, the pipeline of generation projects is pre-emptively narrowing as investors and developers seek safer shores.

Putting aside the *why* of the political agenda, it's essential to ask how this will impact electricity supply in a time of rising demand. The grid may face capacity and reliability challenges if clean energy generation projects are shelved, whether voluntarily or otherwise.



U.S. generation project pipeline | *Global Energy Monitor*

Why This Matters

In this changed environment, a question is whether the U.S. will be able to supply enough electricity with acceptable reliability. If the pipeline of planned clean energy projects dries up further, what will fill the void?

AI, Data and the Demand Crystal Ball

In a steady state, cancellation or delay of major projects would be problematic, but unlikely to lead to shortages. However, in the past two years, the rise of AI and the related proliferation of data centers have sent energy analysts scrambling to rework demand projections.

In early 2023, consulting firm *ICF International* projected a 1.3% annual growth rate through 2030. Two years later, it *more than doubled the projected growth rate* to 3.2%. And thanks to the joy of compounding, those small annual increases result in 25% growth in U.S. electricity demand by 2030 and 78% by 2050, compared to 2023 levels.

Peak load growth projections also have been revised upward; however, with data centers' "always-on" load profile, the result is a more feasible 14% by 2030 and 54% by 2050. While data centers providing cloud computing and AI account for most of the growth in demand, it also is coming from a rise in manufacturing, cryptocurrency mining and building electrification.

One trend that may offset some of the increase in demand is the administration's shift away from electrifying transportation, which still may grow, but at a lower rate than previously predicted. Other actions seem performative: For example, the move to eliminate or privatize the Energy Star program is not going to lead

white goods manufacturers to flood the market with less efficient appliances.

Reliability on the Rails

To ensure a reliable supply during peak demand, utilities and grid operators strive for a reserve margin of at least 15%. While today there's a larger reserve margin, ICF warns, "mapping demand growth estimates against generating capacity online today, including the impact of firm builds and retirements, shows that much of the U.S. will experience below-target reserve margins as soon as 2030."

These analysts, however, use the phrase "firm builds and retirements," but planning is being done now in an environment where many "firm builds" have been demoted to "likely build unless the technologies being targeted by the administration."

If there's continued proactive withdrawal by developers, the reliability risk may grow. It will vary by region, but in New England, the offshore wind farm that now is in suspended animation was critical to manage winter power costs, *Jon Lamson reported* this week. In other regions, the peak summer load is a bigger worry, as longer and hotter heat waves drive up the cooling load.

The question of whether this changed environment will be able to supply enough electricity with acceptable reliability isn't really about the newsworthy disruptions to offshore wind and the ability for other renewables to survive without tax credits; it's about the ripple effect. Will the pipeline of planned clean energy projects dry up further, and what will fill the void?

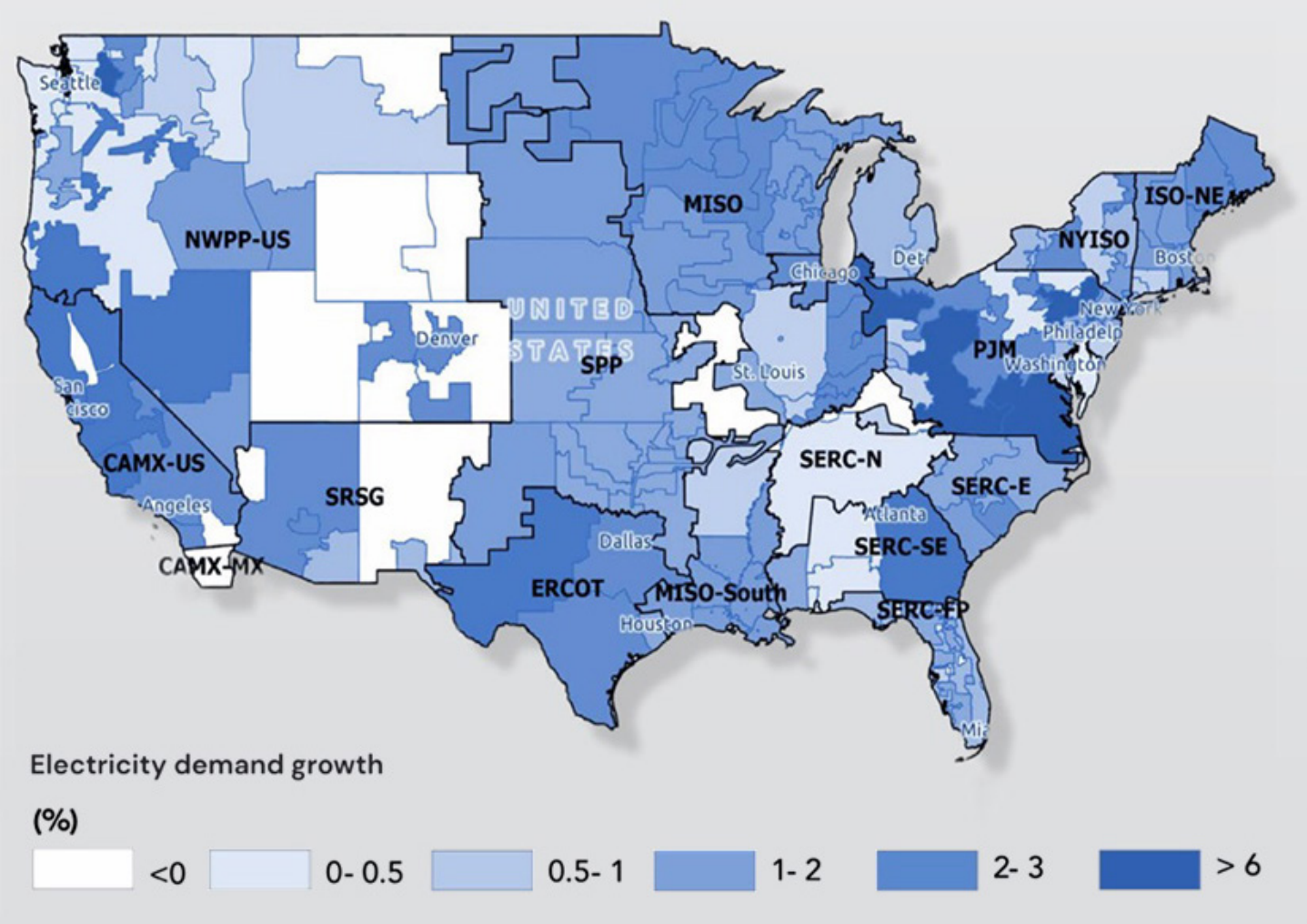
Project Finance is Self-deporting

There are echoes of the administration's immigration policies in the project development world: Make the development environment untenable and the developers will halt their projects without the Interior Department ever issuing a stop-work order. Until those behind a project are sure that their hard-won approvals will be honored, preemptive withdrawal is an increasingly prudent option.

Given the choice between investing time and money in a project that the political rug could be pulled out from under it before it's ever commissioned or putting the project on ice today, some renewables developers and investors are choosing the latter.

BloombergNEF reports "the U.S. saw the greatest drop in new renewable energy investment in 1H 2025, with committed spending down $20.5 billion (36%) from the second half of 2024." Some of the drop is attributable to the artificial bump caused by the rush to start projects before the end of 2024 to lock in tax credits. Still, worsening policy conditions also contributed to it.

The capital is, in essence, self-deporting, and the E.U. is the beneficiary, with an uptick in the number of low-carbon genera-



U.S. regional electricity demand growth and peak demand growth (2025-2035) | *ICF*

tion projects in its development pipeline. The EU-27 saw a 63% rise in investment in the first half of 2025 compared to the last half of 2024.

"These numbers support the idea that companies are reallocating capital out of the U.S. and into Europe — particularly in offshore wind, where several developers refocused to North Sea sites over U.S. projects," BloombergNEF said.

"The unfortunate message to investors is clear: the U.S. is no longer a reliable place for long-term energy investments." - The American Clean Power Association

One Foot on the Gas, the Other on the Brakes

It's not all bad news for capacity: Fossil fuel generation, primarily gas, is benefiting from the administration's focus. *Global Energy Monitor*'s tracker shows almost 100 GW of capacity in preconstruction, up from 15 GW a year earlier. The focus on fossil fuel-powered generation puts the United States at odds with its OECD counterparts. Close to 40% of pre-construction projects in the U.S. now are fossil, compared with less than 6% in the balance of the OECD countries.

A rush to build new fossil capacity won't add to capacity or reliability if the projects can't come online rapidly, and these newly planned plants are just beginning to navigate the yearslong interconnection queues. It's no wonder that data center giants want to skip the grid altogether by building dedicated capacity and energy storage.

Even those projects, however, face a literal pipeline problem unless there is an existing gas supply they can tap into. And if their pipeline crosses state borders, FERC gets involved. "Currently, depending on size and jurisdiction, a pipeline project could take anywhere from eight months to five years," *Norton Rose Fulbright* said. "The federal government has been working on natural gas pipeline permitting reform that would allow pipeline projects to be built more expeditiously."

Similarly, some fossil plants that were scheduled to close are receiving a stay of execution, such as the emergency order from the U.S. Department of Energy to keep two units of the Eddystone Generating Station in Pennsylvania in operation. (See related story *Eddystone Ordered to Remain Operational for PJM 90 More Days*.) The surge in fossil projects may offset some of the decline in renewables. However, even if you assume hydro and geothermal are left alone, there's still a significant portion of planned new generation capacity at risk.

Of the 57 GW of power capacity under construction in North America in August, 23 GW is solar, and 17 GW is wind, according to Global Energy Monitor, meaning more than two-thirds of all power capacity under construction may be at risk. And of the 253 GW in pre-construction? Even after the sharp uptick in fossil plants in pre-construction, utility-scale solar and wind account for 114 GW, or 45%, of capacity in pre-construction.

The critical question is how much of that pre-construction and construction is one revoked permit away from being halted. Some developers — or the project financiers that enable them to exist — aren't waiting around to find out.

What Do We Want? Clarity! When Do We Want It? Now!

The sooner clear and consistent policies are communicated, the faster the markets can start to rebuild trust. If the administration's goal is to prevent all offshore wind projects and allow onshore wind and solar projects to flourish and grow as long as they can pencil out without tax credits, say so.

Investors already fear the worst, and moving to more stable markets but knowing how profound these market shocks will be and how long they will last will enable everyone — developers, investors, utilities, grid operators and regulators—to get back to working out how to build the capacity and reliability electric consumers will need in the coming decades. ■

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

DOT Yanks $679M in Funding for Offshore Wind Ports

Facilities Would Have Supported Projects that are Unlikely to Proceed Soon

By John Cropley

The U.S. Department of Transportation has terminated $679 million in funding commitments for a dozen port and shoreline infrastructure projects planned to serve the offshore wind sector.

The announcement Aug. 29 is the latest in a long series of policy and regulatory moves thwarting renewable energy broadly and offshore wind specifically.

While some actions target existing projects and proposals, others — such as port infrastructure — also are forward-looking and could make it that much harder to restart offshore wind development in U.S. waters under a future administration.

Transportation Secretary Sean Duffy repeated the frequent speaking points of Trump and his cabinet when he announced the "doomed offshore wind projects" would not be getting this financial support.

"Wasteful wind projects are using resources that could otherwise go toward revitalizing America's maritime industry," he said. "Joe Biden and Pete Buttigieg bent over backward to use transportation dollars for their Green New Scam agenda while ignoring the dire needs of our shipbuilding industry."

By far, the largest funding withdrawal announced Aug. 29 was the *$426.7 million allocated in 2024* for a terminal in Humboldt Bay, Calif., to support the floating offshore wind arrays California hopes to place off its coast.

The other projects that saw grants withdrawn or terminated were:

- Sparrows Point Steel Marshalling Port Project, $47.4 million
- Bridgeport Port Authority Operations and Maintenance Wind Port Project, $10.5 million
- Wind Port at Paulsboro, $20.5 million
- Arthur Kill Terminal, $48 million
- Gateway Upgrades at the Port of Davisville, $11.3 million
- Norfolk Offshore Wind Logistics Port, $39.3 million
- Redwood Marine Terminal Project Planning, $8.7 million
- Salem Wind Port Project, $33.8 million
- Lake Erie Renewable Energy Resilience Project, $11.1 million
- Radio Island Rail Improvements, $1.7 million
- PMT Offshore Wind Development, $20 million

Humboldt Bay in Northern California was projected to be home to a major West Coast wind port. | *U.S. Army Corps of Engineers*

Why This Matters

The move is the latest attempt by the Trump administration to stymie offshore wind development.

The Humboldt Bay funding came through DOT's Nationally Significant Freight and Highway Projects program; the other 11 grants were through the Maritime Administration's Port Infrastructure Development Program.

Duffy said DOT chose the 12 projects as part of its review of obligated and unobligated awards made through all discretionary grant programs. He said where possible, the terminated funding will be recompeted to address critical port upgrades and other core infrastructure needs.

The DOT and its Maritime Administration, he said, now are focused on "rebuilding America's shipbuilding capacity, unleashing more reliable, traditional forms of energy, and utilizing the nation's bountiful natural resources to unleash American energy."

The funding termination is in some ways redundant, as the Trump administration has mounted a multipronged, multiagency effort to halt all offshore wind devel-

opment.

But if the funding cuts succeed in slowing and halting construction of offshore wind port facilities, this would slow future development, as well — should anyone ever try to restore the promise and potential that lay before the U.S. offshore wind sector just a few years ago.

The road map that once included thousands of turbines producing dozens of gigawatts by the early 2030s has been eviscerated, along with the federal subsidies that would have made the huge cost of a buildout more bearable for ratepayers.

Seven months into the second Trump administration, investing in a workforce, specialized equipment, a manufacturing base, and a supply chain now is a challenging prospect.

With the port funding cuts announced Aug. 29, one more piece of the puzzle is harder to place.

The Oceantic Network criticized DOT's announcement. The trade association's CEO, Liz Burdock, said: "The Trump administration is weakening our country's national security and destroying good-paying jobs by pulling critical funding designed to update our aging maritime infrastructure.

"Offshore wind port development upgrades facilities and capabilities that serve multiple industries; however, by selectively limiting infrastructure investments and removing mandated agreements in energy and shipyards, the administration is stalling essential development that delivers on shared priorities of national security and energy dominance, and signals to the investment community the U.S is not safe place for investment."

She added: "The U.S. offshore wind industry has sparked $5.1 billion in port funding and created more than 6,000 jobs, making this critical infrastructure mission ready for a variety of roles. It's also expanded tax revenue for seaside communities where port assets were idle or underused for decades. This political action from the administration is another targeted attack on American jobs and American taxpayers, which will raise electricity prices for millions across the U.S. and put thousands out of work." ■

Green America Launches Campaign to Clean up Data Centers

By James Downing

A new campaign from Green America seeks to raise awareness of the impact on the environment from the rush to build data centers for artificial intelligence, calling on tech companies to use 100% renewable energy.

The "*Dirty Data: Stop Big AI From Polluting Our Climate & Communities*" campaign also will push companies to listen to neighbors near data centers and related power plants about exposure to air pollution and related health conditions. Data centers already use electricity to power the equivalent of 7 million American homes and have contributed to higher power prices.

"There is a lot of excitement about artificial intelligence and its potential to make all our lives better," Green America's Director for Climate Campaigns Dan Howells said in a statement. "But for all the benefits, AI comes with a big environmental cost. So, the choices companies like Google, Meta, Amazon and Microsoft make are critical. They could choose a new clean energy future and not return to a dangerous and dirty energy past. In order for the AI revolution to really be intelligent, it must be powered by renewables."

Demand is predicted to rise to between 165 and 326 TWh per year by 2028, which is enough to power 22% of U.S. households and could generate emissions the equivalent of driving a car 300 billion miles, or 1,600 round trips between the Sun and the Earth.

The biggest tech firms have seen emissions rise this decade, growing on average 150% between 2020 and 2023 with 182% growth at Amazon, 155% for Microsoft, 145% for Meta and 138% for Google. All four tech firms made major climate commitments and pledged to get to net zero, but the growth in data center demand is threatening their ability to meet them.

Other industries that rely on data centers have seen emissions decline, with telecom seeing a drop to 94% of 2020 levels by 2023.

The rising demand from data centers is driving utilities to keep coal power plants open that were slated to retire. But a go-to source of energy is natural gas, with plans for 20 GW of new facilities in the American South to serve tech companies.

Another option is nuclear power, with Microsoft helping to reopen an old Three Mile Island plant and a deal with Meta to help expand the Clinton plant in Illinois. Google and Amazon also are investing in small modular reactors.

Green America said its campaign is intended to mobilize its members and others to ensure AI becomes a force for climate solutions. That includes siting them responsibly; boosting efficiency in their operations, including with more efficient microchips; and running their operations on clean, renewable energy.

The campaign also calls for more transparency, so that planned use of electricity and water to run new hyperscale data centers is better known. The sector needs to be honest about the scope of their impacts in order to be good neighbors and take responsibility for the pollution produced, Green America said. ■

Why This Matters

Data centers have made their impact felt on the power industry, and now Green America is starting to organize to ensure clean and affordable power fuels their rise.

A map produced by Green America showing data centers operated by major tech firms. | *Green America*

CAISO's EDAM Scores Simultaneous Wins at FERC

Commission Approves Congestion Revenue Rule Changes; PacifiCorp, PGE EDAM Participation

By Robert Mullin

CAISO's Extended Day-Ahead Market clinched a set of wins Aug. 29 when FERC approved the market's revised congestion revenue allocation model and authorized participation for the EDAM's first two members — PacifiCorp and Portland General Electric, which will join the market in 2026.

