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YES ENERGY

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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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FERC Chair Laura Swett Lays out Priorities at 1st Open Meeting


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The new-look FERC faces major issues, especially a proposal from the energy secretary to assert jurisdiction over large load interconnections aimed at ensuring speed to market for data centers to 'win the AI race.'

CONTINUED ON P.7

PJM


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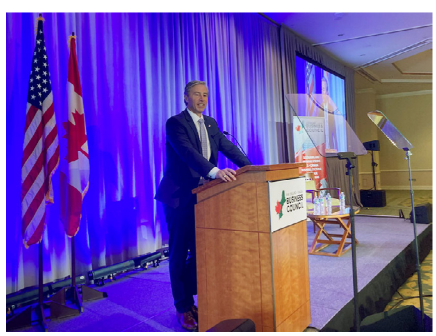
PJM Stakeholders Reject All CIFP Proposals on Large Loads (p.45)

The PJM Members Committee's vote was only advisory to the Board of Managers, which means the board will need to decide itself what to file with FERC in December.

ISO-NE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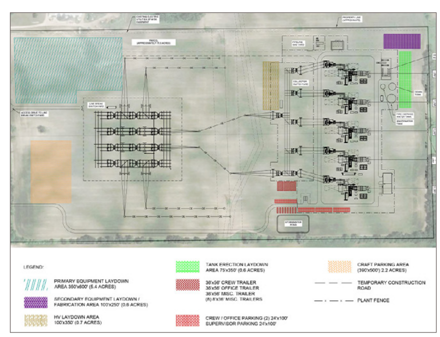
Collaboration Key to Energy Affordability, Say U.S. and Canadian Officials (p.33)

The large-scale development of renewable resources throughout the Northeast likely will rely in part on successful collaboration between states and provinces on transmission projects.

SPP


Invenergy

Enviros Challenge MISO, SPP Queue Express Lanes (p.49)

Environmental groups hope to deliver a one-two punch to SPP and MISO's interconnection queue fast lanes, challenging both at the D.C. Circuit Court of Appeals in a pair of lawsuits.

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In this week's issue

Let's Own the 5th Industrial Revolution

By Pat Wood III

Pat Wood III

Two weeks ago, a reporter asked me what I thought about Energy Secretary Chris Wright's recent Section 403 *directive to FERC*. Being immersed in things ERCOT as of late, I was puzzled. "Rick Perry's 'save the coal plants' project from 2017?"

"No, I'm talking about large load interconnection." Oh.

So, I read it. And it was good, even elegant. I read it again. I liked Wright's strong reliance on the standard generator interconnection policy we adopted in *Order No. 2003* back when I led FERC. There is a clear parallel between what we did then to speed the building of new generation at the turn of the millennium and what DOE wants to do today to accelerate the growth of critical data infrastructure.

States regulate the building of large generation; FERC regulates their interconnection to the interstate transmission grid. States regulate retail service to large loads; why shouldn't FERC regulate their interconnection to the interstate transmission grid?

This symmetry on both ends of the bulk electric system seems like a slam dunk in the courts. From past Supreme Court rulings, and considering its current direction, it would seem FERC would get a warm reception there.

Then, the real question is: In standardizing a large load interconnection process, what could FERC do to actually make things better?

The 'Energy Intelligence' Era

First, acknowledge this is a national imperative. Large new power users must have rapid and predictable access to electricity. The Fifth Industrial Revolution is underway, its start date accelerated, ironically, by the pandemic that spread from China.

This "Energy Intelligence" era is defined by the rapid electrification of the planet and the advent of artificial intelligence. Our failure to timely serve these customers will cede the leadership role for this revolution to China. You don't have to be born on the Fourth of July to know that is unacceptable.

Midlothian data center in Midlothian, Texas | *Google*

ALTERNATE VIEWPOINT:

See related opinion: *A Cooperative Path for Large-Load Interconnection: Why States and FERC Must Work Together*

Why This Matters

The inane pissing match between fossil fuels and renewables, between central station and distributed power benefits only those who don't want American dominance, says former FERC Chair Pat Wood III.

Second, lay down the law about the other two-thirds of the power system: generation and delivery. The inane pissing match between fossil fuels and renewables, between central station and distributed power, benefits only those who don't want American dominance. We need EVERYthing.

To enable that, we need a much more robust and smarter transmission and distribution system. Wind, solar and natural gas are the cheapest fuels to create power, and this country has huge amounts of all of them. Storage and flexible demand are the newest players on the field, and I expect nuclear, geothermal and others will come. All of this is being enabled by dramatically advanced information technology. So, Team America wins with addition, not subtraction. And the faster, the better.

Standardize and Connect

On to substance. Adopt a clear, transparent interconnection process for large load customers. Use a standardized large load interconnection contract and require grid operators to complete interconnection studies on aggressive timetables.

To encourage transmission owners to also move at the speed we need, we should reward them for making network upgrades quickly and penalize them for taking too long. If the large load customer can get local construction and engineering done faster and/or cheaper through a third party than the utility, that adds discipline and cost control to the overall process.

For all connections to the transmission grid, we should embrace the "connect and manage" approach we've used successfully with interconnecting ERCOT generators since 1997. Spread it to all generation and to large loads nationwide.

In effect, we tell the interconnecting facility, "we're going to hook you up pronto and do our best to serve you 24/7, but you're going to get best efforts (interruptible) service for a while until we get the grid beefed up in your neighborhood."

If interruptible service isn't acceptable to large load customers, we should ensure that on-site generation and batteries are a viable option. Assuming most customers want firm service eventually, we can use the network upgrade process from Order No. 2003 where interconnecting customers fully fund their local interconnection costs and front a deposit for new network upgrades that they trigger. This deposit should be large enough to protect other grid customers if the large load fails to show up.

A key factor causing slow interconnections to date is the calculation of needed network upgrades and their cost. On a swiftly evolving network where flows change every second, computing and attributing a transmission network upgrade's cost to a single party is a fool's errand. The important thing is to set a fair deposit amount quickly and conclusively. Ideally, a flat rough average $/kW amount should be sufficient. A version of this "entry fee" concept is being used for generators in SPP.

Manage the Grid with Latest Tools

While the regional infrastructure is being upgraded, utilities and grid operators must manage and get more out of the network with grid-enhancing technologies, advanced power flow controls, topology optimization, dynamic line ratings, reconductoring with high performance conductors and the like.

I've seen these tools employed in specific applications for a couple of decades now; it's time we make them a central part of 21st century grid operations. Large load customers' demand profiles sometimes could resemble those of a steel mill or foundry.

Customers with highly varying loads should be encouraged to manage those with on-site equipment like batteries with inverters and on-site controller software. This could be done through incentives like shorter timetables or reduced entry fees. I prefer carrots like these to sticks, but perhaps this jagged load profile impact upon the grid is one where a requirement may be in order.

'Win-win' Cost Allocation Scenarios

Issues relating to rates that the large load pays to take retail service remain with state regulators. We already see utilities and regulators creating new tariffs to protect other customers from cost shifts from large load customers.

Many of these new customers have deep pockets, so if there is any cost shifting at all, it should benefit existing customers, who have paid plenty already to build the system we have. There are many win-win scenarios here.

Some believe that data centers, in particular, will be the flexible load we've been waiting for to bring discipline to what always has been a generator-centered system. I'm not sure how flexible they really are. But that's OK. Let's set up a market to purchase flexibility just as we buy generation, and we'll find a lot of other customers who are flexible.

Getting the wires interconnection done is crucial, but the power itself is most important. Several large players are developing their own gas/battery/solar microgrids to accelerate their market entry. That's fine as a speed-to-market strategy, but the whole reason we worked for the past generation to set up robust, open access, wholesale market grids was to enable reliable, cheap and clean power for all customers.

Let's bias toward ultimately relying on the grid for primary power, and favoring local assets for backup power, instead of vice versa. But if large loads do add backup power, we should allow and encourage them to use it to benefit all of us, particularly when extreme weather stresses the grid. Again, I prefer market-based carrots rather than regulatory sticks on this.

Thoughtful standardization reduces costs, speeds entry and provides certainty for customers. The Good Lord has blessed our country with abundant natural resources. And with optimism. Let's put it all to work. Now. At scale. Game on. ■

Pat Wood III, Executive Chairman of the Hunt Energy Network, is past chairman of the Public Utility Commission of Texas and of the Federal Energy Regulatory Commission.

A Cooperative Path for Large Load Interconnection: Why States and FERC Must Work Together

By Nick Myers

Nick Myers

The U.S. is entering one of the most transformative periods in the history of its electric grid. Demand growth once projected to be flat or modest has surged dramatically due to the rapid expansion of data centers, semiconductor manufacturing, electrified industrial processes and artificial intelligence infrastructure.

States like Arizona, Georgia, Texas and Virginia are experiencing unprecedented requests from large-load customers — sometimes hundreds of megawatts at a time, often with aggressive deadlines and nearly always with major implications for transmission planning, resource adequacy and local reliability.

Recognizing the magnitude of this coming shift, Department of Energy issued a rare Section 403 directive Oct. 23, requesting that FERC initiate rulemaking procedures and consider an Advance Notice of Proposed Rulemaking (ANOPR) to create a new framework for the interconnection of large loads to the transmission system. The resulting ANOPR, now underway, will shape how quickly, fairly and reliably large loads gain access to the grid for years to come. (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

This development has generated broad national discussion, including among state utility regulators. At the National Association of Regulatory Utility Commissioners' recent annual meeting, NARUC adopted a resolution emphasizing the need for FERC to respect state jurisdiction and collaborate closely with states as it considers how to regulate large-load interconnections. Far from attempting to block federal action, NARUC instead articulates an important message: States and the federal government must be partners in this process, not competitors. (See *Regulators Urge FERC to Honor State Authority over Large Load Interconnections*.)

Collaboration, ultimately, must be the animating theme of our national approach. If we treat this as a jurisdictional contest between Washington and the states, we will fail to meet the urgency of the moment. If, instead, we treat this as a shared responsibility — with states leading on retail impacts and FERC serving as a federal backstop where interstate coordination is essential — we can deliver the infrastructure needed to support economic growth, protect reliability and ensure that retail customers are not unfairly burdened by the costs of new large loads.

The Moment Requires Cooperation, not Competition

It is tempting — especially in the traditionally divided landscape of energy regulation — to gravitate toward turf protection. But the challenge before us is too large, too complex and too time-sensitive for regulatory silos. State regulators, utilities, transmission providers, regional planning authorities and FERC must adopt a posture that is less competitive and more cooperative if we want to succeed.

Large-load interconnections today face three fundamental challenges:

1. Timing: Study processes never were designed for single customers requiring 100 to 1,500 MW of new demand in a matter of months.
2. Cost Allocation: Uncertainty about who pays for transmission upgrades can stall or kill major projects.
3. Reliability: Sudden new demand can strain generation reserves, transmission capacity and local distribution systems.

States understand these impacts more directly than anyone. They see the near-term pressures on local substations, on summer reliability margins and on the retail rates their constituents ultimately will pay. That is why NARUC's resolution emphasizes the need to preserve state jurisdiction and ensure retail customers are not left subsidizing massive data center and industrial loads.

At the same time, FERC is the only entity with legal authority to ensure consistent treatment across interstate transmission systems. Large loads have regional impacts. Their interconnection often triggers bulk-system upgrades that span multiple states. Without a federal backstop, transmission planning across state lines becomes slower, riskier and less predictable.

Neither side can succeed alone. For that reason, cooperation — not competition — must be our guiding principle.

