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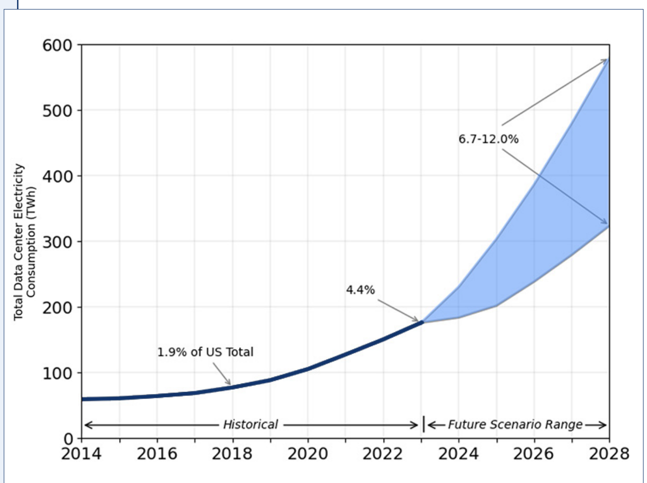

Lawrence Berkeley National Laboratory

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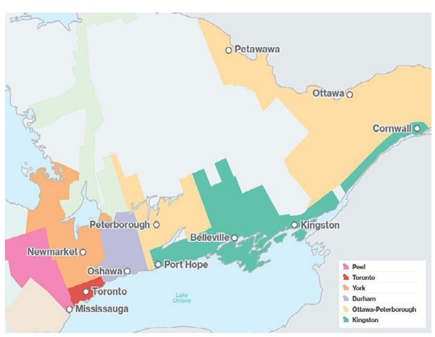

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In this week's issue

Clearing Power Sector Roadblocks with Permitting Reform and Policy Certainty

By Todd Snitchler

"Help me help you." The famous line from the movie "Jerry Maguire" captures the dynamic facing competitive power markets today.

Todd Snitchler | *EPSA*

RTOs have made meaningful progress in clearing interconnection backlogs. PJM alone has processed more than 140 GW of projects since 2023, with 46 GW already holding signed interconnection service agreements. Across MISO, ERCOT, CAISO and other regions, reforms are moving projects through the queue faster and giving developers greater clarity.

So, what's standing in the way?

Though progress on legislative action has stalled, permitting reform remains a vital step forward — one where policymakers can make a meaningful difference. As Congress reconvenes this September, this critical issue is back on the table.

That said, while significant, permitting is just one element of a broader landscape of uncertainty that all participants in the power sector must work to resolve.

Progress in Interconnection, But Projects Still Stalled

Competitive markets have long delivered reliability, efficiency and innovation at lower cost than monopoly procurement. By requiring independent power producers to bear investment risk — rather than captive ratepayers — they drive efficiency and discipline, while shielding consumers from the costs of stranded or uneconomic assets.

That structure is working. RTOs/ISOs have improved their interconnection processes, and developers continue to pursue projects across technologies even as auction schedules change and regulatory proceedings inject uncertainty.

Yet interconnection progress alone does not guarantee timely deployment. The challenge now is converting cleared projects into operating megawatts amid heightened uncertainty — a task that demands policy clarity, durable rules and practical coordination beyond the control of market operators alone.

"Developers stand ready with billions in private capital — but uncertainty stalls projects."

A Key Hurdle: Permitting and Siting

Projects that clear the interconnection queue remain delayed by regulatory hurdles across markets (PJM and MISO, in particular):

- Federal, state and local permitting delays that stretch timelines for years.
- Local opposition and litigation that block projects even after contracts are signed.
- Policy interventions that prematurely retire resources before replacements are online.

These barriers block development of resources that already have been cleared by RTOs. PJM's Reliability Resource Initiative identified 9,300 MW of near-term projects that could be online by 2030, but many hinge on permitting timelines beyond the grid operator's control. Similar stories are playing out in MISO, CAISO and ERCOT. Markets cannot build around these hurdles.

Importantly, streamlining these processes does not mean lowering environmental standards. A more efficient, predictable and transparent review can strengthen outcomes — creating clear timelines, improving interagency coordination and delivering legally durable decisions. Predictable processes are essential to keep investment flowing into renewables, storage and dispatchable resources alike.

"Permitting reform is not about shortcuts — it's about certainty."

Financing, Supply Chains and Policy Uncertainty Add Layers of Risk

With that said, permitting is one major barrier, but not the only one. Developers also must navigate:

Why This Matters

Interconnection progress alone does not guarantee timely deployment. The challenge is converting cleared projects into operating megawatts amid heightened uncertainty — a task that demands policy clarity, durable rules and practical coordination beyond the control of market operators alone, says Todd Snitchler.

- Financing uncertainty: Competitive suppliers invest without guaranteed cost recovery; shifting rules and political interventions raise risk premiums and complicate financing.
- Supply chain delays: Global shortages and trade policies affect delivery of transformers, turbines, panels and other critical equipment, driving up costs and timelines.
- Load forecasting questions: Rapid growth from data centers, electrification and manufacturing challenges traditional forecasting, making it harder to underwrite long-lived investments.
- Tariff and trade policy volatility: Changing tariffs or exemptions can materially alter project economics late in the process.

These hurdles affect resource developers and business models of all kinds, whether they be utilities or independent power producers, or located in vertically integrated and restructured regions alike.

Policymakers cannot control every factor. But they can reduce risk where it matters most — by providing certainty in permitting and market rules, improving coordination among agencies and reinforcing confidence in competitive markets so private capital can move.

The Wrong Focus: Political Attacks on Markets

Even as interconnection reforms advance, some governors and utility boards are focusing on the wrong target. Investigations aimed at second-guessing auction outcomes, calls for price caps or efforts to tilt the field back toward monopoly procurement may be politically tempting in the short term, but they don't solve the deployment challenge — and they risk making it worse.

Price caps, in particular, distort the very signals that attract investment. When policymakers override market outcomes, the message to investors is that politics trumps market discipline. The predictable result is reduced investment, weaker reliability and higher long-term costs. The better approach is to fix the obstacles to building — not to mute the signals that bring private capital to the table.

"Markets deliver innovation and efficiency. Politics delivers uncertainty."

The Risk of Backsliding

Frustration with delays has prompted some to argue for a return to the vertically integrated utility model. That would be a mistake. While monopoly procurement can appear to offer certainty, history shows it often produces inefficiency, cost overruns and stranded risks borne by consumers. Competitive markets discipline investment, reward performance and foster innovation across technologies. The alternative is not better outcomes — it is higher costs and slower progress.

EPSA's Balanced Approach to Reform

EPSA supports permitting reform that modernizes NEPA and related statutes to make reviews efficient, predictable and fair — striking "an appropriate balance between environmental protection and building essential infrastructure." That balance includes:

- Definitive timelines for reviews and litigation: Endless procedural delays increase costs and weaken reliability.
- Better coordination across agencies: Projects should not be subject to duplicative or conflicting requirements.
- Certainty for investors: In competitive markets, developers take on significant risk without guaranteed cost recovery. Clear, durable rules are essential to attract investment.
- Inclusive benefits: All resource types — renewables, storage and dispatchable generation — face permitting barriers.

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Reform should apply fairly across technologies to ensure a balanced and reliable grid.

EPSA's position makes clear: Permitting reform is not about shortcuts. It is about building a transparent, efficient and accountable system that both protects the environment and enables timely development of critical energy infrastructure.

"The alternative to competitive markets isn't better outcomes — it's higher costs and stranded assets."

The Path Forward: Certainty, Not Shortcuts

The interconnection backlog is easing, but deployment still lags because multiple external hurdles converge at once. Policymakers can't solve every problem — nor should they try — but they can reduce uncertainty where only they can: by ensuring clear, consistent, enforceable permitting processes; resisting political interventions that distort market signals; and supporting coordination that aligns siting, environmental review and reliability needs.

Do that, and private capital will do the rest. Competitive markets have proven they deliver innovation, efficiency and reliability when the rules are clear. Now they need partners to help clear the path. As Jerry Maguire put it: "Help me help you." ■

Todd Snitchler is president and CEO of the Electric Power Supply Association, which represents competitive power suppliers who own and operate around 200 GW of capacity from electricity resources of all types in markets throughout the U.S.

Common Charge Wants to Grow Distributed Resources to Meet Spiking Demand

By James Downing

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With rising demand putting pressure on the system, a new group has launched to encourage distributed solutions such as virtual power plants that can be quickly and cheaply deployed.

"Right now, those are two of the biggest issues that we have on hand: affordability and reliability," Katherine Hamilton — acting executive director of the new group, Common Charge — said in an interview. "And, so, the way we want to do that is to maximize distributed assets that are already being developed and can be plugged into the grid, and to ensure everybody has access to those technologies and those applications."

Common Charge is a coalition, not a trade group. While it includes companies in the distributed energy resource industry, it also includes nonprofits and consumers, Hamilton said. Founding members include Advanced Energy United, Charge Ahead Partnership, Coalition for Community Solar Access, Eco Capital, Institute for Local Self-Reliance, Pivot Energy, Solar United Neighbors, Sunrun and Vote Solar.

"Distributed solutions often are not even considered in the mix as part of the solution set for mitigating for rate increases and prices going up," Hamilton said. "So, we want to unlock that and make sure everybody has access to those solutions."

The distribution system is state regulated, and how much distributed resources are used varies by jurisdiction, so part of the group's efforts is to figure out best practices and ensure they are adopted as widely as possible.

Why This Matters

Common Charge launched to help grow distributed resources as the power system needs more supplies to meet rising demand from data centers and other new load.

"If you try to follow the distributed energy resource ecosystem, it is very diverse and very disaggregated," Hamilton said. "And what we're trying to do is bring a little more organization to that and then drive a lot more impact."

Distributed resources are already at work in different regions, with Common Charge pointing to PJM's dispatch of thousands of megawatts of demand response during heat waves this year. New York delivered 6 GW of distributed solar early and under budget last year. New England benefited from behind-the-meter solar this summer as it helped meet high demand reliably.

ERCOT has a pilot program providing the grid with nearly 60 MW of power from customer-sited assets, and microgrids in Texas have helped keep hospitals running. In a recent test in California, 100,000 distributed assets simultaneously discharged to the grid for two hours, functioning like a power plant and helping to cut peak demand.

"From a small business improving operations through an energy management system, to a community leveraging solar to save on energy bills, to homeowners enjoying the comfort of smart thermostats, millions of distributed assets already exist, and more are waiting to be leveraged in a modern, coordinated energy grid," Hamilton said. "These assets are proven to increase reliability, lower utility costs and grow local economies."

Some of the distributed technologies like solar panels are tied to climate change and the divisive politics surrounding it, with skeptics dominating the federal government now, but Hamilton said Common Charge was focused on more bipartisan issues.

"We're trying to address two of the big issues that [exist] regardless of whether people are talking about climate change or not, and we've just seen as demand rises and more strain is put on the grid — from data centers, from increased manufacturing, from electrification — that affordability and rates are going up," she added. "Affordability is huge, and that's regardless of what's happening on the climate side, regardless of what's happening in the federal side; it's really just about affordability on a very day-to-day, kitchen table issue."

The other major issue implicated by demand growth is reliability, which has been a focus of the Trump administration, and distributed resources can help there, Hamilton said.

Former FERC Chair Pat Wood — now CEO of Hunt Energy Network, which is deploying distributed assets across ERCOT — endorsed Common Charge's mission. He is also working on a parallel effort by the Pew Charitable Trusts with former New York Public Service Commission Chair and PJM COO Audrey Zibelman to expand the use of DERs around the country.

The Pew effort is to give decisionmakers, which include utilities, state regulators, governors' offices and even federal officials, a detailed plan for maximizing the benefits of DERs. Wood said he benefited from similar resources while working to restructure Texas' electricity market in the 1990s when he chaired the Texas Public Utility Commission.

"What we're trying to do with this group is put out, not just the principles, but how do you do it?" Wood said. "What do you need to address, for interconnection costs, for timetables, for standardization of equipment, for rates, for customer engagement or other customer protection aspects to it, which we've learned from all the other industries that just because they're a competitor, it doesn't mean they're nice."

The rules need to be balanced so that customers' privacy is protected without being so onerous they hold back the deployment of DERs to benefit the broader grid, he added.

"We're in the mode of no megawatt left behind, because with all this kind of electrification of everything, and then, of course, the data tsunami that's kind of sweeping over everywhere, we're going to need power coming off every corner of the grid," Wood said.

The distribution grid has been used to ship power one way historically, but recently that has changed, with advances in computing enabling appliances from smart thermostats to water heaters, pool pumps and plug-in cars to help balance the power system.

"There's just so much more on the grid than when we opened up the Texas market, or when I was at FERC and we were getting the final rules done on the transmission grid," Wood said. "That same zeal and effort need to continue all the way to the meter."

FERC has issued major orders on tapping the demand side to benefit wholesale markets in the past, and numerous states have held "grid of the future" proceedings, but both Common Charge and Wood think now is the time that the technologies will really take off.

It is twice as expensive to build a natural gas plant as it was five years ago, and while renewables have helped keep wholesale prices in check, that has not flowed through to the distributed grid, with the rates rising.

"The regulated rates are going up way faster, and the competitive rates coming down, [and they] kind of net each other out," Wood said.

The promise of competition was lower prices overall, not just shifting costs from the competitive side of the industry to the regulated side, Wood said, and enhancing DERs can make that promise come true. Now with the pressure of rising demand helping push prices even higher, it has attracted more attention from politicians, with governors and legislators around the country focused on ensuring affordability. Wood said that is not a bad thing.

"They can help create the investments and certainty for generators to come in to help push the monopoly utilities to open up their grid and embrace new technology to incentivize customers to get smart and to use their power in the market to discipline price and service," Wood said. "I mean, who better than the governor or even a president to do that?" ■

Senators Focus on FERC's Independence at Swett, LaCerte Confirmation Hearing

By James Downing

Laura Swett and David LaCerte took questions on FERC's independence during their confirmation hearing before the Senate Energy and Natural Resources Committee on Sept. 4 as the country debates how much control the president should have over the federal bureaucracy.

Swett and LaCerte were nominated to replace former Chair Mark Christie and former Commissioner Willie Phillips by President Donald Trump, who has asserted broad authority over the entire executive branch, including independent agencies such as FERC and the Federal Reserve. (See *FERC's Independence Likely Coming to an End with Christie's Exit*.) Trump's attempts to fire several agency officials have set off numerous legal battles.

Committee Chair Mike Lee (R-Utah) said the confirmation process will allow senators to hear about how the two "view the ongoing legal debate about the status of so-called 'independent agencies' and what that means for accountability to the law and to the American people."

Lee is skeptical of the concept of agency independence and has made it clear he *would welcome* the Supreme Court overturning *Humphrey's Executor v. United States*, the 1935 case in which the court found that it was constitutional for Congress to pass laws limiting the president's ability to fire members of independent agencies.

Democrats on the committee were much more critical of the possible change.

"The commission was designed to serve no president, no political party and no political agendas," Ranking Member Martin Heinrich (D-N.M.) said. "Its job is to serve the public interest fairly and impartially, guided by our laws and the Constitution, not by political whims from the White House. The independence of our independent public institutions, from the Federal Reserve to the Smithsonian Institution, is under attack by this administration, and destroying the independence of the Federal Energy Regulatory Commission would do irreparable damage to public confidence in the commission's decision-making, to regulatory stability and to our energy security."

Laura Swett and David LaCerte at the Senate Energy and Natural Resources Committee's hearing on their nominations to be FERC commissioners. | © *RTO Insider*

Why This Matters

The confirmation hearing comes as the U.S. grapples with President Trump's extraordinary assertions of executive power and whether independent agencies should remain independent.

So far, the Trump administration has tried to control other independent agencies more than FERC, but it was widely reported that the administration pressured Phillips to resign earlier this year, which he did. (See *Commissioner Willie Phillips Announces his Resignation from FERC*.)

"If I have the honor of being confirmed, I will do everything in my power to honor the law and the facts of every single matter before me squarely within the confines of the laws that you, Congress, granted FERC," said Swett, an energy attorney at Vinson & Elkins. Many FERC watchers expect her to be named chair upon her confirmation.

Swett listed three goals for her tenure on FERC: maintaining reliability; meeting the rising demand from artificial intelligence and data centers to ensure the U.S. leads on that technology; and maximizing the commission's ability to facilitate infrastructure development.

Swett has been a staffer at FERC and has litigated before the commission, but LaCerte has little experience with the agency — though he has worked on independent regulatory agencies and is familiar with issues surrounding LNG.

"I think my background, especially as a government executive, and my experience as an environmental attorney provide strong qualifications and a fresh perspective on these issues challenging the FERC," said LaCerte, currently a senior adviser to the director of the Office of Personnel Management. "The outstanding career staff cannot do this alone; as the committee has noted, FERC is most functional with a fully seated board of complementary commissioners prepared to work together, along with stakeholders."

Lee asked LaCerte how his background prepares him for a role on the commission when he has comparatively little experience as an economic regulator of electricity and natural gas.

"I think that the most important qualification I have is that I can bring a common-sense approach to get problems solved," LaCerte answered. "And I've proven that to the president of the United States. I have an outstanding set of experiences in safety, in cyber and in a multitude of issues that can help FERC."

When asked later on about his qualifications, LaCerte argued the fact that he has never litigated before FERC could be viewed as a positive, because "regulatory capture" is a legitimate concern.

Lee then asked the nominees for their views on *Humphrey's Executor*. Both said they would follow the law.

"And of course, I will follow the law and honor the law in everything that I do and consider the merits of every single issue of law and the facts before me, irrespective of where the litigation comes out and the length of my term," Swett said.

Heinrich brought up the Trump administration's executive order seeking to review major decisions at independent agencies and asked why maintaining FERC independence is "critical." (See *Trump Claims Authority over Independent Agencies in Executive Order*.)

Congress created the modern iteration of FERC with the Department of Energy Organization Act, which calls for its independence and provides that none of its work is reviewable by anyone at the department, Swett said.

"And thus, as a lawyer who has been practicing FERC law for 15 years, I will always go back to the statute, and that is exactly what Congress directed, and I will not exceed that jurisdiction," she added.

The Administrative Procedure Act (APA) also governs how FERC works, and Sen. Catherine Cortez Masto (D-Nev.) argued that nothing in the law allows for the White House to review decisions from independent agencies.

"There's no requirement by the president to review anything that we have set laws for a regulatory agency to do, but that's what he has put in this executive order, and that's my concern," Cortez Masto said.

Ultimately, Cortez Masto noted that the issue of the legality of independent agencies is now before the courts. Before gaveling the hearing to a close, Lee noted that the APA also does not specifically bar White House review of agency decisions. ■

Parties Argue for Appeal of Order 1920's Transmission Reforms in 1st Set of Briefs

By James Downing

Why This Matters

Order 1920 was a signature rulemaking of FERC under the Biden administration, and now its review in the courts is picking up speed.

After more than a year of preliminary proceedings, parties filed their first briefs Aug. 30 in *Appalachian Voices v. FERC*, in which the 4th U.S. Circuit Court of Appeals for the Fourth Circuit is reviewing the commission's Order 1920 (24-1650).

Parties from all sides of the argument weighed in. Environmentalists and developers argued the transmission order did not go far enough. States and utilities argued FERC exceeded its authority. And one brief seeks to avoid the reimposition of a federal right of first refusal (ROFR). A response from FERC is not due until early 2026. The court will take other briefs later in February.

A group of more than 30 utilities that includes American Electric Power, Dominion Energy, Duke Energy, Exelon and Xcel Energy Services argued FERC exceeded its authority by forcing them to file cost-allocation proposals they might disagree with.

"FERC compels public utilities to include and promote state-designed utility tariff provisions, including those with which utilities disagree, which FERC would then be free to adopt even though the utility's proposal was just and reasonable (the 'inclusion requirement')," the utilities said. "FERC also requires public utilities to consult with states before exercising their statutory right to amend their long-term transmission cost-allocation, and to explain why they reject contrary state proposals (the 'consultation requirement'). This violates both the FPA [Federal Power Act] and the First Amendment."

In the initial version of Order 1920, FERC declined to make utilities file state agreement approaches against utilities' wishes, but in Order 1920-A, it reversed course and allowed "state entities to infringe on transmission providers' filing rights."

The filings come under Section 205 of the FPA, which is supposed to be reserved for utilities that cannot be forced to include proposals from states or other third parties. FERC said it would consider state agreement approaches on par with utilities' own cost-allocation proposals, even though it is supposed to accept utilities' Section 205 filings if they are in a broad zone of just and reasonable rates.

"FERC cannot circumvent statutory limitations by creating a rule that trumps the FPA's plain meaning and confers on state entities filing rights that Congress withheld," the utilities said.

Even when FERC sets a rate under Section 206 of the FPA, the utility keeps its right to respond and propose its own preferred rate under Section 205, the utilities said.

"Section 206 does not authorize FERC to override utilities' Section 205 rights," they added. "When remedying a rate that it finds no longer just and reasonable under Section 206, FERC must stay within the statutory limits of its power, just as in any other remedial context."

Another brief arguing for rehearing was filed by the American Forest and Paper Association, Industrial Energy Consumers of America, National Rural Electric Cooperative Association, New England States Committee on Electricity, Ohio Consumer's Counsel and others that faulted FERC for failing to adopt cost-management and customer-protection proposals.

"Order 1920 arbitrarily and capriciously facilitates an escalation in transmission rates without implementing any cost controls and cost-containment mechanisms to ensure rates remain just and reasonable," the groups said. "FERC's rejection of its initial proposal to eliminate certain transmission rate incentives for long-term regional projects violated FPA Section 206's requirement that FERC must remedy unjust and unreasonable rates and practices."

That includes a financial incentive that allows utilities to charge consumers 100% of prudently incurred costs before projects go into service, or even if they never go into service. FERC also failed to address ideas of an independent transmission monitor to ensure fair plans, leaving that for another docket where it has no requirement to act.

Order 1920 also shifts the costs of interconnecting generators from developers themselves to consumers, who will pay for those lines under the regional transmission planning process, the organizations said.

Their brief also urged the court to find that electric cooperatives can participate in the cost-allocation process with states. In much of the country, cooperative boards establish their consumers' rates independently of any state regulator.

States including the attorneys general of Texas and Utah, the Arizona Corporation Commission, the Louisiana PSC, the Mississippi PSC, the Ohio PUC's Federal Energy Advocate and others argued FERC goes too far and is trying to encourage a shift to renewable energy with Order 1920.

"It effectively transforms the transmission planning process into a tool to subsidize transmission facilities that support a specific set of favored generation resources," they said.

Order 1920 requires transmission providers to use seven categories of factors to develop planning scenarios that lead to the construction of favored technologies. The factors include state or local policy, including decarbonization and renewable energy targets.

"The effect of this process is to socialize costs of transmission," the state opponents said. "If a city passes an ordinance requiring that all its energy must be solar (without regard to the cost), the transmission provider for the entire region must now account for that policy in its planning and thus build the infrastructure necessary to support the city's power generation goals. The transmission providers cannot disregard the policy as unreasonable."

States that favor traditional methods of power generation are required to subsidize the development of the infrastructure required to support states and localities that favor other methods of generation, they added.

Appalachian Voices, Invenergy, Environmental Defense Fund, Natural Resources Defense Council, Sierra Club and others filed a brief that FERC did not go far enough and that Order 1920 will not fix the "broken" transmission grid that has been neglected by is owners and operators for decades.

"The existing regional grid has experienced catastrophic and deadly failures during extreme weather events," the environmentalists and Invenergy said. "It lacks the infrastructure necessary to adapt to acute changes to electricity supply and demand. And cheaper, cleaner resources wait years to connect to the grid while aging, uneconomic plants are unable to retire, costing consumers billions of dollars every year."

FERC has passed other transmission reforms over the decades where it was clear what the industry had to do, they argued. But when it paired "a choose-your-own-compliance adventure" with a general set of planning principles, then nothing changed.