The three decisions are interlinked in that PacifiCorp's EDAM membership tariff filing to FERC triggered the events that prompted CAISO to revise the EDAM's congestion revenue allocation rules.

Shortly after Portland, Ore.-based PacifiCorp submitted the filing to FERC in January, Powerex, the energy trading arm of Canadian utility BC Hydro, issued a paper contending EDAM contained a "design flaw" in how it treated firm transmission rights and congestion. Powerex argued the design would leave the market's non-CAISO participants exposed to charges for constraints occurring outside their systems while not providing them the ability to recover or hedge against those costs. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

Powerex's argument centered on the possible impact of "parallel" — or loop — flows in EDAM. As an example, the company's paper cited how an energy delivery scheduled between PacifiCorp's East and West balancing authority areas could produce a parallel flow that causes congestion in the CAISO BAA. EDAM then would apply the charge for that CAISO congestion to the PacifiCorp transaction but not provide the PacifiCorp transmission customer with an adequate ability to hedge for that charge, including through an allocation of congestion revenues.

CAISO and PacifiCorp initially defended EDAM's congestion revenue allocation (CRA) design, noting FERC already implicitly endorsed the model when it approved the day-ahead market's tariff in December 2023. But after a broader group of stakeholders expressed similar concerns, the ISO in March launched an "expedited" initiative to address the issue. (See *Fast-paced Effort will Address EDAM Congestion Revenue Issue*.)

Under the new design coming out of that stakeholder process — and now approved by FERC, certain congestion revenues stemming from parallel flows would be allocated to the BAA where the energy is scheduled rather than where the constraint is located. Those revenues would be allocated based on a transmission customer's eligible firm Open Access Transmission Tariff transmission rights submitted and cleared as day-ahead balanced self-schedules. (See *CAISO Approves New EDAM Congestion Revenue Allocation Design*.)

It was PacifiCorp's EDAM tariff filing that kicked off the controversy prompting CAISO to alter the day-ahead market's congestion revenue allocation rules. | *Shutterstock*

Why This Matters

FERC concurrent tariff approvals pave the way for CAISO to launch EDAM on schedule next year with PacifiCorp and PGE as the market's first participants.

In its decision (*ER25-2637*), the commission found the revised rules to be "just and reasonable" because "they will allocate a portion of certain congestion revenues associated with a binding constraint to the EDAM BAA where market participants paid congestion costs associated with the constraint, rather than to the EDAM BAA where the constraint occurs." That will ensure "eligible" firm transmission customers can hedge against day-ahead congestion charges by submitting their self-schedules, the commission said.

The commission noted that commenters in the proceeding "largely support" the proposal as an "interim measure" until CAISO comes up with a permanent solution through its stakeholder process.

"CAISO frames the instant proposal as a 'transitional measure,' and, after EDAM goes live, CAISO states that it intends to begin a stakeholder process, informed by operational data, to identify near-term and long-term revisions for congestion revenue allocation under EDAM," FERC wrote. "We note, however, that the instant proposal does not contain a sunset date. As such, although some commenters are concerned that future tariff revisions might again expose their firm transmission use to congestion charges, such concerns are outside the scope of the instant proceeding."

The commission acknowledged the concerns of some commenters that the rule changes could incentivize increased use of self-schedules among EDAM participants as a means to hedge against congestion charges but said that practice

is not "inherently undesirable" because it could make supplies available to CAISO's markets.

"In any case, even if CAISO's proposal may further incentivize self-scheduling, we note that, under EDAM's current market design, the ability to self-schedule helps participating transmission providers respect their transmission customers' firm transmission service rights, a consideration that must be balanced against any potential market impacts. We find that the likely benefits of EDAM's market dispatches will still incentivize market participants to economically bid into EDAM," the commission wrote.

The commissioners disagreed with commenters — including Powerex — which argued CAISO should allocate congestion revenue directly to transmission customers based on their transmission rights and allow those customers to opt their transmission service rights out of EDAM altogether, as provided for in SPP's Markets+.

"The commission has already accepted in the EDAM order CAISO's allocation of congestion revenue to EDAM entities, who in turn sub-allocate the congestion revenue as provided for in their OATTs. Similarly, with respect to transmission carveouts, the EDAM order approved the CAISO tariff section that provides EDAM entities the discretion to determine the criteria for such carve-outs," FERC wrote.

The commission also rejected various requests that CAISO be required to: "immediately begin a stakeholder process to identify near-term solutions to the issues of the asymmetry between EDAM BAAs" and the incentive to self-schedule; delay EDAM's implementation until a long-term solution for CRAs is identified; or submit CRA rule revisions within two years.

"We disagree with protesters that a deadline for further deliberation should be mandated as we find that CAISO's current allocation methodology for congestion revenue is just and reasonable. Moreover, we will not direct CAISO to delay the go-live date of a market expansion that the commission has already found to be just and reasonable," FERC wrote.

Orders Pave Way for PacifiCorp, PGE to Join EDAM

The CRA issue appeared prominently in the FERC orders approving the utility tariff revisions required for PacifiCorp (*ER25-951*) and PGE (*ER25-1868*) to participate in the EDAM, particularly around the sub-allocation of the congestion revenues back to load-serving entities in the utilities' BAAs.

Over the protests of multiple commenters, the commission approved each utilities' two-step process for sub-allocating those revenues. For both utilities, Step 1 of the process seeks to use EDAM's congestion revenue allocation to reverse day-ahead congestion price differentials arising for self-scheduled energy transfers relying on firm monthly and longer-term transmission service rights. Step 2 will distribute the rest of the allocation to BAA load and exports not already included in the step one allocation.

Using similar language in both rulings, FERC said it found the Step 1 allocation just and reasonable because "it first reverses day-ahead congestion charges on balanced self-schedules associated with long-term transmission service rights to the greatest extent possible, providing long-term firm customers that choose to self-schedule "an opportunity to hedge against day-ahead congestion charges associated with their use of" the transmission system "by submitting balanced self-schedules in the day ahead."

In the PacifiCorp decision, the commission noted that "[w]hile protesters argue that firm transmission customers may not be able to reverse their day-ahead congestion charges if PacifiCorp is not allocated sufficient congestion revenue, we agree with CAISO and PacifiCorp that these issues are outside the scope of the instant proceeding because they pertain to tariff provisions that the commission accepted in the EDAM order."

Both utilities' orders point to the concurrent CAISO CRA order, noting the ISO's tariff revisions "may help to address some of the concerns" raised by protesters in the two proceedings.

Both orders also reject arguments by future participants of SPP's Markets+ that the commission reject tariff provisions around transmission scheduling because they don't accommodate the ability of transmission rights holders to contribute their transmission to Markets+. In both orders, FERC found the revisions do "not bar firm point-to-point transmission customers from contributing their transmission rights to Markets+, insofar as they are able to meet all of the requirements of" the utilities tariff.

FERC found "there is no obligation under the commission's regulations, or the *pro forma* OATT" for either utility "to accommodate transmission contributions to Markets+." ■

Pathways Initiative Unveils RO Proposed Name, Bylaws

Launch Committee Says Funding Challenges Remain

By Henrik Nilsson

The West-Wide Governance Pathways Initiative is preparing to file the incorporation documents for the independent "regional organization" (RO) that will govern CAISO's energy markets, while funding challenges remain.

The committee plans to file the incorporation documents for the RO in early 2026 under the proposed name Regional Organization for Western Energy (ROWE). The RO will be incorporated as a Delaware non-stock corporation and will qualify as a public benefit corporation, Evie Kahl, chief policy officer at California Community Choice Association and Pathways Launch Committee member, said during a committee meeting Aug. 29.

Kahl also presented the draft bylaws, which detail the policies that will guide the RO and future committees such as advisory, public policy and audit and finance committees.

The Launch Committee, consisting of members from several Western states, was formed with the task of establishing an independent RO to oversee CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM) in an effort to expand energy markets. (See *Pathways Initiative Approves 'Step 2' Plan, Wins $1M in Federal Funding*.)

The draft bylaws specify that the "independent governance shall be provided to and for entities and persons operating within the markets, consumers and affected stakeholders while acting in the public interest, and after consideration of consumer interests and the policies of all participating states."

Why This Matters

Ensuring the draft bylaws and incorporation documents sufficiently respect states' rights is key for the success of the Pathways Initiative's proposed 'regional organization.'

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The bylaws also go into the public interest functions of the RO. For example, the RO will establish a public policy committee to engage with states, local authorities, federal power marketing administrations and advocacy organizations about potential impacts of policy initiatives.

Additionally, state authority "has been something that's been important all along," Kahl said.

"We're developing a regional organization, so we need to make sure that we don't trample the rights of the states in the process," Kahl added.

Specifically, the draft bylaws state, "the board shall consistently acknowledge and, where practicable, develop tariff changes, rules or business practices that respect and accommodate participating states' achievement of state or local policy objectives, including procurement, resource adequacy, environment, reliability and other consumer interests."

"The board likewise shall minimize any adverse impacts of revisions to its tariff, rules, and business practices on participating states' policy objectives," according to the draft bylaws.

Meanwhile, the committee has enough money in the bank to cover expenses through the end of 2025, according to Jim Shetler, general manager of the Balancing Authority of Northern California and co-chair of the committee's Priority Administrative Work Group.

The initiative needs roughly $2 million for 2026 and about $4.8 million for 2027.

"To date, we have basically gone through pledges and donations to try to fund this effort," Shetler said. "We acknowledge that $7 million is going to be tough to do that way, but we're going to at least start there."

The work group has issued an updated pledge form and a draft funding agreement to solicit additional funding, Shetler explained. The work group is also considering debt financing as an option, Shetler said.

The group, which has estimated a $7.1 million budget for all three of its phases, hit a financing snare early in 2025 when the Trump administration paused nearly $1 million in funding as part of a larger spending freeze on projects previously promised support by the Biden administration. (See *Pathways Initiative Seeks $7.1M to Fund RO*.)

"Bottom line is, pledge form should be ready here in the next month, and we will be coming out and soliciting funding," Shetler said. "We're setting this up where people could fund over time. We're not necessarily asking for a full commitment day one. But we do need to get some funding in place starting in January of next year in order to support the 2026 budget." ■

Pathways Bill Will Make It to Newsom's Desk, Author Says

Sen. Becker's Office Says Legislature Will Have a Bill Before Session Closes

By Henrik Nilsson

After months of negotiations, the author of the California legislation needed to transform CAISO's market into an independent regional energy market for the West is confident the state legislature will have a bill to vote on before the session wraps up in early September.

California State Sen. Josh Becker (D) introduced SB 540 in February. The bill would implement the plans of the West-Wide Governance Pathways Initiative, a multistate effort to create an independent "regional organization" (RO) to govern CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market (EDAM), the latter set to launch in 2026.

Though the legislative session is set to wrap up Sept. 12, Becker's press secretary, Charles Lawlor, told *RTO Insider* that "there will be a bill before the deadline. Absolutely."

"We've got lots of time to continue working on this bill," Lawlor said Aug. 28. "It's just a matter of finalizing it. I think everybody's on the same page. It's just getting it to a state where we can, you know, make sure everybody's 100% comfortable."

Lawlor noted that the so-called "suspense" file deadline is Aug. 29. A suspense process is part of a normal procedure in which bills are examined in the Senate and Assembly appropriation committees for their fiscal impact before being advanced to the floor.

However, because of SB 540's significance, it will receive a rule waiver and does not have to go through the usual suspense process, according to Lawlor.

The California State Capitol in Sacramento | *Shutterstock*

This will give parties more time to negotiate amendments and "iron out some issues and make sure that it's properly cooked in order to get the final vote and get it across to the governor's desk," Lawlor said.

SB 540 passed the California Senate in June and was set for a first hearing in the state Assembly's Utilities and Energy Committee on July 16. But the hearing was delayed until after the summer break because several organizations withdrew their support unless lawmakers amended the bill. (See *Calif. Pathways Bill Delayed After Orgs Withdraw Support, While Newsom Signals Backing for Effort*.)

In a letter, the coalition said it opposed an amendment creating a new Regional Energy Market Oversight Council responsible for ensuring CAISO's participation in the regional energy market "serves the interests of the state." (See *Amended 'Pathways' Bill Boosts — and Complicates — Calif. Protections*.) The new council would be authorized to mandate withdrawal if those interests are compromised.

The coalition requested lawmakers remove the amendment, stating "the language in this section mandates the withdrawal of California entities from the market without exception or discretion, which is unacceptable."

The coalition also urged lawmakers to remove revisions to California's Renewables Portfolio Standard Program and restrictions on a future market, noting entities in Colorado, New Mexico and Idaho are undecided about whether to join EDAM or SPP's competing day-ahead market alternative Markets+.

'Poison Pill'

The legislature resumed the 2025 session Aug. 19 after a monthlong summer recess.

Since then, California Gov. Gavin Newsom has voiced his support for SB 540, urging the legislature to pass the proposal. In a recent statement, Newsom said, "Over $1 billion in economic benefits to our state is on the line." (See *Newsom Renews Call for Passage of Pathways Bill*.)

Assembly Speaker Robert Rivas has also said he supports "a voluntary, regional power market."

Advanced Energy United was one of the organizations that pulled its support in July. The trade association's California lead, Edson Perez, told *RTO Insider* in an email that legislators say "they understand the importance of establishing a robust regional market to unlock $1 billion per year in energy cost savings."

"However, there's still a gap in understanding the urgency," Perez said. "We keep reinforcing that it's now or never. With a competing market moving forward, we risk watching those savings evaporate if we don't act this year."

Meanwhile, Jan Smutny-Jones, CEO of the Independent Energy Producers Association, former chair of CAISO's Board of Governors and a current member of the Pathways Initiative's Launch Committee, said he's "optimistic."

However, Smutny-Jones said the Regional Energy Market Oversight Council "acts as a poison pill."

"It does not have the support of the whole coalition," he added. "It would be problematic within the Western market, so we need to get that out of the bill. But other than that … things are pretty smooth." ■

Why This Matters

Parties must resolve several issues — chief among them a controversial amendment that would create an oversight council — for the bill to find success in the legislature before the Sept. 12 deadline.

Solar and Battery Cheaper than Gas, Jefferies Finds

Jefferies' Findings Back Renewables but Note Changing Conditions

By Henrik Nilsson

Investment bank Jefferies' latest analysis finds that the levelized cost of solar-plus-battery storage is cheaper than that of gas, saying slow turbine deliveries and inflationary equipment pricing make the renewable alternative an "attractive" opportunity as data centers drive demand.

Jefferies' analysis for combined-cycle gas turbines shows levelized cost of energy (LCOE) at $87/MWh, while paired solar-plus-four-hour battery energy storage systems have a levelized cost of $77/MWh, despite several obstacles ahead, the investment bank said in an Aug. 27 research note.

The renewable alternative will still be cheaper at $83/MWh even after new rules on foreign entities of concern (FEOC) become effective in 2026, according to Jefferies. The rule is intended to prevent tax credits from going to companies owned or controlled by entities tied to China, North Korea, Iran or Russia. (See *Tax Credit Phaseout Threatens Projects, Jobs in New England*.)

"Given the elongated delivery timelines for turbines coupled with inflationary equipment pricing upending project economics, we see attractive solar+battery development opportunity with [investment tax credits] relatively intact," the bank said.

Jefferies' analysis follows the Trump administration's tightening of tax credit rules on new wind and solar construction. However, the new guidance was not as strict as many in the industry had feared. (See *IRS Guidance on Wind and Solar Credits Not as Bad as Feared*.)

To establish eligibility for tax credits under the new rules, developers must now show that significant physical construction has been started before July 5, 2026, proceeded continuously and was completed within four calendar years.

Jefferies said in its update that the "optimum route for developers" is to procure Chinese solar and BESS and claim the base 30% tax credit, while forgoing a 10% tax incentive aimed at promoting U.S.-sourced materials.

"Going into 2026 once FEOC kicks in, we estimate the ideal route is to procure U.S.-made solar panels, but Chinese batteries (still competitive vs. U.S. due to reliance of U.S. on Chinese supply chain) thus claiming ITC+domestic content adder on solar only," Jefferies said.

The bank added that FEOC, tariffs and other potential levies related to national security concerns "will be a major swing factor in our equation."

Fluence

Why This Matters

Jefferies contends that renewables have the upper hand on gas generation when it comes to quickly deploying generation.

Gas plants have timelines of five to six years, given slow turbine deliveries, while renewables have much faster deployment cycles, according to Jefferies. This can give paired solar and batteries the upper hand as data centers continue to drive power demand, the bank said.

"With gas equipment increasingly inflationary, while renewable technology continues to improve AND get cheaper (holding tariffs constant), we see hybrid generation as an increasingly viable solution to meet power demand/supply gap on a timely basis," Jefferies contended. "As data centers begin to explore paths to work with interruptible service (which is happening), expect these tailwinds to strengthen."

Jefferies' report is consistent with findings published in June by financial advisory firm Lazard. (See *Lazard: Solar and Wind Retain Lowest LCOEs*.)

Lazard concluded that wind and solar are the least expensive new-build power generation for the 10th year in a row, while new gas-fired generation has hit a 10-year high, with equipment shortages expected to drive further increases.

"Batteries are not fungible equivalents to gas alternatives — they are simply just available 'today,'" Jefferies said in its note. "We are seeing wider adoption from geographic perspective (Midwest/etc.) to help accelerate data center timelines. Core markets (TX/CA), however, appear to offset meaningful growth elsewhere for storage. What's more is the low cost of Chinese alternatives could yet incent developers to side-step the ITC altogether, given procurement impediments to qualify for [One Big Beautiful Bill Act] benefits." ■

CPUC OKs Large Increase to PG&E Energization Cost Cap

Commission also Approves Energy Efficiency and Savings Goals for 2026-2037

By David Krause

The California Public Utilities Commission approved a plan to increase Pacific Gas and Electric's cost cap for customer energization projects in 2025 and 2026 by more than $1.5 billion, despite acknowledging the utility did not provide data to support its forecast growth in energization applications during those years.