FERC as a Backstop Authority, not the Front-line Regulator

The most productive framing is one that treats FERC as a backstop authority — the referee who steps in when interstate coordination or minimum national standards are needed, but who does not displace the states' essential authority to ensure resource adequacy, reliability and affordability.

Under this model:

- States retain jurisdiction over retail rates, distribution infrastructure and siting.
- States lead the conversations around cost shifts, local planning and reliability impacts.
- Regional transmission operators and utilities handle the technical study processes, applying state-approved resource adequacy and planning assumptions.

ALTERNATE VIEWPOINT:

See related opinion: *Let's Own the 5th Industrial Revolution*

Why This Matters

If we treat large load interconnection as a jurisdictional contest between Washington and the states, we will fail to meet the urgency of the moment, says Nick Myers of the Arizona Corporation Commission.

- FERC sets the minimum guardrails for transparency, open access and interconnection timelines on the transmission system.
- FERC uses its authority only when regional issues cannot be resolved at the state level in a timely manner.

This approach ensures fairness and consistency without undermining state sovereignty. It also provides large-load customers with something they increasingly demand: certainty. Certainty that timelines will not drag on indefinitely. Certainty that rules will not change mid-process. Certainty that their project will not be subject to a patchwork of incompatible interconnection standards across the country.

In other words, FERC should not be the first mover. It should be the backstop — the stabilizing presence that steps in only when needed, and only where states agree that interstate coordination is indispensable.

Why States Must Lead — but not Alone

State regulators are closest to the impacts of large-load interconnection. When a data center proposes a 200-MW facility, it is the state commission that will hear from residents about reliability concerns. It is the state that will be responsible for ensuring adequate generation and reserves. It is the state commission that must determine how costs are recovered — and who bears them.

The NARUC resolution rightly stresses these points. It does not oppose federal involvement; instead, it advocates for a balanced framework in which states maintain authority over matters that directly affect retail customers. The resolution also acknowledges the need for collaboration with FERC and other stakeholders, recognizing that a purely state-led approach cannot solve every regional transmission challenge.

This dual recognition — that states must lead but cannot act alone — is essential. No state wants to see its retail customers subsidizing another state's economic development. No state wants to compromise its reliability due to regional planning failures. And no state wants to be left without the tools to assess or assign the costs of substantial new load growth.

A network of electrical cables feeds power into one of Google's data centers in Midlothian, Texas. | *Google*

The Path Forward: A Shared National Strategy

To deliver the infrastructure required for the next generation of American energy and innovation, we will need a coordinated national strategy built around the following principles:

1. **Clear, transparent interconnection processes.** Large loads must know exactly how long studies will take, what upgrades are needed, and how costs will be allocated.
2. **Strong state-federal coordination.** State commissions must be at the table from the beginning—not reacting after federal rules are finalized.
3. **FERC as a backstop — not an adversary.** Federal authority should be triggered only when regional solutions are required and state-level mechanisms are insufficient.
4. **Protection for retail customers.** States must have a decisive role in evaluating whether new load will shift unfair costs to existing ratepayers.
5. **A commitment to reliability above all else.** New development cannot come at the expense of reliability or resource adequacy.

Conclusion: Meeting the Moment Together

Our country is facing an unprecedented wave of demand growth. We can either rise to meet it or fall behind and risk delaying economic development, hindering innovation and compromising the reliability of the electric grid.

Competition between states and FERC is not the answer. Cooperation is.

By embracing a framework in which states lead, FERC can be an essential federal backstop and provide large-load customers with clarity and predictability. This collaborative approach can support the next era of American growth while maintaining affordability and reliability for all consumers.

This moment demands partnership. It demands humility. And above all, it demands a shared commitment to building the grid of the future — not through conflict, but through collaboration. ■

Nick Myers is vice chair of the Arizona Corporation Commission.

FERC Chair Laura Swett Lays out Priorities at 1st Open Meeting

By James Downing


FERC Chair Laura Swett presides over her first post-meeting press conference on Nov. 20. | © *RTO Insider*

WASHINGTON — FERC Chair Laura Swett presided over her first monthly open meeting at the helm of the commission, giving her a chance to set the tone for her tenure.

"Regarding my priorities, we are at a critical juncture in our nation's history, a time to cement the United States' energy dominance," Swett said. "It is crucial to our economic and national security that we win the artificial intelligence data race for our country so that American data does not go abroad. In addition to our core mission of keeping the lights on for all Americans at reasonable costs, my priority as chairman is to ensure that our country can connect and power data centers as quickly and as durably as possible."

Another priority is to streamline regulations at FERC to ensure that needed infrastructure can get built as quickly as possible, she added.

Commissioners David Rosner, Lindsay See and Julie Chang all welcomed the new chair, as well as new Commissioner David LaCerte, in comments at the start of the meeting.

"We had some more elaborate talking points, but somebody abbreviated them to say, 'Yay, five!'" Rosner joked.

As it was also his first open meeting, LaCerte laid out his priorities for the job.

"I understand our nation's need for critical expansion of generation and transmission," he added. "Now, more so than ever, it's important that companies seeking to generate and transmit our energy are not thrown unnecessary obstacles to stymie their efforts. [National Environmental Policy Act] reviews across the federal government have run off course, failed to protect the environment and often only serve to delay or derail infrastructure projects. All American people deserve better, and we have to do better."

Why This Matters

The new-look FERC faces major issues, especially a proposal from the energy secretary to assert jurisdiction over large load interconnections aimed at ensuring speed to market for data centers to 'win the AI race.'

He added that the AI race needs to be met with bold action to ensure economic and national security.

The Department of Energy already put that issue on FERC's plate with an Advance Notice of Proposed Rulemaking urging it to assert jurisdiction over the interconnection of large loads like data centers for AI. (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

"That obviously is top of mind for me," Swett said during a post-meeting press conference. "That issue is my biggest priority, and an issue facing our country of this import cannot be solved by any one person or one agency alone. And that's why we are so excited to open this docket for comments, because it is so important that everyone weighs in."

Comments are due in the docket (*RM26-4*) by close-of-business Nov. 21, and Energy Secretary Chris Wright asked for a final decision by April 30, 2026.

Another issue looming over FERC and other independent regulatory agencies is Supreme Court case *Trump v. Slaughter*, which will decide whether the president has broad authority to fire members of the Federal Trade Commission, which could be extended to FERC. Recently, a group of 11 former commissioners filed a brief arguing for the court to uphold "for cause" removal protections across the board, or at least separately for ratemaking agencies such as FERC and the Federal Reserve. (See *Former FERC Commissioners Ask Supreme Court to Preserve Agency Independence*.)

Swett was asked about her position on the issue, and she said the law still preserves FERC's independence.

"Everything that FERC does is independent, and it is independently voted on by five people with very diverse viewpoints," Swett said. "I have the honor of being designated chairman based on the president's faith in my independent experience and my independent judgment to run this agency. And by the nature of the statute that created FERC — the DOE Organization Act of 1977 — we are explicitly carved out of DOE jurisdiction, with no review powers from anyone at DOE on FERC's independent actions." ■

FERC Ends Nonpublic Investigations into Winter Storm Uri

By James Downing

FERC said Nov. 20 that it has closed its enforcement investigations into possible unlawful activity related to 2021's Winter Storm Uri, just a few months before the statute of limitations on the issue was to expire.

The storm knocked out power across much of Texas for days, leading to hundreds of deaths, and caused massive electricity price spikes there while driving up natural gas costs across a broad swath of the country.

FERC and NERC quickly released a report on the reliability issues in ERCOT in November 2021, which included recommended changes to winter reliability standards that have since been put in place. (See *FERC, NERC Release Final Texas Storm Report*.)

The commission released its fiscal 2025 *Report on Enforcement* at its regular meeting Nov. 20, but earlier versions of the report for 2023 and 2024 explained some of the nonpublic investigations into activity around the storm.

The 2023 version explained how FERC dropped a probe into a natural gas marketer that cited a "force majeure" clause to stop the sale of gas to one customer, which was sold to another, but the agency lacked evidence to move forward on any allegation. Then-Chair Willie Phillips said additional investigations were ongoing. (See *FERC Enforcement Report Details One Closed Probe into Winter Storm Uri*.)

The 2024 version of the *report* detailed a couple other cases FERC opened and then closed without action. One involved market manipulation in the gas sector in which a firm contacted a price index reporter to remove a price on the lower end from their indices during the storm after learning it would have a significant positive financial effect on the company.

Another one involved a probe into a company doing business in CAISO that was alleged to have withheld physical energy during Uri and at other times to drive up prices and secure firm contracts, but it was closed due to a lack of evidence.

FERC does not name the targets of its investigations unless it decides to move forward with a settlement or other enforcement actions.

"I would not speak to any nonpublic investigations before the commission makes them official," Chair Laura Swett said at post-meeting press conference. "There's a reason for that regulation: It's to protect the entities before we come up with a conclusion, and they are given appropriate due process."

Why This Matters

FERC's move closes the chapter on any agency investigations into the 2021 winter storm event that led to skyrocketing energy prices in Texas and accusations of market malfeasance.

FERC has five years after an event to move forward on cases, which means it would have to do so on any Uri investigations within the next three months — but the agency confirmed that will not be happening.

The storm has sparked many civil lawsuits, and utility customers around the country are still paying for its costs, which in some areas have been securitized over many years in rates to spread out price spikes.

FERC lacks any authority over ERCOT's market and a state court has found the Public Utility Commission of Texas followed the law in keeping prices at the $9,000/MWh cap throughout the week of outages. (See *Texas Supreme Court Rules for ERCOT, PUC During Uri*.)

Other *lawsuits* have targeted natural gas market participants, but many of them involve the intrastate markets in Texas and Oklahoma, which are important even outside those states. In 2023, the 5th U.S. Circuit Court of Appeals ruled that FERC could not fine BP for trades on the Texas gas system during a 2008 event. (See *FERC Approves Smaller Fine for BP After 5th Circuit Decision*.)

One lawsuit filed by CirclesX Recovery against many major natural gas firms contends that widespread withholding of gas during Uri caused its price to spike from about $2/MMBtu to $208/MMBtu at Texas' Waha hub and to as high as $1,200/MMBtu at unregulated nodes on the intrastate natural gas system. That suit is pending at the Texas 1st Court of Appeals. ■

| *Xcel Energy*

NERC Winter Reliability Assessment Finds Many Regions Facing Elevated Risk

By James Downing

Rising electricity demand has outpaced winter capacity growth over the past year, leaving many North American regions at elevated risk for outages if they face extreme weather this winter, NERC reported in its newly released *Winter Reliability Assessment*.

Demand in areas covered by the report has grown by 20 GW since last winter, but corresponding grids have added just 9.4 GW of new supplies to meet the higher consumption, the report said.