"This is unsurprising; incumbent transmission owners tasked with transmission planning and development have financial incentives to avoid the most cost-effective projects, since truly efficient regional transmission introduces competition and reduces profits for them and their affiliated generating resources," the environmentalists and Invenergy said.

They argued that FERC was wrong to let transmission owners ignore benefits like access to cheaper generation, deferred generation investments and increased competition from the planning process. It also failed to consider alternatives such as new transmission technologies and storage, or merchant transmission lines, in the planning process.

The final brief came from industry competition proponents such as Advanced Energy United, Electricity Transmission Competition Coalition, LS Power and others. They argued FERC should not have reimposed a federal ROFR for "right-sized" projects.

Order 1000 had eliminated federal ROFRs, but Order 1920 would reimpose them for projects that come out of local planning processes but would produce more benefits if the need addressed a larger, regionally planned project.

The rule is the first time FERC has imposed a ROFR on its own. The old federal ROFRs were put in place by incumbent transmission owners themselves and filed with FERC under Section 205 of the FPA. It proposed the new one because in earlier rounds of reforms, many incumbent transmission owners were replacing aging infrastructure on their own, avoiding regional planning processes.

FERC reasoned that allowing a ROFR for right-sized projects would subject more transmission to regional planning. Competition proponents argued the lack of planning for such lines was a calculated effort from utilities to counteract Order 1000's attempt to use competitive market forces.

"Order 1920 takes a drastic step in the opposite direction — creating a ROFR from whole cloth and mandating its use in FERC-jurisdictional tariffs — on the flawed theory that the power to find a practice unlawful under the FPA necessarily entails the power to mandate that practice," AEU, ETCC and LS Power said.

"Although FERC's motivation to incentivize regional transmission investment may be well-intentioned, its chosen method is both misguided and unlawful. Giving incumbent transmission owners a monopoly right to build tomorrow's regional grid free from competition is a Faustian bargain. For the incumbent utilities, that deal is too good to be true. For consumers, it is a financial nightmare." ■

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Large-load Tariffs Touted as Alternative to 'Side Deals'

New Mexico PRC Considers Large Customer Rate Design

By Elaine Goodman

Why This Matters

The proliferation of data centers and other large-load customers is raising concerns about the shifting of electricity costs to other ratepayers.

As regulators grapple with rate design for large-load electricity customers such as data centers, some experts are pointing out the transparency benefits of tariffs compared to special contracts between the utility and customer.

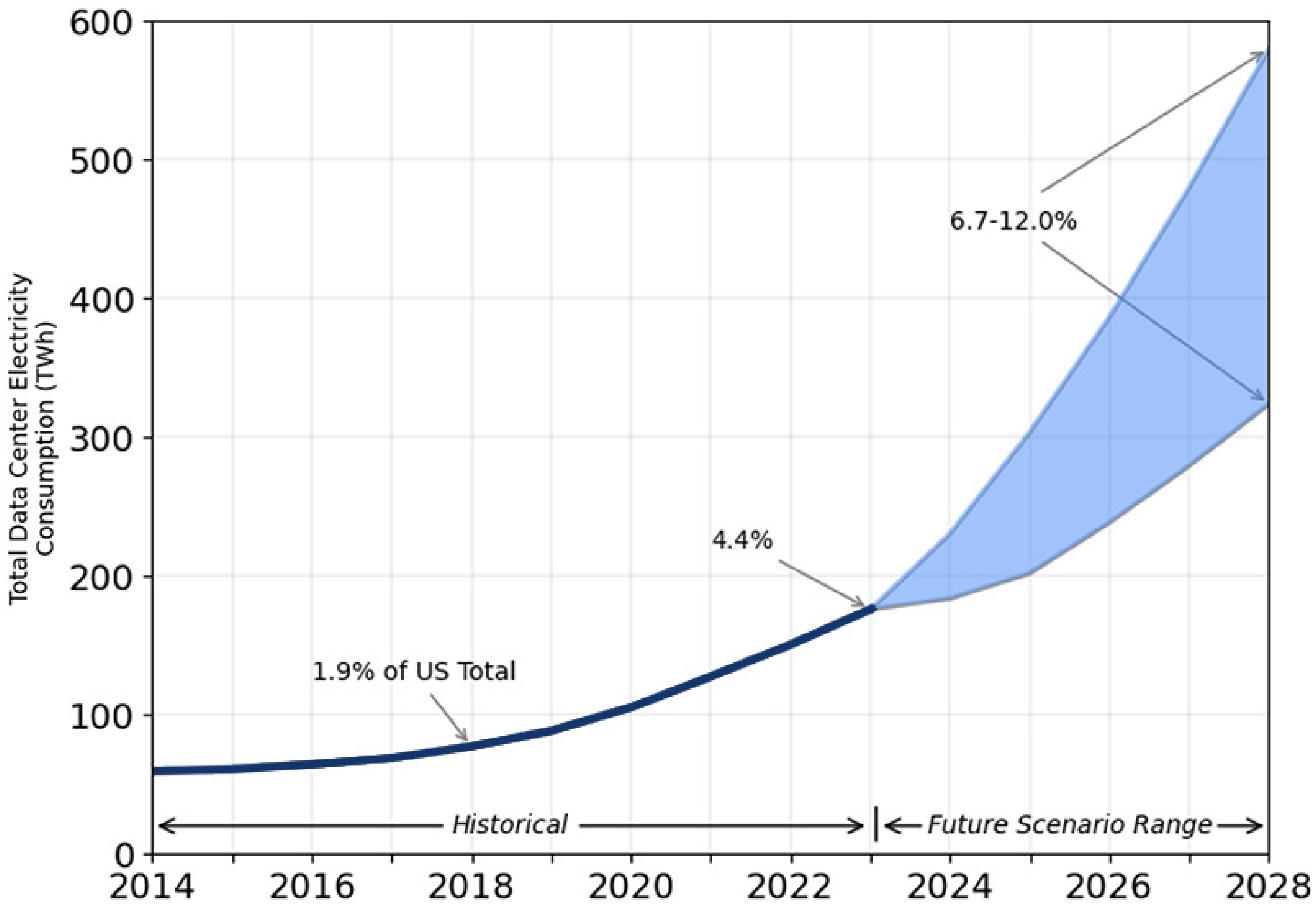
"We don't like these side deals," said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. "We think putting in place data center tariffs is better. It's more transparent. It encourages robust participation in the process in developing these tariffs."

Peskoe was a speaker during a Sept. 2 New Mexico Public Regulation Commission (PRC) workshop focused on large-load rate design. He gave an overview of a *paper* released in March on "How Utility Ratepayers Are Paying for Big Tech's Power."

Peskoe and co-author Eliza Martin reviewed 40 state utility commission proceedings regarding special contracts with data centers. They found that regulators often "reflexively" grant a utility's request to keep the proposal confidential, and then "frequently approve special contracts in short and conclusory orders." That's in contrast to rate cases, which draw robust stakeholder engagement, according to the researchers.

Utility tariffs typically detail the price, conditions and terms of electricity service to customers and must be approved by regulators. In contrast, special contracts are often a bilateral agreement negotiated by the utility and the large customer, according to Natalie Frick, an energy policy researcher in the Energy Markets and Policy Department at Lawrence Berkeley National Laboratory.

"One of the big complaints about special contracts is that there's a lack of transpar-



With data centers projected to account for as much as 12% of all U.S. energy demand by 2028, interest is growing in specialized tariffs for large-load electricity customers. | *Lawrence Berkeley National Laboratory* ency," Frick said in a presentation to the PRC. "They're often confidential, and so there's less public scrutiny about them."

Frick cited as an example an approved special agreement between Meta and Duke Energy Indiana.

"You don't know how much capacity was being procured, you don't know where it's being procured [from], you don't know what the demand fee or energy charge was," she said.

Frick noted that a consumer advocate was able to review the confidential information and found the deal didn't increase costs for other customers.

Grid Readiness Proceeding

The Sept. 2 workshop was part of the commission's proceeding on grid readiness and economic development.

"Data centers are a big topic," said Commissioner Pat O'Connell, noting that the centers create challenges for the electric industry. "On balance, the need for data centers is real, and having them in the United States is valuable. So it's a problem that's worth solving."

The commission is now considering whether a large-load tariff could help address some of the issues.

"For me, it's a lot about a fair allocation of cost to ratepayers, and a fair opportunity for large customers to interconnect and start receiving power from the utility," said commission Chair Gabriel Aguilera. "A tariff — would it make it easier for a large customer to know what to expect?"

Aguilera said one option would be to form a stakeholder group to work on a proposed large-load tariff and associated agreements, focusing first on minimum requirements.

Frick and other Berkeley Lab researchers released a *technical brief* in January titled "Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities." The Brattle Group and U.S. Department of Energy helped with the research.

The report examined 11 large-load tariffs across the U.S. The minimum size to be eligible for the tariff varied, according to Frick's presentation. In the case of Black Hills Power's Economic Flexible Load Service, the minimum is 10 MW, while We Energies' very large customer tariff has a minimum of 500 MW aggregated.

Some tariffs include an exit fee for ending service early. Ohio Power's data center tariff settlement agreement proposed an exit fee of three years of minimum charges.

Frick said most of the tariffs have a ramping schedule, in which customers consume an increasing amount of their capacity over time.

In some tariffs, large-load customers may resize the load they plan to take, without penalty, if they find out before a certain deadline that they need less than they expected.

And sometimes tariffs and special contracts are used together, she said.

What's the Goal?

In Nevada, when a large customer wants to take service under one of NV Energy's large-load tariffs, the utility files an energy supply agreement (ESA) with the Public Utilities Commission of Nevada, according to Karen Olesky, an economist with the PUCN's regulatory operations staff.

The tariff states what should be in the ESA and in the ESA application, while providing some flexibility, Olesky said. Customers might have different energy needs — such as a data center versus a sports stadium — or different renewable energy goals, she said.

NV Energy's large customer tariffs include the clean transition tariff, which the PUCN approved in March. It's a framework developed in partnership with Google that will allow the utility's existing large-load customers to receive power from new clean energy resources. (See *Nevada Regulators Give Nod to NV Energy Clean Transition Tariff*.)

The clean transition tariff was modeled on NV Energy's Large Customer Market Price Energy tariff, which is available only to new customers.

Olesky said regulators should start by considering what they want to accomplish with a large-load customer tariff. That might be attracting new load to the system, lowering rates for large customers or helping a large customer meet renewable energy goals that are beyond renewable portfolio standard requirements.

Determining the tariff's purpose will help regulators decide the acceptable level of subsidy from other customers, she said.

"Is it zero?" Olesky said. "Or is the ultimate goal to bring new load at all costs, so having non-participating customers pay something for this is OK?" ■

West Coast Senators Urge Passage of Calif. Pathways Bill

Support Letter Comes Shortly Before Legislative Deadline

By Henrik Nilsson

Oregon Sens. Ron Wyden and Jeff Merkley were among the six Western senators urging Gov. Gavin Newsom to help advance the Pathways bill through the California Legislature on a tight deadline. | *Office of Sen. Jeff Merkley*

Six Western U.S. senators came out in support of the California legislation needed to transform CAISO's market into an independent regional energy market, saying in a letter to Gov. Gavin Newsom that the bill promises "improved grid reliability and significant energy cost savings."

Democratic U.S. Senators from Oregon, Washington and California issued the *letter* in support of *SB 540*, urging Newsom to help get the bill passed before the Golden State's legislative session ends Sept. 12.

A heavily amended version of the bill passed the state Senate on a 36-0 vote in early July but stalled in the Assembly after many backers *pulled their support* in protest of the amendments.

While one of the bill's sponsors, Sen. Josh Becker (D), recently expressed confidence about passage of a suitable version of the bill this session, supporters are under pressure now to ensure a stripped-down version of the legislation is printed before midnight Sept. 9 to comply with a rule requiring an amended bill to be in print for 72 hours before lawmakers take a vote on it. (See *Pathways Bill Will Make It to Newsom's Desk, Author Says*.)

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.

What's Next

SB 540 supporters are under pressure now to ensure a stripped-down version of the legislation is printed before midnight on Sept. 9 to comply with a legislative rule requiring an amended bill to be in print for 72 hours before lawmakers can take a vote on it.

"In California, Oregon and Washington, broad participation in an expanded regional power market will result in improved grid reliability and significant energy cost savings for our constituents," the senators' letter said.

Sens. Jeffrey Merkley and Ron Wyden of Oregon, Sens. Patty Murray and Maria Cantwell of Washington, and Sens. Adam Schiff and Alex Padilla of California signed the letter.

The lawmakers emphasized many of the arguments EDAM supporters have made, including claims that the day-ahead market option will result in expanded access to generation resources across the West, improved grid resiliency and affordable electricity.

They also noted that the onset of new load from data centers, onshoring manufacturing and increased electrification "is straining both the grid and our constituents' pocketbooks."

"In tandem, consumer electric bills have soared — a result of rising demand, increasing wildfire risk and the misguided, impractical policies of the Trump administration," the lawmakers wrote. "It is now being reported that around 80 million Americans are sacrificing basic expenses like food or medicine just to keep the lights on. Expanded regional power markets would allow for better utilization of existing generation, helping to meet growing demand while lowering energy costs."

"We urge you to take this extraordinary opportunity to jump-start the expansion of regional markets by enabling the CAISO, through legislation, to partner with an independent RO, thereby improving grid reliability and electric bill affordability for all West coast states as soon as possible," the lawmakers stated.

In tandem with CAISO's EDAM, SPP is developing a competing day-ahead market for the West — Markets+.

One of the largest participants in Markets+ is the Bonneville Power Administration, which manages the output from 31 hydroelectric dams in the federal Columbia River Power System, while also operating more than 15,000 miles of transmission lines — about 75% of the Northwest grid.

In the lead-up to BPA's day-ahead market choice, the U.S. senators from Oregon and Washington issued multiple letters, including one in December 2024 saying BPA had failed to make a financial case for joining Markets+. (See *BPA Has not Made 'Business Case' for Markets+, NW Senators Say*.)

After BPA issued its final record of decision in favor of Markets+ in May, Wyden and Merkley told *RTO Insider* that the agency had rushed its decision, expressing disappointment. (See *BPA Chooses Markets+ over EDAM*.) ■

Robert Mullin contributed to this article.

Western Utilities Set Sights on RTO After DAM Choice

4 Utilities Outline Reasoning Behind Market Decisions During EBA Webinar

By Henrik Nilsson

Four Western utility executives participating in a webinar hosted by the Energy Bar Association presented their reasoning for why they ultimately chose either SPP's Markets+ or CAISO's Extended-Day-Ahead Market (EDAM), with some eyeing the creation of a full regional transmission organization in the future.

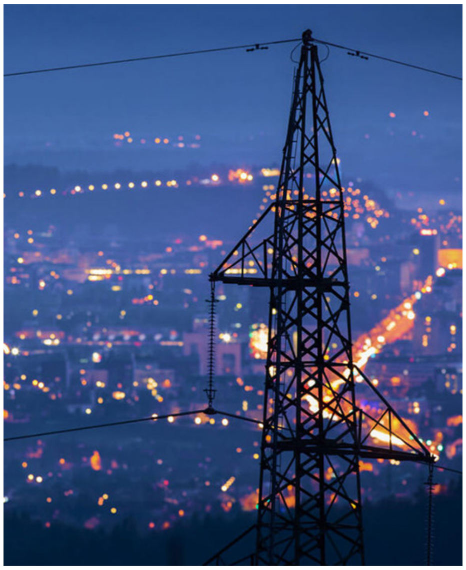
Representatives from Portland General Electric, Bonneville Power Administration, Public Service Company of New Mexico and Salt River Project participated in the Aug. 28 webinar about the development of wholesale markets in the West.

PGE and PNM have both committed to joining EDAM, which is scheduled to go live in spring 2026, and are integrating processes with the day-ahead market alternative.

The utilities' choices boiled down to, among other things, customer affordability and reliability.

Pam Sporborg, director of transmission and market strategy at PGE, pointed to production cost models showing EDAM would provide greater economic benefits than Markets+. Also, the CAISO markets' contiguous footprint "offers us good resource diversity, helping to balance many different geographic regions."

PNM joined for similar reasons, noting the utility delivers significant wind and solar power to California. (See *PNM Signs Agreement to Join CAISO's EDAM*.)



PG&E

"Being in a separate market from that would create huge operational challenges," according to Kelsey Martinez, director of regional markets and transmission strategy at PNM.

Although PNM's decision to join EDAM means there will be market seams with SRP, Arizona Public Service and El Paso Electric, seams with California would be too costly, according to Martinez.

However, "we do want to ultimately have the option to be on a path to an RTO," Martinez said.

"I think it needs to definitely remain optional," she added. "Given our resource diversity with California and our wind shape and the future of our system, we see the benefits of having California footprints in an RTO eventually, and realizing more and more incremental benefits that way. So, we do think that's an important option for us in the future."

Sporborg, meanwhile, said the West will likely see an "incremental advancement" that captures the benefits of an RTO in a way unique to the region.

Sporborg is also co-chair of the West-Wide Governance Pathways Initiative Launch Committee. The Launch Committee, consisting of members from several Western states, was formed with the task of establishing an independent RO to oversee CAISO's WEIM and EDAM.

The Pathways model can help capture the "benefits that we see in the RTO environment, but in a uniquely Western way that is developed ground up from the stakeholders and really targets the specific benefit that we're looking for within the overall market construct in a way that we can hopefully avoid some of the pitfalls and stagnation that we see in some of the Eastern markets," Sporborg said.

'Primary Platform'

Meanwhile, BPA and SRP chose to join Markets+ based on a few other benefits, the utilities' representatives said during the webinar.

Why This Matters

The discussion suggests utilities see further possibilities for markets in the West after SPP and CAISO launch their respective day-ahead alternatives.

Specifically, resource adequacy requirements, an independent governance model and the greenhouse gas accounting mechanism were some of the factors that led BPA to join Markets+ in May following a lengthy public process, according to Nita Zimmerman, acting vice president of bulk marketing at the agency. (See *BPA Chooses Markets+ over EDAM*.)

"We expect day-ahead markets to be the primary platform for wholesale electricity transitions in the West, especially with some states requiring utilities to transition to RTOs," Zimmerman said. "And based on our experience as a later entrant to the Western [Energy Imbalance Market], BPA believes that early [day-ahead market] adoption … will better meet customer and stakeholder objectives, because the first years of a market greatly influence development and maturation of the market design."

For SRP, an important aspect was "having a pathway to an RTO," said Josh Robertson, director of energy market strategy at SRP.

"That's really the next logical step here," Robertson said. "I think we are adding some complexity by doing a day-ahead market and not an RTO, and we're potentially leaving some things on a table. There are issues with moving to an RTO, surely, but we want to make sure that there's a pathway to doing that."

Markets+ has a viable path to a full-fledged RTO, given its independent board and governance structure, Robertson said.

"We did not see that path very viable with the CAISO market," he added. ■

BPA Transmission Pause Questioned During Workshop

Agency Says It Lacks Capacity to Handle Soaring Requests in Interconnection Queue

By Henrik Nilsson

The Bonneville Power Administration estimates it would need up to seven years and billions of dollars in upgrades to handle the 65 GW of transmission service requests in the queue, staff said during a Sept. 4 workshop.

The workshop is part of a series of public meetings the agency is hosting as part of its Grid Access Transformation Project (GAT).

BPA paused certain planning processes and launched the GAT program to consider changes following a surge of transmission service requests. The federal power agency's 2025 transmission cluster study includes more than 65 GW of requests, compared with 5.9 GW in 2021. The requests exceed the total regional load predicted for the Pacific Northwest in 2034, according to the agency. (See *BPA's Proposed Tx Access Changes Prompt Questions of Industry Readiness*.)

Conducting an actionable study would require the agency to "model unrealistic load increases or unrealistic generation dispatch patterns to achieve the load reverse balance that's necessary to perform a power flow study," said Abbey Nulph, manager of transmission commercial planning at BPA, during the workshop.

"Our best estimate is that the batches that we believe would not require unrealistic load or generation patterns would have us batching roughly 10 to 20 GW of batches," Nulph said. "Using our current [Transmission Service Request Study and Expansion Process] timelines, it would take between seven and eight years to process just the existing queue. And while we were undergoing those studies, we would continue to be getting more requested."

BPA's Bonneville Dam | *U.S. Army Corps of Engineers*

Alex Swerzbin, vice president of power marketing and transmission at NewSun Energy, asked about the six- to seven-year timeline, saying others in the industry have estimated the process to take between three to four years under a batch framework.

Nulph replied that even if BPA was able to process 65 GW, the result would be a "massive collection of plans of service."

"And the host of plans of service that will come out of study of this size would likely necessitate several billion dollars more in upgrade," Nulph added. "We do not have that access to capital."

Some of the new proposed updates to planning processes include readiness criteria and a new Network Integration Transmission Service initiative where any new forecast increase of 13 MW or more during any year would require participation in commercial planning.

The agency also is contemplating offering interim service and moving toward proactive planning, meaning building ahead of transmission service requests, according to a July 9 workshop presentation. (See *BPA Outlines Proposed Transmission Planning Reforms*.)

'Slings and Arrows'

NewSun CEO Jake Stephens also weighed in during the Sept. 4 discussion, contending that BPA should have continued processing requests under the current rules instead of issuing the pause. He noted the 2023 TSEP studied 15 GW, triggering "universal upgrades."

"We would recommend go ahead and process the first 15 GW of the current queue without waiting and running a whole litigated process, which could take a long time and is probably pretty contentious, because we actually know right now that you can process at least 15 or 20 GW more," Stephens said.

Nulph said BPA can process many requests but could run into issues that arose during the 2023 process, where a "large portion of our queue drops away because the plans of service are too expensive."

Why This Matters

BPA issued the pause to weed out unrealistic requests in order to spend resources on projects that are likely to move forward.

"So, it feels like a waste of our time and our effort," Nulph said. "Especially when we are relatively resource-constrained in our ability to perform these sorts of studies. We are wanting to spend our slings and arrows on the work that is the most effective for us. And our assessment at this point is that conducting the largest study we think we could will not result in actionable results at the other end."

Stephens responded that the market and studies point to the need for more buildouts, while BPA is "sort of saying, 'Well, we can't build all this stuff that everybody needs, so we want to adopt policies to shrink everything back to a small-enough set that it doesn't need all the upgrades that we all need.' But we do need that."

"It's not what I'm saying," Nulph said.

"I'll clarify," she added. A "vast portion" of requesters dropped out when BPA offered the Preliminary Engineering Agreements after the 2023 TSEP, Nulph said.

"And the cited reasons were that those projects were too expensive for them to proceed with," Nulph said. "So, this isn't a Bonneville assessment that we can't afford to build these. It's that the region is telling us they can't afford these."

Next steps in BPA's GAT process include a customer-led workshop Sept. 10. Additionally, the agency plans to respond to customer comments from previous workshops in October.

BPA is also moving from a business practice process to a tariff proceeding process and will publish a webpage and host additional workshops on those proceedings, according to presentation slides. ■

WEIM Emissions Attribution Rules Apply to EDAM, Wash. Agency Clarifies

By Robert Mullin

Why This Matters

The Department of Ecology's guidance ensures that Western market participants understand that emissions attribution rules apply equally to real-time and day-ahead transactions.

Washington's Ecology Department has clarified that state cap-and-invest rules that apply to CAISO's Western Energy Imbalance Market will also cover the ISO's Extended Day-Ahead Market (EDAM) when it begins operations in 2026.

An agency *guidance document* released Sept. 3 explains how the cap-and-invest program attributes an appropriate volume of greenhouse gas emissions to energy imported into Washington via a centralized electricity market (CEM). The WEIM is presently the only centralized market operating in the West, with SPP's Markets+ expected to go live in 2027.

The GHG attribution process is complicated by the difficulty of pinpointing exactly what resource in a centralized market produced the energy imported into the state to meet a market participant's demand.