The increased cap amounts are mountainous: PG&E can now seek to recover costs for up to about $1.1 billion in 2025 and $1.7 billion in 2026 for certain customer energization projects, according to the *decision*. In a 2024 *decision,* the CPUC approved cost caps of about $619 million in 2025 and $669 million in 2026 for these types of projects.

Increasing the cost caps will allow PG&E to "complete additional energization work in 2025 if it is able to accelerate its energization activity or in 2026 if activities are delayed," the CPUC said in the approved decision.

"We all know that load growth today is looking very different than just a few years ago," CPUC President Alice Reynolds said during the Aug. 28 voting meeting. "Utilities are receiving more energization requests that require substantial electricity capacity. These requests are coming from industries central to California's electrification goals — EV charging infrastructure, high-tech campuses."

The scale and speed of these projects is "leading to the need for significant upgrades and on timelines the utilities have not historically had to meet, leading to delays and backlogs," Reynolds said.

However, Commissioner Darcie Houck voted "no" on the proposal, questioning

whether the decision gives "sufficient consideration to affordability concerns," specifically because it omits estimated bill impacts.

"This is a difficult case and requires balancing of critically important issues," Houck said. "When considering just and reasonable rates, we as economic regulators must balance many factors, including affordability."

"The proposed decision states that it cannot estimate the proposed bill impact due to not being able to calculate potential [electricity] sales," Houck said. "However, this … has not been a barrier for the commission in past decisions authorizing funds for projects and programs that result in increased sales including in our general rate case process."

"There are real dollars that real customers will be paying once the work is performed," Houck added. "In other words, there will be real bill impacts to customers. … I do not make my determination here lightly."

Energization project costs include connecting new customers to the distribution grid, upgrading capacity for existing customer sites and building additional capacity for forecast load, the CPUC said in the 2024 decision. The CPUC is required to accelerate energization processes for investor-owned utility customers per Assembly Bill 50 and Senate Bill 410.

External Labor Versus Internal Labor

PG&E needs to increase energization cost caps in part because it plans to hire external contractors for 45% of projects in 2025 and 2026, according to the decision. In 2024, PG&E projected 22% of work would be performed by external contract laborers.

The utility estimates the cost for external contractors to perform energization project work will be about $137,000 per unit in 2025, compared with $67,000 per unit for internal labor, the decision says.

"There is not adequate time for PG&E to hire and train an internal workforce … to complete all of the energization projects in its backlog in 2025 and 2026," the CPUC said in its decision.

Another factor behind the cost cap increase: PG&E says it needs to spend about $74 million to increase customer outreach and improve customer notifications for its energization process over 2025/26.

According to the decision, PG&E projected an 8% increase in energization applications in the coming years. However, the utility did not provide data that supported its forecast growth in energization applications over 2025/26, the decision says. Comparatively, from 2021 to 2024, PG&E's data showed a 1% increase in energization project applications, the decision says.

The average time for large electric utilities to complete energization projects should be 182 days, according to the decision.

While PG&E said the increased cost cap would translate into a 1.8% rate increase for an average residential customer, the CPUC countered that the "evidence does not support" this projected amount. The Utility Reform Network (TURN) estimates proposed cost cap increases would cost $72.50/year for a residential customer that uses 500 kWh/month.

Energization project costs will be tracked in PG&E's Electric Capacity New Business Interim Memorandum Account (ECNBIMA). PG&E can only seek recovery of costs in this interim memorandum account if the costs exceed what the utility was authorized to recover in its 2023 General Rate Case, the decision says. The CPUC will review PG&E's costs tracked and recovered in its ECNBIMA in the utility's 2027 GRC.

Energy Efficiency Goals Set

At the voting meeting, the commission also approved energy efficiency and energy savings goals for 2026-2037 for California's large IOUs. Energy savings goals are tracked in a metric called Total System Benefit (TSB), which includes the lifecycle energy, capacity and greenhouse gas benefits of an efficiency or fuel substitution measure.

The 2028-2031 TSB goal is about $1 billion for PG&E, $646 million for Southern California Edison and $300 million for San Diego Gas & Electric.

"Today's decision reflects changes in efficiency opportunities and market conditions, including growth in fuel substitution, such as switching from natural gas to electric appliances, a decline in traditional efficiency measures in industrial and agricultural sectors, and a more rigorous cost-effectiveness threshold," the CPUC said in a press release. ■

CPUC Fine-tunes Approach to Utility Climate Adaptation Program

Stakeholders Ask Commission to Avoid 'Paralysis by Analysis'

By David Krause

The California Public Utilities Commission is looking for ways to improve a utility-oriented climate adaptation program designed to help protect the most vulnerable people and lands in the Golden State.

At an Aug. 27 workshop, CPUC staff and representatives from investor-owned utilities (IOUs), tribes and other stakeholder groups unveiled possible ways to improve IOUs' Climate Adaptation Vulnerability Assessments (CAVAs). A CAVA identifies vulnerabilities and risks to IOU assets, operations and services stemming from the effects of climate change.

"Robust climate adaptation planning in a time of worsening climate impacts is a prudent next step to ensure the safety and reliability" of IOUs, the CPUC *said* in the "Climate Adaption" section of its website.

"This [workshop] is really critical work to ensure that equity is part of the [climate change reduction] solution," Audrey Neuman, energy adviser to CPUC Commissioner Darcie Houck, said at the workshop.

In a CAVA, an IOU must describe possible ways to confront vulnerabilities to itself and its infrastructure. These options could be used to determine investments in climate adaptation work, the CPUC said.

The CAVA is part of the CPUC's 2018 *Order* Instituting Rulemaking (OIR) *18-04-019* to consider strategies and guidance for climate change adaptation. IOUs must submit a CAVA to the CPUC every four years.

| *PG&E*

CPUC staff said they are currently working with stakeholders to help create "quantitative equity metrics," such as a matrix that shows the adaptivity potential of vulnerable communities and infrastructure. Other possible metrics include quantifying a community's access to resources during an outage; the cost burden of an outage; the impacts of outages on different populations; the impacts of high-frequency outages; and the impacts of long-duration outages.

At the workshop, some stakeholders said too much analysis would be harmful to people who need support now.

"We don't need to tie together all of the various equity processes … in order to get to some actionable plan that is good enough now," one stakeholder said. "There are things we know we need to do now, and we don't have to wait for paralysis by analysis to get to the optimal answer."

Pacific Gas and Electric representatives said the utility is currently defining which communities need the most attention.

Part of the challenge, the representatives said, is that the definition of disadvantaged and vulnerable communities (DVCs) is not specific, which makes it difficult to determine the most vulnerable groups.

"We are looking to target the most vulnerable communities because the DVC definition is quite broad," said Nathan Bengtsson, PG&E interim director of climate resilience and adaptation. "When we went to [research groups] with the [DVC] definition, almost every group said, 'Wow, that doesn't represent a lot of us. You're leaving out farmworkers, you're leaving out people with disabilities."

In 2024, the CPUC required a CAVA to implement a model called the "global warming levels approach," which seeks to draw a link between regional climate change and specific levels of global warming. This approach is meant to help reduce temperature bias in the CAVA program and "largely separates climate projections from underlying socioeconomic scenario assumptions," as the climate generally acts uniformly at different global warming levels "regardless of how society gets itself there," CPUC staff said in OIR 18-04-019. ■

Why This Matters

The CPUC requires large IOUs in California to ensure disadvantaged and vulnerable communities are included in plans for reducing the effects of climate change.

New Data Show Queues Shrank in 2024 as Reforms Implemented

By James Downing

FERC has processed the first round of Order 2023 compliance filings, and the latest round of interconnection queue reforms is being implemented. Some new data indicate the efforts are starting to work.

A recent *analysis* from consulting firm Wood Mackenzie found that grid operators as a whole in 2024 processed 33% more interconnection agreements than they did in 2023. At the same time, they saw 9% fewer new requests and a 51% increase in withdrawals of non-viable projects. That has helped reduce queue lengths.

Interconnection capacity agreements reached historic highs in 2024, with 75 GW approved. Through July 2025, grid operators had approved an additional 36 GW. That's on pace to match 2024's record, Wood Mackenzie said.

The analysis reports that ERCOT's connect-and-manage approach continues to work, leading to the highest success rates and speed to interconnection in the country. ISO-NE takes second place. Wood Mackenzie notes that the ISO-NE delay from moving serial processing to a new cluster study method means it takes four times as long to sign an interconnection agreement there as it does in Texas.

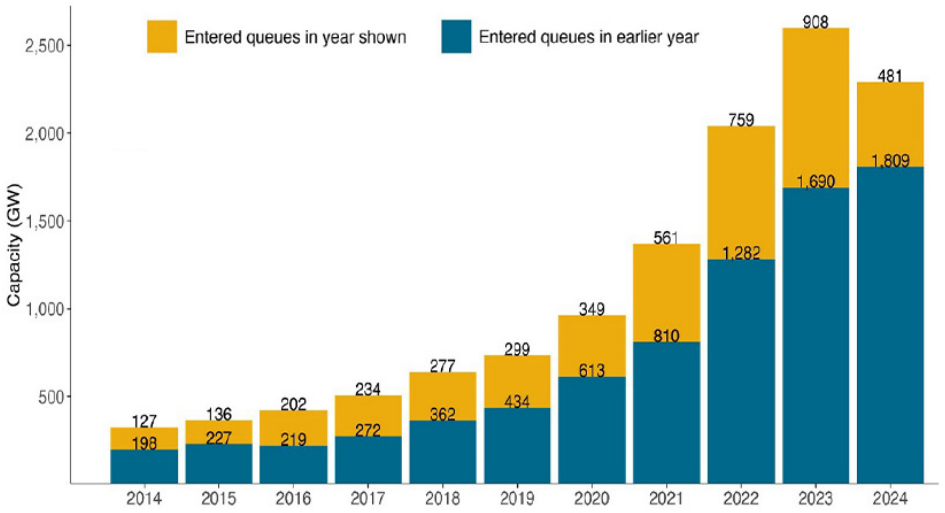
The Lawrence Berkeley National Lab also recently released a nationwide queue *data set*, which includes the same kind of data used to develop its "Queued Up" reports in years past. (See *IRA Driving New Clean Energy as Interconnection Queue Backlogs Persist*.)

LBNL's data comes from all seven organized markets and an additional 49 non-ISO balancing areas that are home to 97% of installed generation in the country. It includes generation projects seeking to connect to the transmission system (with none seeking distribution level interconnection) through the end of 2024.

The country's grid operators had 2,290 GW in their queues at the end of 2024, which includes 481 GW of requests made that year. That is down from 2,598 GW overall and 908 GW of new requests in 2023. The number of older projects from previous years continued to grow, but at just 119 GW, it was at the slowest rate so far this decade.

Nationwide, queues set a record for withdrawals (dating back to 2000), with 340 GW of projects pulling out of the process in 2024. That compares with 127.1 GW in 2023 and is well ahead of the previous annual record of 197.1 GW.

Solar and storage continued to be the two largest technologies seeking to connect to the grid in 2024, but at around 900 GW apiece (including hybrid and standalone projects), both saw the amount in the queues drop from 2023. Natural gas generation is at a fraction of that nameplate capacity, but it saw growth on the year going from 69.4 GW of standalone projects in 2023 to 123.4 GW last year.



A graph from Lawrence Berkley National Lab showing the changes in the queue size nationally by year over the past decade. | *Lawrence Berkley National Lab*

Why This Matters

Getting the projects still in the queues to actually producing electrons has grown in importance due to demand growth. The data show grid operators started to make progress on that front in 2024.

Among the ISO/RTOs, MISO had the largest queue at the end of 2024, with 447.5 GW, with just over half of that coming from solar. ERCOT was second at 346 GW at the end of 2024, including 139.4 GW of solar and 116.8 GW of storage.

CAISO had the largest queue by far in 2023, but its line was down by hundreds of gigawatts in 2024 to a still-large 272.9 GW, with storage representing 167 GW (both standalone and hybrid) and solar an additional 90 GW.

While the number of new requests was down overall, the potential capacity in the queue continues to exceed installed capacity, with 2,290 GW in line compared to 1,322 GW of installed capacity.

LBNL reported that most of the projects in the queue hope to connect to the grid by 2028, with 300 GW planning to connect in 2025, 371 GW in 2026, 403.6 GW in 2027 and 429.1 GW seeking interconnection in 2028.

The data LBNL released includes five-year forecasts of demand and retirements compared to advanced projects in the queue with either signed or drafted interconnection agreements. The one region with a major gap between forecast load and new supply is PJM, which is facing significant load growth. ■

PacifiCorp Moves Forward with Oregon Renewable RFP

Utility Must Allow Bids Reliant on Conditional Firm Transmission

By Elaine Goodman

Oregon regulators have approved PacifiCorp's plans to issue a request for proposals for renewable resources — with a condition that the company accept bids for resources with conditional firm transmission.

The Oregon Public Utility Commission voted 3-0 on Aug. 26 to approve the RFP. The solicitation is for power purchase or energy storage agreements of five to 20 years, for resources that are online by the end of 2029.

The proposed RFP sparked a debate between PacifiCorp and stakeholder groups about whether resources dependent on conditional firm transmission should be eligible to bid.

PacifiCorp has never allowed resources with conditional firm transmission to participate in its RFPs, Rick Link, PacifiCorp's senior vice president for resource planning and procurement, told the commission.

"It's not called 'firm' for a reason," Link told the commission.

The circumstances that may trigger transmission curtailment are unique to each conditional firm agreement, PacifiCorp said in an OPUC filing. And the fact that resource contracts may last as long as 20 years increases the uncertainty.

"These unique conditions for curtailment introduce imprudent and unnecessary risk in planning for reliable operations," the filing said.

The Northwest & Intermountain Power Producers Coalition (NIPPC) and Renewable Northwest argued in favor of allowing bidders that plan to use conditional firm transmission.

"This could substantially increase the bid pool given the sizable queue of projects waiting to be granted long-term firm service at BPA," Renewable Northwest said.

According to NIPPC, Bonneville Power Administration (BPA) offers two types of conditional firm transmission. In one option, BPA may curtail service up to a set number of hours. Alternatively, service curtailment may occur under specific system conditions.

But in reality, BPA rarely curtails conditional firm service, NIPPC said.

In addition, NIPPC said, BPA will lift the conditions on its conditional firm service when transmission expansion projects are completed.

PacifiCorp's renewable resources include the Black Cap solar plant in Lakeview, Ore. | *PacifiCorp*

Why This Matters

PacifiCorp's Oregon RFP comes as the company is working to meet the state's decarbonization requirements amid transmission constraints.

"PacifiCorp, along with other utilities like Portland General Electric Company and Avista, need to be more proactive and innovative in the increasing[ly] transmission constrained world," NIPPC said, while noting that PGE has allowed conditional firm transmission service in recent RFPs.

Growing Constraints

In approving a 2022 RFP, the Oregon commission asked PacifiCorp to analyze potential ways to include conditional firm bids in its next RFP.

"Increasing constraints on the transmission system, particularly on the west side of the PacifiCorp system, make it important to begin to more seriously consider alternative transmission products that may deliver a significant portion of the value that some resources offer the system," the commission wrote in the 2022 order.

But PacifiCorp remained opposed to including conditional firm transmission for resources in its 2025 RFP.

The company said that under rules for the Western Power Pool (WPP) Reserve Sharing Group, any resource procured that uses conditional firm transmission would require PacifiCorp to hold 100% contingency reserves. PacifiCorp wouldn't have access to WPP reserves in the event of the loss or curtailment of conditional firm transmission.

The Reserve Sharing Program is different from WPP's Western Resource Adequacy Program (WRAP).

And conditions leading to curtailments

are more likely when market demand is highest, PacifiCorp said, "which may necessitate the procurement of unspecified market purchases at an elevated price and with the associated assignment of emissions."

Despite PacifiCorp's arguments, the commission ordered the company to accept bids using conditional firm bridge, number of hours or system conditions transmission service in its 2025 RFP. The company will work with an independent evaluator to develop a framework for evaluating those bids alongside firm transmission bids.

2nd Phase Possible

The commission's order leaves the door open for a second phase of the RFP, perhaps in 2026, in the event that questions are resolved around the Boardman-to-Hemingway (B2H) transmission line.

B2H, a partnership between PacifiCorp and Idaho Power, is fully permitted. Idaho Power said on its website that it hopes to break ground on the project in 2025, with an in-service date of 2027. B2H is a 500-kV line that will run about 290 miles from the Longhorn substation near Boardman, Ore., to the Hemingway substation in Idaho.

PacifiCorp included B2H in the preferred portfolio of its 2021 integrated resource plan. At the time, the company expected it would be able to redirect transmission rights with BPA to have a point of receipt at Longhorn, allowing B2H to serve existing load in its West balancing authority area (PACW), according to a report from OPUC staff.

But in 2022, BPA said the redirect requests would need to be evaluated in a cluster study process that had been paused.

PacifiCorp expects B2H to be completed, "but at this time, it is not known when the redirect requests [with BPA] will be granted, when redirect requests might be effective and how much it might cost."

PacifiCorp noted that its RFP doesn't prohibit bids from developers whose resources would use the B2H transmission line.

Decarbonization Goals

The 2025 RFP follows a commission finding that PacifiCorp's 2023 Clean Energy Plan didn't show continual progress toward House Bill 2021 goals. HB 2021 requires the state's large investor-owned utilities to decarbonize their retail electricity sales by 2040.

PacifiCorp's RFP doesn't state the exact amount of resources that will be procured. The company will decide during the scoring process which resource quantities are most cost-effective.