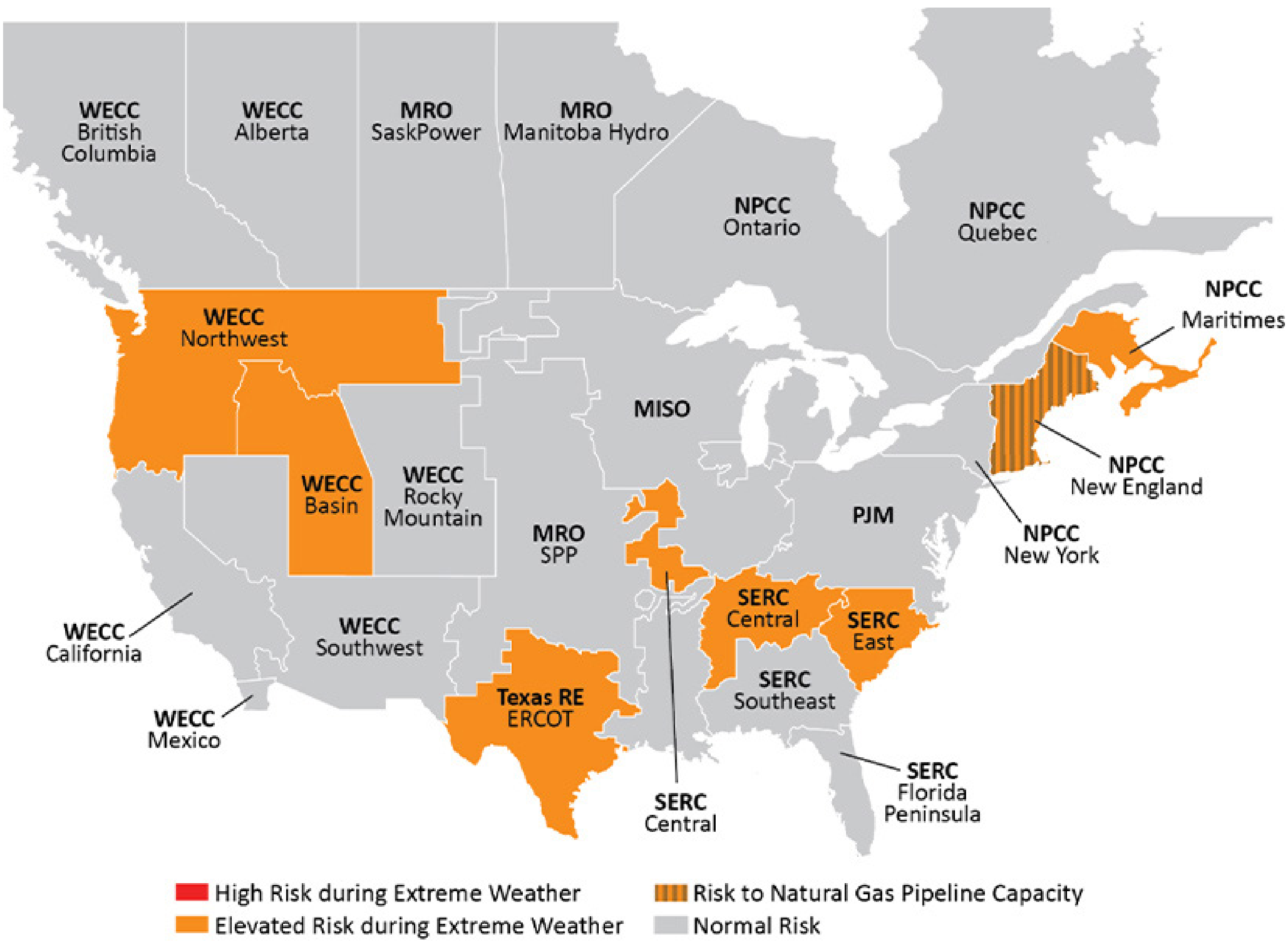
"The bulk power system is entering another winter with pockets of elevated risk, and the drivers are becoming more structural than seasonal," NERC Director of Reliability Assessments John Moura said during a Nov. 18 webinar on the report. "We're seeing steady demand growth faster than previous years, landing on a system that's still racing to build new resources, navigating supply chain constraints, and integrating large amounts of variable and integrated inverter-based generation.

"We also added the continued threat of extreme cold weather, which has changed over the years, and the margin for error narrows quickly," he said.

The assessment finds highest risk of

Why This Matters

NERC's Winter Reliability Assessment found risks for outages during extreme weather across much of the continent, including longstanding energy adequacy issues in New England.



A NERC-produced map showing which regions face higher reliability risks during extended cold snaps this upcoming winter. | *NERC* outages during extreme weather in the WECC Northwest and Basin regions; ERCOT; SERC Reliability's Central and East regions; and the Northeast Power Coordinating Council's New England and Canada Maritime Provinces regions.

While the last two winters have seen noticeable improvements in the delivery of natural gas to bulk power system generators, gas availability remains precarious during extreme cold due to the uneven application of voluntary freeze protection mitigation, NERC found.

"Gas production and supplies going to generators really do strongly affect how well the bulk power system can perform during winter conditions," NERC Manager of Reliability Assessments Mark Olson said during the webinar. "These two systems are inextricably linked."

New England stands alone in the report as facing "risk to natural gas pipeline capacity." The region's demand forecast for this winter is 2.9% lower than last year, and firm imports and demand response can make up for retired power plants, the study said.

"New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies," the report said. "ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls."

'Pragmatic, Proven Tools'

New England has for decades faced the issue of energy shortfalls during winter, and the idea of building new natural gas pipelines there has recently gained traction. (See *Pipeline Expansion Highlights Key Questions About Gas in New England*.)

"Expanding the gas infrastructure into a constrained area like the Northeast would help as you get to these low-temperature periods where gas-fired generation is competing with other users of the gas system; the gas infrastructure would better postured to be able to support the uses," Olson said. "So basically, for electric reliability, we would expect fewer generator curtailments due to fuel issues, if we can expand that capacity, which can provide reliability benefits."

That would mean fewer generator outages and less reliance on backup fuels, allowing the region to be more resilient during extended cold snaps, he added.

NARUC recently released its Gas-Electric Alignment for Reliability report, which recommended construction of more pipelines to improve electric reliability. (See *NARUC Report Seeks to Make Headway on Gas-electric Coordination*.)

Moura said "the preponderance of material that's being presented to decision-makers around gas-electric" points in the same direction: "That alignment between gas and electric are critical, these are interconnected systems, and there needs to be some changes in the future."

The power industry continues to build new natural gas plants, but they are not always paired with new pipelines, or contracts with firm service able to ensure delivery during the coldest days of the year, he added.

"The findings around aligning the markets, being able to put in more resilience through more infrastructure, are all lining up with what we need to have a reliable and resilient system in the future," Moura said.

The National Petroleum Council plans to publish another report on gas-electric coordination in early December that will also include recommendations to shore up the reliability of both systems, Moura said.

Electric Power Supply Association CEO Todd Snitchler said his group's members are investing in the resources needed to maintain reliability, including gas-fired plants and batteries. Evolving demand forecasts increase uncertainty, but competitive markets can shield customers from risk, he said.

"Policymakers should avoid extreme rhetoric or drastic interventions driven by outlier projections and instead focus on pragmatic, proven tools that support reliability and encourage cost discipline," Snitchler said. "Competitive markets remain the most effective mechanism to deliver reliable, innovative and cost-effective energy. With targeted reforms — and continued private investment — we can better ensure the dependable, affordable power system Americans expect this winter and for years to come." ■

House Natural Resources Committee Advances Permitting Bills

By James Downing

The House Natural Resources Committee has passed a package of permitting legislation, which includes reforms to the National Environmental Policy Act meant to speed up the deployment of infrastructure.

The main bills, including the SPEED Act (*H.R. 4776*), had bipartisan co-sponsors. Committee Chair Bruce Westerman (R-Ark.) and Rep. Jared Goldman (D-Maine) cosponsored the SPEED Act, which cleared the committee 28-15.

"The committee took an important bipartisan step toward lowering energy prices for hardworking Americans and building critical projects," Westerman said in a Nov. 20 statement. "The increasing demand for electricity and critical minerals is fueling new investments, and federal permitting laws must keep up. The SPEED Act eliminates bureaucratic delays that hinder projects and restores NEPA to its original purpose."

The bipartisan support for NEPA reform is a victory for government efficiency, economic growth and lower energy bills, he added.

The SPEED Act seeks to speed up the processing time for permits at agencies and limit opposing litigation to parties directly affected by projects. It requires lawsuits to be filed within 150 days of a permit being issued.

Golden introduced an amendment, which was approved by the committee unanimously, that would block the executive branch from revoking permits for projects once they have been approved.

"Both parties have agreed on this problem for years, and today's support from the committee gives me hope that Congress is finally ready to take the win," Golden said. "I'm grateful to Chairman Westerman for his commitment to earning bipartisan support for our bill, and I'm ready to get this passed on the House floor."

Golden and Republicans said presidents of both parties have used their authority to pull permits for projects that were underway. While that will not be possible should the package become part of a broader bill that passes Congress, many Democrats said it was not enough.

Rep. Seth Magaziner (D-R.I.) said during the mark-up hearing Nov. 20 that he was happy Golden's amendment passed, noting that his state has faced the issue with the Revolution Wind project. (See *Judge Lifts BOEM's Stop-work Order on Revolution Wind*.)

"All across the country, from solar projects in Nevada to onshore wind in Idaho, the Trump administration is indiscriminately canceling projects that have already been fully permitted and approved, showing that they care more about culture wars than lowering costs for Americans," he said.

Magaziner submitted an amendment that would have made the language Golden submitted retroactive to Jan. 20, 2025, covering all the projects the administration has blocked since taking office.

"If we do not adopt my amendment, not only will clean energy projects already being held up by the administration not be covered, but also any other projects that they decide to block from now until final passage of the bill," Magaziner said.

The amendment was not agreed to, meaning the prohibition against yanking approved permits would go into effect only when the SPEED Act becomes law.

The desire to address the Trump administration's actions against clean energy projects goes well beyond Democrats on the committee: The 104-member Sustainable Energy and Environmental Coalition, the 116-member New Democrat Coalition and the nearly 100-member Congressional Progressive Caucus released a joint statement saying it was a pre-requisite for any permitting package.

"Ensuring that clean energy projects are treated fairly and can move forward where appropriate is the prerequisite for serious, practical negotiations on a reform package capable of meeting the nation's energy needs," the statement said. "Additionally, to be comfortable with any sort of agreement, we need to be able to trust that this administration is going to follow the law that we write."

Why This Matters

A key committee passed its part of what could be a broader permitting package this session, if support can come together in time before Congress turns its attention to next fall's midterm elections.

The committee opposition to the SPEED Act came from Democrats, with ranking member Jared Huffman (D-Calif.) saying the bill effectively guts NEPA.

"This bill is so extreme that there's simply nothing left in a meaningful way of NEPA if this were to become law," Huffman said. "Now, Democrats are very interested in working constructively in problem solving. We would love to have a meaningful conversation, but it has to start with ending the war on clean energy, which this bill does not do in any significant way."

Several other bills cleared the committee, including the ePermit Act (H.R. 4503) from Reps. Dusty Johnson (R-S.D.) and Scott Peters (D-Calif.). The bill codifies how federal agencies should implement electronic permitting systems.

"The ePermit Act moves us toward a modern, efficient, fully digital permitting system that will cut red tape, and today's passage brings us one step closer to delivering results faster," Peters said. "As energy costs continue to rise across the country, it's important we meet the growing demand for electrification, data centers and clean-tech manufacturing."

Peters has backed reforms to how electric transmission is sited, which is under the Energy & Commerce Committee's jurisdiction. That is one of the other committees, in addition to the Senate, working on permitting legislation. (See *Bipartisan Transmission Permitting Reform Bill Introduced in House*.)

ATC and ITC Midwest

ITC Holdings is one of hundreds of firms and interest groups that endorsed the SPEED Act. *RTO Insider* interviewed its director of federal affairs, Devin McMackin, on the prospects for legislation passing the full Congress in 2025.

"The real limit on when things can get done this Congress is as we get closer to the midterms," McMackin said. "So, there will come a point when, certainly it will be harder to make a bipartisan deal. But I think there's time now for Congress to do that, and it'll depend on a lot of things. But we are cautiously optimistic that there's a window of time right now that kind of goes into the beginning part of next year where something could actually get done."