Under existing rules, energy transferred into Washington via the WEIM is classified as an "unspecified import" and assigned a default emissions factor of 0.428 MT CO2e/MWh. The rules also require that the Washington-based load-serving entity or market participant receiving the import be responsible for reporting the emissions to the Ecology Department.

But a 2024 law (SB 6058) prompted Ecology last December to adopt a new framework that will allow the agency to trace the origin and emissions factor of CEM energy transfers into Washington — transfers that will be categorized as "specified imports" with specific associated emissions rates.

To do that, the new framework calls for centralized market operators such as CAISO and SPP to establish a system for identifying a "deemed market importer" for transfers into Washington, defined as "the market participant that successfully offers electricity from a resource or system into a CEM, which is then "attributed to Washington by the methods put in place by the market operator of that CEM." The deemed market importer will also be the entity responsible for reporting emissions to the agency.

The Sept. 3 guidance notes that existing reporting rules will remain in place through 2026, but it advises market operators to put a "specified imports" system in place by Jan. 1, 2027.

It also clarifies that although the rules were written with the real-time WEIM in mind, they also apply to EDAM.

"Ecology notes that all optimization of electricity supply from market resources and attribution of imported electricity to Washington through the day-ahead market, EDAM, ultimately occurs in real time, within the WEIM," the agency wrote. "For this reason, Ecology clarifies that provisions applicable to the 'energy imbalance market' within WAC 173-441-124(3)(v), apply equally to entities participating in WEIM and EDAM." ■

Washington Department of Ecology headquarters in Lacey, Wash. | *McGranahan Architects*

West Must Step up Gas-electric Coordination, WECC Panelists Say

Region 'Dangerously Close' to Supply Shortage, Utility Rep Says

By Henrik Nilsson

Coordination between the gas and electric industries is becoming increasingly crucial to meet demand and tackle extreme weather events, panelists participating in a WECC webinar said Sept. 3.

Representatives from the Pacific Northwest Utilities Conference Committee (PNUCC), Williams, Arizona Public Service and Portland General Electric discussed coordination between the gas and electric sectors.

The Northwest cold snap over the 2024 Martin Luther King Jr. holiday weekend prompted stakeholders to consider ways to improve coordination between the two sectors, said Crystal Ball, PNUCC's executive director. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

The holiday weekend saw record-low temperatures along with historically high peak demand, prompting five different balancing authority areas (BAAs) to declare energy emergency alerts.

Though the Pacific Northwest relies heavily on the Columbia River hydro system, the cold snap occurred during a low-water year, Ball noted. It also coincided with a fault that caused Washington's Jackson Prairie natural gas storage facility to sharply reduce its sendout, prompting pipeline operator Williams to declare a force majeure that cut deliveries to interruptible customers, including some power generators.

Utilities call for increased coordination between the natural gas and electricity sectors to meet demand. | *Shutterstock*

"We recognize that natural gas is the region's second-largest power source behind hydro, and these two systems are very interdependent, and we will continue to depend on natural gas," Ball said.

To meet the mounting large-load challenges from data centers and the transportation sector, stakeholders must work together, not just on transmission and generation, but also focus on expanding the gas system, according to Ball.

"We need policymakers, regulators, utilities to understand that situation," she said. "There's evidence that demand in our region is growing. But right now, this region is dangerously close to an energy supply shortage. And so I think that my advice to policymakers and other stakeholders is to learn about what these reliability risks are and to come together to think about how the region can maintain reliability."

For PGE, the January 2024 event meant there wasn't any headroom in the utility's systems, according to Aaron Rodehorst, manager of term trading at PGE.

"We're fully using our pipelines. We're fully using our transmission systems," Rodehorst said. "There's a high degree of need for coordination."

Rodehorst said he works closely with balancing authority staff "to make sure they know everything I know that they can then also be coordinating with their peers."

"I've been building a contingency plan at Portland General Electric for four or five years now, and every year it gets better, and it gets better also when I start to share it more broadly and get to think about what pieces I'm not putting into that plan," he noted.

'No More Wiggle Room'

Carolyn Ebner, commercial services lead at Williams, said, "our system is fully subscribed."

> **Notable Quote**
>
> "We're fully using our pipelines. We're fully using our transmission systems. There's a high degree of need for coordination,"
>
> *- Aaron Rodehorst, PGE*

Williams owns the nearly 4,000-mile bi-directional Northwest Pipeline. The pipeline crosses Washington, Oregon, Idaho, Wyoming, Utah and Colorado, according to the company's website.

"We have no more wiggle room," Ebner said. "And Northwest Pipeline is not unique."

Ebner said the company will continue to have conversations with the electric sector, "both confidential and in these group platforms, [and] we're going to continue to prepare options for growth and additional storage on our gas system."

Meanwhile, in Arizona, APS had a peak demand of about 8,500 MW in 2025, but the utility predicts peak demand will reach 13,000 MW by 2038, said Jason Hartzell, manager of fuels and contracts at APS.

APS has had "positive" discussions with Arizona's commissioners and has gained support for natural gas expansion through public forums facilitated through APS, Hartzell noted.

To keep up with customer demand, APS has signed an agreement with Energy Transfer Partners to build a new pipeline from the Permian Basin to Arizona to support new gas-fired power plants, he added.

"We would be one of the shippers of that pipeline," Hartzell said. "So, we're only one of the Arizona utilities that has seen this additional need for natural gas." ■

CPUC Approves Guidelines for Large IOUs' Dynamic Rate Designs

Dynamic Rates Should Reduce Peaker Plant Usage, Commission Says

By David Krause

The California Public Utilities Commission has approved guidelines for utilities to use to design dynamic electricity rates, with one commissioner asking for more research on whether implementing such rates will leave some customers further behind financially.

The *decision* applies to Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric, which must propose dynamic rates in their general rate cases for approval by the CPUC.

And it comes just weeks after publicly owned utilities Sacramento Municipal Utility District and the Los Angeles Department of Water and Power outlined their challenges with implementing the practice in reports submitted with the California Energy Commission. (See *Calif. Utilities Move Cautiously on Dynamic Pricing*.)

The dynamic rate design idea comes from the CEC's load-management standards.

"This is an exciting proposed decision and it really marks another step … to support California's long-term goals: grid reliability, electrification and affordability," CPUC President Alice Reynolds said at the commission's Aug. 28 voting meeting, during which the decision was approved.

Reynolds said the decision addresses key demand flexibility — or dynamic rate — design elements: marginal energy costs based on CAISO's hourly load; day-ahead prices at default load aggregation points; marginal generation capacity costs; marginal distribution capacity costs; marginal transmission costs; non-marginal costs; and line-loss factors.

"Demand flexibility is one of the most important things we are doing as a state

Shutterstock

Why This Matters

The CPUC's decision is an initial step toward rolling out dynamic rates for many customers in California, which could help reduce energy usage during peak demand times. But equity concerns remain.

and will help provide additional resources that we can use," Commissioner Darcie Houck said at the meeting. "I know a lot of time, effort and thought has gone into this decision."

The goal of dynamic rates is to "motivate customers to shift electricity consumption away from high-demand periods, when polluting, peaking plants run and electricity is most expensive," Commissioner John Reynolds added at the meeting. "Dynamic rates promise to achieve this by providing accurate price signals that reflect actual grid consumptions."

However, as California moves from the approved guidelines to implementing these new rates, it is important to evaluate their effect on different types of customers, he said.

It may prove true that factors like income, whether a customer owns their home or a customer's climate zone could "substantially impact their ability to shift energy usage to lower-cost hours," he said.

"We should evaluate these rate design changes to understand these consequences," he said. "This is an equity concern that I think we need to attend to."

In the decision, the commission said community choice aggregators should be able to either design their own dynamic rate or use their associated IOU's dynamic rate. IOUs should describe how they will collaborate with CCAs on

Continued on page 20

CAISO Price Formation Proposal Looks to Reduce ‘Unnecessary’ Market Mitigation

Scarcity Pricing Should be Proactive, Not Reactive, Staff Says

Why This Matters

CAISO’s Price Formation Enhancements initiative is seeking to address issues of scarcity pricing and market power mitigation in a WEIM that now spans most of the balancing authority areas in the West.

By David Krause

After years in the making, CAISO has released a price formation *proposal* intended to reduce “unnecessary” market power mitigation, strengthen reliability and provide consistent pricing incentives in the Western Energy Imbalance Market (WEIM) and future Extended Day-Ahead Market (EDAM).

Release of the straw proposal, which was followed by two workshops Sept. 3 and 4, is part of CAISO’s Price Formation Enhancements initiative, started in 2022 to focus on two key subjects around real-time market pricing: balancing authority area-level market power mitigation and scarcity pricing.

BAA-level market power mitigation is “a ‘nickname’ for market power mitigation applied to WEIM transfer constraints and, in the future, EDAM transfer constraints,” James Friedrich, CAISO policy developer, said at the Sept. 3 workshop.

“So instead of saying that mouthful, we just call it BAA-level market power mitigation,” Friedrich said at the workshop.

“And what it’s doing is ensuring that, when transfer constraints bind between balancing areas participating in the regional markets, that we ensure that there is competitive pricing inside the balancing areas that are price-constrained from the broader market due to these constraints.”

The market power mitigation process “essentially prevents suppliers from within these constrained BAAs from exercising market power over the constrained balancing area,” Friedrich added.

To improve its BAA-level market power mitigation process, CAISO’s proposal is considering using a “grouping approach” for a market power mitigation (MPM) test, one that will try to increase competitive pricing when a participating BAA becomes price-separated from the broader market due to binding transfer constraints, the proposal says.

Currently, during a MPM test, each BAA is modeled individually. This means that power supply from neighboring BAAs is not accounted for during a MPM test. Therefore, this practice could be overestimating market power and could lead to unnecessary mitigation, the proposal says.

The individual MPM test approach “was acceptable when the WEIM had fewer participating entities, but it has become a concern in today’s larger, more interconnected market,” the proposal says.

BAAs rarely operate as fully isolated “islands,” the proposal says. With dozens of BAAs participating in the regional markets, a “rigid one-by-one test could mischaracterize competitive conditions and reflect an outdated methodology,” the proposal says.

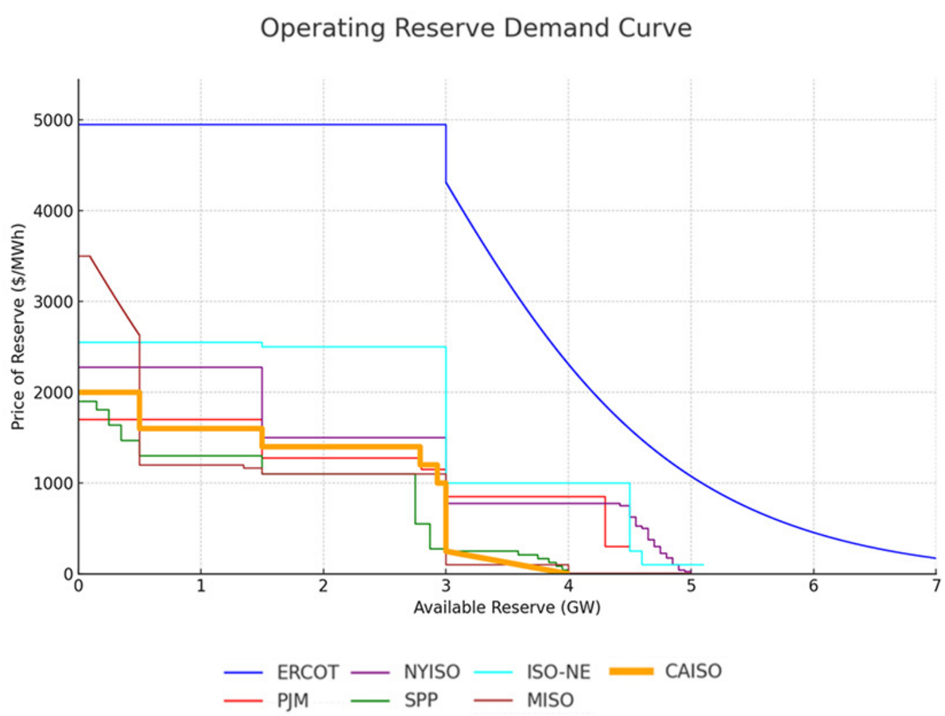
On the other hand, a group of BAAs in a MPM test would become a combined region, allowing the market to assess the BAAs with spare transfer capability, according to the proposal.

Scarcity Pricing Improvements

The second main subject of the proposal is scarcity pricing, a mechanism meant to “create really powerful market incentives,” Friedrich said during the Sept. 4 workshop.

Scarcity pricing incentives coordinate the behavior of all market participants to improve reliability in tight conditions by encouraging generators to be and stay online, getting flexible demand off the system, and incentivizing storage resources to defer charging, Friedrich said.

“More reserves generally means a more reliable system. Fewer reserves mean



Operating reserve demand curves in various RTOs | *CAISO* a less reliable system," Friedrich said. "When you get in scarce conditions, each incremental megawatt is valued not just by the cost of production for the unit to produce [electricity], but also in valuing its role in preventing a system outage."

Currently, CAISO's scarcity pricing mechanisms include:

- a tiered scarcity reserve demand curve (SRDC) that provides the marginal prices of ancillary services when the availability of this type of power supply is low.
- a Flexible Ramping Product (FRP) demand curve that provides the scarcity pricing signal in the real-time market.
- an imbalance reserve demand curve for the extended day-ahead market that allows the market to forgo procuring imbalance reserve.

However, CAISO has found problems with each mechanism. The SRDC applies inconsistently in the real-time market, meaning real-time energy and reserve prices do not consistently incorporate the scarcity value of reserves and "thus do not consistently reflect short-term operating conditions," CAISO said in the proposal. This issue can result in inadequate price signals and increase reliability risks.

"The scarcity reserve demand curve is not really a great tool for scarcity pricing the way we traditionally think about it … because it's not designed to trigger unless there is an actual shortage," making it a reactive rather than proactive price signal, Friedrich said.

"And the gold standard for scarcity pricing are designs that are intended to be proactive, meaning they kick in before the actual shortage condition occurs, which is the whole point," he added.

CAISO staff and stakeholders said the ISO should consider "re-optimizing" ancillary services in the real-time market. Doing so would "allow the market to better reflect real-time system conditions and costs by releasing ancillary services capacity procured in the day-ahead market that could be more valuable for energy or other services in real-time," CAISO said in the proposal.

CAISO and stakeholders are also considering extending procurement of ancillary services into the five-minute market to provide more consistent price signals, the proposal says.

Additionally, CAISO is looking to improve scarcity pricing mechanisms so they gradually increase energy and reserve prices ahead of supply shortages. CAISO's Department of Market Monitoring suggested extending use of the FRP, which could help the real-time market better position resources and improve pricing signals ahead of potential scarcity conditions, the ISO said in the proposal. ■

CPUC Approves Guidelines for Large IOUs' Dynamic Rate Designs

Continued from page 18

dynamic rates and programs, the commission said.

Marginal vs. Fixed Costs

In the decision, the commission said IOUs' dynamic rates must include a marginal generation capacity cost (MGCC), which is the cost to procure and maintain sufficient generation capacity to reliably serve an incremental unit of electric demand at all times, including during peak demand and ramping periods.

The MGCC price "must account for costs associated with both peak and flexible capacity needs during periods of grid stress," the commission wrote. An IOU's proposal must include a price component that recovers an IOU's MGCC revenues "to ensure that generation capacity costs are appropriately reflected in DF rates."

"I expect the marginal costs on our grid to be much lower than our current electric retail rates," John Reynolds said at the meeting.

The reason for that is that California's electric system has many fixed costs, he said.

"For example, using more electricity does not really change the amount of money needed to trim vegetation to reduce wildfire risk," he said.

Historically, the state recovers these fixed costs in the electricity rate, making that rate higher than the marginal costs of energy.

However, the modest fixed charge that the state already adopted still "does not fully cover our fixed costs of the system," John Reynolds said.

"There will be debate about which costs are actually marginal and which are fixed, and that's healthy, and we will need policy decisions resolving that debate," he said.

"As we make policy decisions evaluating the nature of marginal costs, I expect that truly reflecting marginal costs in hourly prices will be lower rates and higher fixed charges," he added. "These will be revenue neutral … and should actually lead to a lower overall cost grid."

But fully moving to hourly marginal pricing will mean customers who can shift their usage will "have greater opportunities for bill savings than customers with inefficient appliances and leaking homes that don't stay cool on hot days," he said.

The large IOUs should use CAISO's locational marginal prices at default load aggregation points in CAISO's day-ahead market, CPUC staff said in the decision. This approach provides customers with a degree of rate certainty because electricity prices in the day-ahead market at default load aggregation point prices represent a majority of load-serving entities' actual energy purchase costs, staff said. ■

Google, SRP Team up on Long-duration Storage

Still Unclear What Technology the Partnership will Choose

By Elaine Goodman

Arizona utility Salt River Project (SRP) and Google are partnering to study the real-world performance of non-lithium-ion, long-duration energy storage (LDES) technologies, the parties announced Sept. 8.

Google will fund some of the costs for LDES pilot projects developed for SRP's grid, according to a release. Google will crunch numbers on the pilot projects' performance and help with the research and testing plans.

The goal is to help the emerging storage technologies scale more rapidly.

"We believe that long-duration energy storage will play an essential role in meeting SRP's sustainability goals and ensuring grid reliability," Chico Hunter, SRP manager of innovation and development, said in a statement. "This first-of-its kind research collaboration with Google will bring additional insight into the viability of these new technologies that could move them to maturity more quickly."

SRP serves about 1.1 million customers in the greater Phoenix area. The utility now has about 1,300 MW of energy storage, including 1,100 MW of battery storage at eight facilities. An additional 200 MW is pumped hydro storage.

The SRP-Google collaboration may include multiple LDES projects. SRP noted that it issued requests for proposals in 2022 and 2024 for LDES demonstration projects.

"Long-duration energy storage is a key technology in the portfolio of advanced energy solutions that we want to bring to market faster — to unlock stronger, cleaner, more resilient grids," Lucia Tian, Google's head of advanced energy technologies, said in a statement.

Although the type of LDES technology to be deployed in the project isn't yet known, Google announced in July a partnership with Energy Dome, which makes a carbon-dioxide-based energy storage system.

The system uses renewable energy when it's abundant to compress CO_2 gas into a liquid. When the grid needs more power, the liquid CO_2 expands back into a hot gas under pressure, which spins a turbine. The energy generation lasts for eight to 24 hours.

Why This Matters

Long-duration energy storage is seen as a complement to shorter-duration storage for decarbonizing the grid.

Google said it will support commercial deployments of Energy Dome's technology globally as well as invest in the company.

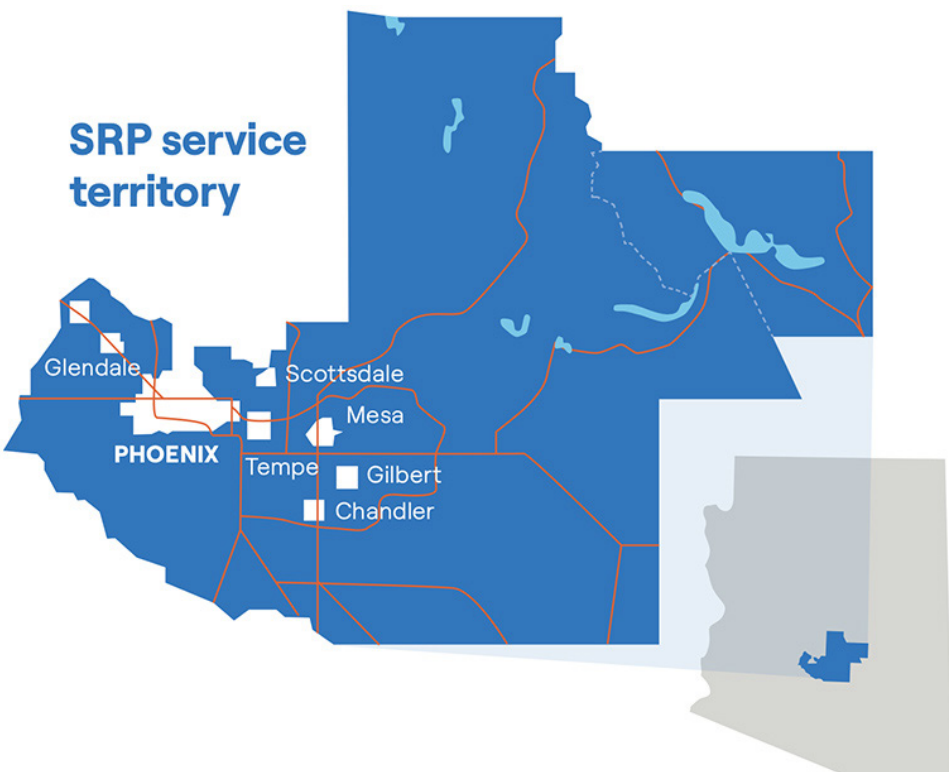
SRP has committed to reaching net-zero carbon emissions by 2050. Google wants to run its global data centers and offices on carbon-free energy and achieve net-zero emissions across its operations and value chain.

Google and SRP have partnered on clean energy resources to power Google's future data center in Mesa, Ariz. The resources include the Sonoran Solar Energy Center, a 260-MW solar facility with 1 GWh of battery storage; Storey Energy Center, an 88-MW solar and battery storage system; and Babbitt Ranch Energy Center, a 161-MW wind farm.

Meanwhile, SRP wants to at least double the number of generating resources on its power system in the next decade to maintain reliability and resilience.

On two consecutive days in August, SRP set new records for system peak load: 8,429 MW on Aug. 6, followed by 8,542 MW on Aug. 7. High temperatures hit 116 and 118 degrees Fahrenheit on those days; peak energy demand was between 3 and 4 p.m.

SRP's previous record peak of 8,361 MW was set July 9. ■



| Enel North America

Clean Energy Sector in Texas Grapples with New Legislation, Large Loads

Infocast Summit Addresses Numerous Challenges Facing Industry

By Tom Kleckner

Jupiter Power's Caitlin Smith (left) and Vistra's Ned Bonskowski listen to Shell Energy's Resmi Surendran during an Infocast panel discussion. | *© RTO Insider*

AUSTIN, Texas — The dust has settled in Texas after another biennial legislative session that installed guardrails for data centers and other large loads and avoided stiff penalties on the clean energy sector. At the same time, ERCOT stakeholders are still digesting the massive federal budget reconciliation bill that was signed into law in July.

Both pieces of legislation weighed heavily on the minds of panelists during Infocast's annual Texas Clean Energy Summit Aug. 26-28.

The summit's opening panel took on Texas' *Senate Bill 6*, which governs the planning, interconnection and operation of large loads and generation resources in ERCOT. The bill directs the state's Public Utility Commission to set rules that address cost-sharing and interconnection standards for new large load customers (defined as any load 75 MW or greater). These loads will be required to contribute to utilities' costs to connect them to the grid.

The legislation also requires electric cooperatives and municipally owned utilities that have not adopted retail choice to pass through reasonable interconnection costs for large loads.

Ned Bonskowski, vice president of Texas regulatory affairs for Vistra, pointed out that SB 6 didn't occur in a vacuum.

"It wasn't like on the first day, the Legislature said, 'Let there be Senate Bill 6,' and then that was the first energy policy that we had in the state," he said. "There's a long continuum of statutory and regulatory policies that it has to fit in, and that goes way back beyond Senate Bill 6. I honestly think that about 75 to 85% of what you see in Senate Bill 6 was already happening or was going to happen anyway, so it's really codifying in statute, putting some guardrails that the Legislature said they learned how they wanted to be implemented."