But the company notes that its 2025 integrated resource plan calls for 1,570 MW of utility-scale solar, 1,400 MW of utility-scale wind resources and 320 MW of small-scale solar resources by the end of 2029, along with 781 MW of energy storage of various durations.

An earlier version of the RFP included a requirement that resources be deliverable to Oregon load. PacifiCorp said that was needed due to transmission constraints. But the company agreed to remove that requirement and will instead allow delivery to its six-state system. ■

Newsom Renews Call for Passage of Pathways Bill

Calif. Governor Reiterates Support as Legislative Session Draws to a Close

By Robert Mullin

California Gov. Gavin Newsom renewed his call for state lawmakers to pass a bill to authorize CAISO to relinquish governance of its electricity markets and allow it and the state's utilities to participate in a new "regional organization" designed to oversee a West-wide market.

The bill would implement the plans of the West-Wide Governance Pathways Initiative, a multistate effort to create an independent "regional organization" (RO) to govern CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market (EDAM), the latter set to launch in 2026.

"I'm calling on the Legislature to pass a viable proposal to expand regional power markets — it's our best shot at affordability this year," Newsom said in press release Aug. 27. "Over $1 billion in economic benefits to our state is on the line, and failure to get this done will mean higher electric bills, more pollution and a less reliable power grid. Californians deserve action now to make their electric bills more affordable."

The statement was the first from the governor on the issue since the Legislature resumed the 2025 session Aug. 19 after a monthlong summer recess.

Newsom's reference to a "viable proposal" suggests it's still an open question whether the legislation will be *Senate Bill 540* — known as the "Pathways" bill — or another bill. With the legislative session set to wrap up Sept. 12, the clock is ticking on any effort to get a bill passed.

SB 540 passed the state Senate in June on a 36-0 vote, but the bill's first hearing in the Assembly's Utilities and Energy Committee, scheduled for July 16, was delayed until after the summer break at the request of the bill's author, Sen. Josh Becker (D). (See *Calif. Pathways Bill Delayed After Orgs Withdraw Support, While Newsom Signals Backing for Effort*.)

An Aug. 13 photo posted on Gov. Gavin Newsom's X account shows the governor meeting with a coalition of Pathways supporters. | *Office of Gov. Gavin Newsom*

Becker sought the delay after 21 organizations pulled their backing for the bill in response to an amendment that would establish a new Regional Energy Market Oversight Council charged with ensuring CAISO's participation in the RO "serves the interests of the state." The new council would be authorized to mandate withdrawal by the ISO and utilities if those interests are compromised.

The organizations — which include Environmental Defense Fund, PacifiCorp, Advanced Energy United, Amazon and Portland General Electric — called the amendment "unacceptable" and asked lawmakers to remove it.

Responding to a reporter's question during a July 31 press conference, Newsom reiterated his previous support for the Pathways effort and praised the coalition behind SB 540, saying, "I'm not aware of a more diverse and large coalition I've seen on an issue of energy in some time." The group includes labor unions and publicly owned utilities that strongly opposed past efforts to "regionalize" CAISO.

Newsom's Aug. 27 press release contained a link to an Aug. 13 *post* on the governor's X account showing him meeting with a coalition of Pathways supporters.

"I'm calling on the Legislature to enable the expansion of regional energy markets to lower energy costs, reduce air pollution and avoid power outages," Newsom said in the post.

Pathways Leader 'Optimistic'

But the language coming out of the offices of Newsom and Assembly Speaker Robert Rivas has left open the possibility that the provisions in the original Pathways bill could be tacked on to another bill. With fewer than three weeks left in the session, SB 540 hasn't been scheduled for an initial Assembly committee hearing.

Why This Matters

With the California Legislature nearing the conclusion of its 2025 session, Gov. Newsom's support will become increasingly important for passage of a bill to implement the plans of the Pathways Initiative.

Still, when *RTO Insider* previously asked the two offices about the potential for other strategies that don't include SB 540, both declined to comment, while a source in the governor's office said Newsom would let lawmakers take the lead on the effort.

In an Aug. 26 email to *RTO Insider*, Kathleen Staks, co-chair of the West-Wide Governance Pathways Initiative's Launch Committee, noted that Newsom and Rivas have come out in "very public support" of the Pathways bill.

"In addition, there continues to be an enormous diverse coalition in support of getting this policy done this year (entirely separate from the Launch Committee, which is not engaging in legislative efforts)," said Staks, who is executive director of Western Freedom. While the committee is not involved in lobbying, some of its California members are working to advance the bill in their other organizational capacities.

"The bill has not yet been scheduled for a policy committee hearing in the Assembly because it has been in negotiations between the Gov's office, Senate and Assembly, along with some other big energy issues," Staks wrote. "The coalition continues to advocate for passing a version of SB 540 that works for the West, and we are optimistic that it will get done this year."

The offices of Sen. Becker and Speaker Rivas did not respond to requests for comment in time for publication of this article. ■

ERCOT Stakeholders Endorse 2026 AS Methodology

TAC Also Approves New Requirements for IBRs

AUSTIN, Texas — ERCOT stakeholders, while raising concerns over the grid operator's use of conservative operations, have endorsed staff's recommendations for computing minimum ancillary service quantities for 2026.

The proposed methodology was opposed by the Technical Advisory Committee's six-person consumer segment. They argued in filed comments that the "over-procurement" of ancillary services "starves the energy market of resources" just when it is poised to respond to scarcity conditions.

ERCOT has been using its conservative operations approach as a response to 2021's disastrous Winter Storm Uri. The ISO sets aside larger amounts of operating reserves, one of several out-of-market actions that consumers said "inhibit" the energy market.

"We believe conservative operations undermines efficiency in the energy market," Mark Dreyfus, who represents several public power entities, said during TAC's Aug. 27 meeting. "We all understood after the winter storm here the need for conservative operations, but we are in such a dynamic industry, and we've seen so many changes since then. We're somehow stuck with this policy adopted for a [different] world."

Harika Basaran, director of market analysis for the Public Utility Commission, reminded TAC of the PUC's *2024 report* on ancillary services. The report found the grid operator's use of conservative operations should be maintained to balance system improvements made since the winter storm until additional data is available.

TAC's leadership — ERCOT's Keith Collins, Oncor's Martha Henson (from left) and Jupiter Power's Caitlin Smith (standing) — listen to the discussion | © *RTO Insider*

Why This Matters

Some ERCOT stakeholders are questioning ERCOT's use of conservative operations to set aside large amounts of reserves to address potential risks. However, it will be up to state regulators to change the ISO's conservative approach to operations.

Michele Richmond, Texas Competitive Power Advocates' executive director, reminded members that any decision on conservative operations lies with the Public Utility Commission.

"It seems like we keep going round and round with the same debate about conservative operations, when that's a policy call at the commission," she said. "We keep having the same conversation, and it keeps holding up a lot of the meetings about whether conservative operations is the right call or not. It just seems kind of an exercise in futility to continually have this debate when that's not a decision that anybody in this room or in this building has the ability to make or change."

Staff said the AS methodology's focus is not on scarcity days or hours, but to ensure sufficient services are procured when capacity is available but otherwise may not be online or available in time to cover risks.

TAC agreed with staff's proposal to continue using the regulation service methodology approved in December 2024, but after removing feedback from fast-responding reg service. That service will be retired when the real-time co-optimization plus batteries (RTC+B) project is deployed later in 2025.

ERCOT also wants to use a probabilistic model to establish quantities for ERCOT contingency reserve service (ECRS) and non-spinning reserve service. The model is designed to establish sufficient ECRS plus non-spin reserve quantities for those non-scarcity days when capacity is available but otherwise may not be online or available in time.

Finally, staff recommends that minimum responsive reserve service from primary frequency response be updated to 1,377 MW, aligning with NERC standards.

TAC approved the methodology, 19-7, with three abstentions. The consumer segment was joined by AP Gas & Electric in voting against the measure.

The Independent Market Monitor, which has said the ISO's use of ECRS has created artificial supply shortages, proposed an alternative approach: using a three-hour load forecast error and a one-hour energy storage resource duration to reduce procurement but still maintain reliability.

Requirements for IBRs

Committee members approved revisions to the Nodal Operating (*NOGRR272*) and

Planning guides (*PGRR121*) that establish new advanced-grid support requirements — including model-quality tests and unit validation requirements — for inverter-based ESRs with a standard generation interconnection agreement (SGIA) executed on or after April 1, 2025.

TAC's *Reliability and Operations Subcommittee* granted NOGRR272 urgent status at staff's request. Staff submitted the measure to provide greater support for system resiliency and to maintain stable operations with the prevalence of wind and solar IBRs. ERCOT says it has created and enforced in real time more than 20 generic transmission constraints, most of which are related to IBRs, and the monthly interconnection report says more than 100 GW of IBRs could join by grid by 2026.

"We're going to be talking about this for a long time," ENGIE North America's Bob Helton said, noting that a market-based approach would be more efficient by targeting grid-forming resources.

ROS Chair Katie Rich, with Vistra Operations, said the changes do not "close the door" from looking at market aspects and noted ERCOT staff has committed to further developing a market-based approach.

"I just want folks to know this is not the end-all be-all. You're taking a vote on what's before you today, but there is still more work to be done on this," she said.

ERCOT filed late comments to both the NOGRR272 and PGRR121 approach to target grid forming resources where needed.

Members unanimously approved the combined measures, 27-0. Jupiter Power, Shell Energy and Vistra all abstained.

$827M in Tx Projects OK'd

Members endorsed staff recommendations for a pair of regional transmission projects with projected capital costs of more than $827 million. Both projects require board approval because of their costs.

CenterPoint Energy's Baytown Area Load Addition project costs $545.3 million, as recommended by ERCOT's Regional Planning Group. CenterPoint submitted a $141.7 million estimate to address reliability issues caused by proposed new load in a region thick with petrochemical facilities.

The project involves only about 45 miles of 138-kV lines and adding capacitors. However, staff said its analysis found additional temporary work would be required for all structure replacements, accounting for about 45% of the capital costs, maintenance-outage issues and the expense of rebuilding 138-kV lines among industrial facilities increased the project's costs.

"All consumers in Texas are being asked to spend a half a billion dollars for CenterPoint to be able to upgrade their system," said Beth Garza, representing residential consumers.

Garza voted against the proposal, as did the Office of Public Utility Counsel and retailer Rhythm.

CenterPoint expects to complete the upgrades in January 2028.

The Texas A&M University System RELLIS Campus reliability project has an estimated capital cost of $282.1 million and a projected October 2029 completion date.

The project includes 40 miles of new 345-kV double-circuit lines to the *RELLIS campus*, constructing or rebuilding about 10 miles of 138-kV lines, and expanding the campus' existing 138-kV substation with four additional 138-kV breakers in the existing 138-kV ring bus and four 345-kV breakers in a ring bus configuration.

The RPG shortlisted three options, choosing one that it said performs "significantly better" serving a 1,200-MW load with a formal interconnection request in the study area. Texas A&M is working with four developers to build *small modular nuclear reactors* at the RELLIS campus.

The project was submitted by Bryan Texas Utilities. Dreyfus, who represents BTU among other public power entities, abstained from the vote.

"As a [University of Texas] grad, I find it hard to vote for this," Reliant Energy Retail Services' Bill Barnes cracked. "One possible solution would be to make Kyle Field (Texas A&M's football stadium) an interruptible load."

Combo Ballot Approved

TAC's combination ballot included six nodal protocol revision requests (NPRRs), single NOGRR and PGRR changes, and a system change request (SCR) that, if needing board approval, will:

- *NPRR1265*: Implement procedures for distributed generation (DG) reporting by clarifying DG's definition and defining the new term, "unregistered distributed generators (UDGs)." The NPRR would establish procedures for UDG reporting to ERCOT and reporting requirements from the ISO.
- *NPRR1266*: Specify that a transmission-voltage customer that is a securitization uplift charge opt-out entity may not transfer its status to other entities. The measure adds a requirement that a transmission service provider (TSP) associated with an electric service identifier originally granted opt-out status must compare at least monthly the names of transmission-voltage customers originally granted the status and inform ERCOT of any changes. The TSP requirement excludes those that are securitization uplift charge opt-out entities.
- *NPRR1279*: Enables generation resources to file exceptional fuel costs that include contractual and pipeline-mandated costs and strengthens the process for ERCOT and the IMM to verify the costs.
- *NPRR1283*: Require that any necessary subsynchronous resonance (SSR) studies be complete and mitigation be in place before the initial synchronization of an ESR, new generation resource or a settlement-only generator before the initial energization.
- *NPRR1290*, *NOGRR278*: Address several gaps and clarify protocol language to support the RTC+B initiative's implementation.
- *NPRR1291*: Incorporate the PUC's substantive rule setting a goal for average total residential load reduction into the protocols, specify data exchange methods and formats, and extend the deadline for posting the annual demand response report.
- *PGRR129*: Establish requirements for posting the Grid Reliability and Resiliency assessment and update a list illustrating data sets and classifications.
- *SCR832*: Discontinue and eventually retire a report not being used by market participants. ■

— Tom Kleckner

New Study Highlights Winter Benefits of OSW in New England

By Jon Lamson

The addition of 3,500 MW of offshore wind capacity would have reduced ISO-NE energy market costs by about $400 million over the past winter, according to a recent *study* by Daymark Energy Advisors. The study also found the added capacity would have eliminated $128 million in costs associated with a higher capacity price in the Southeast New England capacity zone.

The study, sponsored by clean energy association RENEW Northeast, comes in the wake of the Trump administration's stop-work order on Revolution Wind, a 704-MW project contracted by Connecticut and Rhode Island that is estimated to be 80% complete. (See *BOEM Slaps Stop-work Order on Revolution Wind*.)

"This study shows that delays in bringing offshore wind projects online are costing New England families and businesses real money," said Francis Pullaro, president of RENEW Northeast.

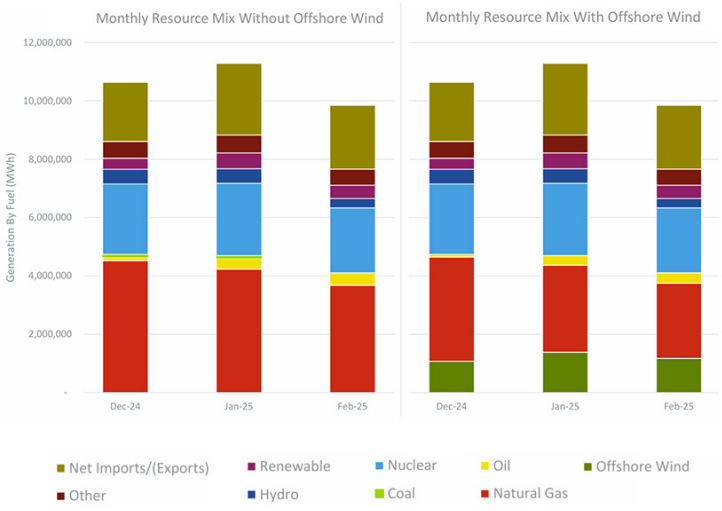
Daymark used historical weather data to estimate the offshore wind production profile over the past winter and compared this forecast production with ISO-NE real-time energy offer data. The firm estimated that the added wind resources would have contributed 3.6 billion kWh of electricity over the winter months, reducing the need for high-cost fossil units. The study also found that the wind resources would have reduced carbon emissions by about 1.8 million tons.

In the capacity market, Daymark noted that a shortage of capacity cleared in the Southeast New England zone caused a higher clearing price ($3.98/kW-month) than the rest-of-pool (ROP) price ($2.611/kW-month). It said the injection of 3,500 MW of offshore wind would have avoided this issue, saving $128 million in capacity costs by substituting the higher zone-specific price with the ROP price, "even after accounting for increased cost of winter excess capacity."

"The OSW capacity would have also displaced the highest price cleared capacity in ROP, likely decreasing the ROP price," Daymark added. "Our analysis conservatively assumes no additional savings from this likely outcome."

New England faced high electricity prices and high consumer energy costs over the past winter due to consistently cold weather.

The region's power sector has become increasingly reliant on natural gas over the past decade, but gas infrastructure into the region is constrained, leaving it susceptible to large price spikes during cold periods. Gas generators typically do not enter firm gas supply contracts, and gas resources often struggle with gas supply during cold periods when heating demand from gas distribution utilities is high.



ISO-NE winter resource mix with and without added offshore wind capacity | *Daymark Energy Advisors*

According to ISO-NE, energy costs over the past winter were *147% higher* than the previous winter, driven by a 179% increase in gas prices, and the total estimated wholesale market cost of electricity increased by about $2.4 billion. (See *New England Energy Market Costs Grew by over $2B in 2024/25 Winter*.)

Why This Matters

While rising winter energy costs in New England have increased the cost-based case for offshore wind, the Trump administration's moves to undercut the US offshore industry have driven a highly uncertain outlook for offshore wind development in the region.

The RTO has said offshore wind's increased production profile during the winter would provide significant reliability benefits by allowing generators to conserve stored fuel. (See *ISO-NE Warns Halting Revolution Wind Boosts Reliability Risk*.)

However, the offshore wind industry in the region faces an uncertain future due to antagonism from the Trump administration, which has created both short-term challenges and long-term concerns about the ability to attract the investment needed for development.

"With several OSW projects already contracted but delayed, the findings underscore the urgent need to accelerate offshore wind deployment to meet both economic and climate goals," Pullaro said.