The SPEED Act would help the major transmission upgrades being planned in the MISO and SPP, he added.

"I think it's reasonable to foresee that there are some number of these projects, especially the greenfield ones, that are going to need to traverse some sort of federal land or some sort of protected area," McMackin said. "And then that, of course, triggers federal reviews under NEPA and other environmental laws, and the potential for there to be litigation, because there usually is whenever there's sort of federal permitting processes happening."

The SPEED Act does not render NEPA toothless environmentally. Rather, it provides better clarity for how agencies can review projects and places limits on litigation.

"Litigation is kind of the thing that can really hold up projects when you have sort of injunctions and starts and stops and things like that, and that can also really raise the cost of projects, which we're very conscious about as well," McMackin said.

The American Clean Power Association also supported the SPEED Act. CEO Jason Grumet said it would create key milestones throughout the permitting process that provide greater certainty for developers.

"The SPEED Act reforms are necessary to develop all forms of American energy infrastructure enabling a comprehensive response to soaring energy demand," Grumet said in a statement. "Absent these improvements and additional efforts to support pipeline and transmission infrastructure, energy prices will spike and system reliability will be threatened."

The Sierra Club, Earthjustice and the Union of Concerned Scientists all signed onto a letter, along with about 100 other environmental groups from around the country, in opposition to the SPEED Act.

"The urgency many feel to accelerate this buildout [of better transportation systems, more affordable housing, semiconductor fabrication facilities, transmission lines, renewable energy and more] is well founded, but the SPEED Act takes exactly the wrong approach," the letter said. "We cannot simply deregulate our way to a smarter, more efficient permitting system. Stripping away safeguards does not create better processes or stronger projects. It only invites more mistakes, conflict and harmful development." ■

DOE Announces $1B Loan for Constellation's Crane Energy Center

By James Downing

Why This Matters

The loan announcement marks the first project to get a concurrent conditional commitment and financial closing under the Trump administration.

U.S. Secretary of Energy Chris Wright announced a $1 billion loan for Constellation Energy's project to bring back the Crane Clean Energy Center, which has a long-term contract with Microsoft. (See *Constellation to Reopen, Rename Three Mile Island Unit 1*.)

The renamed Three Mile Island Unit 1 in Londonderry Township, Pa., will require $1.6 billion to reopen. Microsoft has signed a 20-year contract to buy electricity from it to power its data centers. Unit 1 closed in 2019 due to adverse economic conditions. It's adjacent to TMI Unit 2, which partly melted down in 1979.

The loan to restart Unit 1 was funded by the Energy Dominance Financing program passed under the One Big Beautiful Bill Act, which Republicans now call the Working Families Tax Cut, earlier in 2025.

"Constellation's restart of a nuclear power plant in Pennsylvania will provide affordable, reliable and secure energy to Americans across the Mid-Atlantic region," Wright said in a statement. "It will also help ensure America has the energy it needs to grow its domestic manufacturing base and win the AI race."

The loan announcement marks the first project to get a concurrent conditional commitment and financial closing under the Trump administration. DOE said it remains committed to maximizing the speed and scale of nuclear capacity.

"DOE's quick action and leadership is another huge step towards bringing hundreds of megawatts of reliable nuclear power onto the grid at this critical moment," Constellation CEO Joe Dominguez said in a statement. "Under the Trump administration, the FERC and DOE have made it possible for us to vastly expedite this restart without compromising quality or safety."

The loan will cut Constellation's financing costs for the nuclear unit restart.

The Crane center is more than 80% staffed with more than 500 employees on site, Constellation said Nov. 18. Inspections of key plant components and regulatory reviews for the restart remain on schedule.

"Utilities and grid operators are moving too slowly and need to make regulatory changes that will allow our nation to unlock its abundant energy potential," Dominguez said. "Constellation and nuclear energy are helping to lead the way, and we are thankful to President Trump and Secretary Wright for putting the 'energy' back into DOE." ■

The former Three Mile Island nuclear power plant | *DOE*

FERC Report Urges West to Address Looming Market Seams Issues

Staff White Paper Details Recommendations Based on Eastern Practices

By Robert Mullin

A new FERC report adds to the growing body of work showing the sheer complexity of confronting the seams issues likely to arise between the West's two day-ahead markets when compared with challenges at the borders between RTOs and ISOs in the Eastern U.S.

In their white paper "*Seams Coordination in the Western Interconnection*," released Nov. 21, FERC staff urge Western electricity industry stakeholders to get ahead of seams issues before CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+ both go live, scheduled to occur in 2026 and 2027, respectively.

And the authors recommend steps the two market operators can take to manage the myriad challenges — mostly unique to the West — related to the existence of seams between the markets.

The authors acknowledge the analyses already published on the issue, saying their report is intended "to support the ongoing discussions among stakeholders and highlight the importance of collaboration by relevant parties to address these complex issues." (See *'Islanded' BAs Face Tough Choices in Western Market Future, Experts Say* and *Western Market Seams Issues to Differ from East, Study Finds*.)

"These seams can create operational and reliability hurdles that arise from several related issues: overlapping transmission ownership and rights, differences in transmission modeling, and congestion caused by loop flow," they said. "The same issues could diminish the economic benefits of EDAM, [CAISO's Western Energy Imbalance Market] and Markets+ by limiting the ability to trade across markets."

The paper outlines the history of seams coordination in the Eastern Interconnection, including the development of congestion management processes and market-to-market agreements typically wrapped into the joint operating agreements among RTOs such as PJM, MISO and SPP, and their neighboring non-market areas. Those JOAs also include provisions for handling emergency energy flows between balancing authorities and managing trades across boundaries, such as through coordinated transaction scheduling (CTS), FERC staff noted.

The paper points to two efforts already underway to address seams issues in the West.

The first, not directly related to the two markets, is the joint work by CAISO's RC West and SPP RC to propose improvements to the Western Interconnection Unscheduled Flow Mitigation Plan to the North American Energy Standards Board.

In April 2024, NAESB's Enhanced Curtailment Calculator (ECC) Task Force — which includes members from both reliability coordinators — issued a *white paper* describing the problems with current unscheduled flow mitigation practices in the West. It explained that the region's BAs and transmission operators largely rely on their own individual methods to resolve unscheduled flows, meaning that transmission customers on one system might experience curtailments for different reasons than similarly situated customers on a different system. To remedy the problem, the task force recommended expanded use of the ECC tool to bring more uniformity.

The second seams effort underway is the Markets+ Seams Working Group (MSWG), as well as work undertaken by other working groups helping to develop that market.

"From its inception, the MSWG was charged with supporting the development of seams coordination frameworks and identifying potential seams-related tariff content; early discussions on the working group's scope included import/export and wheel-through issues and congestion management topics," the paper says.

At the direction of the Markets+ Participant Executive Committee, the MSWG in 2024 began developing the *Seams Strategy and Roadmap*, designed to identify focus areas for policies and governing documents related to seams issues with neighboring areas.

Why This Matters

The report signals that FERC is paying close attention to an issue that could soon bring significant complications to electricity transfers and trading in the Western Interconnection.

Going to Flow-based Modeling

In the paper, FERC staff called out "three primary categories of issues that Western entities should consider addressing through seams coordination agreements," including:

- use of flow-based modeling rather than contract path modeling;
- coordinating interchange between market areas to prioritize maintaining reliability and managing congestion; and
- coordinating electricity flows to maximize economic efficiency.

On the modeling issue, the authors note that transmission availability in the West is still mostly modeled on contract path-based models that assume flows on contracted paths between generation sources and load sinks, compared with the flow-based approach in the East that relies on a flowgate methodology to calculate available transfer capability (ATC).

"Because flow-based modeling uses actual power flows to model the transmission system, it is generally considered to be more efficient and robust than the contract-path based methodology," FERC staff wrote, adding that use of the two methods is "inconsistent" across the West.

"The continued use of contract path-based modeling and the use of different modeling methodologies may complicate efforts to maintain reliability, mitigate congestion and enhance economic benefits in the Western Interconnection. Thus, before discussing more specific approaches to coordinating operations in the West, it is important to ensure that the transmission availability and usage metrics these markets rely on be modeled as consistently and accurately as possible," they wrote.

Adoption of flowgate modeling would have two benefits, they said: more accurate estimation of ATC and "better coordination across seams during day-ahead and real-time operations by market operators and BAs."

Given that EDAM and Markets+ will both rely on transmission capacity being made available by market participants rather than transmission owners handing over control of their systems as in a full RTO, FERC staff said, "flow-based modeling of ATC could provide a more accurate view of how much transmission is actually available to allocate between the markets compared to the results of contract path-based modeling prior to the actual day-ahead and real-time market runs.

"Western entities could investigate whether this would ease longer-term transmission expansion needs and make more transmission available for day-ahead and real-time market optimization."

Managing Reliability, Congestion

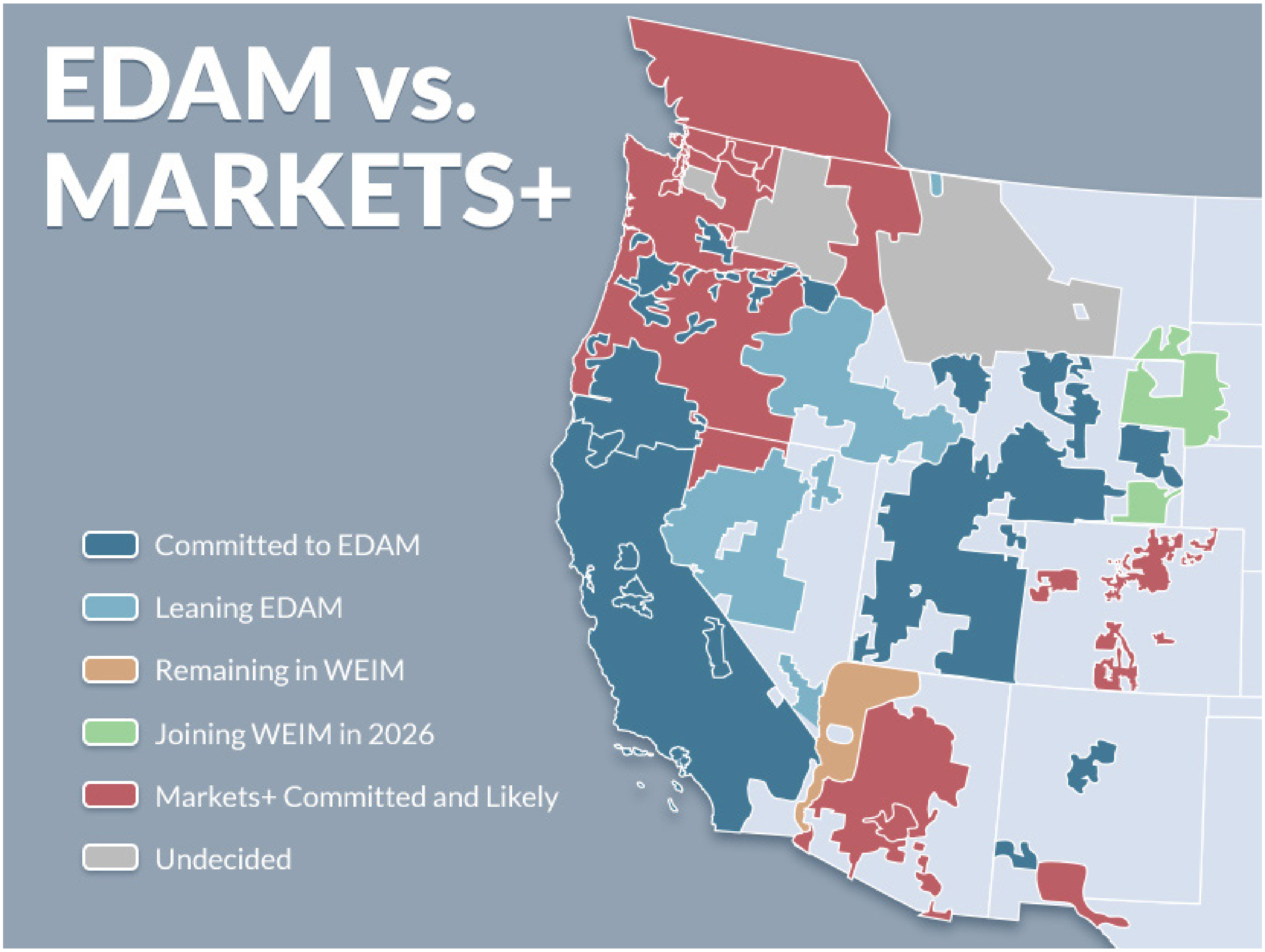
On the subject of coordinating interchange between markets, FERC staff called the process a "key tool" in maintaining reliability and managing congestion.