"Load growth, triggered largely by data centers, is creating a lot of anxiety in different markets and we're seeing different approaches to how to manage that pending issue," Samantha Robertson, director of global strategy at cryptocurrency miner Bitdeer, said. "In Texas, it's codified in statute, but we've seen it in other jurisdictions where [transmission and distribution providers] are dealing with it differently in their specific service territory or it's happening at the RTO level. Not only do we have a lot of tools, but we're in a market where finding innovative approaches and looking at problems in a completely new way is possible based on how the market is designed."

Caitlin Smith, policy lead for storage developer Jupiter Power, called for load forecasts that are accurate and believable. Load forecasts help transmission planning, she said, but the market also needs to know what is coming in order to serve resource adequacy.

"We've had what we all recognize as these kind of very bloated load forecasts. I think we will see that what comes out of this law is hopefully a more accurate load forecast," Smith said. "Load being the signal that you need more generation, but my understanding what may be different about the data center loads and the AI loads is they're not price responsive. That creates a tricky situation when you're thinking about these things, too, right?"

PUC Reviewing 4CP Program

High on the PUC's priority list is a review of ERCOT's 4CP program, which assesses transmission charges for the following year based on the grid's overall — or coincident — peak demand during four 15-minute intervals, one from each summer month. The Texas grid's increased

Why This Matters

Senate Bill 6 in Texas and the federal government's budget reconciliation bill have clarified some of what lies ahead for the clean energy sector. However, the industry must still grapple with the Trump administration's tariff wars, supply chain issues and other uncertainties in the months ahead.

reliance on solar power has shifted tight conditions from the load peak to the net load peak at the same time as more flexible crypto miners and data centers are connected to the system.

That has caught the attention of lawmakers, who directed the PUC to review 4CP within the context of SB6. The review must be completed by the end of 2026.

"[4CP] has long been a subject of discussion and debate. It certainly will have an impact on incentives for loads and for the market," Bonskowski said.

Michael Macias, vice president of operations for Electric Transmission Texas, a joint venture between American Electric Power and Berkshire Hathaway Energy subsidiaries, urged his panel's listeners to engage themselves in the stakeholder process.

"I think it's clear that 4CP is on the table for a revision. What's not clear is how that's going to be implemented," Macias said. "What's also clear is that we know that in order to support the substantial growth that we're seeing in our time, we're going to have to spend tens of billions of dollars. If we're going to build the system up to bring the new load in, then we need to make sure that we're putting protections in place for everybody, for the folks that are investing in that infrastructure, folks that are using that infrastructure, and then for everybody else that wasn't planning on having to pay for 760 pipelines around the state."

Robertson said the conversation needs to include how costs are allocated to large loads.

"I think it's largely the expectation that AI or high-performance computing data centers wouldn't necessarily participate in 4CP, so their demand would be whatever their load contribution is during the coincident peaks," she said. "I think another question that SB6 is asking is how transmission costs are allocated. ... That's something that is going to go back to addressing utility business models. And again, I think it also goes back to the fact that if you want to be interconnected to the grid very quickly and you're willing to pay for it, maybe you can shoulder 100% of the cost. So, I think that's a bigger question that isn't necessarily addressed by 4CP or 8CP or 12CP or whatever it ends up being."


Michael Macias, ETT | © *RTO Insider*

Managing Large Load Forecasts

Kristi Hobbs, ERCOT's vice president of system planning and weatherization, keynoted the summit's second day with a discussion of — what else? — large loads and their effect on the market.

She said ERCOT's regional transmission planning studies look six years into the future because "we know it takes time to build transmission on the system."

As part of ERCOT's latest regional plan, staff asked transmission service providers how much load they were expecting to hook up to their systems. They told staff they expected more than 218 GW of demand.

"Anyone in this room believe that we're going to hit 218 GW of demand in six years?" Hobbs asked.

A few hands shot up.

"Anybody believe we won't?" she asked.

More hands were raised.

"Yeah, we were a little bit uncertain about that as well," she said. "If we would have taken the entire forecast that we received from the transmission service providers, it would have been 85,000 MW of demand from data center loads. That's more than the entire United States."

ERCOT is currently tracking about 188 GW of large loads seeking interconnection, compared with 63 GW in December 2024. The grid operator has reviewed and approved planning studies for more than 19 GW of large loads over the past two years. Almost 7 GW have been approved to energize.

A *report* released in August by Enverus Intelligence Research said load projections from ERCOT and PJM widely differ from the company's models.

"ERCOT's and PJM's estimates imply that each of the next five years, their regions alone would absorb more than 100% of U.S. annual data center capital spending, an assumption we believe is unrealistic," according to Enverus senior analyst Kevin Kang.

"We know a lot is coming in Texas, but we need to be careful that we're balancing the cost to consumers with the transmission build for those that will actually be here," Hobbs said. "They're very motivated, they've got contracts ... and they're wanting to move forward. They come motivated.

"We also have some that come, and I feel like they're just fishing," she added. "They put in a request over here, they put a request over there, and they see which utility bites. Whichever one bites first, they're going to go with that, and then they let the other one just fade off."

Clean Energy Still Faces Uncertainty

With the federal budget reconciliation bill hamstringing the development of clean energy, the only resource that can quickly and cheaply be brought to market, the sector is grappling with an uncertain future. The bill took away tax credits from wind and solar projects unless they were able to begin construction by July 4, 2026 — or be in service by Dec. 31, 2027, if they did not meet the July 4 deadline.

Clean energy advocacy group E2 said companies have *canceled or scaled back* more than $22 billion in projects since the start of 2025, including $6.7 billion in investments in June alone.

"It is going to be impactful long-term and in the immediate, too," said Doug Pietrucha, senior principal with Advanced Energy United. "Realistically, those resources needed to have steel in the ground in the next 10 months to have any ability to take advantage of the remaining tax opportunities that exist for them. So really, the quickest turnaround for those resources is creating a huge decision-point bottleneck for those developers at the moment. There are a lot of projects that are on the bubble."

Pietrucha noted that batteries are eligible for credits into the 2030s, as long as they maintain *Foreign Entity of Concern* compliance.

"Certainly, storage has the capacity to do procurement in a way that will permit them to qualify into the future, but the reality of navigating how to do it and actually getting your hands on components that are going to keep you compliant is a whole ballgame in itself," he said.

"We're on pause right now, there's so many moving pieces," energy storage consultant Katherine Meik said. "It's not just about the tariffs. Sometimes, it's about equipment availability. I think a lot needs to be defined. We'll start seeing some of those answers, but we need to get through the tariff wars first and then we have to figure out who can manufacture and where it's coming from."

Asked how ERCOT is dealing with the uncertainty, Hobbs said SB6's directive to standardize the information required to be included in load forecasts will help. Large load customers must also disclose whether they are pursuing similar interconnection requests elsewhere in Texas that could affect the planning and timing of their requests.

"We're working with the utilities who have the relationships with the customers making the load request to better understand the level of certainty," she told *RTO Insider*. "I think we have more certainty on those developments in the shorter term and then it's getting the best information on the longer-term [loads]."

Developers: Chaos is Good

That uncertainty is not necessarily a problem, agreed a panel discussing the future of the Texas grid, which leads all other states in clean energy installations.

Nemica Kadel, Lightsource BP | © *RTO Insider*

Doug Pietrucha, AEU | © *RTO Insider*

Former ERCOT staffer Nemica Kadel, now with Lightsource BP, advocated for a hybrid solution where everyone contributes to the cost of building out the grid because "we're all working towards a stable grid."

"[Cost allocation] has always been a heated topic, especially in Texas, where it's a socialized cost. There's questions of who gets to hold the bag right now," Kadel said. "The way it is, all the ratepayers are paying for it. There's also a lot of demand, and I know that that the policymakers are working on trying to come up with the optimal solution."

"I've always been told that power development is no place for the faint of heart," moderator Dino Barajas, with the Baker Botts law firm, said. "If you have a weak stomach, you're probably in the wrong industry, because everything changes on the dime."

"Every chaos is an opportunity, right?" Kadel responded.

"I love the chaos, just simply because we do have chaos and people have to be talking about it. People talking about it is a good way to get improvements," said Alex Shattuck, director of grid transformation for Energy Systems Integration Group.

As an example, he used the technical aspects of recent regulatory changes for clean energy being critical facts for eight years.

"We're just now getting there and putting them into place because people are finally talking," Shattuck said. "The conversations they're having give [the regulatory space] momentum to actually get improvements and enhancements to regulatory procedures done."

"The chaos is 100% a good thing," OTC Global Holdings' Campbell Faulkner said. "We finally went from the power industry being rather boring to being interesting again." ■

ERCOT Fills out Board with 2 Final Selections

By Tom Kleckner

ERCOT's board selection committee has chosen two new independent directors, restoring the Board of Directors' full complement of seats after several departures earlier in 2025.

The grid operator said Houston's Christopher Krummel and Austin's Kathleen McAllister will fill the remaining vacancies on the 12-person board. The selections were announced and became effective Sept. 3.

Christopher Krummel | *Centuri Holdings*

Kathleen McAllister | *NACD*

Krummel has more than 30 years of financial executive experience in the energy and construction industries. He is a founding partner of Krummel, Ellis & Weekley Advisory, which provides sell-side transaction advisory services to energy focused clients, and previously served as McDermott International's CFO.

He has a bachelor's degree in business administration from Creighton University and a master's in business administration from The Wharton School of the University of Pennsylvania.

McAllister has more than 15 years of experience in corporate governance as a CEO, CFO and board director. She currently serves on the boards for Black Hills Corp. and Höegh LNG Partners after spending years in executive roles with offshore driller contractor Transocean Partners.

McAllister holds a bachelor's degree in accounting from the University of Houston and is a certified public accountant.

Board Chair Bill Flores welcomed the newest members to the board, saying in a *press release*, "Their background, knowledge and expertise will continue to support ERCOT's strategic objectives of maintaining a dynamic, reliable and resilient electric grid."

Two independent directors resigned from the board earlier in 2025 to pursue "new opportunities" in the ERCOT market. That left the 12-person board three short of full membership. Industry insider Bill Mohl was selected in July to fill one of the vacancies. (See *ERCOT Adds Industry Vet to Board of Directors*.)

The ERCOT board is subject to oversight by the Public Utility Commission and the Texas Legislature. By law, all board members must be Texas residents.

The board's selection committee was created by state law in 2021. It is composed of three appointed members, with the governor, lieutenant governor and the speaker of the Texas House of Representatives each selecting a representative. ■

Ontario Govt. Moves to Tighten Grip on OEB, IESO

By Rich Heidorn Jr.

Why This Matters

The government's latest moves raise questions about the independence of IESO and its regulator, the Ontario Energy Board.

Ontario's Progressive Conservative government last week continued to put its stamp on the province's energy policy, proposing legislation that would add "economic growth" to the missions of IESO and the Ontario Energy Board (OEB).

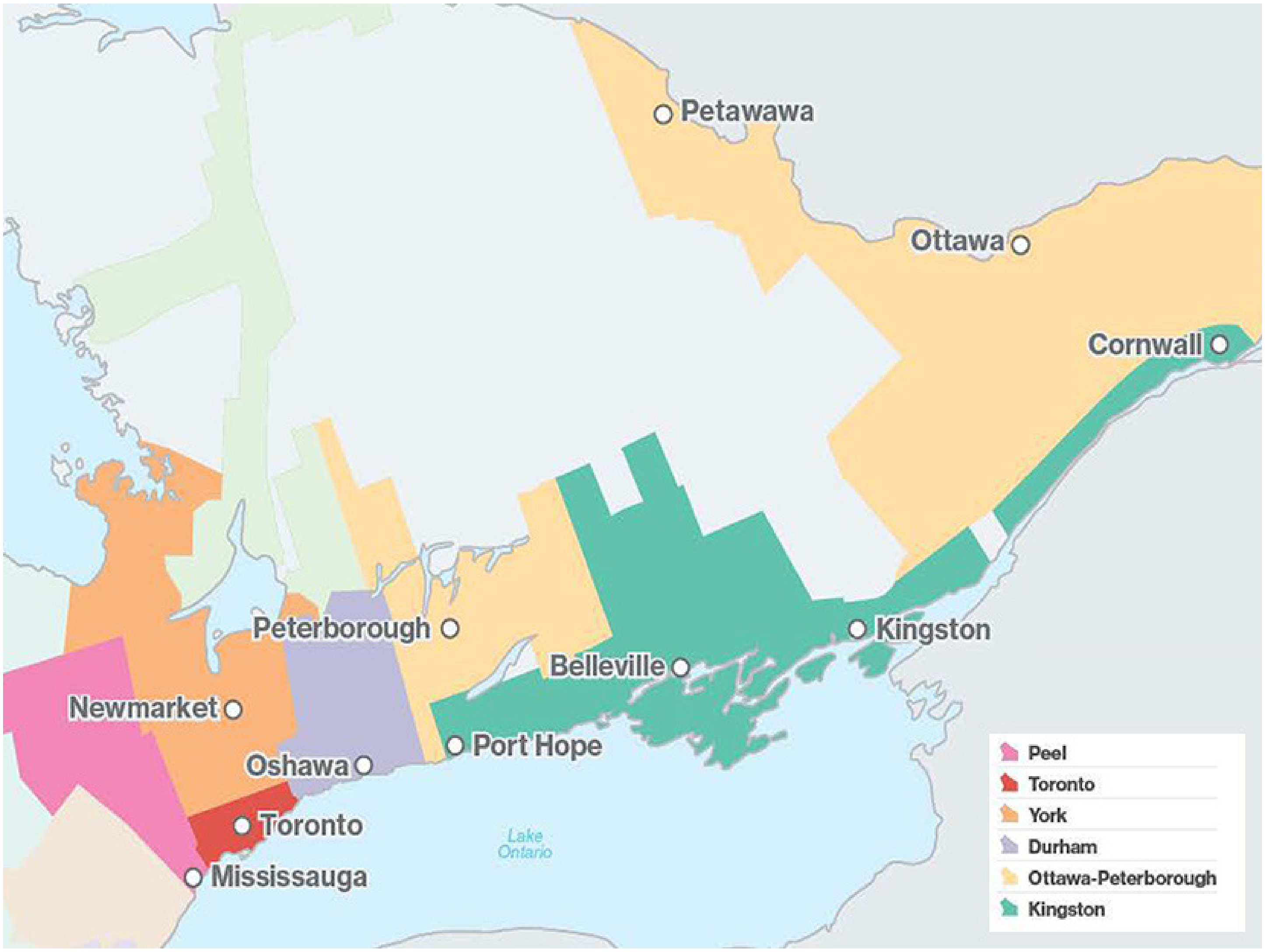
The Ministry of Energy and Mines posted the legislation Sept. 4, a day before the provincial government announced Geoff Owen as the OEB's new chair. Owen, who has served on the board since 2021, was appointed chair at the recommendation of Minister Stephen Lecce.

The ministry's *proposed legislation* is intended to support the province's first Integrated Energy Plan, which seeks to ensure sufficient capacity for a forecast 75% increase in electric demand over the next 25 years. (See *Ontario Energy Plan Gives IESO Long 'To Do' List*.)

The bill would amend the Ontario Energy Board Act of 1998 and the Electricity Act of 1998 to update the missions of the OEB and IESO, making economic growth a "core consideration" in electric rulings and system planning. "The proposed amendments are targeted towards enhancing electricity transmission and distribution planning processes to account for the expediency of the electricity grid buildout to drive innovation and economic growth, and to strengthen self-reliance and energy security," the ministry said.

In addition, the legislation would:

- give the lieutenant governor authority to set connection requirements for data centers, which IESO projects will account for about 13% of new electricity demand by 2035.
- allow rate-regulated entities to establish accounts to track increased costs that could result from territory-of-origin restrictions on energy procurements. The OEB would review for prudency and rate recovery.



Enbridge Gas central distribution service area | *Enbridge Gas Distribution and Storage*

- expand the purposes of the Electricity Act to allow IESO to undertake clean hydrogen pilot projects with non-electricity applications such as transportation and industrial use.
- amend the Ontario Energy Board Act to enable the OEB CEO to issue "scoped policies" such as timelines for adjudicative proceedings and the information to be considered, such as relevant government policy statements. "This authority would not bind commissioners to make determinations in alignment with government direction/policy," the ministry said.
- amend the Municipal Franchises Act to eliminate requirements that a municipality's voters approve new natural gas municipal franchises. "The process to obtain municipal electors' assent can be administratively burdensome and costly for some municipalities," the ministry said. "Franchise applications often include a request to waive this requirement, and the OEB has granted that request in the vast majority of cases."
- implement the Future Clean Electricity Fund, which would make payments to non-emitting hydro and nuclear electric resources and transmission projects. The FCEF will be funded by the Emission Performance Standards program, which is designed to reduce greenhouse gas emissions from large industrial facilities by "setting standards, rewarding innovation and taking into consideration specific industry/facility conditions while allowing for economic growth," the ministry said.

Blowback over Gas Ruling

The Progressive Conservative Party, led by Premier Doug Ford, has controlled Ontario since 2018, when it ended 15 years of Liberal Party rule.

After canceling hundreds of what it said were above-market renewable energy contracts, the Ford administration has committed to expanding renewables in the province. But it also is backing an expansion of nuclear power and continued use of natural gas. In support of its Integrated Energy Plan, the Ministry of Energy and Mines issued a prescriptive 12-page directive spelling out in detail how IESO is to carry out its policy, with sections on planning, district energy systems, distributed energy resources, transmission, low-carbon hydrogen strategy, hydro and nuclear generation, and export opportunities. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

The OEB has attracted increasing attention from the government since the board's December 2023 *decision* rejecting a rate proposal by Enbridge Gas. OEB said it would require Enbridge or developers to pay 100% of the cost of new natural gas connections in advance. The board said the previous policy, which spread the costs to consumers over 40 years, would result in stranded assets as the province moves to meet Canada's 2050 target for net-zero greenhouse gas emissions.

In February 2024, then-Energy Minister Todd Smith *announced* legislation to reverse the OEB ruling and said he would be appointing a new OEB chair.

"Natural gas will continue to be an important part of Ontario's energy mix as we implement our pragmatic plan to invest in and bring online more clean nuclear energy," Smith said. "Unlike the previous government, which saddled families with sky-high hydro bills, our government is taking a thoughtful approach that keeps costs down for people and businesses and delivers energy security."

In addition to reversing the OEB decision, the *Keeping Energy Costs Down Act*, which was approved in May 2024, authorizes the minister to issue directives requiring the OEB to hold a generic hearing to determine any matter respecting natural gas or electricity.

The ministry said OEB's decision could add tens of thousands of dollars to the cost of new homes.

But an *analysis* by Western University's Ivey Business School concluded that "the government's decision to override the OEB should have virtually no effect on affordable housing in the province. Based on our admittedly rough estimates, their policy might reduce the annual cost of buying a home by $92.74 or it could possibly increase it $32.90. Hardly seems worth damaging regulatory independence for."

In a December 2024 *report*, Ontario's auditor general challenged the ministry's claim that the new law would have no impact on the environment. "The ministry did not explain that the proposed changes had the potential to increase greenhouse gas emissions by encouraging the continued construction of new natural gas infrastructure and continuing Ontario's reliance on fossil fuels instead of shifting to electricity," it said.


Geoff Owen, chairman of the Ontario Energy Board | *Foresight Strategic Advisors*

OEB Chair

Owen, a principal at Foresight Strategic Advisors, joined the board in 2021, becoming vice chair in 2024 and acting chair in April. He previously held executive positions at the Royal Bank of Canada in regulatory affairs, business strategy and public affairs. He has also served in the offices of the Premier of Ontario, Minister of Finance, Minister of Economic Development and Minister of Municipal Affairs and Housing.

"Mr. Owen assumes his role at a pivotal time, as the Ontario Energy Board begins to deliver on the Minister of Energy and Mines' Integrated Energy Plan directive and continues carrying out our core regulatory responsibilities while supporting Ontario's economic, social and environmental development," OEB said in a press release.

Owen replaced Mark White, who served less than a year after being *appointed* OEB chair in July 2024. ■

Ontario Energy Board Plans 22% Spending Increase

32 New Hires Planned

By Rich Heidorn Jr.

The Ontario Energy Board (OEB) plans a 22% increase in its 2025/26 budget with the addition of 32 employees, its biggest hiring surge in at least five years.

The board cited "the increased volume and complexity" of its job in announcing the hirings, which would increase OEB's staff by 14% to 260 full-time equivalents.

"We are building an organization that can enable government policy and be the regulator Ontario needs during the energy transition," OEB said in its *Business Plan* for 2025/26 through 2027/28, which outlines $70.3 million in spending for the current fiscal year (beginning April 1) and preliminary budgets for the following two years.

The board said the $12.5 million budget increase was needed to respond to the Ministry of Energy and Mines' 2024 *vision statement* and the ministry's Dec. 19, 2024, *Letter of Direction*, which outlined the province's strategy for responding to an expected 75% increase in electric demand by 2050.

"These additional resources will enable the OEB to deliver on its mandate, which, when coupled with the minister's letter, requires taking on additional deliverables at a time when the organization is at full capacity with existing commitments and adjudicative work," the board said.

"Resources will be applied across the organization to meet the highest-priority needs at any point in time, balancing adjudicative support and policy development, and matrixing resources depending on expertise, topic and timeline," it added.

Three initiatives will each receive six new FTEs:

Why This Matters

The Ontario Energy Board answers to the Ministry of Energy and Mines and regulates IESO, giving it a key role in the province's electric policy.

- Advancing the Energy Transition: ensuring regulated entities plan across fuel types; considering how to apply the "beneficiary pays" principle; and streamlining approvals for electric connections and "priority" pipeline projects.
- Driving System Modernization: developing local market opportunities for

The Ontario Energy Board, which regulates IESO, summarized its role and values in its business plan. | *Ontario Energy Board*

	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
FTEs	192	203	203	228	228	260
Additional FTEs approved in Business Plan		11		25		32
Actual FTEs hired at end of fiscal year*		8	3	24	1	

The Ontario Energy Board plans to hire 32 new employees in 2025/26, the biggest contributor to a 22% budget increase for the year. | *Ontario Energy Board*

distributed energy resources, such as distribution system operators; implementing performance-based rate regulation for electric distribution companies; supporting Indigenous participation; and ensuring cost-effective integration of innovative business models.

- Sustaining Resources: adding legal, public affairs, finance and human resources staff to support OEB's expanded operational requirements and strategic priorities. OEB said those functions "have not kept pace with recent growth across the organization."

The board also plans five new staffers to boost DERs, including providing incentives for implementing non-wires solutions, publishing capacity maps for distribution and transmission systems, and reducing barriers for new energy efficiency programs.

In total, the salaries and benefits budget is increasing by 19% to $50.4 million.

Because they will have staggered start dates, the 32 new hires will cost $4.15 million in 2025/26 and $6.2 million annually thereafter.

The budget also includes $1.8 million for salary increases for existing staff and $1.2 million for short-term contract staff needed to "backfill" for subject-matter experts shifted under the Business Operations Optimization and Systems Transformation (*BOOST*), a new platform for data and workflow management across OEB processes.

The plan pointedly reiterates the board's belief that "diversity, equity and inclusion (DEI) is not just an ideal but also our competitive business advantage, a defining characteristic of our culture and an essential organizational strategy."

The new hires will allow OEB to "provide strategic and prudent oversight of Ontario's energy sector through initiatives that support broader government priorities such as planning for growth, keeping costs down, enabling energy system modernization and streamlining solutions that will make Ontario an energy superpower," the board said.

Impact of Integrated Energy Plan?

Roy Hrab, senior manager for policy research at Power Advisory, noted on LinkedIn that OEB's plan was completed before the release of Ontario's Integrated Energy Plan (IEP) in June "and the accompanying (quite prescriptive) implementation directive to the OEB." (See *Ontario Energy Plan Gives IESO Long 'To Do' List* and *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

"How the OEB's planned key projects presented in the plan have changed and will be prioritized post-IEP (and directive) remain to be seen," he added.

The big spending increase caught the attention of Martin Benum, former director of regulatory affairs for London Hydro.