Susan Muller, a senior energy analyst at the Union of Concerned Scientists, said the Daymark study "shows the power of offshore wind to lower energy prices in New England, especially in winter," and added that "New Englanders need rate relief and a more reliable grid now, and President Trump's nonsensical decision to stall a nearly completed project cannot stand." ■

FERC Approves ISO-NE Follow-up Compliance Filing for Order 2023

By Jon Lamson

FERC has approved a follow-up filing for ISO-NE's compliance with Orders 2023 and 2023-A, authorizing variations from the final rule related to interconnection point modifications, cost allocation and commercial readiness deposits (*ER24-2009-001*).

Order 2023 requires grid operators to adopt cluster processes to study interconnection requests on a first-ready, first-served basis. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

The commission accepted the bulk of ISO-NE's first compliance filing for Order 2023 in April but required ISO-NE to make a series of minor changes and clarifications in a follow-up order, which the RTO submitted in early June. (See *FERC Approves ISO-NE Order 2023 Interconnection Proposal*.) The second filing was supported by NEPOOL and was not protested before the commission.

FERC has accepted this subsequent filing in its entirety, effective Aug. 12, 2024.

In its approval, FERC ruled that ISO-NE can allow interconnection customers to modify their interconnection points during a cluster study. The commission wrote that this change "provides flexibility … to adjust the point of interconnection in the event that unexpected results show that the originally selected point of interconnection is not technically feasible."

ISO-NE wrote in its filing that providing this flexibility should reduce risks of withdrawals from the cluster study process.

FERC also approved ISO-NE's clarification of how it will allocate costs of network upgrades for "reactive devices or any substation additions beyond the point of interconnection."

ISO-NE proposed to allocate these costs proportionately "based on the type of violation and each facilities' impact to that violation," FERC noted.

Regarding commercial readiness deposits, ISO-NE clarified it was to begin accepting surety bonds as of Sept. 1.

"This means that interconnection customers seeking to participate in the transitional cluster study will be able to submit surety bonds to secure commercial readiness deposits for that study," ISO-NE wrote in its filing.

The follow-up filing also included variations related to site control, interactions between cluster studies and ISO-NE cluster enabling transmission upgrade studies, modeling and ride-through requirements for non-synchronous generators, and a series of "minor clean-up revisions," including amendments to typos and unintended errors. ■

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ISO-NE Open to PFP Changes Following NEPGA Complaint

By Jon Lamson

Responding to a complaint about "serious flaws" in ISO-NE's Pay-for-Performance (PFP) design, ISO-NE said it is open to capping the balancing ratio used to calculate PFP payments at 1.0 to prevent capacity resources from being required to provide more power than their capacity supply obligations (CSOs).

Multiple generation companies, associations and municipal utilities supported the New England Power Generators Association (NEPGA) complaint and the proposed solution. Consumer advocates and the New England states expressed support for the general concept that generators should not be required to provide more power than stipulated in their CSOs (*EL25-106*).

NEPGA's complaint stems from an ISO-NE capacity shortfall event on June 24, in which New England experienced its highest peak load in over a decade. ISO-NE estimates that PFP payments associated with this event totaled over $114 million. (See *Extreme Heat Triggers Capacity Deficiency in New England*.)

The RTO's PFP mechanism compensates resources for performing beyond their obligations during scarcity events, while charging these costs to underperforming resources with CSOs. The amount of power that capacity resources are required to provide during shortage events is determined by the balancing ratio, which equals the region's capacity requirement divided by the total amount of available capacity.

During the June 24 event, the balancing ratio exceeded 1.0 for the first time in the region's history, averaging 1.031 over the three-hour scarcity period. This required capacity resources to provide power in excess of their CSOs, costing capacity resources about $25.6 million.

In a Section 206 complaint submitted by NEPGA to FERC following the event, the association argued that ISO-NE should be required to cap the balancing ratio at 1.0 to prevent "improper charges" on capacity resources. (See *NEPGA Seeks Relief for 'Improper' Pay-for-Performance Costs in ISO-NE*.)

NEPGA also took issue with ISO-NE's method for allocating stopped losses for underperforming resources. ISO-NE's PFP rules include stop-loss provisions capping the total charges an underperforming resource can accrue each month. ISO-NE allocates the under-collection of charges caused by the stop-loss limit to all capacity resources that have not hit their limit.

NEPGA argued that these costs should not be socialized among capacity resources and that the under-collection instead should be deducted from the credits paid to performing resources.

Stakeholders including RENEW Northeast, the Electric Power Supply Association, LS Power, FirstLight Power and the Massachusetts Municipal Wholesale Electric Co. supported NEPGA's filing in comments submitted to FERC prior to the Aug. 21 deadline.

Bellingham Energy Center in Bellingham, Mass. | *NextEra Energy*

Why This Matters

Stakeholders expressed concern that, if left unaddressed, risks of excessive or unfair Pay-for-Performance penalties could push up capacity prices in future auctions.

"The proposed changes are not only reasonable but essential because they eliminate penalties on perfectly performing resources and preserve durable, risk-balanced price signals for future scarcity events," wrote LS Power.

The New England States Committee on Electricity (NESCOE) and a coalition of consumer advocates from five of the six New England states offered general support for the concept of capping the balancing ratio.

"NESCOE does not take a position on whether or not the commission should grant or deny NEPGA's complaint or whether or not the commission should order NEPGA's requested relief," the states wrote. "However, NESCOE does agree with NEPGA on the general principle that a capacity resource should not be held to a performance standard that exceeds its capacity supply obligations."

The states also echoed NEPGA's concern that penalizing perfectly performing capacity resources "will eventually either disincentivize resources from participating in the Forward Capacity Market or cause higher risk premiums, which in turn increases both reliability risks and prices."

The consumer advocates took a similar stance, and encouraged FERC, ISO-NE and stakeholders "to develop a solution that (1) retains the existing insulation of load from direct financial costs of CSCs [capacity scarcity conditions], and (2)

avoids the incorporation of unnecessary and potentially substantial risk premiums into future capacity supply offers due to the now material possibility that a capacity resource could be financially liable for failure to overperform during a CSC."

They noted they generally are "wary of any rule or market design that could broadly disincentivize participation in the capacity market," and that, "in a time of increasing demand forecasts and already increasing capacity product prices, the region cannot afford the financial or reliability ramifications of a short capacity market."

ISO-NE did not endorse any changes to the PFP methodology but said it "would not oppose an order from the commission to cap the balancing ratio at one … so long as adequate time is provided for the ISO to evaluate and make other necessary changes to the Forward Capacity Market rules so that the capping does not create other problems."

The RTO wrote that capping the balancing ratio likely would not "materially undermine" incentives for resources to perform during capacity scarcity events.

It acknowledged that many suppliers are not capable of providing power in excess of their CSOs and conceded NEPGA's argument that "the risk of the balancing ratio going above one was discussed only as a theoretical possibility, and that suppliers very well may not have accounted for it as a result."

However, ISO-NE opposed NEPGA's complaint and proposal regarding the allocation of stopped losses.

It argued that all resources with CSOs "potentially benefit from the stop-loss mechanism because — in addition to limiting a supplier's net financial losses — it enables a supplier to know its maximum loss exposure prior to participating in the Forward Capacity Auction, and to communicate its maximum loss exposure to third parties with which it may do business, such as external entities providing financing."

While ISO-NE argued that NEPGA failed to demonstrate that the allocation of stopped losses is not just and reasonable, it acknowledged NEPGA's proposal to adopt PJM's cost allocation methodology may be a viable alternative. The RTO said that "implementing such a replacement rate is feasible under the 180-day compliance timeline."

Vitol, which operates as a power marketer in New England, opposed NEPGA's complaint in its entirety, arguing that NEPGA failed to demonstrate that the current rules are not just and reasonable.

"NEPGA cannot escape the fact that the PFP program FERC approved in 2014 was designed to impose a share-of-system obligation on capacity resources during scarcity events, and that it was expressly recognized that the balancing ratio could exceed 100%," Vitol wrote. "The PFP design feature at issue in the complaint was debated, and it was approved by the commission."

Vitol noted it does not hold capacity commitments in the region, and that it earned PFP credits by importing power to the region during the scarcity event. It argued that NEPGA's proposed changes "would harm reliability in New England by diluting incentives for suppliers to deliver energy in scarcity circumstances when it is most needed." ■

Stakeholders Mixed on ISO-NE Prompt Capacity Market Proposal

Shift to a Prompt Market Could Have Big Impact on Resource Entry, Exit

By Jon Lamson

As the first phase of ISO-NE's capacity market overhaul nears its final form, New England stakeholders remain mixed on the proposed move from a forward to a prompt capacity auction.

While the second phase of the RTO's capacity auction reform (CAR) project — centered on capacity accreditation changes and splitting capacity commitment periods (CCPs) into seasonal periods — will likely draw more attention, the prompt changes would still cause a major shift in the region's approach to procuring capacity and could have significant effects on market outcomes.

ISO-NE's proposed transition from a forward capacity market, with auctions held more than three years before each capacity commitment period (CCP), to a prompt capacity market, with auctions less than a month prior to each CCP, requires significant changes to the RTO's rules regarding resource entry and exit from the market.

In a prompt market, new resources would need to prove they are fully operational to gain a capacity supply obligation (CSO), and resources under development would have no guarantee of future capacity revenues until they come online.

This would also affect the costs resources are allowed to include in bids: generators could only include incremental costs associated with assuming a CSO in their bids and not include development costs that have already been incurred.

The shift to a prompt market would also significantly affect ISO-NE's rules for retiring resources. The RTO currently processes retirements in the capacity auction process, providing the region with about four years' advanced notice on retirements. In a prompt auction format, ISO-NE has proposed decoupling the retirement process from the capacity auction process and would require retiring resources to submit a binding deactivation notice one year prior to the relevant CCP.

Why This Matters

Uncertainty remains around how the shift to a prompt capacity market will affect overall capacity costs in New England.

The effects these changes will have on resource entry and exit is unclear; while some NEPOOL members are optimistic the new auction format will more accurately reflect the capacity available to the region in each CCP, stakeholders have also expressed concern that it will create challenges for resource development and could lead to more prolonged reliability must-run (RMR) agreements.

Tom Kaslow, chief market policy officer at FirstLight Power, said the prompt proposal "appears to present both improvement and concern."

He said the requirement for resources to be fully operational before participating in auctions will eliminate market distortions caused by new resources that gain CSOs in the forward capacity market but fail to come online in time to meet their obligation.

However, he said it is unclear how this requirement will affect the ability to develop new resources that lack long-term power purchase agreements with states or utilities.

"The prompt auction framework also raises questions regarding the extent to which existing resources will be able to reflect their going forward costs, such as major maintenance, in capacity auction offers," Kaslow said. "In addition, if the cost of new entry is sunk before a new resource's first capacity auction opportunity and existing resources face difficulty in reflecting the full extent of their going forward costs, the market could face greater volatility where sizable exit and entry occur."

Some stakeholders have also raised the concern that ISO-NE's proposal could increase reliance on long-term state power purchase agreements to ensure resource adequacy.

This concern is not universal, however, and one representative of a renewable energy company expressed optimism that a prompt market would lower risks for solar and storage developers, as they would not have to commit to a CSO years prior to their commercial operations date.

ISO-NE said in a statement that the prompt auction format "allows new resources to sell capacity as soon as they are operational and no longer have to predict their commercial date three years in advance."

"We generally expect that capacity revenues are just one piece of a project's economics that developers consider in addition to the expected energy and ancillary services a resource can contribute over the project's lifetime," ISO-NE added. "The capacity revenue for a single year comprises only a small portion of these expected lifetime revenues."

Some NEPOOL members have also argued that ISO-NE's proposed one-year notification timeline for resource retirements could increase the length of reliability-must-run agreements if retiring resources trigger reliability issues, saying that developing a reliability solution within a year would be challenging.

ISO-NE initially proposed a two-year retirement notification timeline, but reduced it to one year, saying a shorter timeline "allows resources to consider as much relevant information as possible, maintaining as much option value as possible, hence improving the probability of efficient deactivation decisions."

At the NEPOOL Markets Committee (MC) meeting in August, the RTO acknowledged that "the shortened notification timeline may increase the duration of a reliability retention."

"However, the improvement in a resource's assumptions about future market prices and operating conditions

may prevent a premature deactivation, thereby potentially eliminating the need for a reliability retention," said ISO-NE analyst Kevin Coopey.

Unclear Effects on Market Outcomes

Multiple stakeholders emphasized also the difficulty of forecasting how the prompt changes will affect market outcomes, especially when coupled with the seasonal and accreditation changes. The two phases of CAR will be filed separately with FERC but are both intended to take effect for the 2028/29 CCP.

The Massachusetts Attorney General's Office (AGO), which advocates for the state's ratepayers, has asked ISO-NE to provide quantitative analysis on the prompt proposal, but the RTO has provided little information on how the updated proposal would affect market outcomes.

ISO-NE commissioned Analysis Group to conduct a preliminary *analysis* in late 2023 on a prompt-seasonal market. The findings indicated that, relative to the existing forward capacity market, a prompt-seasonal format would reduce total capacity payments by about 12% and that the prompt changes alone would reduce total costs by about 10%. (See *NEPOOL Markets Committee Briefs: Jan. 11, 2024*.)

In a recent statement, ISO-NE said this analysis demonstrated "numerous benefits to consumers and suppliers, as well as market efficiency gains, which helped inform the decision to pursue the Capacity Auction Reforms."

The RTO plans to conduct a comprehensive impact analysis during the second phase of the CAR project, allowing it to quantify the effects of both the prompt and the seasonal/accreditation changes.

In a recent interview, the Massachusetts AGO said it has been closely following the proposed resource entry and exit changes associated with a prompt auction, but added it lacks clear insight into how the changes will affect prices, and is eager to see more specific numbers on the expected impact of the proposal.

Canal 3 Generating Station in Cape Cod, Mass. | *Burns & McDonnell*

Other consumer advocates in the region expressed a similar interest in better understanding how the changes will affect costs for ratepayers.

Matthew Fossum, director of regional and federal affairs at the New Hampshire Office of the Consumer Advocate, emphasized the importance of ensuring the shift to a prompt market "does not create for New England the kind of issues that we have seen recently in other regions, particularly PJM."

"With the long lead times and supply chain we are hearing about for investments in generation resources, and with the uncertainty around state and federal policies at present, we need to be thoughtful about the reforms that shorten the time frame for capacity auctions so New England does not end up designing markets that land us in the same unwelcome place," Fossum added.

Connecticut Consumer Counsel Claire Coleman commented that she hopes transitioning to a prompt auction "will reduce costs for consumers by removing some of the risk that suppliers build into their capacity auction bids" and "will make it easier to bring new energy supply online and facilitate more accurate modeling of what generation assets are available for use within the region."

However, she acknowledged the impact on consumers "remains to be seen" and said the Office of Consumer Counsel is approaching the capacity market overhaul "with the hope that some of these changes will result in bills reductions for consumers down the road."

Next Steps

In a memo Aug. 20, ISO-NE announced a one-month delay to the NEPOOL voting schedule for the prompt proposal and now plans to seek a vote at the MC in November and the Participants Committee in December. The RTO said this delay will not affect the timeline for commencing work on accreditation.

Several NEPOOL members said they are anxious to get started with the work on the seasonal/accreditation changes, which will almost certainly be the more controversial phase of the project, and may ultimately have a riskier path to approval with FERC if the RTO is unable to build a broad consensus. ■

MISO Seeking Realistic Gen Buildout for Tx Planning Futures

By Amanda Durish Cook

MISO said its set of 20-year transmission planning futures must be further fine-tuned after the Trump administration's repeal of tax credits for renewable generation.

The grid operator said introducing the constraints of the One Big Beautiful Bill Act into its capacity expansion modeling returned a build rate that cannot be achieved.

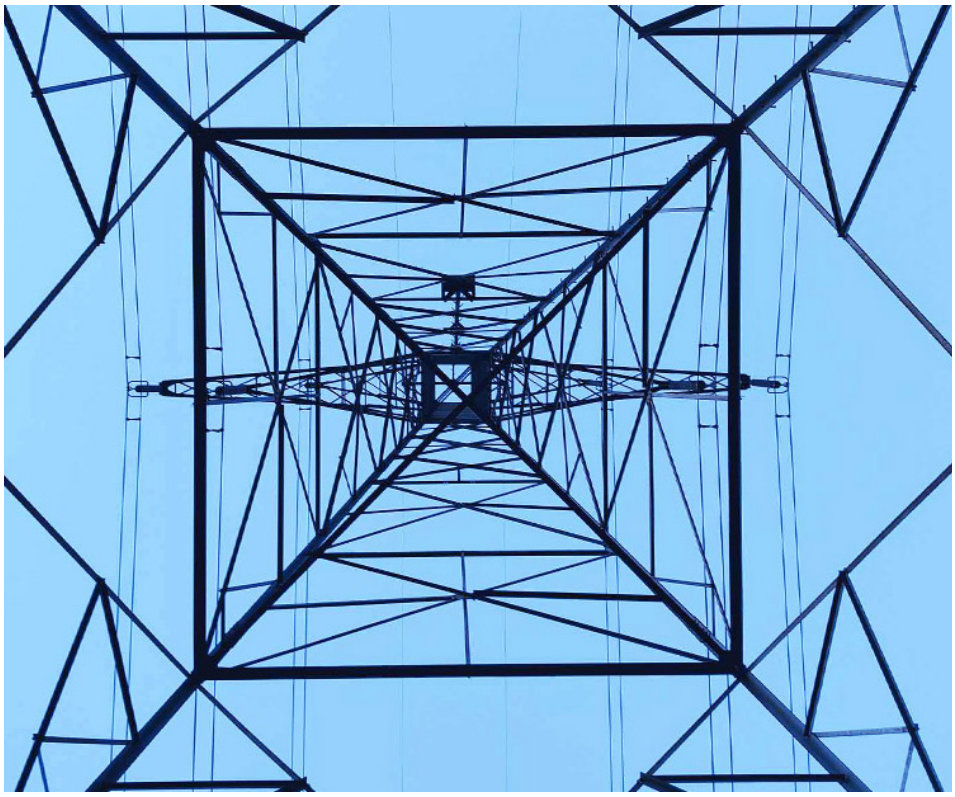
MISO announced it would take a few months to rework the capacity assumptions in its four 20-year transmission planning futures after passage of the sweeping law in July. (See *MISO Revising Transmission Futures After Repeal of Tax Credits*.)