"Agreements that formalize interchange procedures during critical system conditions between markets, as well as those between markets and non-markets, have generally provided greater certainty to system operators and improved cooperation between BAs. These include agreements such as emergency energy agreements, reserve sharing arrangements and JOAs," they wrote.

The paper recommends that Western entities consider how reliability agreements across seams address data and model coordination, emergency event protocols, and loop flow management.

FERC staff wrote that the expansion of centralized markets in the West "introduces new challenges and opportunities for managing congestion between markets areas as well as between markets and non-markets," with EDAM and Markets+ schedules potentially causing loop flows that extend beyond their borders.

To limit the effects of congestion, the



Given the relative footprints of CAISO's EDAM and SPP's Markets+, seams issues between the two markets are likely to be especially complicated. | © *RTO Insider* paper recommends the adoption of M2M coordination, which seeks to reduce congestion at the lowest cost through the sharing of market pricing data between two RTOs/ISOs to bring about the most efficient redispatch.

Economic Trading Across Seams

The paper says cross-seam coordination of electricity transfers for cost savings will likely take on different forms in the West than in the East.

Part of that has to do with the differences between how EDAM and Markets+ deal with bidding at their interties with non-participating BAs.

Under existing WEIM and EDAM rules, participating BAs can decide whether to allow non-resource specific bidding at their interties with non-participating BAs. In Markets+, intertie economic trading will be implemented uniformly along its seams, allowing participants to submit buy and sell offers for imports and exports as long as they have the necessary transmission rights — an approach the authors say "could facilitate more economically efficient trading across its seams."

FERC staff suggest that Western market operators could implement coordinated economic trading between their two areas. That might entail a practice such as CTS, which allows market participants to use a single portal to submit bids based on spreads between delivery points on either side of market seam.

The market operators could also implement "some form of interchange optimization" that gives them visibility into each other's system and pricing for each trading interval. That approach would allow market participants to submit bids within their own markets, with the operators then using that information to determine whether they can meet their needs most economically from their own resources or from transfers out of a neighboring area based on transmission constraints and other factors.

The FERC paper did not explore another complicating factor for the Western markets compared with the East: the highly fractured boundaries between EDAM and Markets+ that will likely effectively island some participants — particularly in Markets+. During a meeting of CAISO's Western Energy Markets Regional Issues Forum in April, Richard Doying of Grid Strategies, one of the designers of the MISO market, noted that non-contiguous market zones "will require drive-out, drive-through and drive-in transmission service and schedules," an arrangement that will require new types of transmission service and coordination to avoid diminishing the value the markets are intended to bring.

"The complex seams arising in the West from the expansion of Western markets present challenges to operations, reliability and the efficiency of the markets," FERC staff wrote in the conclusion of their white paper. "To address these challenges, FERC staff believe it is important that Western entities continue their work coordinating operations to ensure the reliability and efficiency of their markets and BAs as Western markets proceed toward implementation and in advance of live operations." ■

FERC Mostly Accepts Calif. IOUs' Order 2023 Compliance Filings

By Henrik Nilsson

Why This Matters

The orders come as part of FERC's effort to speed up interconnection queues throughout the U.S. as electric demand continues to rise.

FERC largely approved filings by California's three major investor-owned utilities to comply with interconnection queue requirements under Order 2023 (*ER24-2776*, *ER10-1391-003* and *ER24-3032*).

In three separate orders Nov. 20, FERC mostly accepted Southern California Edison, San Diego Gas & Electric and Pacific Gas and Electric's tariff revisions, but the utilities must clarify some issues within 60 days.

In SCE's case, FERC ordered the utility to file revisions related to storage operating assumptions, network upgrade cost allocation requirements, site control, the definition of regulatory limits and cluster study provisions.

On the operating assumptions, SCE argued it did not need to include those because it already offered similar provisions for electric storage resources under a commission-approved settlement agreement.

FERC rejected this argument, siding instead with renewable energy company Terra-Gen and the California Energy Storage Alliance (CESA), which contented the settlement agreement "is expressly conditioned on future compliance with commission orders."

"Terra-Gen and CESA explain that while the settlement agreement has a moratorium prohibiting revisions to SoCal Edison's tariff, there is also an exception allowing changes to be made if directed by a commission order or a final rule, such as Order No. 2023," FERC said.

The two protesters asked FERC to reject SCE's proposed revisions and direct the utility to revise its tariff to allow interconnection customers to provide operating assumptions for storage resources, according to the order.

FERC agreed, stating that "SoCal Edison has failed to adequately justify excluding the requirement for transmission providers to use operating assumptions, at the request of the interconnection customer, in interconnection studies that reflect the proposed charging behavior of an electric storage resource."

"We are evaluating the order and are pleased to see much of our proposal approved," Jeff Monford, spokesperson for SCE, told *RTO Insider*.

Meanwhile, in the SDG&E docket, CESA, along with the Clean Energy Alliance, San Diego Community Power and the Clean Coalition, also filed objections.

In one matter, CESA objected to SDG&E's proposed rules regarding affected systems, arguing that they "are insufficiently detailed and could give rise to discriminatory practices." FERC said it was "unpersuaded" by CESA's arguments, finding that the utility included "requirements for circumstances where SDG&E is the host service provider."

But the commission did order SDG&E to file revisions related to network upgrade cost allocations, commercial readiness and regulatory limits.

FERC likewise required PG&E to clarify or correct provisions pertaining to co-located generating facilities, operating assumptions, cluster study and site control, among other issues.

CESA contended PG&E failed to "provide interconnection customers with electric storage resources with the ability to design and charge their facilities in a manner sufficient to satisfy their proposed operating parameters," according to FERC. The organization argued PG&E failed to explain how it would review interconnection customers' requested operating assumptions or whether the company would allow customers to operate in accordance with those assumptions after entering service.

FERC noted that some of CESA's concerns should be addressed by PG&E in its subsequent compliance filing but that its "concerns about PG&E not describing how it will analyze requested operating assumptions or allowing additional flexibility for interconnection customers to adopt control technologies are outside the scope of this compliance filing because these requirements were not established in Order No. 2023."

The utilities said in their filings that they must navigate between Order 2023 requirements as well as their CAISO tariffs. FERC noted this and pointed to overlap in, for example, cluster study requirements in both CAISO and Order 2023.

PG&E spokesperson Jennifer Robison told *RTO Insider* that "FERC's order will help expedite interconnection of wholesale generation on markets managed by [CAISO]."

"This is an important step in meeting CAISO's load forecasts, which project significant electric demand growth in California driven mostly by new data centers, EV charging and building electrification," Robison added. "We look forward to continuing to work with CAISO and other stakeholders on additional improvements to the interconnection process."

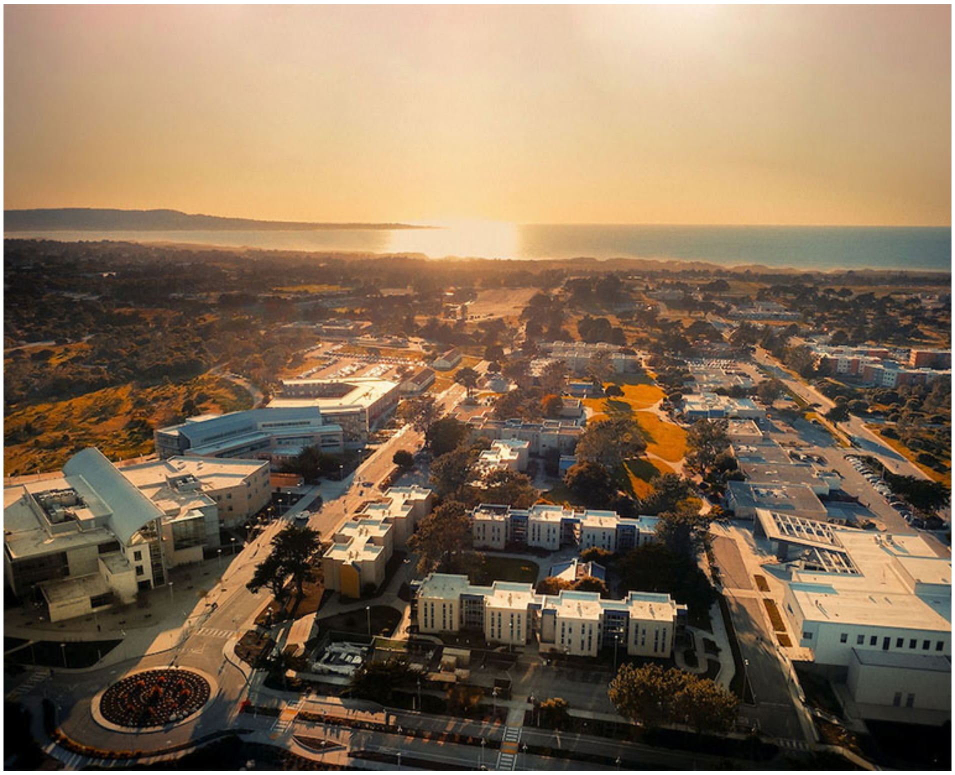
FERC issued Order 2023 in July 2023 with the goal of clearing backlogged interconnection queues by implementing a first-ready, first-served cluster study process; increasing interconnection customers' financial obligations; and penalizing grid operators for missing study deadlines. (See *FERC Partly Accepts SPP's Order 2023 Compliance*.)

In 2024, the commission rejected challenges to the order, though it made several clarifications and minor modifications and established an extended compliance deadline with Order 2023-A. (See *FERC Upholds, Clarifies Generator Interconnection Rule*.) ■

CPUC Approves PG&E Cancellation of University Electrification Project

Safety Concerns Arise Around Plastic Fusion Pipe Failures

By David Krause



Cal State Monterey Bay campus in Marina, Calif. | *Cal State Monterey Bay*

The California Public Utilities Commission approved a request to cancel Pacific Gas and Electric's contract with California State University, Monterey Bay to convert hundreds of the university's residential units from gas and electric service to all-electric service.

The project between PG&E and CSU Monterey Bay included retirement of about eight miles of existing natural gas piping and installing electric-only service and equipment at about 1,200 dwellings. As part of the project, the university would have waived its right to receive gas service in the future, said the *decision*, approved at a Nov. 20 voting meeting.

The project would have addressed customer safety needs, long-term rate affordability and customer energy preference, and would have aligned with California's climate goals, PG&E said in its application.