"The OEB is supposed to regulate industry costs, not grow into another bloated cost-recovery machine itself," Benum said in response to Hrab's posting. "Is the OEB still focused on consumer protection and efficiency, or are we watching another cost monster take shape here in Ontario?"

Capital Spending Trending Down

While the board is increasing spending on personnel, it expects capital spending (business systems, infrastructure and end-user computing) to drop slightly, from $474,000 in 2025/26 to $451,000 in 2027/28.

"With more resources available as services, the OEB's IT capital budget is expected to be stable in the coming period with some spending moving to the IT operating budget," it explained.

Priorities

The board's priorities for the coming year include simplifying the connection processes for DERs, incentivizing electric distribution companies to use third-party DERs as non-wires alternatives and a benefit-cost analysis framework for addressing system needs.

OEB also is considering changes to its rate design to accommodate electric vehicles and battery storage, following up on its analysis of the impact of delivery costs on EV charging facilities. "The OEB is also planning to consider reforms to rate design for resources providing grid services and other emerging technologies," it added.

Also on the schedule for the board is a ruling on Enbridge's 2026-2030 electric demand-side management application, which includes a residential program that would be delivered through a "one-window" approach in conjunction with IESO. OEB said it expects to rule on the case this fall. ■

Revolution Wind Sues to Lift Federal Stop-work Order

704-MW Wind Farm Off Rhode Island Coast is 80% Complete

By John Cropley

Revolution Wind is seeking an emergency injunction against the federal stop-work order slapped on its offshore wind project.

The Bureau of Ocean Energy Management's Aug. 22 order was arbitrary and capricious, violated the due process clause of the Fifth Amendment and is beyond statutory authority, attorneys argued in a complaint filed Sept. 4 in the U.S. District Court for the District of Columbia (1:25-cv-2999).

The project off the southern New England Coast would send 704 MW at peak output to Connecticut and Rhode Island. BOEM approved it two years to the day before the stop-work order, and construction is 80% complete. Developers say they have spent or committed more than $5 billion so far on Revolution Wind and had expected a first-half 2026 commercial operation date.

Also Sept. 4, the attorneys general of Connecticut and Rhode Island announced a lawsuit in U.S. District Court for the District of Rhode Island seeking to overturn the stop-work order.

Developer Ørsted *said in a news release* that while Revolution Wind would seek to work collaboratively with the administration and other stakeholders for a prompt resolution, litigation is necessary due to the substantial harm the stoppage inflicts on the project.

Why This Matters

Billions of dollars and hundreds of megawatts potentially hang in the balance.

Components are assembled for delivery to the Revolution Wind construction site off the New England coast. | *Revolution Wind*

The new litigation is the latest step in what largely has been a one-sided battle over U.S. offshore wind energy development that began a few hours after the inauguration of President Donald Trump, an outspoken opponent of the technology.

Trump's executive actions and his Cabinet's multitude of policy adjustments have made it unlikely any new construction will start during his term, but he has been more ambiguous about the five projects already under construction in U.S. waters.

A previous stop-work order against Equinor's Empire Wind in April was widely seen as an attempt not to kill the project but to twist New York's arm to reconsider previously rejected gas pipeline proposals. Equinor lost millions of dollars in the monthlong stoppage; it threatened to take the administration to court but never did.

Some have speculated the Revolution stoppage is Trump's attempt to twist the arm of Denmark, which owns a majority of Ørsted and also controls Greenland, which Trump covets.

But if there is such an ulterior motive, it has not been stated. Connecticut Gov. Ned Lamont (D) has said he thinks there is one but needs to find out what it might be.

The stop-work order references national security interests, and Interior Secretary Doug Burgum later offered a vague explanation in a CNN interview about the wind power array interfering with defense against submarine and aerial drone attacks.

Revolution Wind occupies a seabed lease awarded in September 2013. Ørsted and its partners — first Eversource, now a consortium led by Skyborn Renewables — spent years preparing the project.

The complaint states that every conceivable aspect of construction was reviewed by 15 state and federal agencies (including the Department of Defense) during three presidential administrations, resulting in more than 20 local, state and federal permits and approvals.

The stop-work order does not accuse Revolution of violating any law or condition of approval, the complaint states, and is unlawful, lacks evidentiary basis and was issued without statutory authority.

The attorneys general, meanwhile, say the stop-work order did not identify any violation of law or imminent threat to safety.

"Revolution Wind is fully permitted, nearly complete and months from providing enough American-made, clean, affordable energy to power 350,000 homes," Connecticut Attorney General William Tong said. "Now, with zero justification, Trump wants to mothball the project, send workers home and saddle Connecticut families with millions of dollars in higher energy costs. This kind of erratic and reckless governing is blatantly illegal, and we're suing to stop it."

Rhode Island Attorney General Peter Neronha cited the Trump administration's "all-out assault" on wind energy: "Just yesterday, we learned of reports that the administration is pulling in staff from several different unrelated federal agencies, including Health and Human Services, to do its bidding. Does this sound like a federal government that is prioritizing the American people? This is bizarre, this is unlawful, this is potentially devastating, and we won't stand by and watch it happen."

National trade group Oceantic Network does not comment on active litigation, so it had nothing to say Sept. 4 about Revolution Wind's court filing, but it reinforced its longstanding message about the importance of offshore wind in general and Revolution Wind specifically to the American economy.

Various media outlets have placed the project cost at $4 billion or $6 billion. Ørsted will not provide an exact cost but said in the Sept. 4 court papers it has cost $5 billion so far and said Aug. 25 that the combined investment in its two active U.S. offshore wind projects — Revolution and Sunrise — is expected to be in the $16 billion range.

Oceantic pointed out the secondary benefits of all this: 183 Revolution Wind supply contracts for 179 companies in 34 states, with over $1.4 billion in related investments and 2,500-plus American jobs supported.

The renewable energy industry has been making similar statements about the sector's importance to the grid and to the economy since Election Day, but that has had minimal effect — Trump and his Cabinet and his congressional allies have loosed a flurry of actions to stymie solar and especially wind development. ■

ISO-NE Monitor Discusses Market Trends, Energy Transition

By Jon Lamson

BOSTON — The New England wholesale electricity markets performed competitively in 2024, while decreased imports and higher emissions compliance rates increased overall market costs, the ISO-NE Internal Market Monitor told the NEPOOL Participants Committee on Sept. 4.

David Naughton, executive director of the IMM, discussed the group's 2024 *annual report*, which was originally published in May.

The IMM found that wholesale market costs totaled about $10.2 billion in 2024, up by about $1 billion from 2023. This increase largely stemmed from higher energy market prices, which were caused by greater emissions compliance costs and a significant drop in imports from Quebec, which caused the region to rely more heavily on higher-priced natural gas generation, Naughton said. (See *Drought, Climate Drive Uncertainty on New England Imports from Québec*.)

Regional Greenhouse Gas Initiative (RGGI) costs increased by about 55% in 2024 compared to the prior year, he noted, adding that this increase was partly offset by a 61% decline in Massachusetts' cap-and-trade program. Overall, carbon compliance costs totaled $509 million for New England generators, Naughton said. This translated to $910 million in added wholesale market costs, as higher marginal resource costs increased the clearing price paid to all participants.

He noted that the New England states reinvest most of the RGGI proceeds in energy efficiency programs, which help mitigate the cost impacts of carbon prices.

"These energy efficiency programs saved approximately 17.5 TWh in energy, or roughly $757 million in wholesale energy market costs based on the 2024 LMP," the IMM wrote in its annual report.

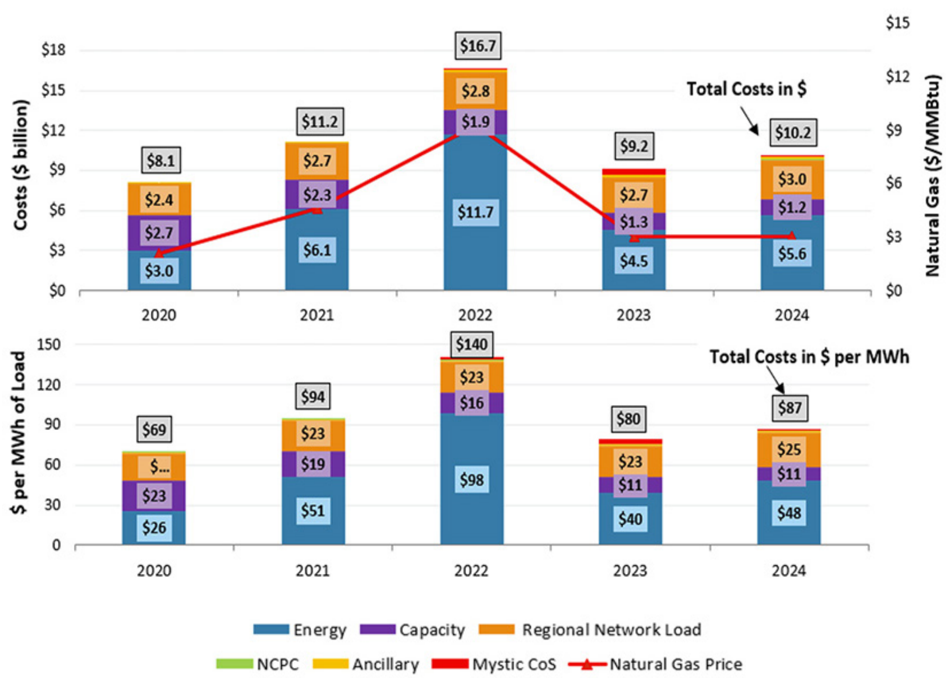
In 2025, wholesale costs are on track for a significant year-over-year increase, largely from low winter temperatures and periods of extreme heat in the summer, Naughton said.

He noted that market revenues in 2024 were lower than the cost of entry for most new resources.

"Market-based revenues in 2024 were below the going-forward costs of new entrant gas-fired generators," Naughton said. Market revenues for wind and solar resources were also well below the CONE, and these resources remain heavily reliant on state programs, he added.

What's Next

Wholesale market costs are on track for another significant increase in 2025, largely driven by cold weather and extreme heat.



ISO-NE wholesale market costs | *ISO-NE*

Naughton also noted that, while combined cycle plants generally earn more from the capacity and ancillary service markets than in the capacity market, fossil peaker plants are increasingly reliant on capacity market revenues.

"These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses," the IMM wrote in its report.

Naughton said the IMM has seen "gradual" impacts of the clean energy transition so far on supply and demand. Average solar output in the region doubled between 2020 and 2024, but wind output remained stagnant during this period.

Behind-the-meter solar growth has led to a growing duck curve in the region, with mid-day demand frequently dropping below nighttime levels. This has caused growing morning and evening ramp requirements and is beginning to present increased arbitrage opportunities for energy storage resources, Naughton said.

While the saturation of the storage market has led to declining regulation revenues, energy market revenues have started to tick up for storage resources, he said.

Recommendations

Naughton also discussed the IMM's recommended market changes, which include a proposal to subject exports to Pay-for-Performance (PFP) penalties during capacity scarcity events.

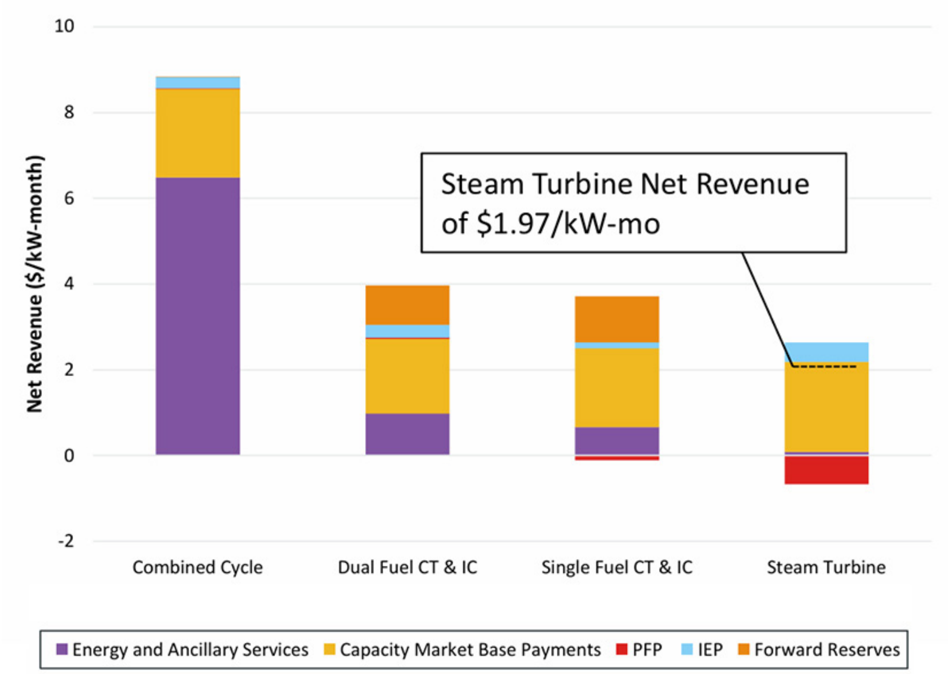
PFP payments are intended to incentivize resource performance during capacity shortages. While imports receive the PFP rate and LMP, "exporting-only participants are only charged the LMP," Naughton said, adding that this "over-incentivizes procuring imports" instead of limiting exports.

He said participants that both import and export power during a scarcity event are subject to PFP netting rules, but there could be a "gaming opportunity" for related companies to schedule imports and exports during a scarcity event and profit without delivering actual energy.

To fix this issue, the Monitor has recommended that ISO-NE "apply the PFP rate symmetrically to exports, aligning financial incentives and ensuring that external transactions — whether imports or reduced exports — are valued equally for their contribution to system reliability."

Responding to the proposal, some stakeholders expressed a concern about applying the PFP to capacity-backed exports and asked ISO-NE to exempt them from performance penalties.

The Monitor has also recommended that ISO-NE update its bidding software "to allow low-cost resources to more easily submit real-time specific offers" and change the external interface clearing rules "to reduce incentives for strategic virtual bidding and incentivize participants to submit more accurate, cost-reflective offers closer to the operating day."



2024 net market revenues for fossil generators | *ISO-NE*

Asset-condition Review

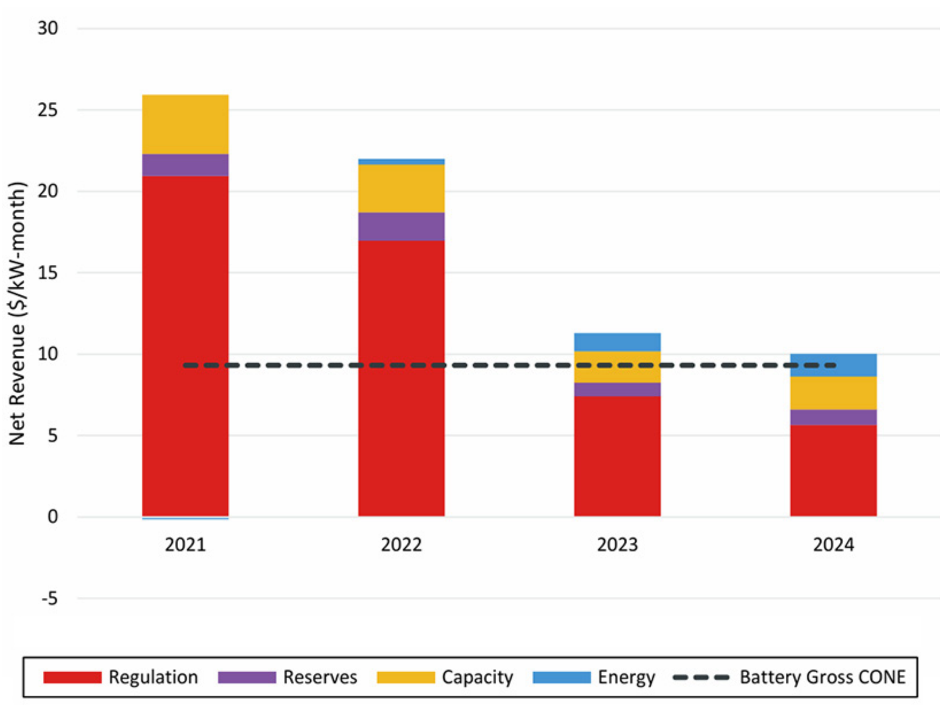
Also at the MC meeting, ISO-NE COO Vamsi Chadalavada discussed the RTO's work to establish an asset-condition reviewer role.

The RTO has agreed to pursue this role at the urging of states and consumer advocates and with the agreement of the transmission owners. It has stressed it will not take on a regulatory function investigating the prudence of investments. Instead, its role would be aimed at increasing transparency into projects and could, hypothetically, provide information that would aid stakeholders in prudence challenges with FERC. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Chadalavada said ISO-NE's work is complicated by the fact that no similar role exists elsewhere in the U.S., requiring the RTO to develop these capabilities from scratch. Once developed, the role could serve as an example for the rest of the country, he added.

He noted that ISO-NE has hired Electrical Consultants Inc. to "help develop a framework for a new asset-condition reviewer role," as well as to "review selected asset-condition projects in the interim review cycle, through the end of 2026."

ISO-NE is still working to determine which projects it will include in this interim review process but will generally focus on high-cost or abnormal projects, he said. ■



Net market revenues for battery storage resources | *ISO-NE*

Study Details Business Case for BTM and FTM Storage in Mass.

By Jon Lamson

A new economic *study* found that front-of-the-meter battery storage systems in Massachusetts "significantly outperformed" behind-the-meter systems despite significant programs and incentives supporting BTM storage.

The study authors said the economic advantage of FMT storage would be even greater in states with less robust BTM incentives. However, they emphasized that BTM systems typically provide resilience benefits that aren't easily quantified, which may justify the higher costs for some customers.

The report was written by American Microgrid Solutions and commissioned by the Clean Energy Group; it is intended to help the Cape and Vineyard Electric Cooperative evaluate its storage options.

It compared one, 2-MW FTM battery with five smaller BTM batteries, with equal capital costs between the FTM and BTM options. "Commercial-scale BTM battery storage is the most expensive type of battery system at this time," the authors wrote.

They noted that large FTM batteries "benefit from economies of scale, can execute lucrative tolling agreements with utilities and can more easily access wholesale energy markets," while small residential storage systems "benefit from off-the-shelf, fully commercialized components that do not require custom engineering and design, and do not typically encounter costly interconnection barriers."

Nexamp

"Commercial-scale [BTM] systems, which typically fall into the 60- to 200-kW range, often require custom engineering and design and may encounter interconnection barriers, but do not enjoy easy access to utility tolling agreements and wholesale energy markets," the authors added.

The report found the payback period for an FTM battery to be about 14 years, compared to a 19-year payback period for BTM storage, assuming 20 years of continued state incentives. The BTM payback period increased to about 24 years when the duration of incentives was cut to five years.

Cumulative 20-year revenue and cash flow was estimated to be about $1.6 million for FTM storage, compared to about $300,000 for BTM storage with 20 years of incentives. The study noted that FTM storage is heavily dependent on the rates it is paid via contracts with electric utilities, while BTM storage systems "rely heavily on incentives and subsidies."

While BTM storage is supported by the federal investment tax credit (ITC) and Massachusetts state programs including the ConnectedSolutions, SMART and Clean Peak programs, FTM resources with utility contracts are eligible only for the ITC, the authors said.

Overall revenues could change significantly if the assumptions related to state policy or utility contracts are altered, the authors found. Reducing the tolling rate paid by utilities by 20% lowered the 20-year cash flow by $1.3 million, while reducing the duration of state incentives to just five years resulted in a negative cash flow of nearly $500,000.

Although FTM storage outperformed BTM storage in the modeling, the study noted that BTM storage can provide significant reliability benefits by supplying backup power during outages.

"The differential between net costs of the FTM system versus the BTM systems effectively establishes the cost of providing backup power to the facilities," the authors wrote. "The 'resilience premium' on the BTM systems averages $13,300 per site per year, or $66,500 annually for five sites, assuming state performance incentives continue at their present values for 20 years."

Why This Matters

The study outlines the pros and cons of behind-the-meter and front-of-the-meter battery storage, and could help inform state and utility procurement strategies.

They also noted that FTM systems may be more susceptible to interconnection barriers "because they are typically much larger than their BTM counterparts and have no capability to manage loads 'behind the meter' to limit reverse flow," adding that interconnection uncertainty can "make forecasting financial returns for FTM batteries challenging."

Battery storage projects make up *about half* of the ISO-NE interconnection queue, with more than 15 GW of storage seeking to interconnect.

The ISO-NE queue has been frozen since June 2024 as the RTO transitions to its new cluster study process, which was mandated by FERC Order 2023. The order is intended to help address interconnection backlogs and barriers across the country. (See *FERC Approves ISO-NE Order 2023 Interconnection Proposal*.)

ISO-NE's first cluster study, which will be conducted under transitional rules, is scheduled to begin Oct. 10. Interconnection customers have until then to submit executed cluster study agreements, and stakeholders should get a better sense of which projects intend to proceed with the interconnection process following the deadline. The cluster study will take 270 days, and the restudy process will take 90 days. ■

MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class

By Amanda Durish Cook

MISO has assembled 10 generation finalists to enter its first interconnection queue fast track, and the list includes five natural gas proposals, three solar farms, one wind farm and a battery storage facility.

About 4.3 GW of the projects' combined installed maximum capacity of nearly 5.3 GW would come from natural gas generation. The *projects* under evaluation span six states and have in-service dates ranging from January 2027 to August 2028. MISO whittled the list down from 47 applications. (See *26.5 GW of Mostly Gas Gen Compete for MISO's Sped-up Grid Treatment*.)

The RTO said it continues to evaluate the remaining 37 proposals for inclusion in upcoming study cycles. MISO plans to study up to 10 generation projects per quarter, with a maximum of 68 projects, before it retires the temporary express lane process Aug. 31, 2027. The fast track aims to get necessary generation interconnected sooner than MISO's regular queue currently allows.

MISO said the first cycle of generation projects to enter the expedited study process were selected by a combination of the timestamp of their application submission and application withdrawals, a review of common constraints near the project and developers' ability to rectify shortcomings in their applications prior to the study kickoff.

"The first 10 projects cover all three regions of MISO, stretching from Louisiana to Minnesota," MISO Senior Vice President of Planning and Operations Jennifer Curran said in a press release.

Why This Matters

Half of the first class admitted into MISO's interconnection queue fast lane are natural gas units. Capacity-wise, they account for 4.3 GW of the 5.3-GW lot.

A rendering of Meta's proposed data center in Richland Parish, La. | *Meta*

Curran said each project "must meet rigorous standards to make sure only necessary and feasible proposals move forward."

Applicants had to identify a specific resource adequacy need their projects would address and secure a blessing from their relevant regulatory authority to be considered.

Entergy La.'s Gas Plants for Meta Make the List

Entergy Louisiana's proposed 1.64-GW gas plant, intended to meet the upward of 2 to 2.3 GW Meta will need to operate its $10 billion, hyperscale data center, is the largest on the list. (See *Louisiana PSC Approves 3 Controversial Gas Plants Ahead of Schedule for Meta Data Center*.) The Franklin Farms units are two of the three Entergy Louisiana would need to build to keep Meta's facility powered.

Invenergy's proposed 1.2-GW gas plant in Kenosha County, Wis., to address a 1.75 to 2 GW need among Wisconsin Electric customers is the second-biggest project.

Otter Tail Power is the sole battery facility to make the cut. The 75-MW Hoot Lake Battery Energy Storage System is proposed to serve a need highlighted in Minnesota's Integrated Resource Plan.

MISO also agreed to study Interstate Power and Light Co.'s separate requests for a 750-MW combustion turbine and 350-MW wind farm in central Iowa to help serve a 3.2 to 3.5-GW projected need in MISO's Local Resource Zone 3.