But Director of Economic and Policy Planning Christina Drake said MISO's modeling using the confines of the law is building too much capacity too fast before the full phaseout of renewable tax credits. Drake said models included an infeasible amount of generation in the first five years.

MISO's modeling contemplates a 20-year expansion period and builds according to economic conditions and incentives.

"We need to have a reasonable band for what can be built in the near term," Drake told stakeholders at an Aug. 29 workshop to discuss the futures.

MISO now is looking for "practical limitations to near-term build-out," Drake said. She said MISO is assessing its queue delays and sluggish supply chains alongside the rollback of incentives for renewable energy to figure out what developers realistically can build. Drake said MISO's historical build rate with recent supply crunches factored in results of only 9 GW built per year.



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MISO plans to hold more workshops Sept. 24, Oct. 29, Nov. 18 and Dec. 17. MISO added the last two dates after it realized it would need to modify its capacity expansion estimates.

Drake said MISO did a "hard pivot" in its futures after the passage of the bill.

The four futures will be used when MISO resumes its long-range transmission planning in 2026. ■

MISO on Track to Wrap Summer with 122-GW Peak, Addresses Frequent South Advisories

By Amanda Durish Cook

MISO is poised to close the door on summer 2025 with an almost 122-GW peak while issuing several capacity advisories for MISO South.

MISO *recorded* a 121.6-GW peak on July 29, a few gigawatts more than July 2024's 118.1-GW peak. Load for the month averaged 92.2 GW, higher than any July in recent years.

Hot weather across the footprint led MISO to its late July peak, which occurred during a maximum generation warning and conservative operations instructions for the entire footprint and while MISO South was under a local transmission emergency. (See *MISO Skirts Max Gen Emergency in July Heat*.)

Before summer, MISO estimated it would navigate a 122.6-GW peak in its most likely forecast scenario. (See *MISO Braces for Hot Summer, Potential 130-GW Peak*.) The last time the MISO system hit 122 GW was August 2024.

At an Aug. 28 Reliability Subcommittee meeting, MISO Senior Director of Reliability Coordination John Harmon said the system performed as expected during a "hot, hot, humid and stormy month."

July's average daily generation outages were 40 GW, higher than the average 32 GW of the past three years in July. The month's solar peak at 13.1 GW closed in on a 15.4-GW wind peak. Both occurred in early July.

July's real-time prices averaged $47/MWh, owing mainly to higher gas prices at $3/MMBtu. In July 2024, $2/MMBtu gas held prices at $30/MWh. Day-ahead market congestion collections for the month more than doubled to $116.59 million from $63.23 million in July 2024.

MISO published more than 50 notifications throughout July for various reasons, including cautioning members about a lack of capacity or transmission capability, warning of severe weather, or updating or canceling instructions and alerts. Many of the notifications were aimed at MISO South.

Why This Matters

One stakeholder said MISO's capacity advisories for its South region have become so frequent that they're easy to ignore.

Majority of Days Come with Capacity Advisories in MISO South

MISO kept up a near-daily cadence of capacity advisories for MISO South — namely Entergy — throughout August. The RTO cited either higher-than-forecast load, squeezed transfer capabilities or forced generation outages as reasons behind the advisories. So far, MISO South has been the focus of 17 capacity *advisories* in August.

MISO expanded a capacity advisory to the Midwest as well as the South in mid-August as heat enveloped the footprint.

Stakeholders at the Reliability Subcommittee meeting asked MISO what's behind the more prevalent advisories for the Entergy territory. Harmon said MISO "made a change to increase the communication about the risk that we see in load pockets" throughout the South. Otherwise, Harmon said systemwide July notifications were from a combination of hotter weather and generation outages.

"They're almost daily, aren't they?" Mississippi Public Service Commission consultant Bill Booth said of the advisories directed at Entergy.

WEC Energy Group's Chris Plante said the declarations have been issued on top of one another, with another announced moments after one expires.

Harmon said MISO's advisories are only for specific hours of the day that contain elevated risk. He said that's why MISO terminates them and reissues them for the following day.

Booth asked if the capacity advisories are part of MISO's communication response to the Memorial Day weekend load-shedding event in greater New Orleans. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

Harmon said the string of advisories aren't a direct result of the New Orleans outage, but that it lines up with "how can MISO communicate risk further in advance." He said they're meant to communicate greater risk beyond a normal operating day in MISO South.

"You just see so many of them that after a while you tend to ignore them," Booth observed.

MISO also announced at the Reliability Subcommittee meeting that it will redraw an operating reserve zone in Louisiana and Texas.

MISO South's Operating Reserve Zone 7 currently includes the West of the Atchafalaya Basin (WOTAB) load pocket. The RTO wants to trim the eastern portion of WOTAB out of the zone to make the Southeast Texas (SETEX) load pocket the more consequential area to the zone.

MISO's operating reserve zones are different than its local resource zones and are split up so MISO can ensure ancillary services like regulating and contingency reserves can be dispersed to meet predicted shortages. The RTO currently has eight such zones and can alter them after conducting quarterly studies.

MISO's Dalton Daughtrey explained that SETEX is a more transfer-limited pocket than WOTAB. He said MISO is initiating the change so it can more "sufficiently manage reserves in real time."

Daughtrey explained the narrowed reserve zone aligns with Entergy's operating guide for the area. He said SETEX contains more "impactful tie lines" and explained there is smaller transport capability in SETEX.

Harmon added the change will make sure reserves are deliverable.

MISO plans to relegate the eastern portion of WOTAB cut from Zone 7 to Zone 8, which encompasses most of MISO South that isn't in either Zone 7 or Zone 6 (the Amite South load pocket in southeastern Louisiana). ■

26.5 GW of Mostly Gas Gen Compete for MISO's Sped-up Grid Treatment

By Amanda Durish Cook

MISO announced that its first interconnection queue express lane application window turned up 47 projects at a little more than 26.5 GW of proposed new capacity, with natural gas generation accounting for about 20 GW.

The grid operator said projects are spread across 12 states and include 74% natural gas, 15% battery storage, 4% wind, 4% solar and 3% nuclear power. MISO's interconnection fast lane is meant to maintain resource adequacy and was approved by FERC in July. (See *FERC Approves MISO Interconnection Queue Fast Lane*.)

Despite the apparent dominance of natural gas across 22 project requests, MISO leadership said the applicant pool represented a "large, diverse" assortment.

"This broad mix underscores MISO's evolving energy landscape and the urgent need to bring new resources online to address growing reliability challenges," MISO Vice President of System Planning Aubrey Johnson said in a press release. "These projects are designed to meet localized and accelerating demand growth."

MISO's temporary fast lane process is designed to study up to 10 projects per quarter. MISO will discontinue the special study process after it processes a maximum of 68 projects, with the program due to sunset no later than Aug. 31, 2027. MISO said some projects on the first *list* may have to be shifted to future study cycles.

MISO said it's evaluating the applications for completeness and will publish an approved list of projects that will proceed to study sometime after Sept. 2. Projects must show they will help serve "clear resource adequacy or reliability need," according to MISO, and must have verification from relevant regulatory authorities. Projects also need to be commercially operable within three to six years.

We Energies' natural gas-fired Weston Power Plant near Wausau, Wis. | *We Energies*

"These projects must meet strict requirements to ensure that only viable, needed projects are considered," Johnson said.

MISO accepted the interconnection requests Aug. 6-11 as part of its first study cycle and has said eligible projects will be studied on a first-come, first-served basis.

Critics of the process said it would give thermal resources preferential treatment over renewable energy and favor load-serving entities' projects while discriminating against independent power producers. (See *MISO's Queue Fast Lane, Take 2, Nets Déjà vu Arguments*.)

MISO declined to comment on what share of the generation proposals originated from independent power producers versus load-serving entities. It also refused to say whether it expected the majority gas proposals. Spokesperson Brandon Morris said MISO had nothing further to add at this time.

MISO's list appears to include NextEra Energy's attempt to recommission the Duane Arnold nuclear power plant in Iowa. (See *NextEra Closer to Recommissioning Duane Arnold with FERC Waivers*.) Louisiana held the highest number of gas requests, at five, which includes a trio of recently approved gas plants to power a $10 billion Meta data center in the northeastern part of the state. (See *Louisiana PSC Approves 3 Controversial Gas Plants Ahead of Schedule for Meta Data Center*.)

Wisconsin, which has a goal to achieve 100% carbon-free electricity by 2050, followed with four requests for gas plants. Indiana and Iowa followed with three requests apiece.

Environmental nonprofits and clean energy groups have sought a rehearing of FERC's decision to approve the expedited interconnection process. Clean Wisconsin, Natural Resources Defense Council, Sierra Club and the Sustainable FERC Project have banded together to *file* one rehearing request, while the American Clean Power Association, the Solar Energy Industries Association, the Southern Renewable Energy Association and Clean Grid Alliance have *joined* forces on another. Both rehearing requests, filed Aug. 20, again allege the process is discriminatory and challenge the notion that MISO faces imminent resource adequacy deficiencies that justify a queue fast track.

"This is a predictable and devastating outcome for the 200 GW of clean, affordable energy that are being punished for playing by the rules," Sierra Club senior campaign adviser Jessi Eidbo said in a statement to *RTO Insider*. Eidbo was referring to existing renewable energy and clean generation in MISO's approximately 300 GW normal interconnection queue.

"Millions of people served by utilities in the central United States will see unnecessarily higher monthly electric bills because MISO and Trump are needlessly dismantling the clean energy economy," Eidbo said. ■

Why This Matters

MISO said it will winnow down the 47 project applicants to get to its allotted 10 projects for fast-tracked interconnection study this quarter.

Eddystone Ordered to Remain Operational for PJM 90 More Days

Secretary Wright Issues 2nd Emergency Order on Units 3 and 4

By John Cropley

The U.S. Department of Energy has issued another emergency order keeping Units 3 and 4 of the Eddystone Generating Station in Pennsylvania in operation.

The dual-fuel, 380-MW subcritical steam boiler-turbine generator units are 55 and 58 years old, and Constellation Energy had scheduled them for retirement May 31.

But Energy Secretary Chris Wright on May 30 issued an emergency order keeping them in operation to minimize the risk of energy shortfalls in the Mid-Atlantic region.

That order was to expire the evening of Aug. 28. Wright issued the follow-up order to Constellation Energy and PJM the evening of Aug. 27.

In an Aug. 28 news release, he said keeping Units 3 and 4 operational has improved energy security in the PJM region. He pointed to the June and July heat waves, when PJM called on the two units to generate electricity. And he said the emergency conditions that led to his first order persist.

The new order continues until Nov. 26.

PJM spokesperson Jeff Shields described the order as a "prudent, term-limited step" to keep Eddystone operational.

"PJM has previously documented its concerns over the growing risk of a supply-and-demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers," he wrote in an email. "PJM supports the U.S. Department of Energy's extension of its order, originally issued May 30 pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint, which spans all or part of 13 states and the District of Columbia."

FERC approved a PJM filing to allocate the costs across all RTO load that Constellation incurs keeping Eddystone operational. But that proposal was effective only until Aug. 28. Stakeholders are working toward a longer-term solution for addressing cost allocation for DOE emergency orders through the DOE 202(c) Cost Allocation Senior Task Force. The RTO did not answer questions about whether another Critical Issue Fast Path (CIFP) process is expected to be required for costs under the latest DOE order. (See *FERC Approves Cost Allocation for Eddystone Emergency Order*.)

Eddystone Generating Station in Eddystone, Pa. | *Constellation*

Why This Matters

FERC has said the cost of keeping Eddystone open would be spread across all PJM load, with charges determined by multiplying load-serving entities' share of the RTO monthly unforced capacity obligation by the monthly credit paid to Constellation.

President Donald Trump, Wright and other administration officials have been pushing to halt retirement of gas- and coal-burning power generation facilities as part of their pro-fossil, anti-renewable campaign for American energy dominance, saying a power generation crisis is developing.

Wright also blocked retirement of the J.H. Campbell coal-burning plant in Michigan in May and issued a follow-up order Aug. 20 extending its potential operation for another 90 days.

Wright also lifted annual run-hour restrictions on the H.S. Wagner Generating Station Unit 4 in Maryland in July.

In both cases, Wright cited a shortage of generation capacity.

These orders and others issued by Wright are under authority of Section 202(C) of the Federal Power Act, which historically has been an obscure provision but is seeing more frequent use in the second Trump administration.

The Biden administration issued 11 emergency orders under Section 202(c) in four years, all weather-related. With the Eddystone order, the Trump administration has issued eight orders and two extensions in a little more than four months. ■

Robert Ethier, Le Xie Nominated for PJM Board

RTO's Members Committee Expected to Vote on the Candidates at Next Meeting

By Devin Leith-Yessian

PJM's Nominating Committee has named two candidates to fill vacant seats on the RTO's Board of Managers: Robert Ethier, former ISO-NE executive, and Le Xie, faculty co-director of the Power and AI Initiative at the Harvard School of Engineering and Applied Sciences.

The RTO's Members Committee (MC) will vote on the two candidates during its Sept. 25 meeting. Ethier and Xie would be filling board positions left open after PJM stakeholders declined to re-elect two members during the May Annual Meeting. (See *PJM Stakeholders Reaffirm Board Election Results*.)

During his time at ISO-NE, Ethier filled three vice president positions — system planning, market operations and market development — between 2008 and 2024 and is now a principal at Stickney Brook Consulting, based in Florence, Mass.

In a June 2024 *announcement* of Ethier's retirement from the New England grid operator, ISO-NE President Gordon van Welie said, "Bob possesses a wide breadth of knowledge coupled with deep understanding of many aspects of the incredibly complex system we manage."

Robert Ethier | *ISO-NE*

What's Next

PJM's Members Committee will vote on Ethier and Xie at its next meeting in September.

Xie has served as a professor at Harvard since 2024, before which he taught at Texas A&M University starting in 2010 and held previous roles at Massachusetts Institute of Technology and the University of California, Berkeley. He is also a fellow and distinguished lecturer at the Institute of Electrical and Electronics Engineers and has served as an editor for the group's *Transactions on Power Systems* journal.

In an *announcement* of the selection, Nominating Committee Chair Jeanine Johnson recognized the widespread interest in PJM's leadership. Nine state governors wrote to the Board of Managers in a July 16 *letter* requesting a formal, permanent role for member states in selecting two seats on the nine-member board. Virginia Energy Director Glenn Davis attended the July 23 MC meeting, along with a delegation from other states, calling for a new vision of how PJM and the states interact.

"The Nominating Committee is confident that Bob and Le will make significant contributions as PJM board members," Johnson wrote. "The Nominating Committee would like to acknowledge the interest of the PJM states in the activity of the Nominating Committee and appreciates the proposal of candidates. The Nominating Committee considered the proposed candidates, followed its process and code of conduct, and selected nominees best aligned with the position description adopted by the committee."

The governors of Pennsylvania and Virginia co-signed an Aug. 11 letter recommending recently retired FERC Chair Mark Christie and former FERC Commissioner Allison Clements to fill the positions. (See *Pa., Va. Governors Float Clements, Christie as PJM Board Candidates*.)

Le Xie | *Harvard John A. Paulson School Of Engineering And Applied Sciences*

"As governors from different parties, we have points of disagreement on energy policy, but we are united by the need to get PJM back on track to fixing the problems we collectively face," the two governors wrote. "By working together with a diverse, bipartisan coalition of governors, we are committed to solving these collective problems and to ensuring that the citizens of our states and the region receive the affordable, reliable power that they deserve."

FERC granted PJM a waiver of the requirement that it take no more than one month to bring board candidates before the MC following a vacancy, a move the RTO argued was necessary to "ensure sufficient time to identify potential board members and to complete appropriate due diligence, including background checks, prior to announcing the proposed nominees to be considered and voted on by the Members Committee." (See *PJM Files Waiver Seeking Additional Time to Select Board Candidates*.) ■

NRG, PJM IMM Disagree on LS Power Deal's Market Power Impact

By James Downing

NRG Energy is pushing back against arguments from PJM's Independent Market Monitor (IMM) that its deal with LS Power would increase market concentration in the RTO and needs to meet conditions before FERC approval (*EC25-102*).

In an earlier protest, the IMM called for bidding limits on generation and demand response resources. (NRG will acquire CPower in the deal.) Those resources have grown in importance as the supply-demand balance in PJM has narrowed. (See *PJM Monitor Calls for Bidding Limits on NRG Generation, DR in LS Deal*.)

NRG told FERC in an Aug. 7 response that its deal to buy power plants and a DR aggregator from LS Power would not have an adverse impact on PJM. NRG filed a delivered price test (DPT) and updated analysis from economist John Morris. As in past proceedings, the IMM proposes conditions that are directed at the effectiveness of the PJM markets and mitigation measures as a general matter that goes beyond FERC's normal merger review process, NRG said.

The DPT analysis from Morris "showed that the transaction will have no adverse effect on competition in PJM or any relevant or potentially relevant PJM sub-market," the firm said. "Indeed, while applicants are not required to show that the transaction will enhance competition, the DPT analysis shows that the transaction would actually reduce concentration in the PJM market and all relevant or potentially relevant sub-markets in most time periods."