PG&E originally introduced the project as a case study in "how a utility can use building decarbonization as a tool to both reduce emissions and promote long-term gas ratepayer affordability," the decision says.

The company's original application showed that electrification instead of new gas infrastructure would have resulted in "net present value of approximately $1 million to benefit utility customers," the Natural Resources Defense Council said in a *filing*.

Why This Matters

The CPUC's approval of PG&E's cancellation of the CSU building electrification project could signal a slowdown in California's ambitious plans to move structures off natural gas heating.

"This is in addition to the climate and air quality benefits of these investments, and the avoided risk of future stranded assets," the NRDC said in the filing.

But in January, PG&E requested to withdraw the project application due to safety concerns, specifically around plastic fusion failures on the existing gas piping system. These failures needed to be repaired or replaced by Dec. 15, 2026.

However, PG&E said 2026 was the earliest year the regulatory approval process for the project would have concluded. This timeline would be too late to safely remediate the piping issues, the decision notes.

The NRDC disagreed with PG&E's request, saying the investor-owned utility did not prove the timing of the project was infeasible.

CPUC ruled that it is "reasonable and in the public interest" to grant PG&E's motion to withdraw the project application: The terms agreed to by PG&E and CSU Monterey Bay allow either entity the option not to pursue the project at any point, the decision says.

CPUC ordered PG&E to submit a lessons-learned report that summarized ratepayer impacts and operational experiences associated with the canceled project, the decision says.

SCE Reliability Contracts Approved

At the meeting, CPUC approved eight Southern California Edison contracts with energy storage and solar generation facilities as part of SCE's midterm reliability request for offers to cover the agency's 2023-2028 resource procurement compliance requirements.

The battery storage and solar facilities have capacities between 20 MW and 238 MW and are expected to start providing energy in 2026 and 2027, according to the *resolution*.

The contracts are part of CPUC's Decision 21-06-035, which required load-serving entities to procure 11,500 MW of midterm reliability capacity. ■

NWPCC Study Finds Market Availability Steady Across Different Scenarios

By Henrik Nilsson

The buildout of new resources in the Western Interconnection over the next 20 years is “remarkably similar” across a variety of scenarios tested in the Northwest Power and Conservation Council’s market availability study.

Staff members presented the study results at a council meeting Nov. 18. The study will inform the upcoming Ninth Power Plan, which the council is required to develop under the Northwest Power Act “to ensure an adequate, efficient, economical and reliable power supply for the region.” NWPCC publishes a plan every five years, according to the council’s website. (See *NWPCC’s Initial Demand Forecast Sees Sharp Growth for NW*.)

The market study evaluates out-of-region load growth and resource buildouts in the West over the next 20 years under different scenarios, including constrained buildout, delayed storage availability, existing transmission, increased transmission, emerging technology cost uncertainty, federal policies and hydro operations.

The study found that “market availability does not change significantly across the various sensitivities,” according to *council presentation slides*.

Though near-term buildouts of resources shift slightly, primarily where there are limits in resource availability, the 20-year buildouts are “remarkably similar.”

“In other words, there isn’t something so disruptive in one of the sensitivities that we’re seeing a major change in trajectory,” said John Ollis, manager of planning and analysis.

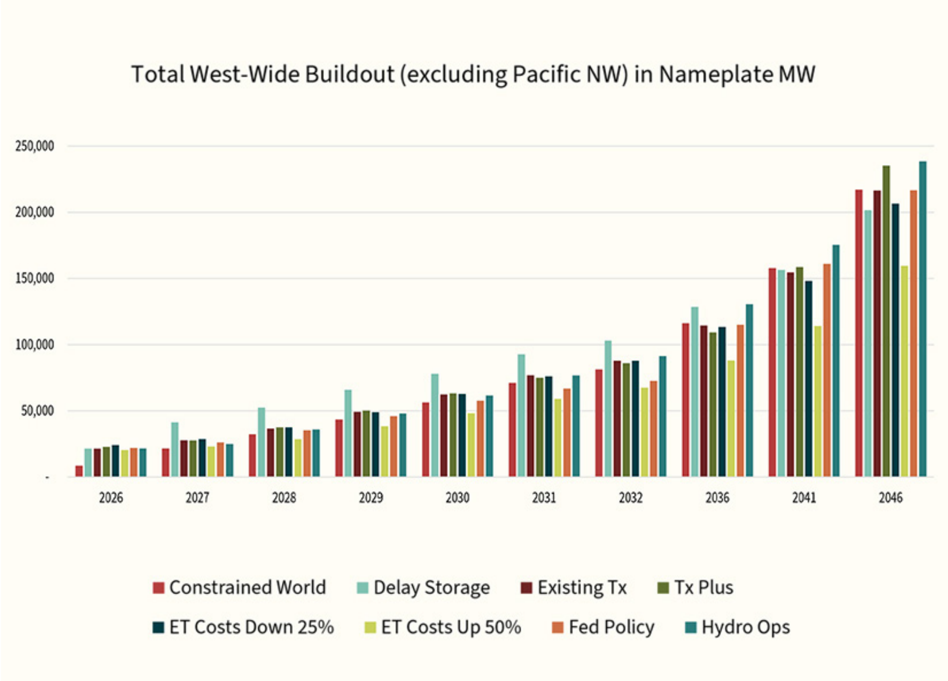
Ollis noted some variation among the scenarios in the pace of uptake of certain types of resources. For example, delays in short-duration storage increase variable energy resource (VER) build by more than 20% and gas build by 25% by 2032, but they decrease VER by 25% by 2046, according to the presentation.

The study found expansion of gas resources under scenarios in which transmission builds are limited, resource acquisition is delayed or emerging tech costs are high.

The majority of resources built across all sensitivities are a mix of renewables, storage and gas. Demand growth and carbon pricing policies in California, Washington and Canada are key drivers for buildout, according to the study.

Why This Matters

The study will help the council develop the upcoming Ninth Power Plan and provides insight into two key pieces that tie into the plan: economics and resource adequacy.



Northwest Power and Conservation Council

The market study helps power planners better understand the economics and resource adequacy issues underlying the power plan, Peter Jensen, a spokesperson for the council, told *RTO Insider*.

On the economics issue, Jensen said, “Even though we only plan for the region, the economics of every regional resource decision depends not just on the regional market fundamentals and policies, but on the market fundamentals and policies throughout the WECC.”

Similarly, “even though resource adequacy depends primarily on regional resources, understanding what resources might be available outside the region during stressful times is also important for informing adequacy and keeping rates down,” Jensen added.

On Nov. 5, the council’s System Analysis Advisory Committee — which includes regional utilities, Bonneville Power Administration staff, regulators and technical experts — reviewed the market study’s results.

“We had an opportunity to gut-check the size of the build, size of investments, risks and other key findings, and the committee members were broadly comfortable with the results,” Jensen said. “We appreciate the opportunity to collaborate and check the assumptions and results of our analysis with these experts as we continue to develop the Ninth Plan.”

The council aims to have a draft of the Ninth Plan ready for public comment by July 2026, and a final version by the end of 2026. ■

Avoiding Bunker Fuel: CEC OKs 54 MW of Additional Gas Generation in Burbank

Vice Chair Gunda Asks Public to Keep 'Pushing Back' on Emitting Resources

By David Krause

Magnolia Power Plant | *Burbank Water and Power*

The California Energy Commission approved a request to increase the output of a Burbank gas-fired power plant to address grid reliability issues, prompting some organizations and locals to protest out of concern about the facility's emissions and costs.

The CEC during its Nov. 17 business meeting granted about $36 million to the City of Burbank to refurbish the Magnolia Power Plant's (MPP) compressor system for about $23.2 million and add a new gas path system for about $12.8 million.

The project would increase MPP's capacity by 54 MW to make up for lost output stemming from degradation at the plant, a CEC *resolution* says. MPP's added capacity will be available during extreme events for five years from the commercial online date.

The increased capacity was needed due to tight grid conditions in California over recent years, CEC Vice Chair Siva Gunda said at the meeting.

"[We've] had to throw everything on the table to keep the lights on," Gunda said. "That meant basically turning on every backup generator in the state, like diesel backup generators, and unhooking large marine vessels from shore power and running them on bunker fuel."

The CEC's docket for the MPP project contained letters from nearby residents asking the commission to reject the facility's renovation plan.

Why This Matters

California energy officials have recently taken another look at existing generator plants, including gas-fired ones, as possible reliability sources for the state during peak times, but many have aged to the point of requiring renovations to keep them churning out power.

"Investing more money into an aging gas plant risks stranded assets — infrastructure that soon becomes unusable but still costs ratepayers," wrote Suzanne York of Pasadena to the CEC on Nov. 14.

Gunda said that it is "really important for us to acknowledge the comments that were made by many of the community members."

"Please don't stop pushing back because … the next choice will be influenced by the comments you all make."

The renovated MPP facility will operate with fewer environmental impacts than a peaker plant, Mandip Samra, general manager of Burbank Water and Power, said in a Nov. 14 *letter* to the CEC. Renovating MPP is also more cost effective than constructing a new facility, she added.

The CEC certified MPP in 2003, and the facility began operations in 2005. MPP is owned by the Southern California Public Power Authority (SCPPA) and operated by the City of Burbank and Burbank Water and Power.

The project's funding is part of the CEC's Distributed Electricity Backup Assets (DEBA) program, which provides incentives for constructing cleaner and more efficient distributed energy assets to strengthen electricity reliability, the commission said in its resolution.

At this point, the CEC has approved all natural gas efficiency improvement projects presented in the DEBA's notice of proposed awards, a CEC spokesperson told *RTO Insider* in an email. The facility will never go beyond its nameplate capacity or what was originally certified for its output, the spokesperson wrote.

The CEC has approved two similar projects in recent years: the *Lodi Energy Center* in March 2025 and the *Roseville State Power Augmentation Project* with the City of Roseville in August 2024. ■

PacifiCorp Staffs up Ahead of EDAM Launch

Utility Gearing up to be Pioneering Participant in West's 1st Day-ahead Market

By Henrik Nilsson

PacifiCorp is hiring additional employees to prepare for CAISO's Extended Day-Ahead Market in 2026, with staff expecting the launch will bring a few "scratches and bruises."

Daniel Koppes, director of main grid operations at PacifiCorp, said during an EDAM workshop Nov. 17 that his department plans to hire a new team of eight engineers who will work seven days a week "to help analyze how our system is going to operate every single day, so that way we can optimize the market solution [and] help prevent curtailments."

The new hires come as PacifiCorp develops new tools aimed at maintaining grid reliability under EDAM, Koppes said. Contrary to the existing real-time market, CAISO's Western Energy Imbalance Market, EDAM requires PacifiCorp to analyze how its system will work 24 hours in advance.

"Because of the financial impacts of a 24-hour ahead, every change that we make is going to cost more money than the current market does if … it creates curtailments," Koppes said.

Koppes' department will hire staff "to look at how did we do yesterday … so we know how we can do better. So, we've hired one, and we're working on hiring a couple more business analysts to look at every day after the fact," Koppes said.

Other PacifiCorp departments have staffed up or are doing so, including energy supply management, transmission services, business and accounting.

"The added staff that we've hired will allow us to stand a second operational desk," said Parker Floyd, generation dispatch manager.

"We're in the process of rebuilding our small control space into a slightly larger control room," Floyd said. "With more responsibility and more full-time employees, we need more space, but we also need space to house and protect cyber assets that we'll need."

PacifiCorp is expected to begin participating in EDAM on May 1, 2026. Some models estimate EDAM will bring approximately $900 million in annual savings, and more than $300 million for PacifiCorp customers, according to a company *presentation*. (See *'Aggressive' EDAM Schedule 'Going Smoothly' for PacifiCorp, PGE*.)