Other contenders in the fast lane include: MidAmerican Energy's 263-MW natural gas combustion turbine in Adair County, Iowa; Lincoln Capital Land's 125-MW solar farm to serve City Water Light & Power's unmet needs from generation retirements in downstate Illinois; Ameren Missouri's 300-MW solar farm in the northern portion of the state; Minnesota Power's 85-MW Boswell Solar Project in Itasca County, Minn.; and an upgrade of the gas turbine at Minnesota Municipal Power Agency's Faribault Energy Park in southern Minnesota that requires 60 MW of additional interconnect capacity.

Curran called the queue fast track a "critical tool we can use to support reliability as we work toward long-term improvements in the interconnection process."

MISO plans to accept another round of applications for expedited study in early November and begin studying them at the beginning of December. ■

MISO: Market Platform Replacement will be Overbudget, Stretch into 2028

By Amanda Durish Cook

Why This Matters

MISO leadership has long said that the current, monolithic market platform — built using technology from the 1990s — is in need of replacement, but the planned overhaul has taken more time than anticipated.

MISO said its nine-year-old effort to replace its market platform will exceed original budget contingencies and will not be completed until 2028, three years later than it previously predicted.

Chief Digital and Information Officer Nirav Shah told a Sept. 4 meetup of the MISO Board of Directors' Technology Committee that the RTO now expects the full integration of a new real-time market clearing engine to extend into 2028.

In early 2024, MISO expected to have all projects associated with its new, modular market platform fully operational in late 2025. When MISO announced the project in 2017, it originally estimated it could migrate to the new modular computer system by 2023. (See *New MISO Day-ahead Market Engine to Emerge Soon After Delay* and *MISO Sets Sights on 2025 Completion for New Market Platform*.)

Shah said the overall cost of the platform overhaul has increased to about $175 million "due to the complexity of completing the real-time market clearing engine." He said he would have more details on the higher costs of the project later this year.

MISO originally allotted $130 million for the platform swap with a 25% contingency.

"I look back to 2017, and we're in a very different place. A lot has changed," Shah explained. He said technology functions differently today than when MISO announced the replacement project nine years ago. He also said FERC has released several orders with new requirements in that time frame, such as real-time ambient-adjusted line ratings under Order 881.

Shah said that overall, requirements on the market platform replacement are 11% higher than when MISO first gauged them.

"It's a pretty disappointing miss this late in the project," said Director Todd Raba, who added that "one of these days," he'd like to see an IT project end on time and on budget.

Director Theresa Wise said the market platform replacement can be thought of as "a series of projects over time," with the final projects having vastly different parameters than MISO originally anticipated. Wise said the last two projects are significantly larger with more requirements.

"I think we're clouding things together," Wise said in defense of the project's progress.

Shah said vendors originally estimated the look-ahead commitment component of the project to be about $7 million in 2017. The effort is now predicted to cost about $16 million. He also said the new unit dispatch system has gone from an $8 million estimate to more than $18 million.

MISO CEO John Bear said the RTO probably should have "recast" and repriced the remaining elements of the platform replacement around 2021 to capture rising technological complexities and inflation.

"We didn't do that, and I want to apologize for that. … Time is not your friend on these projects," Bear said.

Bear, however, stood by the project even with the late-stage additional costs.

"If you step back from this … the value from the project is still there, even with the increases. The benefits overall are going to be enormous," Bear said.

For nearly a decade, MISO leadership has said the current, monolithic market platform — built using technology from the 1990s — is poised to become so obsolete that it won't be able to clear the day-ahead market or accommodate the more scattered, numerous generation assets that the fleet transition has introduced. (See *MISO Makes Case for $130M Market Platform Upgrade*.)

Director Erik Takayesu asked if the vendors on the market platform replacement are taking responsibility for some overages. The replacement is being completed with vendors General Electric and Siemens.

"We absolutely are pushing back on the vendors," Shah said. He said that, for instance, MISO refused to take on additional costs of "poor architecture decisions" that necessitated a redesign on some of the look-ahead commitment components.

"It absolutely is making them uncomfortable, but that's the right thing for our stakeholders," Shah said.

MISO estimated that it will take until 2026 for the look-ahead commitment software to enter final testing and parallel operations. By 2027, the RTO estimates it would be able to test its new unit dispatch system and enter it into parallel operations.

Through the remainder of 2025, MISO plans to begin testing the look-ahead commitment software and launch its new one-stop model manager so it can cease operations of its old, siloed modeling systems. Shah said MISO had to work through some data quality issues as it migrated data to the new management system. The RTO's model manager project aims for one system of record for all planning and operations models to eliminate redundant data entry and review.

MISO also said the technology to use real-time AARs is in the testing stages for the remainder of 2025, with production still on track for 2026.

Over 2024, the RTO entered its new day-ahead market clearing engine into standalone production and retired its legacy day-ahead market. ■

MISO 2025 Tx Expansion Estimate Drops Slightly to $12.4B

By Amanda Durish Cook

The cost estimate for MISO's 2025 Transmission Expansion Plan (MTEP 25) has fallen slightly from previous estimates to $12.36 billion.

MISO previously clocked MTEP 25 at $13.1 billion and 444 projects, driven by growing load. (See *MISO 2025 Transmission Planning Cycle Rises to $13B*.) The newest *version* includes 10 fewer projects.

The RTO said MTEP 25 "is shaping up to be another significant year driven by load growth and reliability." According to the grid operator, MTEP 25 includes 1,930 miles of transmission lines (44% of which are new) that would accommodate nearly 11.6 GW of spot load additions.

The 2024 MTEP included $6.7 billion worth of projects. That figure does not include the $22 billion second long-range transmission portfolio that was technically included under the annual planning cycle.

MTEP 25 contains $3.44 billion in baseline reliability projects as dictated by NERC standards, $673 million in projects necessary for generator interconnections, nearly $5 billion in projects for load growth, $1.38 billion in projects to address the age and condition of existing facilities, $1.3 billion in projects to satisfy locally defined reliability criteria and $489 million to address more general local needs.

Louisiana is set to receive the most investment this year, at more than $3.4 billion. The amount is split between baseline reliability projects and those needed to meet load growth.

MTEP 25's 10 most expensive projects account for 44% of the portfolio's total cost, with four of the 10 in Louisiana. Entergy Louisiana's Cargas 500-kV station and Smalling 500/230-kV station project in the northern part of the state is the year's most expensive, at $1.2 billion. Entergy Louisiana said the project is necessary to support new customer load. The work would be located near a proposed Meta data center slated for Richland Parish.

Entergy Louisiana's Babel-to-Webre 500-kV baseline reliability project takes the second-most expensive slot at almost $1.1 billion.

This year, 49 projects went through MISO's expedited project review and were cleared to begin construction before MISO's Board of Directors votes on approving this year's transmission package in December.

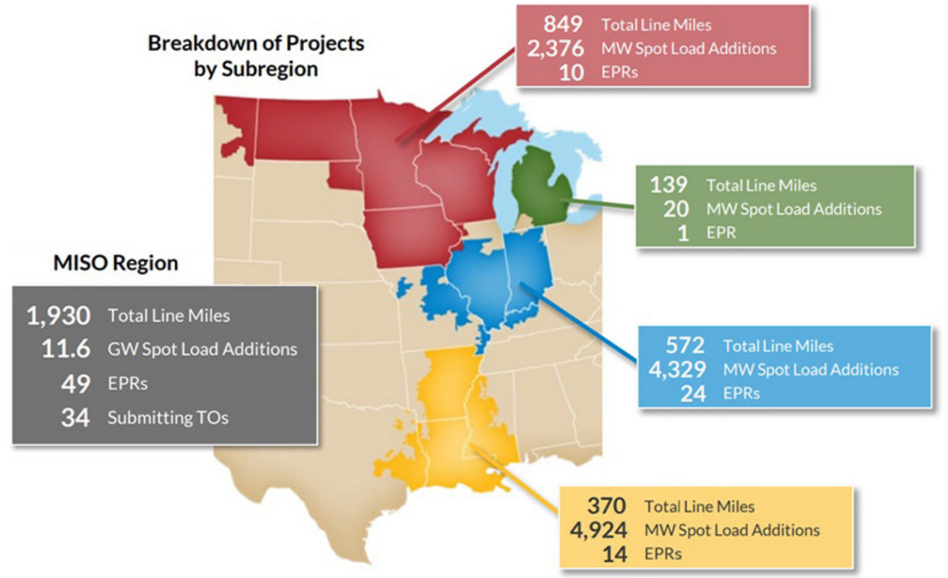
At a Sept. 5 West Subregional Planning Meeting, Joseph Dunn, MISO director of transmission planning, said the "tremendous" number of expedited review requests were brought on by load growth.

MISO's modeling for MTEP 25 assumes projects from the second long-range transmission portfolio enter the scene on schedule in 2035. Five MISO states — the majority of which won't contain a project — are trying to revoke the cost-sharing of the $22 billion portfolio, which would put the projects in jeopardy. (See *MISO States Split on FERC Complaint to Unwind $22B Long-range Tx Plan*.)

This year's transmission expansion package also contains a blast from the past, as Northern States Power has entered a $92 million maintenance project for a 345-kV line that was part of MISO's 2011 Multi-Value Project portfolio.

According to MISO, any maintenance on Multi-Value Projects must be classified under the multi-value category.

MISO plans to publicly post its MTEP 25 report Sept. 29, kicking off a two-week comment period for stakeholders. The grid operator will preview a more final MTEP 25 report at the Oct. 8 Planning Advisory Committee meeting. ■



MTEP 25 by the numbers: The total line miles, supported load additions and expedited project requests from each region | *MISO*

MTEP 25 spending by category | *MISO*

What's Next

As it stands, MISO's Board of Directors will likely vote on whether to approve a $12.4 billion MTEP 25 in early December.

Aging, Expensive NY Nuclear Plants a Bargain, Report Finds

Brattle Calculates 4 Reactors Would Yield $50B in Savings if Operated to 2050

By John Cropley

A new report estimates keeping New York's aging commercial nuclear reactors running through 2050 would save $50 billion in energy.

Other economic and environmental benefits would accrue from continued operation of the four reactors, which now account for nearly half of New York's emissions-free electricity, the authors point out.

The state's energy planners have concluded the same — they included nuclear energy in the state's updated energy plan and have recommended the state continue subsidizing the reactors until 2049.

The Carbon Free NY Coalition, a nuclear power advocacy group, *announced the new report* by the Brattle Group on Sept. 4.

Along with the $50 billion in savings, the Brattle analysis concluded that extended operation would contribute $38 billion to the state's economy; support 2,020 direct jobs and 12,380 other jobs; and preserve $10 billion in tax revenue, $4 billion of it going to the state.

The four reactors also are increasingly important to New York's decarbonization goals, as efforts to develop solar and wind generation within the state's borders are proceeding more slowly than hoped.

Fossil generation equivalent to the reactors' 27.5 TWh output in 2024 would have emitted 16.4 million tons of CO_2, the coalition noted. The state has paid the reactors' operator $3.69 billion in subsidies since 2017, in recognition of the reactors' high cost of operation as well as their high value to the state's grid and environment.

"Keeping the upstate nuclear plants operating until midcentury will contribute substantially to New York's clean energy goals and keep costs lower for ratepayers. It will also support the New York economy, contributing substantially to GDP and jobs — particularly in the upstate region," said Dean Murphy, lead author of the report and a principal of The Brattle Group.

The four reactors at three plants in two locations along the south shore of Lake Ontario all are owned by Constellation Energy, which is part of the coalition that commissioned the Brattle report.

Nine Mile Point Unit 1 is the oldest operating commercial reactor in the nation, and the Ginna reactor is the second-oldest. The FitzPatrick reactor entered commercial operation in 1975; Nine Mile Point Unit 2 is a relative youngster, entering commercial operation in 1988.


Constellation Energy's Nine Mile Point Clean Energy Center contains the oldest and youngest commercial nuclear reactors operating in New York state. | *Constellation Energy*

Why This Matters

Keeping the four reactors running is expensive for New York, but losing their output would be more expensive.

Constellation needs signals of support to take the step of updating and relicensing the geriatric plants, and New York is moving to provide those signals. (See *N.Y. Makes Case for Extending Nuclear Subsidies to 2049*.)

Given that renewables are developing slowly in New York, and given that the state is pinning its energy strategy on the hope that new technologies will be perfected, affordable and scalable, nuclear power takes on considerable importance for the Empire State if it is to meet its decarbonization targets. (See *N.Y. Considers New Fossil Generation as Renewables Lag*.)

The report analyzes the impact of FitzPatrick, Ginna and Nine Mile Point 1 retiring in 2029, due to expiration of New York's ZEC subsidy program, and Nine Mile Point 2 retiring in 2032, due to expiration of the federal 45U tax credit.

They have a combined nameplate rating of 3,537 MW and run at a five-year average 94% capacity factor, and their retirement would lead to an average 3.36% annual increase in retail prices from 2030 to 2050, the report states.

Retirement of the four reactors likely also would increase the amount of fossil generation the state needs — the report points out that this is exactly what happened when the Indian Point nuclear plant was shut down.

Earlier in 2025, Gov. Kathy Hochul (D) directed the New York Power Authority to develop new nuclear generation. (See *N.Y. Pursuing Development of 1-GW Advanced Nuclear Facility*.) ■

Report: Big Beautiful Bill to Increase Power Prices in NYISO, PJM

By Vincent Gabrielle

EDF Renewables

A new analysis of the One Big Beautiful Bill Act from Aurora Energy Research *found* that the bill will likely increase wholesale power prices in NYISO and PJM by up to \$8/MWh, driven by reductions in renewable energy development and increases in fossil fuel plant operation.

"When you cut off some of the capacity that was going to come through as a result of faster buildout of things like offshore wind, you get a lot of baseload gas moving in to fill in the gap, and that has a significant longer-term impact on prices," said John Kidenda, a researcher for Aurora.

Kidenda estimates that PJM will experience a \$6 to \$8/MWh price increase by 2035. NYISO is estimated to increase by \$5 to \$7/MWh in the same time frame.

The end of tax credits coupled with deployment hurdles and tariffs will likely cause PJM and NYISO to have 10% fewer renewable resources by 2040 compared to Aurora's base case. Roughly 10 to 15 GW of renewables are at risk of missing the new in-service deadline for tax credits across both grid operators. This will force them to rely on thermal plants more often, resulting in 5 to 7% more runtime.

A separate *analysis* of the clean energy and transportation sectors under the OBBBA by Rhodium Group and MIT illustrated the challenges that renewable energy development faces nationwide. New utility-scale clean energy projects declined 51% between the first and second quarters of this year. New industrial decarbonization developments declined 17% in the same period and 38% year-to-year.

Why This Matters

The One Big Beautiful Bill Act could delay renewable projects for half a decade.

The Rhodium/MIT group also examined the outstanding projects receiving Inflation Reduction Act credits. Roughly \$517 billion of outstanding investment remains to be spent on construction and installation; \$406 billion of that is tied to electricity and industrial investment, and 42% is tied to wind and solar generation projects.

The findings of both reports point to large nationwide pressures on renewables to get to market and qualify for tax credits, a far cry from Aurora's stance late in 2024, when it said the projected impact of a second Donald Trump presidency on New York's grid were "minimal." The assumption was that, despite Trump's promise of ending the IRA's tax credits, congressional Republicans would be unwilling to pass legislation repealing them because they benefited their districts. (See *NY Well Positioned to Push Forward on Climate Goals Under Trump*.)

That assumption — *like that of* President Joe Biden and congressional Democrats when the IRA was enacted in 2022 — turned out to be very wrong.

Kidenda said that despite Trump's desire to keep natural gas prices down and increase gas generation, the long waits for new turbines coupled with increased demand mean there is significant upward pressure on gas prices.

"As that tightness comes through and you get demand from heating, then you get price increases," Kidenda said. "Not because baseline gas prices are increasing but because people are bidding up the right to access the pipeline."

Kidenda said it was critical for New York to step up and ensure that renewable projects like Sunrise Wind are finished. The state runs the risk of blackouts and loss of load without added capacity, particularly in New York City and Long Island, he said. ■

NYISO Puts Storage as Transmission on Pause

By Vincent Gabrielle

ALBANY — At a recent Budget and Priorities Working Group meeting, NYISO presented its final *recommendations* for 2026, which will define where the ISO puts its market design resources. The storage-as-transmission project, while on the budget, faces an uncertain future.

While the project will be on the budget for 2026, NYISO does not consider the project to be "continuing." This designation means a project was approved in a prior year and has progressed to a late stage of project development and is picked up automatically in the following prioritization cycle.

"We're going to add storage as transmission to be included into the budget," said Kevin Pytel, director of product and project management for NYISO, at the Aug. 25 BPWG. "This does create resource constraints for us, adding this in. We do not have all the resources necessary to complete this project."

That means the ISO does not think it has the money and staffing hours to complete the project as budgeted but also does not want to abandon it. That leaves storage as transmission in the unusual position of waiting for other projects to meet milestones early and under budget so resources can be shifted to it.

The storage as transmission project would allow energy storage systems to act as regulated transmission, making them eligible for cost-of-service rate recovery and to be considered as transmission solutions in ISO planning processes. Assets developed under the "storage as transmission" designation would not be dispatched by the wholesale market beyond what would be necessary for them to remain ready to inject or withdraw from the grid.

The ISO's initial proposal limited storage as transmission to 200 MW systemwide with 20 MW per substation. (See *NYISO Outlines Storage as Transmission Proposal*.)

Pytel said that due to resource constraints, storage as transmission would not receive a continuing status even though it has hit a development milestone of "functional requirement specifications" that ordinarily would grant it that status. In the NYISO project development cycle, some project development milestones like "development complete" automatically continue into the next year. Pytel said if other projects come in under budget, then storage as transmission would receive extra money and work hours.

"But when we come back and talk about project prioritization in April or May of next year, we will not have a strong handle on whether or not we're really marching toward the deliverable," Pytel said. "I can confidently say that when we come back … we would not consider this as continuing."

Pytel added it's unlikely NYISO staff would be able to work on storage as transmission by Q1 of 2026.

"I am extremely concerned about what I am hearing," said Kevin Lang, a lawyer representing the City of New York. "You have a project, but it's not clear what work you're actually going to do on it or when you might be doing the work."

Lang said this is troubling because the ISO hadn't really committed to work on the project and it wasn't clear whether or when resources would open up to make it possible.

"The NYISO is acting as a barrier to technology and that is wholly inconsistent with your mission and its wholly inconsistent with open markets," Lang said. He asked that the ISO provide a list of the other projects ahead of storage as transmission so market participants could weigh in on whether the projects at the front of the line were prioritized appropriately.

Pytel said those other projects were discussed in the last BPWG when the ISO had presented stakeholder *scoring*. Storage as transmission received modest scores in the stakeholder survey. Twenty-five stakeholders supported the project, with most of them in the public power/environmental sector and end-use consumer. Some generators and transmission owners also supported the project. It came in 12th out of 28 projects by weighted score.

Tony Abate, representing the New York Power Authority, said he saw things differently. He credited the ISO for its flexibility and for being generally progressive on including new resources. He didn't think the ISO was putting up a barrier to an imminent storage application that would benefit ratepayers.

| NYPA

Chris Hall, representing the New York State Energy Research and Development Authority, thanked Pytel for not dropping the project completely and leaving some way for it to be finished. He said that while the current proposal was limiting, it could serve as a platform to leverage future use cases.

Other Business

The ISO presented an *update* on how its budget forecasts from 2024 compared to actual spending for 2025. So far, the ISO generally is on target with a $3.8 million over-collection. NYISO forecasts that the over-collection will continue through the end of 2025, totaling $7.2 million. Additionally, NYSIO collected $1.4 million more than expected due to interconnection study deposit cash balances.

At the same time, NYISO predicts an under-spend of about $4.6 million due to lower-than-expected professional fees and higher-than-expected "miscellaneous revenues."

Patrick Kelly, NYISO's controller and assistant treasurer, said that was in large part due to savings seen in consulting. Some of the savings is due to the cancellation of the Public Power Transmission Need project, which would have served offshore wind. (See *NYISO Cancels Offshore Transmission Studies*.) Kelly anticipates $1.4 million in labor savings due to the PPTN cancellation.

Kelly said that as of June, NYISO anticipates an excess of $11 million between over-collections and under-spends. ■

NYISO Increases Budget for 2026

By Vincent Gabrielle

NYISO expects its 2026 *budget* to be $210 million, $8 million more than the 2025 budget, CFO Cheryl Hussey told the Budget and Priorities Working Group on Sept. 5.

The increase means that NYISO will need $8 million more in revenue from Rate Schedule 1, an increase of 3.96%. RS1 is the administrative fee that NYISO collects to cover its operating costs. The ISO is expecting a 3.8% increase in demand over the next year, which means that RS1 can remain "virtually flat," with a 0.2-cent/MWh increase over the current 94 cents/MWh.

Hussey said the key drivers of the budget increase include salaries, which are benchmarked against peer ISOs and RTOs and expected to increase between 3.5 and 6% in 2026. The ISO is also planning on hiring eight new full-time positions in 2026 to support increasingly complex market designs and forecasting analytics.

The positions include two data scientists, an economist, a software and power system applications engineer, and a stakeholder services manager.

At the same time, computer services have increased costs because of vendor consolidation and increased usage of cloud services.

Payments on outstanding debt also continue to increase each year. In 2024, NYISO borrowed $37 million and plans to borrow another $37 million in 2025, which is higher than normal.

The RS1 carryover is also lower than it was in 2024/25. The ISO is anticipating a carryover of $3.5 million for 2025/26, which is $1.5 million less than the prior fiscal year.

Hussey said that to avoid capital costs for server acquisition, the ISO is going to pursue a strategy of cloud computer migration, which would result in about $0.8 million in savings. Ongoing measures to reduce computer software subscriptions and eliminate redundant or unneeded services are expected to shave an additional $1 million in costs. The ISO is also planning on delaying and deferring some hiring throughout the year to avoid salary costs to the tune of about $0.8 million.

Additionally, some debt will be repaid early, reducing debt service costs in 2026 by $3.3 million and debt service costs in 2027 by $6.3 million.

Rate Schedule 1 Highlights for 2026

The ISO is projecting that RS1 will include 160,600 GWh of *demand*, the vast majority of which will be net load at 148,650 GWh systemwide.

The ISO anticipates 8,000 GWh of billable exports to other regions and 350

NYISO headquarters in Rensselaer, N.Y. | *NYISO*

GWh of wheel-throughs in the New York Control Area. Incremental supply — the additional supply above net load to compensate for transmission losses and non-billable exports to New England — is expected to total about 6,000 GWh.

These projections assume normal weather conditions, which are a significant driver of net load variability, both in terms of load reduction via behind-the-meter solar and demand. Load growth is anticipated to grow because of climate change, large load growth and building electrification.

2025 has seen higher-than-expected load in July and August and in the winter, which has driven overcollections. It's possible that this trend will continue into 2026 because of weather events that are more severe than forecasted. ■

Feds Pull $716M Loan Commitment from N.J. Offshore Wind Project

Funds Planned for SAA Transmission Upgrades

By Hugh R. Morley

The U.S. Department of Energy has withdrawn a $716 million loan commitment that would have helped New Jersey upgrade the state's transmission system to connect offshore wind to the grid.

DOE approved the loan commitment to Jersey Central Power and Light (JCP&L) in January, shortly before President Donald Trump took office. A department spokesperson called the commitment "conditional" and said "DOE and JCP&L mutually agreed to withdraw from the commitment," declining to comment further.