FERC staff posted a *deficiency letter* Aug. 13, seeking more information on the deal, including questions about whether demand response resources were included in the horizontal market screens for PJM and NYISO. Staff asked other questions about data NRG submitted around generation.

The IMM filed an answer Aug. 27 arguing that NRG failed to rebut findings that its structural market power would grow with the deal as measured by the "three pivotal supplier [TPS] test."

"NRG applicants should not be permitted to exercise market power, and the transaction should not be approved without reasonable measures to protect the public interest in competition and competitive market outcomes," the IMM said.

The deal will increase market power in sub-markets of PJM, and NRG misstates the deal's impact on the concentration of ownership in demand response, the IMM said.

"The applicants must provide record support for a finding that a transaction is consistent with the public interest," the IMM said. "Showing that a transaction has net positive benefits for competition would provide evidentiary support … consistent with the public interest finding. Showing that a transaction does not harm competition is the minimum. No transaction can be approved under the applicable standard if it harms the public interest."

NRG pushed back by saying the IMM failed to provide enough evidence backing up its "alternative competitive analysis" and instead relies on a dataset that is not available to NRG or the public.

"Over and above the unfairness to applicants of accepting such an analysis, doing so would create massive regulatory uncertainty extending beyond this proceeding as entities considering transactions involving assets in the PJM market would be left with no way of evaluating, in advance, whether those transactions could even potentially be deemed to present competitive issues," NRG said.

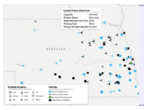
Morris' initial analysis argued that the deal essentially will flip the supply positions of NRG and LS Power in PJM, with very little change in market concentration. NRG would grow from 1.2% of supply to 5.4%, but LS' share falls from 6.5% to 2.4%, resulting in lower market concentration across the RTO.

The IMM and consumer advocates ignore the second part of the deal, NRG said,

Why This Matters

The IMM has brought up similar arguments in the past, and while FERC has not conditioned its merger approvals on them, other firms pursuing mergers have worked with the Monitor to get deals done.

National/Federal news from our other channels



Neb., Miss. Utilities to Pay $186K in Penalties — ERO Insider

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Texas RE Speaker Discusses Cyber Recovery Obligations — ERO Insider

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focusing on NRG's growth and ignoring the shrinking supply of LS Power, which will remain as a competitor in PJM.

While FERC previously said it does not rely on the TPS test for analysis of mergers, NRG noted that even so, the market already has rules in place when a firm fails the TPS test — when its generators are dispatched for constraint control, the unit is dispatched at the lower of the cost or price offer, NRG said.

While FERC has said it does not condition approval of mergers on the TPS test, it has never said the Monitor's analysis is irrelevant or uninformative, the IMM said.

"The transaction creates new opportunities and/or enhances existing opportunities for NRG to raise energy market prices (LMP) to the benefit of its generation through economic or physical withholding because PJM needs NRG's supply to manage transmission constraints," the IMM said. "The transaction creates new opportunities for NRG to raise capacity market prices, and energy market prices on peak days, by significantly increasing ownership concentration in PJM demand response resources. Both areas of concern are relevant to the transaction."

NRG also pushed back on worries about DR — noting the resource does not operate as a separate product in PJM and is bid into its markets alongside generation.

"Moreover, even as to measures of who controls demand response, the figures provided in the IMM report are misleading, because as Dr. Morris indicates, curtailment service providers, like CPower, are just 'intermediaries between retail customers and PJM,' and it is the retail customers that 'control whether demand response will be provided and, if accepted as a capacity resource, whether they will perform,'" NRG said.

"It is also the case that demand response represents a small percentage of the total capacity in the PJM market. What appears to concern the IMM is not increased concentration in some imagined demand response market but instead perceived inadequacies in the rules governing demand response participation in the broad energy, capacity and ancillary services markets." ■

NRG headquarters in Princeton, N.J. | *NRG*

N.J. Plan Would Put RGGI Funds into Storage, Infrastructure

State Looks Beyond Past Spending on Transportation, Building Electrification

By Hugh R. Morley

New Jersey is looking to broaden the portfolio on which it will spend hundreds of millions of dollars from the Regional Greenhouse Gas Initiative (RGGI) to include electrifying multifamily housing and accelerating investment in wind and solar infrastructure.

The state's draft investment plan for 2026 to 2028 — known as the *"Auction Proceeds Scoping Document"* — also calls for investment to boost energy storage capacity and to provide incentives for development of the clean energy supply chain and manufacturing facilities.

The proposal outlines how the state, which has received a total of $922.9 million for two funding plans since it rejoined RGGI in 2020, could use its third tranche of funds. The final plan will be shaped by stakeholder input from four public hearings and other comments. The first hearing took place Aug. 21. Three more are scheduled.

Under the *RGGI system*, which includes

Why This Matters

New Jersey has thus far received hundreds of millions of dollars from the RGGI since rejoining it in 2020; the latest investment plan offers a look at how the next tranche of funds could be used.

An 876-kW solar installation in Hopewell, N.J. | *Advanced Solar Products*

New Jersey and 10 other states, the coalition sets a steadily declining regional cap on carbon dioxide emissions. Certain plants that exceed the cap must pay for a "RGGI CO_2 allowance" for every short ton of CO_2 emitted, and the proceeds are distributed among the participating states for use in combating climate change emissions.

New Jersey's two earlier funding plans focused on projects to cut emissions in the transportation sector, the largest emitting category with 34% of the state's emissions, and building electrification. While electricity generation is the second-largest category, with 17%, the three components of the building sector — residential, commercial and industrial buildings — account for 32% of the state's emissions.

Innovation Sought

The new elements in the latest plan seek to cut that pollution, Sean Sonnemann, manager of clean energy for the New Jersey Economic Development Authority (EDA), said at the first hearing to gather input on the plan. The agency administers about 60% of the RGGI funds, while the New Jersey Board of Public Utilities (BPU) and Department of Environmental Protection each administer 20% of the funds.

"We are considering supporting multifamily buildings in the state, especially those that may not be covered by other state programs, such as corporate or cooperatively owned buildings, senior housing and public housing," he said.

The agency also is considering "other ways to encourage the development of zero-energy new construction buildings, rather than continue with business as usual, older technologies that may be more damaging to the environment," he said.

The BPU, meanwhile, intends to support programs such as commercial-scale geothermal projects. It also plans to support income-qualified customers who use existing energy efficiency programs to implement additional decarbonization efforts such as heat pumps, he said.

New Jersey's emphasis on using RGGI funds to address transportation emissions continues as a key element of the third plan. The plan says the state's number of non-private charging stations, which now stands at 4,400, increased 30 to 40% between 2023 and 2024. It proposes for the first time to fund the installation of EV workplace charging stations and the creation of "charging depots" for medium- and heavy-duty vehicles.

Other new elements include providing support for "managed charging programs and other capacity limiting measures" that help cut ratepayer bills by reducing energy use in peak hours. The plan also looks to "promote electric micro-transit and community mobility, public-serving vehicles and related infrastructure."

Alternative Energy

The public airing of the plan drew a handful of speakers. One asked if the state planned to look beyond "wind, solar and batteries" to "more innovative clean energy technologies — for example, "waste heat to power." He noted that the federal government provides a tax credit to support such projects, but the state does not.

Sonnemann, of the EDA, said the state wants to dedicate funds for non-traditional "emerging renewable and clean technologies" but has not yet put together a list of what the endorsed technologies might be. He said the intent can be found in a section of the plan that says the state could invest in technologies such as "fusion, tidal." The section also calls for investment to create "innovation hubs and related clean energy technology accelerators" and to strengthen the clean energy supply chain.

"New Jersey has the potential to be a leader and clean energy technology exporter, by developing innovative technologies" that could be used to "decarbonize other economies across the globe," the plan says.

Another speaker, Matt Polsky, said that given the change in attitude toward clean energy in the federal government, he felt New Jersey's plan was insufficient.

"They have gone from being a partner to actually part of the problem," he said of the current administration. "And therefore you really, really need to be thinking out of the box a lot more than I've ever seen you do over the decades."

'Leakage' Concerns

The plan comes amid criticism that RGGI, having successfully pushed New Jersey to reduce or eliminate emissions from fossil fuel generators, may be hampering the state as it searches for ways to address the expected significant shortfall of generation.

Data center expansion amid fossil fuel generator retirements is exacerbated by the slow pace that new energy sources are coming online. Emissions restrictions imposed by RGGI may limit the development of some of those new sources.

Liam Baker, senior vice president for regulatory affairs at Alpha Generation, a Connecticut-based electric generation company, expressed concern at an Aug. 5 resource adequacy conference held by the BPU that while RGGI had been "very successful" at cutting emissions, it now is "increasing PJM-wide emissions by millions of tons while costing New Jersey ratepayers hundreds of millions of dollars annually."

Baker and other critics, among them Fred DeSanti, executive director of the New Jersey Solar Energy Coalition, argue that the RGGI system causes "leakage."

"Leakage means it's cheaper to operate coal-fired generation in Pennsylvania and export it to New Jersey," Baker said at the Aug. 5 conference. "It's cheaper to do that than operate our clean in-state combined-cycle fleet." ■

MMU: Average WEIS Energy Prices up in Spring

By Tom Kleckner

SPP's Market Monitoring Unit says in its latest report that the Western Energy Imbalance Service (WEIS) market's average load energy prices rose "significantly" during the spring quarter (March-May).

The increase was driven primarily by elevated natural gas prices in March, the MMU said in its quarterly *State of the Market report* for the WEIS market, published Aug. 29.

Spot prices for natural gas at the Cheyenne hub started the quarter at $2.85/MMBtu and closed at $2.18/MMBtu. Gas prices averaged $2.342/MMBtu during the quarter, about 45% higher when compared to the same quarter in 2024. Settling additional generation out of the market also increased gas prices.

Energy prices averaged $34.93/MWh in March, up from $19.78/MWh a year ago. Prices dropped to $22.83/MWh in April, slightly higher than a year ago ($19.19/MWh), before averaging $23.09/MWh in May, up from $13.05/MWh in 2024.

The MMU noted coal generation continues to be the primary fuel type for the WEIS market, accounting for about 33% of total generation during the quarter. It said the WEIS market is a voluntary imbalance market. The price volatility is strongly associated with the supply — or lack thereof — of interval-by-interval rampable capacity, it said.

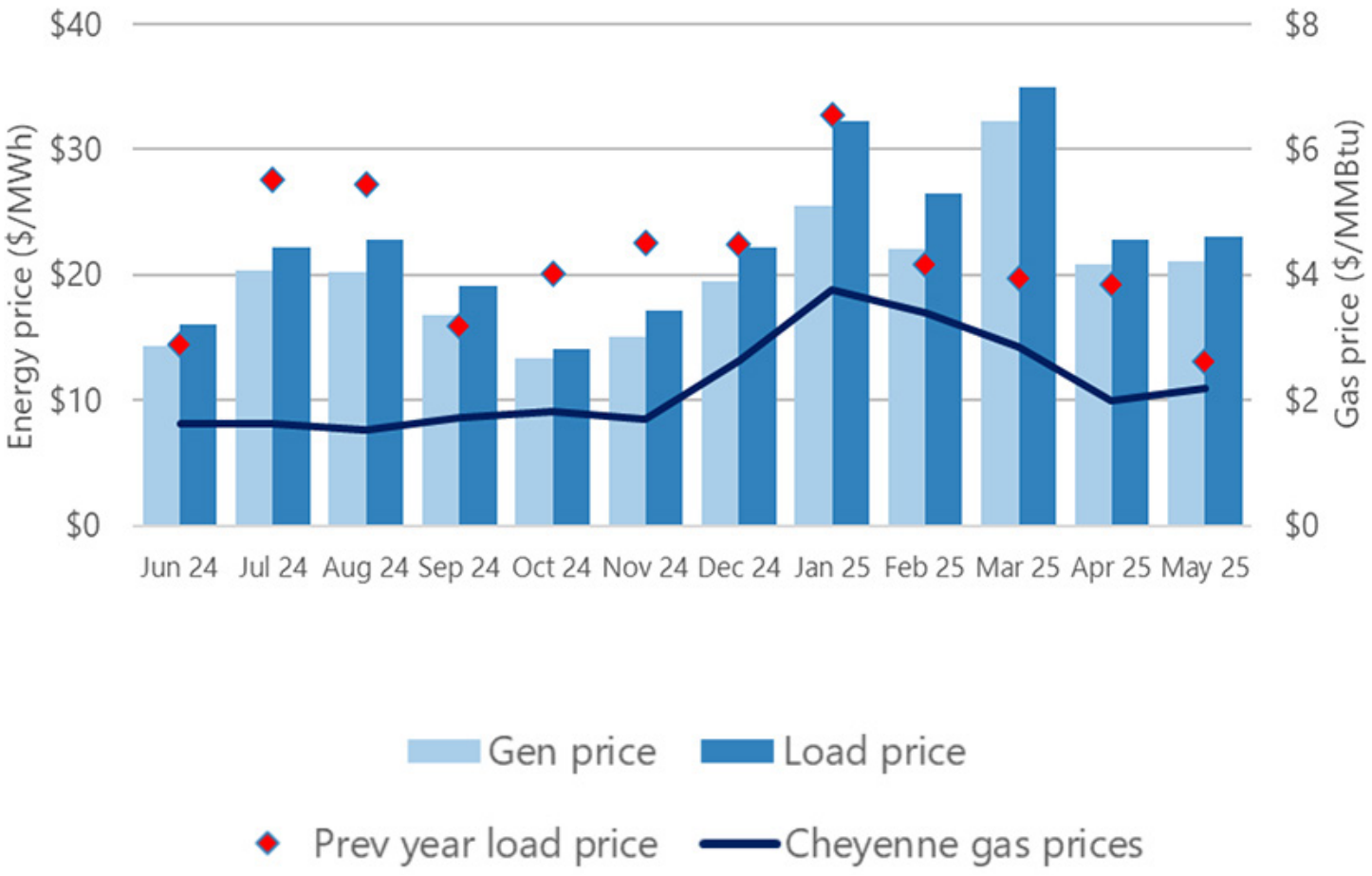
The frequency of negative intervals started at 3.25% in March and increased to 7.43% in April and 9.16% in May, making it difficult for market participants to sell energy to the market and earn revenue. Negative price intervals can be caused by many factors, usually including high amounts of renewable generation and associated subsidies, a lack of dispatchable range and external impacts, the MMU said.

The WEIS market's total generation nameplate capacity grew by 579 MW. The market added 405 MW of solar, 162 MW of gas and 12 MW of "other."

This quarter provided a total revenue neutrality uplift credit to the WEIS market of just over $700,000. The uplift was mostly composed of revenue inadequacy surpluses in April and May and uninstructed resource deviations and out-of-merit energy in March.

SPP operates and administers the WEIS market, a price-based, centralized real-time energy imbalance service market. The market gives participants the ability to submit offers and bids for imbalance energy, settling the net supply or obligation for an asset owner.

The grid operator plans to terminate the WEIS market April 1, 2026, when it integrates western balancing authorities into its Western Interconnection expansion. The MMU said market improvements supporting reliability, transparency and operational efficiency should continue to be implemented as needed. ■



WEIS market's energy and natural gas prices. | *SPP MMU*

Hepper Replaces Cupparo as SPP Board Chair

SPP said Aug. 27 that Vice Chair Ray Hepper has been serving as the Board of Directors' chair since Aug. 12.

Hepper replaced John Cupparo, who is stepping away from the position's time commitments because of personal reasons, SPP said.

Cupparo was not present for the board's August meeting, but did call in. He was elected to the board in 2022 and became chair in 2024. He plans to continue participating in the Strategic Planning and Corporate Governance committees and Interim Markets+ Independent Panel.

The RTO said it will announce a new vice chair before October.

Hepper has more than 30 years of experience in the electric utility industry. He served as ISO-NE's general counsel until retiring in 2018. He also represented California in restructuring the billions of dollars' worth of power contracts entered into during the 2000 energy crisis.