> **Notable Quote**
>
> "We are working on sticking the landing, and I'm confident that we will do so. We may come out of it with a few little scratches and bruises and maybe some unkempt hair, a little bit overtired. … As someone in charge of the implementation, I have confidence that we will get there, confidence in our partners."
>
> *– PacifiCorp's Kerstin Rock*

'Sticking the Landing'

But to reach that point, PacifiCorp has a lot of work to do.

"My team is spending an enormous amount of time working on the software upgrades that are necessary to implement EDAM," said Kris Bremer, transmission customer services managing director. "Specifically, in my team, it's the customer portals that are going to be used for scheduling for various activities on our transmission system. That is a massive upgrade to what we've done in the past."

Getting PacifiCorp's legacy customers ready for EDAM is another challenge, because not all those customers fall under the company's tariff and operate under old transmission agreements, Bremer noted.

Making sure those customers know how to schedule and how their transmission rights can be configured with EDAM is "also a big deal we're working through right now," Bremer said.

Dave Novom, manager of energy accounting and jurisdictional loads, said his department has hired one additional person who focuses on validating meter data and "working to make sure that we can submit actual meter data for settlements."

In addition to PacifiCorp, five other entities have signed implementation agreements with EDAM, with more likely.

"With the expanded footprint, I think we know it's going to become more complex, especially around optimization and cost allocation," said Joseph Holland, finance and accounting manager.

"One of our major settlements initiatives, or workflows, right now is to enhance our … vendors' ability to shadow settlements in EDAM," Holland said. "This shadowing allows us to ensure that the CAISO settlement is accurate before we suballocate those charges on to customers to avoid having to rework. That's one of the major areas where staffing is critical for us, adding new folks early in the process, which we've done."

While the EDAM implementation mostly is running smoothly, two areas — CAISO integration and software upgrades — have run into some issues, according to Kerstin Rock, EDAM implementation director.

"It's all very connected, in some cases, for really trying to orchestrate almost the cascading implication on the different applications," Rock said. "So, at this point … we have risks that we're managing. They're not high-level risks. We have a few issues, which are generally related to timing."

Rock said she expects the issues to be fixed, adding, "I'm not going to sit here and pretend that we plan to stick our landing perfectly."

"We are working on sticking the landing, and I'm confident that we will do so," Rock said. "We may come out of it with a few little scratches and bruises and maybe some unkempt hair, a little bit overtired. … As someone in charge of the implementation, I have confidence that we will get there, confidence in our partners." ■

Market Monitor Urges CAISO to Reconsider EDAM Intertie Proposal

Transitional Period Planned for EDAM Start

By David Krause

CAISO's Department of Market Monitoring has asked the ISO to re-evaluate its intertie scheduling proposal for the Extended Day-Ahead Market because of potential impacts on market participants.

CAISO held an impromptu workshop Nov. 14 to address outstanding stakeholder questions and concerns about the proposal after receiving the DMM's *comments*, which urged the ISO to use an alternative for EDAM's go-live in 2026. (See *EDAM Intertie Scheduling Processes Raise Stakeholder Concerns*.)

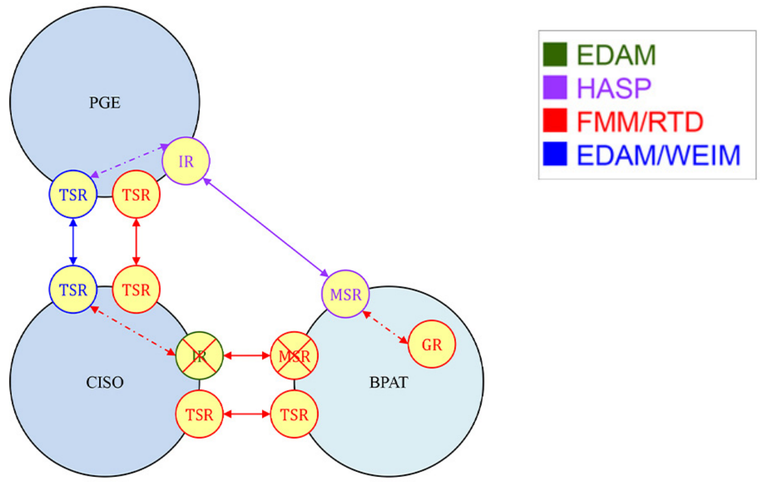
A primary issue is that in CAISO's existing market, intertie schedules are at a scheduling point (SP). However, a generation facility or load is not exactly at its assigned SP node, and this discrepancy affects congestion management, pricing and settlements, DMM noted in its comments.

CAISO tried to solve this problem by modeling intertie injections and withdrawals at one of several generation aggregation points (GAPs). Each GAP would have its own congestion and loss prices, so the prices of imports and exports at the same intertie would be different for schedules associated with different GAPs, DMM said. This new approach will create multiple prices for the same intertie and will affect market participants with transactions at EDAM and bilateral market interties, DMM said.

"It seems clear to DMM … that market participants are concerned that these changes could negatively impact their business operations and practices, or at the very least they have not had adequate preparation to consider the potential impacts," DMM said in its comments.

Why This Matters

CAISO's proposed intertie scheduling method in EDAM has come under heavy scrutiny. It plans to hold a transitional period in which the new and existing intertie methods overlap when the market starts up.



This is an example of intertie scheduling between CAISO, PGE and BPAT. | *CAISO*

The GAP intertie proposal could cause market participants to be left without knowing which GAP combination will be used for their day-ahead pricing. The GAP approach also could result in a market with multiple prices for the same intertie, meaning imports could clear at higher offer prices than other imports that are offered at lower prices, DMM said.

DMM recommended CAISO either keep the current SP approach or assign each intertie to a single generic GAP until stakeholders have the chance to go through the proposal in the ISO's policy revision process.

At the Nov. 14 workshop, CAISO staff said the ISO realizes there are a lot of questions and concerns about "how fast we are moving" and that the grid operator is working on implementing a transitional period for the EDAM GAP intertie approach.

"We are interested in making sure everyone is ready for whenever we make these changes in our market's design," said George Angelidis, executive principal at CAISO. "We would like to actually work with you and work on a transition plan that would [take] us through the journey together to maintain the timing of EDAM in May 2026."

CAISO is developing a transitional period for implementing certain intertie scheduling processes, including continuing to use SPs at CAISO interties for scheduling, mirroring and scheduling distribution, among other functions. At non-CAISO EDAM interties, the transitional period would include using a single GAP for scheduling, schedule distribution and locational marginal pricing calculations.

Resource adequacy import processes will be "simplified" during the EDAM transitional period, Angelidis said. RA monthly showings will occur at a CAISO SP tie, which is the same process used today in the ISO's market. The process for reassigning RA obligations will stay the same in EDAM during the transitional period, specifically for those that are not reassigned in a WEIM or non-WEIM BAA.

CAISO has not designated a concrete time frame for the transitional period, an ISO spokesperson told *RTO Insider* in an Nov. 17 email. Before transitioning to the FERC-approved intertie scheduling model, the ISO would have extensive discussions with stakeholders to determine the timeline and ensure alignment, the spokesperson said. ■

FERC OKs Extension of WEIM Assistance Energy Transfer Feature

Transfers Occur Infrequently, CAISO Market Monitor Says

By David Krause

FERC granted CAISO's request to remove the sunset date on the Western Energy Imbalance Market Assistance Energy Transfer feature, which has been used by more than 10 of the market's balancing area authorities in recent years.

CAISO originally planned to end the AET feature Dec. 31, but asked FERC to allow it to keep the program in place to accommodate BAAs that continue to experience supply constraints during certain trading intervals in the WEIM (*ER25-3491*).

Under the WEIM tariff, when a BAA has insufficient supply or ramping capacity, CAISO can use the AET feature to limit the amount of market transfers into and out of the BAA. The BAA receives a surcharge based on the lower of either the failure amount or of the final incremental transfer amount.

The WEIM resource sufficiency evaluation shows whether a BAA has enough capacity and flexibility to meet forecast demand and uncertainty. The evaluation has four tests: a feasibility test, a balancing test, a capacity test and flexibility test. CAISO's AET feature is open to a BAA that fails the capacity and/or the flexibility test.

Before the AET feature was implemented in 2023, if a BAA failed a capacity or flexibility test, they became ineligible to receive incremental energy transfers from other balancing areas in the WEIM, CAISO said in its Sept. 23 *filing* with FERC to extend AET.

Supporters of the AET extension include the Balancing Authority of Northern California, NV Energy and CAISO's Department of Market Monitoring (DMM).

© RTO Insider

Why This Matters

FERC's approval allows WEIM participants to continue to rely on Assistance Energy Transfers as many face increasing shortfalls in resource adequacy.

In the past two years, DMM has not found that a BAA systematically relies on the AET feature, DMM said in Oct. 14 *comments* to FERC.

"AET transfers occur relatively infrequently, and at relatively low volumes with low associated cost when they do occur," DMM said in the comment filing.

However, DMM said it still has outstanding concerns about the feature, such as its potential to allow BAAs to inappropriately lean on the WEIM footprint for capacity, and the possibility for surcharges to apply to WEIM transfers that are not the direct result of selecting the program, the order says. However, neither of these concerns requires immediate action: Each could be addressed in future revisions of the AET feature, DMM said, according to the order.

As part of the approved order, CAISO will also adjust the AET feature to exempt surcharges that occur when a BAA fails the resource sufficiency evaluation, as long as the BAA works with its reliability coordinator to ensure reliable operations, the order says. This change will help ensure WEIM participants do not need to weigh potential surcharge liabilities against prudent reliability-driven actions, the order says.

When CAISO launches its Extended-Day-Ahead Market next year, participants in that market will also be able to access the AET feature, the ISO said in the Sept. 23 filing. ■

ERCOT: New Ancillary Service Key to Resource Adequacy

By Tom Kleckner

ERCOT staff have told the Public Utility Commission they plan to file two urgent protocol changes with the Board of Directors in their latest push to design a new ancillary service that strengthens the grid's resource adequacy.

Staff said the new service, now branded Dispatchable Reliability Reserve Service (DRRS) Ancillary Service Plus, will provide the most reliability benefit at the least cost compared to other market design options. Citing an Aurora Energy Research *report* commissioned by the grid operator, they said the service's design adds more cost-effective dispatchable capacity and provides greater resource adequacy benefits in different load and extreme weather conditions (*55797*).

ERCOT's Keith Collins, vice president of commercial operations, told the commissioners during their Nov. 14 open meeting that staff have been working on "refinements" to DRRS after getting feedback from the PUC, Independent Market Monitor and stakeholders. Collins said the grid operator plans to file two *protocol changes* and an accompanying revision to the Nodal Operating Guide in November.

Staff plan to ask the board during its Dec. 8-9 meetings to designate the changes as a board priority, Collins said.

The first Nodal Protocol revision request (NPRR) will establish DRRS as an ancillary service that addresses supply and demand forecast uncertainty and reduces reliability unit commitments. The second change will describe a proposed energy storage resource participation model and a "release factor" concept that allows the service to also support resource adequacy. Both designs open DRRS to online resources instead of just those offline.

Mandated by a *2023 state law*, DRRS procures reserves of dispatchable power through the day-ahead market to ensure grid reliability during periods of uncertainty. Its sources include thermal generation, batteries and large loads that can come online within two hours and are able to provide service for at least four consecutive hours.