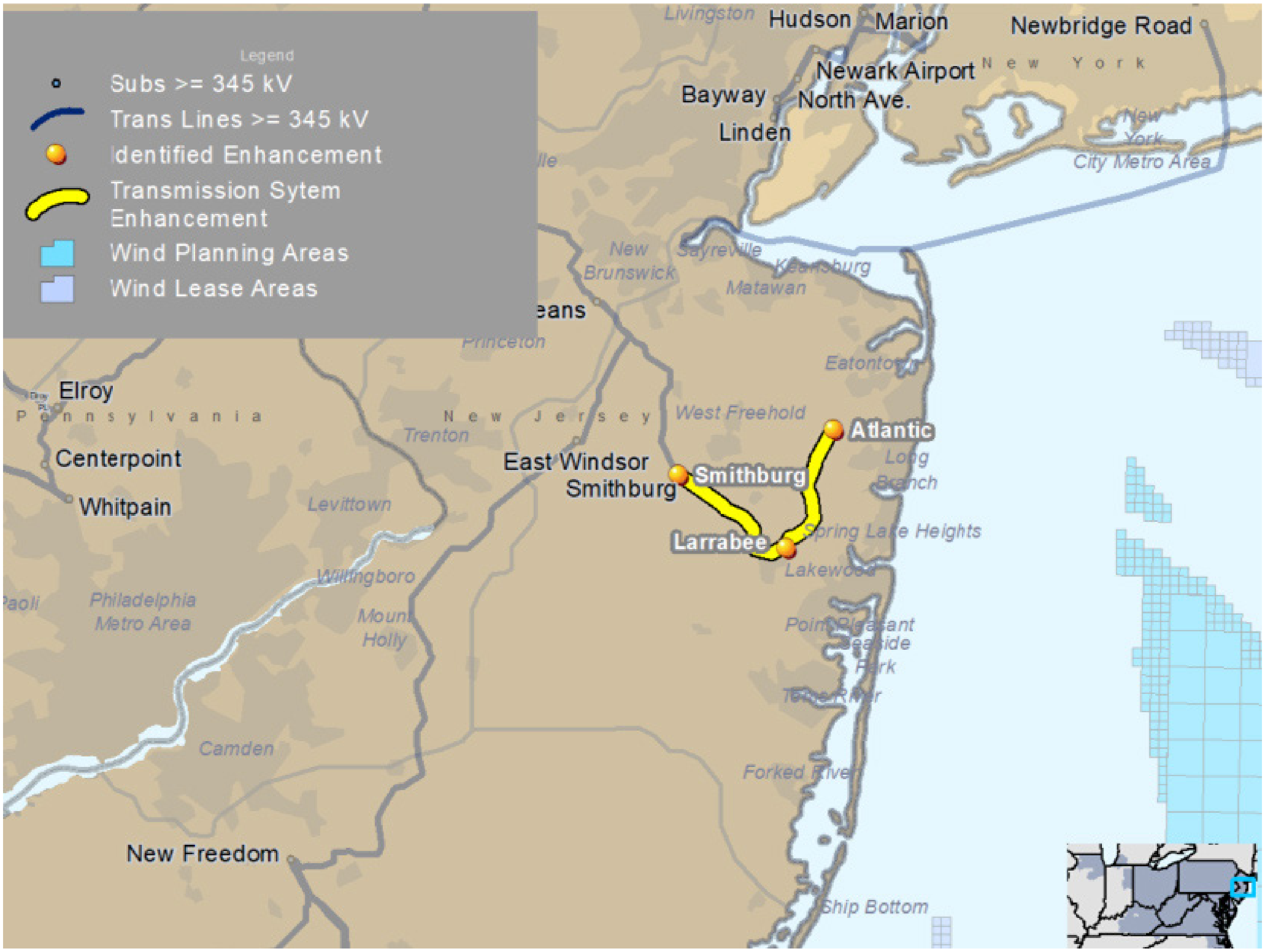
New Jersey Board of Public Utilities spokesperson Alonza Robertson said the agency is "deeply disappointed in the federal government's decision to cancel funding for critical transmission infrastructure projects."

The loan commitment would have supported the New Jersey Clean Energy Corridor, a transmission infrastructure upgrade project. Specifically, it would have funded a portion of the work that resulted from the agency's use of FERC Order 1000's State Agreement Approach with PJM.

Why This Matters

The cancellation is another blow to the offshore wind industry struck by the Trump administration.

The $1.07 billion series of projects, in which JCP&L had a major role, were centered around a new $504 million substa-



Jersey Central Power and Light's proposal to expand its existing stations to enable offshore wind injections of 2,490 MW at Smithburg, 1,200 MW at Larrabee and 1,200 MW at Atlantic. | *PJM* tion next to the utility's existing Larrabee substation. The package of transmission upgrades would have enabled the state to deliver 6,400 MW of offshore wind generation to the PJM grid.

Grid Plans Postponed

The BPU, however, put the project on hold for 30 months on Aug. 13 after the state's only remaining viable offshore wind project, Atlantic Shores, asked to terminate its Wind Renewable Energy Agreement because of opposition to the project from the Trump administration (See *N.J. Puts on Hold Remaining Pieces of $1.07B OSW Transmission Project*.)

"These transmission investments are essential for grid reliability, energy security and economic development in our state," Robertson said in a statement to *RTO Insider*. "The cancellation of committed federal support undermines the certainty that developers, utilities and ratepayers need to plan for our energy future and represents a step backward in building a clean energy future."

A spokesman for JCP&L, which is owned by First Energy, declined to comment.

The loan commitment withdrawal emerged several days before a *Labor Day statement* jointly signed by New Jersey Gov. Phil Murphy and four other governors reaffirming their commitment to offshore wind. The statement called on the Trump administration to "uphold all offshore wind permits already granted and allow these projects to be constructed." It followed a stop-work order issued by the administration against Ørsted's Revolution Wind project off the coast of Massachusetts and Rhode Island. (See related story, *Revolution Wind Sues to Lift Federal Stop-work Order*.)

"Efforts to walk back these commitments jeopardize hardworking families, wasting years of progress and ceding leadership to foreign competitors," wrote Murphy and the governors of New York, Connecticut, Massachusetts and Rhode Island. "These projects represent years of planning, billions of dollars in private investment and the promise of tens of thousands of additional jobs. They are revitalizing our ports, strengthening our supply chains and ensuring that America — not our competitors — leads in clean energy manufacturing and innovation."

Projected Ratepayer Savings

New Jersey's offshore wind sector, like those of other states, initially struggled amid high equipment costs and logistical challenges, which resulted in Danish developer Ørsted's abandonment in October 2023 of its Ocean Wind 1 and 2 projects, two of New Jersey's first three projects, leaving only Atlantic Shores moving forward.

The state's ambitious effort to use the SAA to create grid upgrades that would tie several projects to the grid, rather than leaving each to forge their own connection route, was seen as innovative. DOE's proposed loan to the project was among several loan commitments totaling $22.9 billion made to utilities for transmission, pipeline and clean power investments in the waning days of the Biden administration. (See *LPO Offers Eight Utilities $22.9B in Loan Guarantees*.)

Announcing the loan commitment Jan. 16, DOE's Loan Program Office (LPO) said the project "comprises 40 miles of transmission and substation upgrades and expansions." The department said the proposed loan would "reduce upward pressure on electricity rates for ratepayers from project costs as a result of the reduced cost of debt associated with LPO financing" and would produce "an estimated $150 million in savings for JCP&L ratepayers over the life of the loan."

In a July 30 *quarterly report* filed as required by its agreement with the BPU, JCP&L said the project was on schedule and in the engineering, procurement and permitting phase. One element, the Larrabee Substation, was in construction, the report said. About 45% of the permitting and 60% of the engineering had been completed, the report said.

The report said the utility had spent about $59.5 million of an expected cost of $910 million. ■

3rd Circuit Reaffirms Ruling in Favor of Transource 9A Project

Pa. PUC Decision Violated Supremacy Clause, Court Finds

By Devin Leith-Yessian

The 3rd U.S. Circuit Court of Appeals *ruled* Sept. 5 that the Pennsylvania Public Utility Commission violated the Constitution in denying Transource Energy permits necessary to construct the Independence Energy Connection (IEC) transmission project.

The court reaffirmed the ruling of a lower court, finding the PUC contravened the supremacy clause by deviating from PJM's approach to determining the benefit-cost ratio of two transmission lines designed to reduce congestion by increasing access to generation in Pennsylvania.

The PUC had argued that PJM's method was flawed because it only weighed the reduced congestion against the project development costs, while not factoring the increased rates for Pennsylvania consumers. The commission denied Transource siting and eminent domain permits to proceed with construction in May 2021.

The appeal followed a Dec. 6 ruling by the U.S. District Court for the Middle District of Pennsylvania finding that the PUC's approach violated the commerce clause of the Constitution as an instance of economic protectionism.

The 3rd Circuit focused instead on the supremacy clause to arrive at its conclusion that the commission would undermine federal objectives by supplanting the approach for mitigating congestion developed by PJM and approved by FERC. (See *Federal Court Rules in Favor of Transource Congestion Project in PJM*.)

The 3rd Circuit wrote that its ruling does not strip states of their jurisdiction over siting but instead determines that the rationale for rejecting a permit application cannot conflict with federal objectives.

> **Notable Quote**
>
> "The question before us is not whether the PUC was acting within the ordinary scope of state authority, but whether its action poses an obstacle to the accomplishment of federal objectives. As we explained above, it clearly does."
>
> *– 3rd Circuit*

"What matters for preemption purposes is that the PUC's reasons for denying the siting applications amounted to 'second-guessing the reasonableness'

A PJM map shows the route of the proposed Transource 9A transmission project. | *Transource* of PJM's FERC-approved approach to determining which projects should be built," the court said. "The question before us is not whether the PUC was acting within the ordinary scope of state authority, but whether its action poses an obstacle to the accomplishment of federal objectives. As we explained above, it clearly does."

The IEC project was designed to resolve congestion on the AP South Reactive Interface, which is composed of four 500-kV lines between West Virginia and Maryland skirting the Pennsylvania border. The congestion cost consumers in the eastern PJM region around $800 million between 2012 and 2016 by limiting the transfer of cheaper energy generated in the west. Development costs were estimated between $509 million to $528 million, with an initial benefit-cost ratio of 2.48 calculated by PJM.

In recommending the PUC deny permits for the project, a Pennsylvania administrative law judge wrote that congestion on the interface had fallen from $486.8 million in 2014 to between $14.5 million and $21.6 million in the following years. The ALJ argued that an estimated $812 million in increased rates for Pennsylvania consumers should be accounted for in the benefit-cost analysis, resulting in a cost-saving of $32.5 million over 15 years.

The appeals court acknowledged that Pennsylvania rates would increase as a result of low-cost generation being made more widely available, but said the federal government holds the objectives of ensuring reliable, economic and nondiscriminatory access to transmission, as well as counteracting the monopolistic nature of state utilities.

"The regional planning process developed as a counterweight to state interests, and precisely because FERC determined that it could not depend on the states to address regional concerns such as congestion and grid reliability," the court wrote.

Past Criticism from Christie

The PUC had also argued the issue preclusion precedent should prohibit Transource from presenting its claims around the commerce and supremacy clause in federal court when they had not been part of its case before the Commonwealth Court of Pennsylvania, which ruled in favor of the PUC.

The 3rd Circuit noted that Transource had reserved the right to make those arguments in the federal courts within a footnote in its summary judgment briefing and stated they were not integral to the case before the Commonwealth Court, which centered on whether the PUC decision involved errors of law and was an abuse of discretion. (See *Transource Challenges Pa. PUC Decision in Court*.)

PJM said it would recommend that its Board of Managers revise the scope of the IEC project to eliminate the eastern segment, which would construct a 230-kV line between the Conastone substation in Harford County, Md., and the Furnace Run substation in York County, Pa. The western leg of the project would construct a 230-kV line from the Ringgold substation in Washington County, Md., to the Rice substation in Franklin County, Pa.

PJM's Tim Horger told the Transmission Expansion Advisory Committee that regulatory and constructability challenges with the eastern portion led staff to determine it no longer is worth pursuing, though both components continue to exceed the 1.25 benefit-cost threshold. (See "PJM Recommending Changes to Independence Energy Connection," *PJM PC/TEAC Briefs: May 6, 2025*.)

FERC's then-Chair Mark Christie criticized PJM for continuing to proceed with the project despite the opposition from state regulators in his comments on a waiver request the RTO filed to delay the deadline for completing its 2024 evaluation of the project. The commission dismissed the waiver as moot when PJM opted to proceed with the same system modeling used in the 2023 evaluation. (See *Christie Blasts PJM Pursuit of Transource Market Efficiency Project*.) ■

Tri-State Seeks FERC Approval for Data Center Load Tariff

Colo.-based Co-op Looking to Protect Existing Customers from Unexpected Costs

By Robert Mullin

Tri-State Generation and Transmission is seeking FERC's approval for a new tariff designed to manage the heavy volume of data center load expected to materialize in its member utilities' service territories over the next decade (*ER25-3316*).

The filing is part of a growing trend among utilities and states in crafting policies to protect ratepayers from the financial — and reliability — risks stemming from the voracious energy demands of new artificial intelligence data centers. (See related story, *Large-load Tariffs Touted as Alternative to 'Side Deals'*.)

The proposal is the product of "months of collaboration with members and stakeholders," the Colorado-based cooperative said in an Aug. 29 *press release*.

"The proposed tariff is designed to establish a repeatable and fair process for incorporating high-impact loads onto the Tri-State system without adverse impacts to reliability or affordability," Tri-State said. "The process would allow Tri-State members to respond in a consistent manner to requests for services from heavy energy users, such as data centers."

"We're in the business of providing electricity, and we are committed to doing it in a way that can meet the needs both of new loads and Tri-State members," said Lisa Tiffin, Tri-State's senior vice president of energy management. "This approach allows us to grow responsibly and limits the potential for stranded assets that could result in financial risk to Tri-State and our members."

Tri-State is a power supply cooperative that serves electric distribution cooperatives and public power districts across four states. It said in its filing with FERC that new load requests from data centers among its members would, over the next 10 years, more than double its current system peak demand of 2.5 GW.

In the filing, Tri-State noted that data centers "support local economic development, improve the efficient utilization of utility resources and provide steady revenue streams when fully integrated into a service provider's system."

But it also warned that integrating such large loads also "carries risks," including the need to build new transmission lines and generation, and the potential for increasing interconnection queue backlogs and delays in procuring needed resources.

"Large load interconnections also present serious reliability and cost-shifting risks for a utility's customers," Tri-State added.

Tri-State's Escalante Solar Project near Grants, N.M. | *Tri-State Generation and Transmission Association*

Why This Matters

Tri-State's filing is part of a growing trend among utilities and states in crafting policies to protect ratepayers from the financial — and reliability — risks stemming from the voracious energy demands of new AI data centers.

Tri-State's existing Electric Resource Planning (ERP) process, designed for a more measured rate of native load growth, is not equipped to handle those risks and the expected pace of new demand from what the co-op calls high-impact load (HIL) projects, it explained in the filing.

"HIL projects are more speculative than utility members' prior requests for new or modified delivery points, or native load growth in general. HILs also require accelerated and significant transmission upgrades that do not fall neatly into the existing ERP process," Tri-State said.

'Avoid Socializing the Risk'

Tri-State's proposed High Impact Load Tariff (HILT) would provide an alternative planning approach for integrating those loads into its system.

According to the filing, the "guiding principles" for the HILT are: "(1) facilitating economic development across Tri-State's utility members' systems at an unprecedented level and pace; (2) limiting the risk of stranded assets resulting from high-impact load integration, which could create financial risk for Tri-State and its utility members; and (3) continuing to meet all resource planning and associated regulatory requirements."

Modeled on similar tariffs filed by other U.S. utilities, the Tri-State HILT would establish a biennial planning cycle for customer loads rated at 45 MW or higher.

"This separate HIL planning cycle process is necessary because HILs are of a size that require significant generation capacity additions or procurement of long-term [power purchase agreements], which necessitates proper planning. Ratepayers may suffer financial consequences if capacity additions are completed only for a HIL to not materialize," Tri-State wrote.

Each planning cycle would begin with a "kickoff" meeting among Tri-State, co-op members and potential HIL customers, where participants will "set forth the requirements and timing for a HIL participation package [prepared by the utility member], a process for verifying the participation package components are met and a HIL evaluation process."

Intended to ensure that only non-speculative projects are presented to Tri-State for study, the participation package would include:

- a completed member project request form;
- evidence that the HIL customer has at least 90% site control over its project location;
- payment of a nonrefundable HIL evaluation fee;
- a certified engineering diagram of the project's expected load and property acreage;
- an executed member-customer high-impact load (MCHIL) agreement; and
- a high-impact load agreement (HILA) to be executed between the utility member and Tri-State.

For HIL requests under 80 MW, the evaluation fee would start at $35,000 plus $1,000/MW, increasing to $150,000 for projects between 80 and 200 MW, and $250,000 for projects above 200 MW — levels Tri-State said are consistent with the megawatt deposit thresholds under its large generator interconnection procedures.

Tri-State said the evaluation process would focus on "reliability, economic and environmental criteria, as well as transmission metrics."

"The reliability review will ensure the HIL will not have an adverse impact on the reliable operation of Tri-State's system, including compliance with Level I (base metrics) and Level II (extreme weather events) reliability metrics. The economic criteria focuse on whether the HIL project is economically priced so as to minimize Tri-State's system costs, and reduce or maintain Tri-State's rate requirements," the co-op said.

The proposed HILA would include "minimum billing demand and energy floors" intended to ensure that, regardless of whether a HIL customer's load grows as forecast, Tri-State is compensated for system upgrades sufficiently enough to avoid shifting costs to other customers.

The HILA would also stipulate that a HIL customer provide a minimum security deposit of $2.7 million/MW to offset the risk that "the HIL customer begins commercial operations late [or] ceases operations before the expiration of the HILA term or the HIL does not operate at the expected level (or at all). In short, the security requirement enables Tri-State to avoid socializing the risk of the HIL customer's under- or nonperformance across Tri-State's entire membership." ■

SPP Board Approves 765-kV Project's Increased Cost

Revised Large Load Integration Policy also Endorsed

By Tom Kleckner

SPP's Board of Directors has approved a pair of contentious measures that were put aside during its August quarterly meeting: a tariff change to integrate and operate high-impact large loads, and a revised cost estimate for a 765-kV transmission project in New Mexico and Texas.

The latter approval is contingent on cost and schedule control measures that "meet the [board's] expectations."

Southwestern Public Service's 345-mile project, SPP's first 765-kV line, was approved in February with an estimated cost of $1.69 billion. SPS filed a revised cost estimate of $3.62 billion in June, more than double the earlier projection and easily outside the variance bandwidth of +/-30% that can lead to a re-evaluation. (See *SPP Board Sets Aside 765-kV Costs, Large Load Policy*.)

SPS CEO Adrian Rodriguez said during a Sept. 4 special board meeting that the utility has committed to a cost cap and regular reports to the board. He also said it is open to a third-party monitor, as suggested by Texas regulatory staff.

"We're talking about working with the Southwest Power Pool board, the Southwest Power Pool staff, for this type of transparency and scrutiny and highlight that this is important not just for us, not just for our customers, not just for our regulators in Texas and New Mexico, but for all of you," Rodriguez told the board, state commissioners and members. "We're focused on reliability in the Southwest Power Pool and being mindful of the cost impacts to customers across SPP."

Why This Matters

The board's approval of an increased cost estimate for SPP's first 765-kV transmission project could be a case study, its developers say, ensuring stakeholders understand the issues behind future major infrastructure builds and where cost mitigations can occur.

SPS CEO Adrian Rodriguez explains his company's position during SPP's August board meeting. | © *RTO Insider*

SPP staff said the Potter-Crossroads-Phantom project, which crosses the New Mexico-Texas state line, remains the best technical solution to provide the region with voltage support. It also resolves several needs in the 2025 and 2026 Integrated Transmission Planning assessments and addresses load projections; the RTO's latest 10-year forecast indicates 105 GW of potential load, almost doubling its current peak of 55 GW.

Casey Cathey, the grid operator's vice president of engineering, said that when the 765-kV project is removed from the 2025 ITP models, staff must add nearly 4 GVARs of temporary reactive power to support the region's voltage. He said 35 generation projects totaling 10 GW of capacity, some of which are already under construction, are also contingent on the SPS line.

"[The SPS project] is required before we can even contemplate moving forward with the 2025 ITP assessments and understanding what that portfolio looks like," he said. "We did look at alternatives, multiple 345 facilities [and] double-circuit 500-kV facilities. All of those were actually more expensive, [had] wider rights of way and were just less optimal compared to the single 765."

SPS submitted a *cost-cap proposal* to the board as part of its commitment to build the project in a "cost-effective manner, with reasonable and measured oversight and customer protections." It also said it will forgo the return on equity applicable to the cost overruns above the current cost estimate and a 20% variance cap.

The company's guarantee can be adjusted for exceptions consistent with those provided in competitive bids, such as changes in statutory tax rates, investment costs, import tariffs or secondary impacts on domestic markets, or the schedule resulting from changes in federal, state or local legislation and laws that became effective after Jan. 1. Other exceptions include *force majeure* (as defined in the SPP tariff) and increases in interest rates.

"I hope we have demonstrated our commitment and transparency to SPP, the staff, board and the commissioners by setting the foundation for 765-kV estimates," Rodriguez said. "I want to highlight our commitment to being competitive, being transparent and being committed, not just to our customers at SPS but to the entire SPP as we're evaluating this reliability project."

He noted the exclusions are primarily based on items that are outside of SPS' immediate control and those for which it has limited opportunity to mitigate.

The Members Committee approved the revised cost estimate with an 11-1 advisory vote. EDP Renewables opposed the motion, casting doubt on SPS' cost-containment guarantee, and nine other members — primarily public power entities — abstained.

"We can be a case study on 765," Rodriguez said. "Our transparency means that we have informed the market, including bidders, of our perspectives on this line, and we can be the case study to make sure that these types of major projects move forward with a clear understanding from the board, from the staff, as to what can be done, what issues arise and where cost mitigations can occur."

Large Load Integration OK'd

Similar cost concerns were raised by regulators during a Sept. 3 education session on the 765-kV project and SPP's fast-track study to integrate high-impact large loads (HILLs).

While they favored SPP's tariff change (*RR696*) to expedite faster and more predictable interconnection timelines for rapidly developing large loads, they also want to maintain regional reliability, transparency and equitable cost allocation.

Minnesota Public Utilities Commissioner John Tuma spoke for several when he expressed worries about accommodating large loads that might not show up. He drew on the state's experience in the Iron Range, where he said loads with service agreements don't always materialize.

"We see a big technology boom. There's going to be a lot of capital flowing in. It'll look really sexy," Tuma said. "Everybody wants to get in the middle of it, but some of them are going to bust, and that's just a reality that we have to live with. … That's one of the big concerns as a state that we have because in the end, we pay for our neighbors' mistakes.

"We want to be quick and nimble. We don't want to be dumb," he added. "And so, I'm hoping that we continue to analyze these things carefully. We're all partners in this together, and if one of our partners screws up, it could cost us and our ratepayers money."

SPP CEO Lanny Nickell agreed. He said staff will work with the regulators and the Regional State Committee to develop a "fully informed and appropriate" cost-allocation approach for the future.

"The amount of load growth being projected, with much of that driven by data centers, will certainly drive significant transmission upgrade investment," he said. "We need to make sure that ratepayers aren't having to bear unfair portions of the cost needed to connect those loads while we have some time to figure out the best cost-sharing approach."

Staff revised the large load policy to reflect the numerous comments and feedback received from stakeholders, removing conditional high-impact large load service (CHILLS) and the design associated with dispatch, study and charges for the service from its original proposal. It also removed one of three paths for high-impact large load generation assessment (HILLGA).

HILL studies will remain on a 90-day timeline. Changes include a revised HILL definition that clarifies its transmission service study process and its independence from non-conforming load.

SPP members endorsed the tariff change, 18-1, with three abstentions. OGE Energy voted against the measure, citing concerns with delays in the interconnection process and accreditation issues with increases to the planning reserve margin.

Approval is contingent upon SPP modifying the tariff to reinstate a 60-day study under Attachment AQ, which governs upgrades or other changes to delivery point facilities.