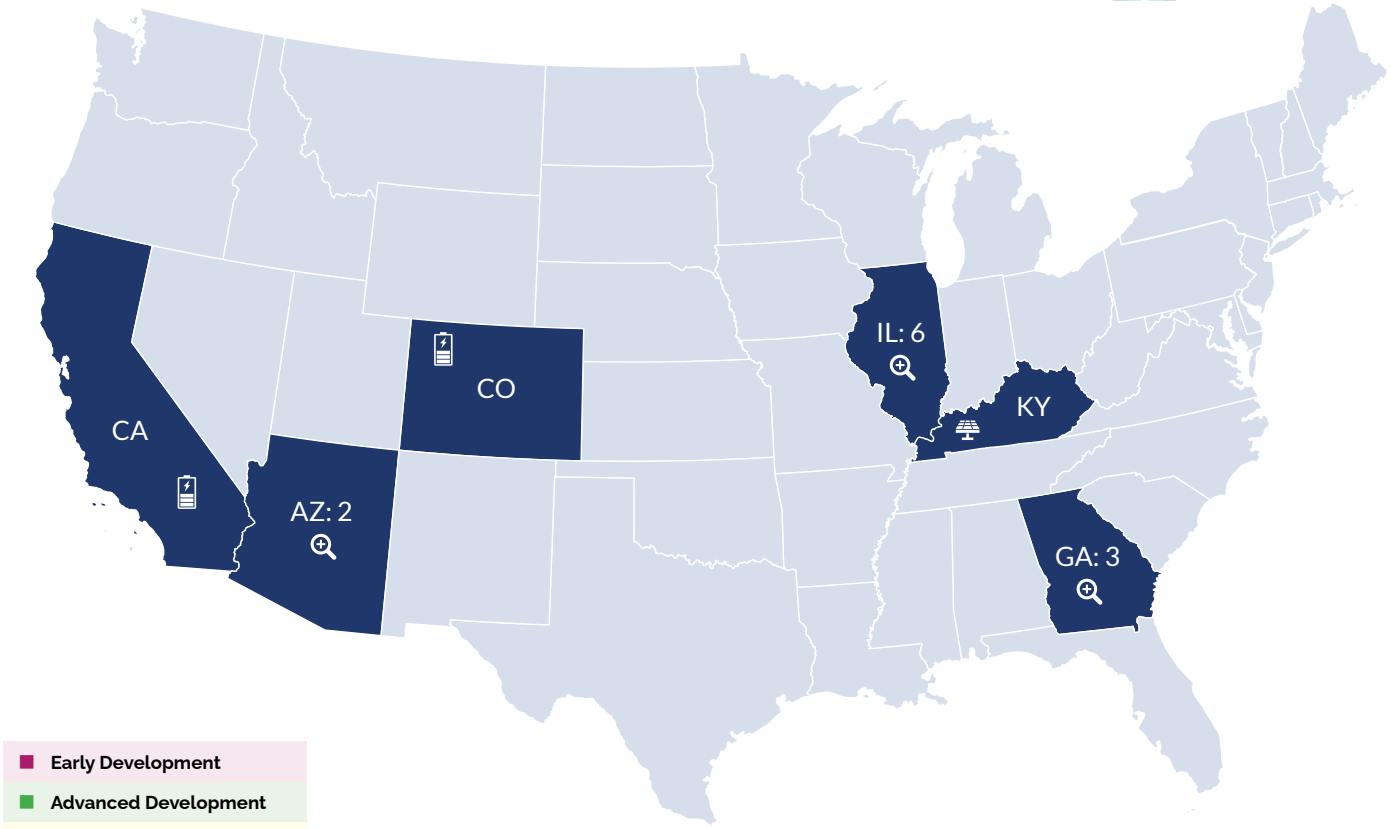
Hepper briefly served on ERCOT's board in 2021. However, state law following that year's Winter Storm Uri required that the ISO's independent directors all reside in Texas. ■

— Tom Kleckner

Ray Hepper (left) chairs the August board meeting. | © *RTO Insider*

Generation Projects Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

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

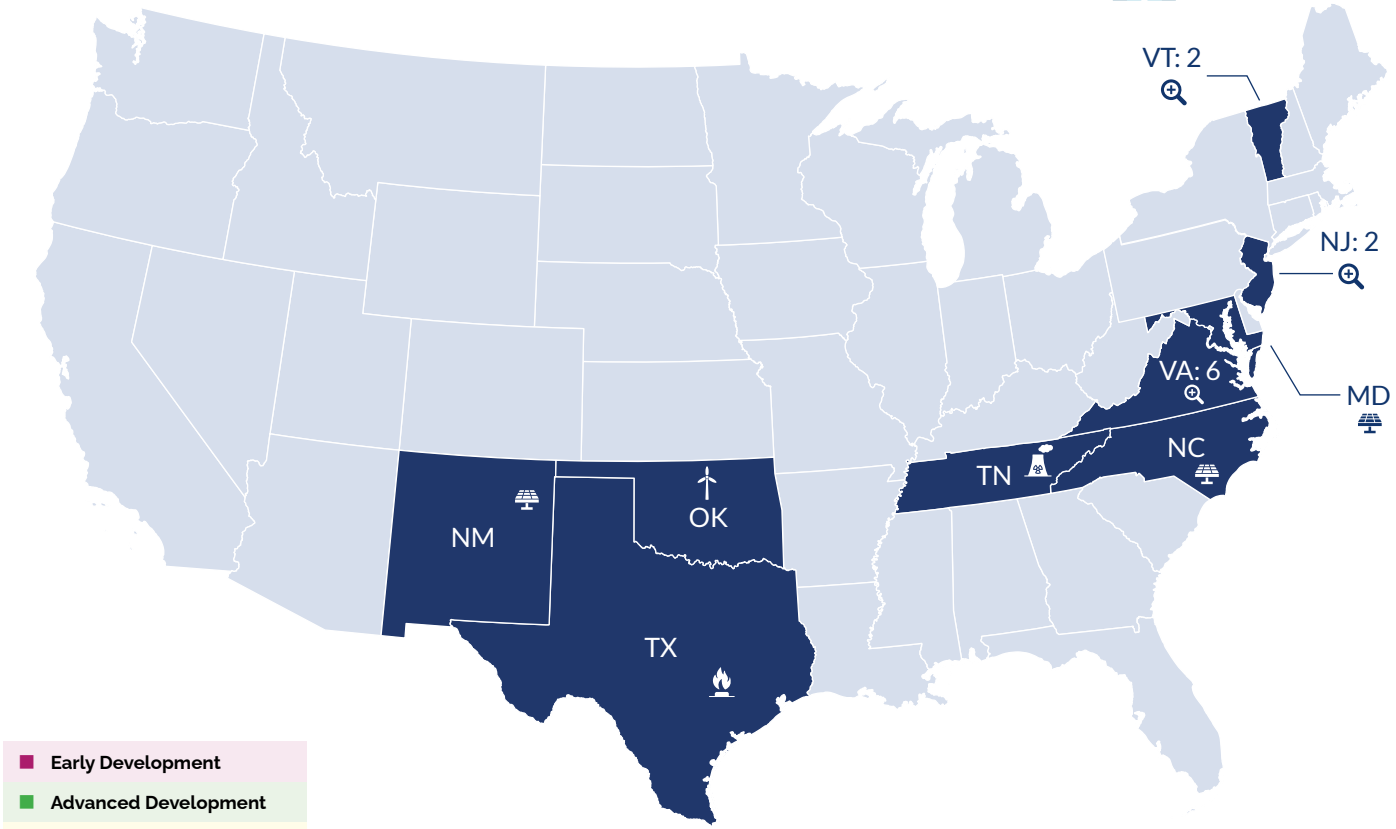
Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Hashknife Solar BESS I	Invenergy		AZ	275	2026
Hashknife Solar I	Invenergy		AZ	275	2026
Soda Mountain Solar BESS	Vitol Holding B.V.	VC Renewables LLC	CA	300	2027
Yampa Storage	AES Corp.		CO	100	2029
Stellar Dry Creek Solar	Stellar Renewable Power		GA		2100
Stellar Shamrock Solar	Stellar Renewable Power		GA		2100
Beaver Creek Solar I	Grenergy Renewable Energy Co	Grenergy USA, LLC	GA	183	2028
Blue Iris Solar	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
Bluestar Solar Project	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
Horseshoe Solar Project	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
Kanesolar01	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
Spillertown CSG 1	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
Spillertown CSG 2	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
Lost City Solar Project	Copenhagen Infrastructure Partners	Lost City Renewables LLC	KY	250	2029

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

Generation Projects Added in the Past Week

YES ENERGY



Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Nanticoke Road Solar 2	Energy Capital Partners	New Leaf Energy	MD	5	2028
SR Duplin Solar	Silicon Ranch		NC	80	2030
Oyster Creek SMR 300	Holtec Decommissioning International		NJ	1,200	2100
Oyster Creek Solar	Holtec Decommissioning International		NJ	150	2100
Juniper Sol Solar Community Solar Garden	SunShare	CSolPower, LLC	NM	5	2026
Kay Wind Repowering	Southern Company	Southern Power	OK	299	2026
Hermes 2	Kairos Power		TN	50	2030
Timmerman Power Plant Phase 2	Lower Colorado River Authority		TX	188	2026
Monarch Solar BESS	Brookfield Asset Management	Urban Grid	VA	300	2030
Boston Hill Solar	TerraForm Power	Sun Tribe Development LLC	VA	115	2026
Dunn Solar Facility (Kevin Dunn Solar)	Energy Capital Partners	New Leaf Energy	VA	3	2027
Rowlette Solar 1	Energy Capital Partners	New Leaf Energy	VA	3	2027
Rowlette Solar 2	Energy Capital Partners	New Leaf Energy	VA	3	2025
Plank Road Solar	CEP Solar		VA	10	2100
Stone House Solar	MHG Solar	MHG Solar	VT	5	2027
Mill River Solar	Ownership Undisclosed		VT	5	2026

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

Company Briefs

GM Plans Shift Shutdowns at Factory Zero EV Plant

General Motors last week said its EV manufacturing plant Factory Zero in Detroit will partially shut down first- and second-shift production beginning Sept. 2 through Oct. 6.

"Factory Zero is making temporary adjustments to production to align to market dynamics," GM spokesman Kevin Kelly said. "General Motors updates schedules as part of our standard process of aligning production to manage vehicle inventory."

Production of the GMC Hummer EV and Cadillac Escalade IQ will be impacted.

More: *Detroit Free Press*

Equinor Pledges Support for Ørsted with $1B in Capital

Norwegian oil giant Equinor this week pledged to support Ørsted with almost $1 billion of fresh capital, backing the company amid sustained attacks on offshore wind projects from the Trump administration.

Equinor also signaled its intention to participate in Ørsted's planned $9.4 billion rights issue and said it intended to hold on to its 10% ownership in the company. The company said its support of the rights issue reflects its confidence in Ørsted's underlying business and the competitiveness of offshore wind in the future energy mix. The state-backed Norwegian energy group is the second largest shareholder in Ørsted, behind the Danish government.

More: *CNBC*

Fermi America Raises $350M for Texas AI Energy Project

Fermi America announced the closing of a total $350 million financing package to support the development of its HyperGrid project; a behind-the-meter energy campus designed to meet the growing needs of artificial intelligence.

The financing includes a $100 million Series C preferred equity raise and a $250 million senior loan facility, both led by Macquarie Group.

The planned Advanced Energy and Intelligence Campus will span approximately 5,800 acres near Amarillo and include 18 million square feet of AI data centers powered by 11 GW from nuclear, solar, wind and natural gas sources.

More: *energynews*

Federal Briefs

Report: U.S., Canada Had Highest Air Pollution Surge in 2023

The United States and Canada endured the planet's biggest air pollution surge in 2023, according to the University of Chicago's Air Quality Life Index.

For the U.S., the report determined that wildfires contributed amounts of air pollution the country had not seen in more than a decade. Compared to just the year before, particulate pollution levels rose nationwide by an average of 20%, the data showed. The resultant pollution from the Canadian blazes spread across Wisconsin, Illinois, Indiana and Ohio and even reached as far as Pennsylvania, Oklahoma and Mississippi.

Canada experienced its highest levels of fine particulate pollution in at least 26 years, with more than half of residents exposed to contaminant concentrations that surpassed national standards. Worldwide, the index determined that air pollution increased slightly.

More: *The Hill*

FEMA Dissent Letter Signees Put on Leave

Employees at the Federal Emergency Management Agency were placed on leave last week after signing a public letter criticizing the agency's leadership, according to Stand Up for Science, the group that helped facilitate the letter's publication.

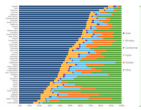
More than 180 current and former FEMA staffers signed a public letter warning the Trump administration is weakening the agency's capacity and preventing it from carrying out its mission.

In July, EPA placed staffers who signed a letter of dissent against the Trump administration's actions and policies on leave.

More: *The Hill*

National/Federal news from our other channels

State-level Efforts to Limit Renewables Blunted in 2025 — NetZero Insider



Analysis Shows Varied Renewable Energy Workforce — NetZero Insider

RTO Insider subscribers have access to two stories each month from *NetZero* and *ERO Insider*.

State Briefs

COLORADO

Xcel Asks PUC to Expedite RFP Decision

Xcel Energy last week filed a motion with the Public Utilities Commission to expedite approval of 4,500 MW of generating and battery resources due to expiring tax credits.

To be eligible for an investment tax credit, a project must begin construction by July 4, 2026, and if it starts after that date, it must be in operation by the end of 2027. Xcel's motion is supported by PUC staff, the Colorado Energy Office and Colorado Office of Utility Consumer Advocate.

More: *The Colorado Sun*

FLORIDA

JEA Board Approves Construction of $1.57B Power Plant

The JEA board last week approved construction of a $1.57 billion natural gas-fired power plant, opting for the utility to take on the project itself instead of buying additional power from Florida Power & Light.

The plan is to build the plant on about 40 acres in the former St. Johns River Power Park. JEA shut down and demolished a more than 30-year-old coal plant there in 2018.

JEA will next issue a request for proposals from contractors to build the facility and will work to obtain regulatory approvals for construction with a goal of bringing the plant online in late 2031 or early 2032.

More: *Jacksonville Daily Record*

IDAHO

PUC to Accept Public Comments on Idaho Power's Proposed Rate Hike

The Public Utilities Commission last week announced it will seek public comments on Idaho Power's rate increase application.

Beginning in September, PUC will conduct several public meetings and solicit public testimony on the proposed increase. The first meeting will be online on Sept. 16. Public hearings will be conducted on Oct. 27 and Nov. 20.

In May, Idaho Power filed an application seeking an overall rate increase of about $199 million (13%). If approved, the average residential bill would increase by about $21.66 each month.

More: *Idaho Capital Sun*

INDIANA

Appeals Court Reverses URC Decision

The Indiana Court of Appeals last week voted unanimously to reverse a decision by the Utility Regulatory Commission that allowed Duke Energy to recover millions of dollars from customers for cleaning up coal ash at its power plants in the state.

The panel ruled that the URC incorrectly allowed Duke Energy to collect $62 million for the work from ratepayers. The decision focused on cleanup costs incurred prior to 2023, and Duke may still be able to recoup some of the costs going forward.

URC spokesperson Luke Wilson said the commission could not comment since the court's decision is within an appeal window. Duke Energy spokeswoman Angeline Protogere said the utility is still reviewing the court's opinion.

More: *Indianapolis Star*

MICHIGAN

AG Seeks to Slash DTE Rate Hike Request by 75%

Attorney General Dana Nessel last week filed testimony in DTE Energy's latest rake hike request, urging the Public Service Commission to reduce the rate hike by nearly 75%.

DTE is seeking a more than $574 million increase from the commission. Although the rate hike would only amount to an 11% increase, the full dollar amount is staggering, Nessel said, and comes just three months after DTE received PSC approval to increase its rates by $217 million.

More: *Michigan Advance*

MISSOURI

New Law Widens Window of Non-disconnections

Under a law passed by the Legislature, utilities are now prevented from shutting off service to customers for 72 hours if temperatures are predicted to be extreme.

In the summer, the temperature cutoff is 95 degrees Fahrenheit or a 105-degree heat index. The winter cutoff is 32 degrees or freezing. The law would have added 43 more protected days in 2024.

Prior to the shift, utilities had to pause disconnections for only 24 hours.

More: *St. Louis Public Radio*

NEW MEXICO

Santa Fe County Commissioners Approve Solar Project

Santa Fe County commissioners last week voted 4-1 to approve the Rancho Viejo Solar project in the Eldorado area.

Aiming to generate 96 MW of power and 45 MW of battery storage, the project would cover 680 acres of a roughly 800-acre parcel and include a solar facility, a 1-acre collector substation, a 3-acre battery storage system and a 2.3-mile generation line.

Public Service Company of New Mexico is the intended client for the project.

More: *Santa Fe New Mexican*

Zenith Obtains Planning Approval for 1.24-GW Data Center

The Chaves County Commission last week approved Zenith Volts' plans for a data center project in Roswell.

The commission granted approval for a 300-acre data center designed to support 1.24 GW or more of capacity.

The company expects the project to be fully operational by November 2027.

More: *Data Center Dynamics*

OHIO

Supreme Court: AES Should Have Refunded $61M

The state Supreme Court said the Public Utilities Commission erred when it al-

lowed AES to keep $61.1 million in "significantly excessive" profits rather than refunding the money to customers.

The PUC determined that AES in 2018 and 2019 failed the "significantly excessive earnings test" in state law. Instead of demanding a refund, the PUC in 2021 unlawfully allowed AES to keep the money because it promised to invest it in the grid over the next four years, the justices said, adding there is nothing in state law that allowed AES to keep significantly excessive profits based on a commitment to make investments down the line.

The justices ordered the PUC to redo the earnings test. If corporate profits are deemed "significantly excessive," then the regulators must issue refunds.

More: *Signal Ohio*

PENNSYLVANIA

PUC: PPL Tops List in Year for Record Outages

Pennsylvania experienced the highest number of electricity outages in 30 years in 2024, as reportable outages jumped from 49 in 2023 to 71, and affected customers increased from 1.67 million to 2.8 million, according to a Public Utility Commission report.

PPL experienced 17 of those outages, the most by an electric distribution company in the last 32 years, the report said. Approximately 60% of PPL's outages were attributed to damage from trees.

Met-Ed experienced nearly 1.2 million customer interruptions, up from 739,898 in 2023, while PECO customer interruptions held steady at 1.3 million in 2024 and 2023.

More: *Reading Eagle*

SOUTH DAKOTA

Company Seeks Approval for $750M Wind Farm

Philip Wind Partners is seeking Public Utilities Commission approval to construct a $750 million, 300-MW wind farm.

The plans call for up to 87 turbines and up to seven miles of electrical transmission lines on 70,000 acres of privately owned land in Haakon County.

The PUC will review the application over the coming months. If approved, construction could begin as early as next year, with operations beginning by 2027.

More: *South Dakota Searchlight*

VIRGINIA

Developer Backs out of Charles City Data Center Campus

Diode Ventures withdrew its application for a proposed data center campus at Charles City County's Roxbury Technology Park.

The company's plan for the campus included around six buildable areas for data centers and a 100-acre conservation area across 515 acres.

"Despite the county planning commission's support of the project earlier this year, we made the decision to shift our focus elsewhere based on the results of conversations with our local collaborators and analysis of the site's availability to be shovel-ready with power and municipal support," the company said in a statement.

More: *Richmond Times-Dispatch*