Stakeholders approved RR696, as modified, during the Markets and Operations Policy Committee's own special meeting in August. The measure passed with 95.7% approval after failing during MOPC's regular quarterly meeting in July at 53.7%. (See *SPP MOPC Passes Revised Large Load Policy*.)

The tariff change resulted from a directive by then-Chair John Cupparo in May that staff propose by the board's August meeting a timely, scalable and reliable approach to manage the exponential growth of load demand across the footprint. (See "Cupparo Issues 'Executive Order,'" *SPP Board OKs 1-time Study for LREs' Gen Needs*.)

The CHILLS policy will be taken up during the MOPC, RSC and board meetings in October and November. ■

SPP, Members Developing 765-kV Transmission Overlay Plan

By Tom Kleckner

SPP has hinted to members that its 2025 transmission planning assessment will be another large one — larger, even, than last year's record $7.65 billion package.

One of the drivers is a draft 765-kV overlay that staff and members have been engaged with. It builds on SPP's first 765-kV project that was approved as part of the 2024 assessment, Southwestern Public Service's 354-mile transmission line crossing the New Mexico-Texas border. (See *SPP Stakeholders Endorse Record $7.65B Tx Plan*.)

Casey Cathey, the RTO's vice president of engineering, shared the overlay during a Sept. 3 education session with the Board of Directors and Regional State Committee.

"What we have done is a preliminary look based on the [Integrated Transmission Planning] loads that the members have provided us," Cathey said.

The draft overlay extends from SPS' Potter-Crossroads-Phantom line into Oklahoma, where much of the state would be encircled. Another 765-kV line would shoot off to the Southeast and into Louisiana, the site of two load shed events in April. (See *SPP Addresses 3rd Load Shed Since March 31*.)

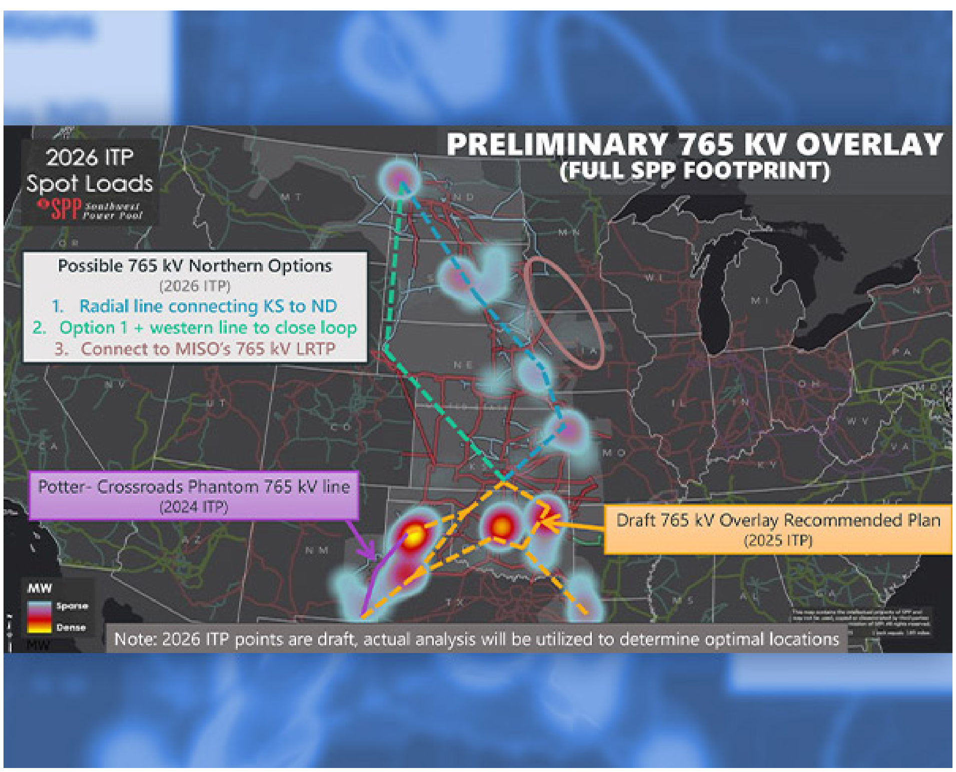
Looking ahead, the 2026 ITP is considering a 765-kV radial line that connects Kansas with North Dakota. One option would close the loop on the western side of the footprint.

"The 2026 plan is going to be a much more detailed engineering analysis, so it may not look exactly like this next year," Cathey said.

Pointing to large loads "peppered throughout" the map, he said that will "necessitate a version of a 765 footprint."

"I'm giving some caveats here because there's a lot of engineering connection points that we may need to change from a reliability perspective," Cathey said. "However, we are seeing the need for some version of what this looks like moving forward."

One reason the time is now ripe for 765-kV transmission in SPP's footprint is the 345-kV build that members have undertaken in recent years. Cathey said the 345-kV backbone gives staff options that didn't exist 15 years ago to sustain the transfers necessary should a 765 line be lost.



SPP's preliminary 765-kV overlay | *SPP*

Why This Matters

SPP's 765-kV overlay builds on a recently awarded large transmission project in New Mexico and Texas. The recent 345-kV buildout now gives the RTO an option should one of the larger lines be lost.

SPP has increased its 765-kV line costs from $4.2 million/mile to $5.8 million/mile, comparable to ERCOT's and MISO's projections for their 765-kV projects.

"This is consistent. We've gotten some recent feedback from our membership that this is the right way to go and then that the costs are making more sense," Cathey said. "We don't have 765 in this region, but it's been built before. We need to recognize that some things are going to come up. This is going to be pricey. We need to make sure that we're going into it with eyes wide open."

The SPS project was awarded in February with an estimated cost of $1.69 billion. SPS filed a revised cost estimate of $3.62 billion in June, more than double the earlier projection and easily outside the variance bandwidth of +/30% that can lead to a re-evaluation. SPP has said the project is still viable, despite its cost. (See *SPP Board Sets Aside 765-kV Costs, Large Load Policy*.)

The RTO has scheduled an *education session* on the 2025 ITP for the Markets and Operations Policy Committee meeting Sept. 23. The assessment and its portfolio will be brought before MOPC, state regulators and the board in October and November for their approvals. ■

TVA, ENTRA1 to Collaborate on up to 6 GW of Nuclear Build

NuScale Aiming to Have its SMR Ready for Market by 2030

By John Cropley

The Tennessee Valley Authority is taking another step to boost next-generation nuclear technology, collaborating to site up to 6 GW of generation within its seven-state footprint.

TVA *announced the "landmark" deal* with ENTRA1 Energy on Sept. 2, calling it the largest ever of its kind. The two plan to develop new nuclear plants using the small modular reactor NuScale Power expects to deploy by 2030.

ENTRA1 holds the commercialization rights to NuScale's products and services. It presents itself as a one-stop shop for development, financing and management of NuScale's SMRs, with multiple options for development, management and operation.

The new agreement calls for ENTRA1 to develop and own the power plants and sell the output to TVA under future power purchase agreements. They called it an important step to promote advanced nuclear technology in the U.S.

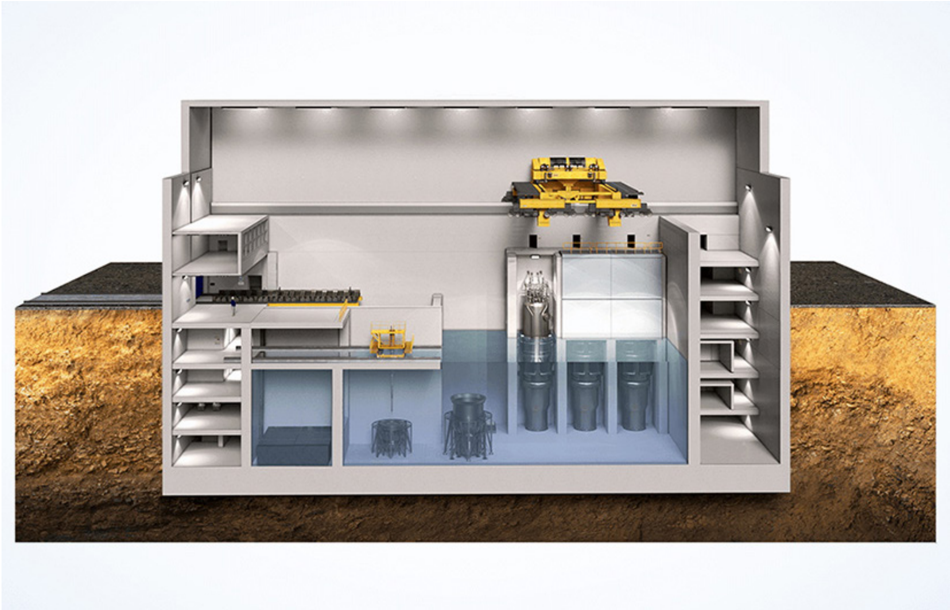
Accelerating nuclear deployment has been a stated priority for President Donald Trump; TVA's rate of progress on nuclear development has been a target of Republican criticism.

TVA said in a news release that it "stands at the forefront of America's advancements in nuclear energy — and its bold partnerships and national leadership continue to power the nation's nuclear renaissance."

CEO Don Moul said: "TVA is leading the nation in pursuing new nuclear technologies, and no utility in the U.S. is working harder or faster than TVA."

Why This Matters

The agreement is the latest endorsement of the potential of advanced nuclear power, and apparently the largest of its kind.



A cut-away diagram shows a potential configuration for a plant containing six of the small modular reactors NuScale is developing. | *NuScale*

Trump began removing members of TVA's board after it appointed Moul the new CEO. The president reportedly demanded that the remaining members remove Moul, but they refused. (See *TVA Board Promotes Nuclear Veteran from COO to CEO* and *Trump Nominates Four to TVA Board of Directors*.)

TVA in its news release said the ENTRA1 deal "aligns with the administration's energy dominance agenda and focus on America's energy security. The partners are identifying opportunities to work with other federal agencies and explore potential sites with new nuclear generation and joint gas-fired capabilities."

Other recent nuclear updates by the nation's largest public power supplier include:

On Aug. 18, TVA and Kairos Power announced the first-ever PPA by a U.S. utility for electricity from an advanced GEN IV reactor. (See *Kairos Power, TVA Announce Nuclear PPA*.)

On May 20, TVA announced it was the first U.S. utility to submit a construction permit application for GE Vernova Hitachi Nuclear Energy's BWRX-300 SMR. (See *TVA First U.S. Utility to Request SMR Construction Permit*.)

And on April 23, TVA said it and a coalition of industry and state leaders had reapplied for funding under the U.S. Department of Energy's $800 million Generation III+ Small Modular Reactor Program.

NuScale, meanwhile, is part of the crowded U.S. SMR field. It was the first and so far only company to receive Nuclear Regulatory Commission approval for its reactor module design, then obtained a *second NRC approval* in May on an uprated design that boosts output from 50 MW to 77 MW.

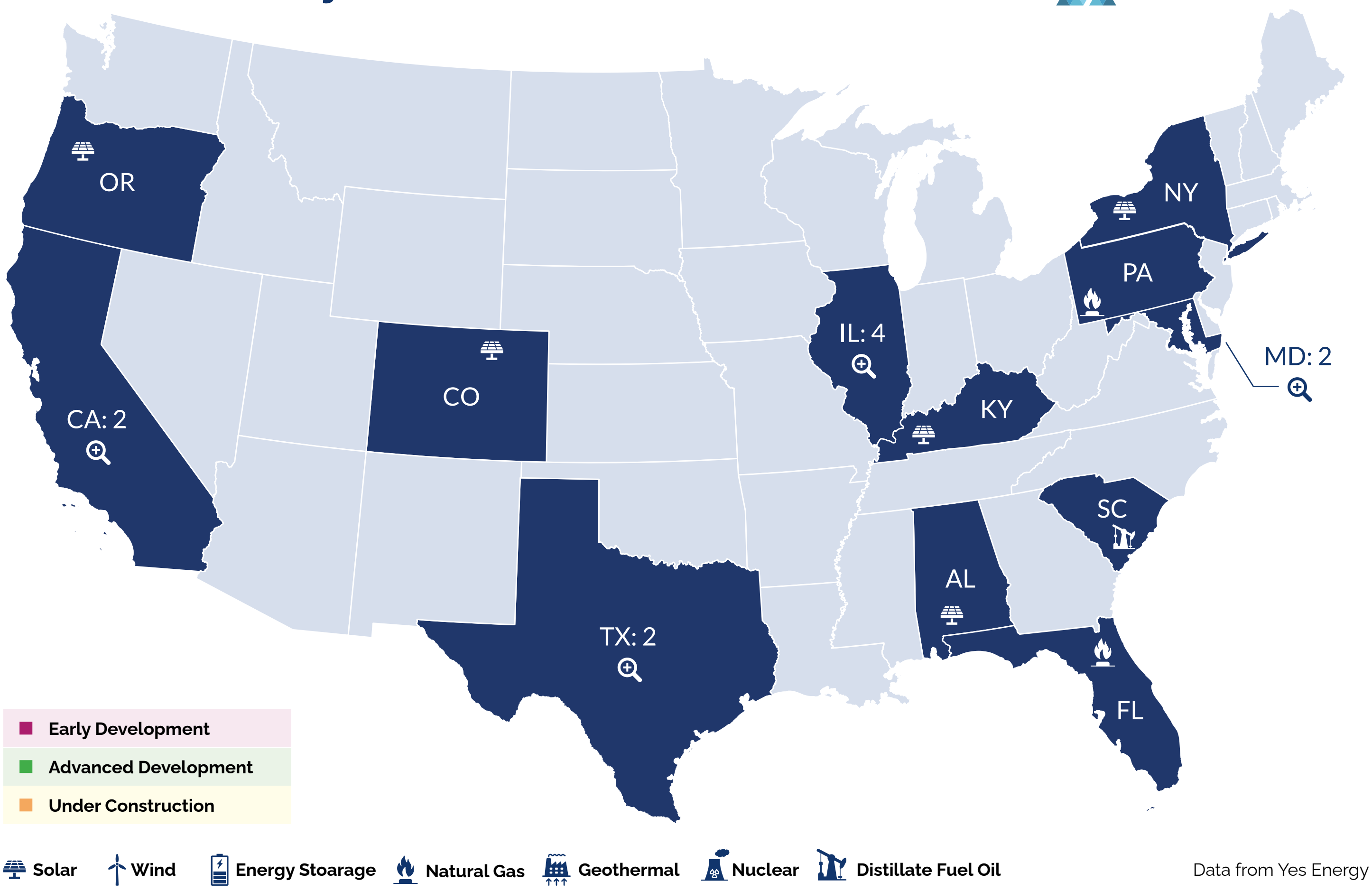
That has not translated into many announced deals, however.

A groundbreaking project planned in Idaho was canceled in November 2023 when subscriptions for the power it would produce proved too difficult to secure. (See *Pioneering NuScale Small Modular Reactor Project Canceled*.)

NuScale's stock closed 7.5% higher in trading Sept. 2. ■

Generation Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
Stellar Longleaf Solar	Stellar Renewable Power		AL	80	2027
West Stanislaus Irrigation District	White Pine Renewables	White Pine Development, LLC	CA	5	2025
Whiterock PV	White Pine Renewables	White Pine Development, LLC	CA	5	2027
Weld Solar	NextEra Energy, Inc.		CO	150	2100
JEA St. Johns River Combined Cycle	Jacksonville Electric Authority		FL	675	2032
Brighton Station 1	SUSI Partners	Encore Renewable Energy	IL	5	2026
Brighton Station 2	SUSI Partners	Encore Renewable Energy	IL	5	2026
Johnson Lake 1	SUSI Partners	Encore Renewable Energy	IL	5	2026
Johnson Lake 2	SUSI Partners	Encore Renewable Energy	IL	5	2026
Mantle Rock Solar BESS	Energy Capital Partners	Atlantica Development Company LLC	KY	59	2028
Betterton Solar	Halo Energy Co.		MD	5	2026
Waller Road Solar 1	Energy Capital Partners	New Leaf Energy	MD	5	2027
Fisher Solar (NY)	True Green Capital Management LLC	CleanChoice Energy	NY	5	2025
Springdale Solar [Molalla]	Conifer Energy Partners, LLC	Conifer Energy Partners LLC	OR	8	2028
IEP Hummingbird Energy	International Electric Power	International Electric Power III, LLC	PA	944	2029
Winyah Generating Station LM6000	Santee Cooper		SC	107	2028
Pegasus Solar	I Squared Capital	Priority Power Management, LLC	TX	10	2025
Ferrovial Milam County Solar	Ferrovial S.E.		TX	250	2027

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

Company Briefs

Battery Startup Natron Energy Closing Mich., Calif. Facilities

Battery startup Natron Energy has filed a notice saying it will shut down both of its facilities in Michigan and California, terminating 95 employees.

Prior to the filing, Natron believed it could secure the capital and commercial business needed to avoid or at least postpone the closure. However, late last month the company's board of directors determined that efforts to raise sufficient new funding were unsuccessful.

Last year, Natron announced it would build a $1.4 billion plant in North Carolina. After investor dollars stopped coming in, however, the project was suspended, according to reports.

More: *MLive*

PGE, Mitsubishi Power Exit Regional Clean Energy Project

Portland General Electric and partner Mitsubishi Power last week shelved plans for a hydrogen production, storage and hydrogen-fueled generation complex in Oregon.

"Given the exit of an essential project partner in June, along with challenging project economics for utility customers and federal policy changes, PGE is no longer pursuing" the hydrogen complex, PGE spokesman Drew Hanson said.

PGE's pivot calls into question what will happen at the Port of Morrow, where Air Liquide planned to build a hydrogen liquefaction plant to support distribution of clean hydrogen to fueling stations and the ports of Seattle and Tacoma. PGE and Mitsubishi were supposed to supply the gaseous hydrogen to Air Liquide via a short pipeline from the site of PGE's demolished coal power plant outside Boardman.

More: *Washington State Standard*

Hitachi Energy to Invest $457M in Virginia Transformer Facility

Hitachi Energy last week announced it will invest $457 million in a new production facility that will manufacture large power transformers.

The investment will add 825 jobs at its South Boston campus in Halifax County, Va., and is part of a $1 billion investment that includes expanding other company facilities around the country as artificial intelligence and data centers contribute to energy demand, the company said.

Construction of the facility will begin this year, and it should be operational by 2028.

More: *Cardinal News*

Federal Briefs

DC Circuit Throws EPA Green Bank Case to Claims Court

A federal appeals court last week voted 2-1 in the EPA's favor regarding its attempt to freeze green bank funds, saying the agency should not have been blocked from terminating the grants and the climate groups' arguments had no place in federal district court.

A lower court previously said EPA couldn't support Administrator Lee Zeldin's accusations and the agency was wrong to try to end contracts with the nonprofits without substantiating allegations against them. Now, the appeals court said the case should be heard in a federal claims court that hears contract disputes.

The groups were seeking an order allowing them immediate access to their funds, which total about $16 billion.

More: *CNN*

BLM Geothermal Leases Net $430K; More Parcels Set for October Sale

The Bureau of Land Management last week announced it has leased two parcels in Malheur County, Ore., totaling 5,235 public acres for $430,518.

The sale generated an average of $82/acre, which was the most per acre revenue generated from a BLM geothermal lease sale in Oregon in recent history.

The BLM will also hold a geothermal lease sale for 113 parcels totaling 377,678.89 acres across several counties in Nevada in late October.

More: *Morning Ag Clips*; *Think GeoEnergy*

Japan Explores Alaskan LNG Purchases as Part of $7B Deal

Japan last week confirmed its commitment to an annual $7 billion of energy purchases from the U.S. while exploring its new Alaskan liquefied natural gas offtake agreement.

The U.S. will also ensure it applies its lowest tariff rates to Japanese pharmaceuticals and semiconductors after President Donald Trump signed an order to lower tariffs on Japanese goods.

More: *Reuters*

State Briefs

CALIFORNIA

DOJ Seeks $77M in Lawsuits Against SoCal Edison for Wildfires

The Department of Justice last week filed a pair of lawsuits against Southern California Edison seeking at least $77 million in damages and accusing the company of igniting this year's Eaton fire and the Fairview fire of 2022.

The government is seeking $40 million in damages for the Eaton fire and $37 million in damages for the Fairview fire. The funds are what the U.S. estimated it spent on fighting the fires and for the damage suffered to federal property.

SCE said it is reviewing both lawsuits and plans to respond "through the appropriate legal channels," spokeswoman Gabriela Ornelas said.

More: *The Press-Enterprise*

LS Energy Solutions' Big Rock Storage Project Now Online

LS Energy Solutions last week announced it has commenced operations of its Big Rock energy storage site in Imperial County.

The 200-MW/400-MWh project is now providing resource adequacy and ancillary services for CAISO.

More: *Solar Power World*

COLORADO

State Launches New Building Code

The Energy Office last week published its Model Low Energy and Carbon Code designed to make homes and offices more climate friendly.

After July 1, 2026, all cities and counties must adopt the regulations whenever they update local building codes or adopt tougher local building efficiency rules. The new minimum requirements are part of a multiyear plan to bring local building codes in line with state climate goals.

The latest minimum code takes aim at emissions from homes and offices, which account for almost 10% of the state's emissions.

More: *CPR News*

INDIANA

Gov. Braun Names New Utility Consumer Counselor

Gov. Mike Braun last week appointed Abby Gray as the state's new utility consumer counselor.

Gray previously spent more than 16 years directing legal operations for the Office of Utility Consumer. Before that, she served 23 years as a senior administrative law judge and senior commission counsel for the Utility Regulatory Commission.

More: *Mirror Indy*

MICHIGAN

Senate Approves Carbon Capture Legislation

The Senate last week passed three bills that will allow the state to permit carbon capture and storage projects.

Sen. Sean McCann (D-Kalamazoo) said the legislation built upon laws passed by other states and included incorporating high fees for storing carbon dioxide underground and sending money collected from those fees into a newly created Community Benefits Fund.

The bills now head to the House of Representatives.

More: *Michigan Public Radio*

MINNESOTA

PUC Approves Permit for Primergy Solar-plus-storage Project

The Public Utilities Commission last week unanimously approved a site permit for Primergy's Northern Crescent Solar + Storage project.

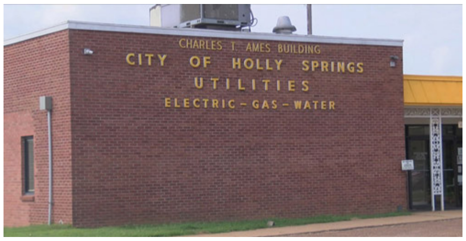
The project, slated for Faribault County, offers up to 150 MW of grid-interconnected solar and 50 MW of storage capacity.

More: *Primergy*

MISSISSIPPI

PSC Takes Action Against Holly Springs Public Utility

The Public Service Commission last week voted unanimously to place Holly Springs Public Utility in receivership after



years of customer complaints about prolonged power outages, millions of dollars of debt and failure to heed warnings from the commission.

By going into receivership, a chancery court judge will determine the future of the utility's operations. Options outlined by the PSC included being placed for sale, becoming a cooperative model or eminent domain.

A report commissioned by the PSC found that the electric division of the utility does not adhere to basic safety functions and that the utility has not completed an audit in several years and is tens of millions of dollars in debt.

More: *Magnolia Tribune*

MONTANA

PSC Denies Climate Petition

The Public Service Commission last week voted unanimously against declaring the state's constitution requires it to consider the impacts of climate change in its work.

The PSC also disagreed that it must consider climate in a set of statutes outlined in a petition filed in February 2024 by more than 40 businesses and organizations.

The PSC said making such a declaration would exceed its authority as it exercises powers granted by the Legislature.

More: *Daily Montanan*

OHIO

Clark County Bans Utility-scale Solar, Wind in Unincorporated Areas

Clark County commissioners last week voted 2-1 to approve a two-year moratorium on wind and solar projects that produce more than 50 MW of power in the county's townships and unincorporated areas.

The moratorium will last until the end of 2027.

More: *WYSO*