ERCOT's Keith Collins briefs the PUC on the planned Dispatchable Reliability Reserve Service. | *AdminMonitor*

The stakeholder-led Technical Advisory Committee is expected to make a recommendation on DRRS' design by the board's June 1-2, 2026, meeting. DRRS originally had a 2024 go-live date, but ERCOT told *RTO Insider* that implementation is expected to take 24 to 30 months after a design is approved.

PUC Chair Thomas Gleeson, saying he and his fellow commissioners are not "prone" to curse from the dais, still uttered what he called a "four-letter word": PCM. It was a reference to the late performance credit mechanism pushed by former Chair Peter Lake, which was likened by many to a capacity construct and a verboten concept in these parts because of ERCOT's energy-only market. (See *Texas PUC Shelves PCM Design Over Lack of Benefits*.)

Gleeson asked Collins to explain how DRRS Ancillary Service Plus differs from the PCM. Collins used an analogy involving whales and fish to point out that the huge mammal with fins flopping in the surf is not the fish it appears to be.

"Unfortunately, when you develop something new and innovative, people tend to look for things that look alike and will say, 'Well, it looks like PCM' or 'it looks like capacity markets,'" he said. "When you get down to the actual mechanics of actually how it works, they're very different."

The PCM was a forward-procurement mechanism designed to generate credits for thermal resources, Collins said. DRRS AS Plus will perform like all ERCOT ancillary services in that it will be procured in the day-ahead and real-time markets, the latter happening once Real-time

Co-optimization + Batteries (RTC+B) is deployed Dec. 5.

Stoic Energy principal Doug Lewin, who monitored the meeting and shared a live thread, didn't agree with Collins.

"Collins is working hard right now to differentiate between PCM and DRRS [AS] Plus," he wrote. "But they're different in degree, not in kind. And in degree, only barely."

According to the Aurora report, ERCOT's "status quo" market design will lead to reliability challenges under both moderate and high-load growth scenarios. It said with 22 GW of data center load by 2030 and 60% of the facilities participating in demand response, the chances of load shed during Winter Storm Elliott in 2022 and the 2023 heat wave would have been zero.

"When you have more data centers, you have more flexibility," Collins said.

ERCOT will host a workshop on the Aurora report at its Austin headquarters *Dec. 17*.

Braunig Outage to End in December

ERCOT staff told the commission that CPS Energy's Braunig Unit 3 is expected to return to service by Dec. 15 after an extended outage following the grid operator's decision to enter a reliability-must-run (RMR) contract with the aging gas unit (*55999*).

The 400-MW unit, which went online in 1970, has nearly completed a maintenance outage that began in March. CPS Energy soon discovered it needed to replace a boiler superheater header, which required steel from South Korea and Italy. The header was built in North Carolina and installed in October. All welding, X-ray examinations and hydrostatic pressure testing have been completed, said ERCOT's David Kezell, director of weatherization and inspection.

"All of that seems to be working fine," he said.

The expenses are piling up, though. The Unit 3 outage is expected to cost $32.9 million when it is completed after Thanksgiving. The grid operator has accrued more than $31.8 million in approved costs through June for CPS capital investments and fuel expenses. A 10% incentive factor is applied to other eligible spending, which eventually will exceed the cost of the maintenance outage.

What's Next

The grid operator plans to file two protocol changes and an accompanying revision to the Nodal Operating Guide in November. Staff plan to ask the board during its Dec. 8-9 meetings to designate the changes as a board priority.

ERCOT attorney Nathan Bigbee, tag-teaming with Kezell, said the 15 mobile generators Houston utility CenterPoint Energy loaned to the San Antonio region have all been installed and synchronized to the grid. Three of the units are dealing with power-control issues, but the other 12 are available for dispatch during emergency conditions.

LifeCycle Power, the generators' provider, is exploring options to address voltage ride-through events, Bigbee said. However, he said the units are not expected to operate frequently.

"Our priority right now is getting these units commissioned," Bigbee said.

ERCOT, CPS and LifeCycle entered a contract that runs through March 2027 and costs about $51 million for the entire term. The grid operator has piled up nearly $27 million in costs through October.

Under the *contract*, ERCOT will be able to dispatch the units only during actual or expected emergency conditions. The costs (an estimated $51 million) will be uplifted to qualified scheduling entities representing load on an hourly load-ratio share basis.

The ISO can terminate the contract early if transmission facilities addressing a regional constraint are completed ahead of schedule.

CPS Energy said in 2024 that it was planning to retire all three Braunig units in March 2025, but the ISO determined that Unit 3 was needed for reliability reasons. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

ERCOT's RMR contract with Braunig is its first since 2016, when it entered into an agreement with NRG Texas Power over a previously mothballed gas unit near Houston. The contract ended in 2017, thanks partly to transmission facilities that increased imports into the region. (See *ERCOT Ending Greens Bayou RMR May 29*.)

CenterPoint SRP Approved

The commission approved CenterPoint's *proposed system resiliency plan*, a three-year, $129.7 million initiative, after Commissioner Courtney Hjaltman said the original filing lacked enough data to support the utility's main vegetation-management measure (*57579*).

Hjaltman trimmed more than $10 million from the plan by accepting an estimated cost of $137.9 million in a supplemental filing; CenterPoint's original budget was listed at $141 million. She cut an additional $8.2 million from the revised figure by striking 350 projects with benefit-to-cost ratios less than 1.0 or without ratios.

CenterPoint said its resiliency plan mitigates the effects of extreme wind, water and temperature events. The plan strengthens the physical security and cybersecurity of its infrastructure and technology assets and the ability to monitor and respond to resiliency events.

The PUC also approved a pair of orders related to the $10 billion Texas Energy Fund.

- It endorsed *staff's recommendation* to enter into grant agreements with four cooperatives, totaling $60.6 million, for reliability, resiliency and facility weatherization projects. The grants are the 14th awarded through the TEF's Outside ERCOT Grant Program of the $10 billion Texas Energy Fund. The program has granted more than $680 million to projects that update transmission and generation infrastructure and provide vegetation management (*58492*).
- The commission also accepted *staff's recommendation* to accept an extension request from Hull Street Energy, an applicant for a prospective loan under the TEF's In-ERCOT Loan Generation Program. The private-equity firm requested an extension to Dec. 31, 2026, saying a "confluence of market forces" outside its control made it unlikely to enter into a loan agreement with the PUC (*56896*). ■

ERCOT Stakeholders Endorse $9.4B 765-kV Build

Staff Preparing for Post-RTC+B Go-live Issues

By Tom Kleckner

ERCOT stakeholders have endorsed a 1,109-mile, single-circuit 765-kV backbone transmission project that is expected to cost nearly $9.4 billion in capital, making it the largest initiative for the grid operator in decades.

The Texas 765-kV Strategic Transmission Expansion Plan (STEP) Eastern Backbone project is so large that some stakeholders referred to it with an uncapitalized term not found in the protocols.

"This project falls into the category of just a really big ass project," the R Street Institute's Beth Garza, who represents the Consumer segment, said during the Technical Advisory Committee's Nov. 19 meeting. "It's really big. It has the potential to be very impactful."

The project involves four transmission service providers (American Electric Power, CenterPoint Energy, CPS Energy and Oncor) who will build seven segments of the extra-high-voltage transmission lines, four 765-kV substations, 11 765/345-kV transformers, and 69 765- or 345-kV circuit breakers. The result will be a rectangular network from Northeast Texas down to the Coastal Bend.

The backbone project dwarfs ERCOT's Competitive Renewable Energy Zone program, which was completed in 2014 at a cost of $6.9 billion. The project came in $2 billion over projections, but the 3,600 miles of 345-kV CREZ lines freed up more than 23 GW of wind capacity in West Texas.

The 765-kV STEP was developed in 2024 along with ERCOT's *Regional Transmission Plan* to address load projections of 150 GW — 65 GW above its current demand peak — in 2030 on an already congested system. ERCOT staff said the 765-kV backbone would enable power to flow more efficiently through long-distance transmission from resource-rich regions to urban load centers. (See *765-kV Lines in West Texas Inch Closer to Reality*.)

Prabhu Gnanam, ERCOT's director of grid planning, said the Eastern Backbone, a subset of the 765-kV STEP Core Plan, addresses the statewide EHV reliability needs identified in the RTP. He said the RTP's sensitivity analysis indicated major portions of the Core Plan would still be needed, even with 20 GW less load.

Why This Matters

ERCOT's proposed 1,109-mile, 765-kV Eastern Backbone project involves four utilities and a projected $9.4 billion in capital capital costs, making it the largest ERCOT initiative in decades. The grid operator says the 765-kV transmission lines will enable power to flow more efficiently on an already congested system.

TAC endorsed the project in a 23-2 vote, with two abstentions. South Texas Electric Cooperative and Brazos Electric Power Cooperative both voted against the measure.

STEC's John Packard questioned the "unprecedented" speed of the project, which was submitted to ERCOT's Regional Planning Group (RPG) in July before being recommended by staff. He said the proposal also lacks an accompanying legislative or regulatory mandate.

"I think a lot of this load that's forecast … doesn't hit ERCOT until 2030 to 2032, so there's other projects that are going to be carrying some of this large load in the meantime," he said. "I think it only makes sense to take maybe a more measured approach and incorporate some of these policy initiatives."

"Generally, I'm in favor of transmission. In order to have a truly competitive market, we need robust and reliable transmission," said Nick Fehrenbach, manager of regulatory affairs and utility franchising for the city of Dallas. "My real concern, though, is 1,100 miles of new right of way. We can get [construction permits] and get it built in five to seven years … but this price is going to creep as we start acquiring that right of way."

The project's price tag easily met the $100 million threshold to be classified as a Tier 1 project, requiring approval by the ERCOT Board of Directors.

TAC endorsed two other RPG-recommended Tier 1 projects, adding them to the combination ballot that is the committee's answer to a consent agenda:

- Oncor and AEP's proposed 104-mile, single-circuit 765-kV project in West Texas that closes the western end of ERCOT's EHV backbone. The Drill Hole-Solstice project has a projected capital price tag of $742.2 million.
- Oncor upgrades to a 345/138-kV switch and 9 miles of 138-kV line, and 13 new miles of 345-kV lines in far West Texas. The project has an estimated capital cost of $110.6 million and completion date in December 2026.

All three projects will require construction permits from the Texas Public Utility Commission.

ERCOT Looks Past RTC Go-live

With the Real-time Co-optimization plus Batteries (RTC+B) project barreling toward its Dec. 5 go-live date, attention has begun to turn to the stabilization period after the market mechanism begins *procuring energy and ancillary services every five minutes*.

Matt Mereness, ERCOT | © RTO Insider

The committee and ERCOT's Matt Mereness, chair of the RTC+B Task Force, discussed who would be responsible for monitoring and tracking the market's data and issues, and for how long. Mereness said the task force could be sunset or incorporated in another stakeholder group.

TAC Chair Caitlin Smith, with Jupiter Power, pointed out ERCOT has been setting aside several other market designs to observe RTC's effects on the market.

"I feel like as soon as RTC goes live, you're going to have maybe even more on your plate, more varied things," she told Mereness. "All the things you've said, 'We'll get back to it after RTC.' All the things you've said, 'We can revise as we go along with RTC and have data.'"

Harika Basaran, the Texas PUC's director of market analysis, noted RTC is one of ERCOT's performance measures. She pointed out that ERCOT will have initial RTC settlements but could have an old system using data from the new system. She suggested a "stabilization piece and the writing out of issues and getting those assigned to a safe landing spot or dealing with them there."

"We could do that," Mereness said.

Smith agreed that the proposal makes sense. Protocol revision requests would go through the normal process, but the task force or its successor would handle the "plan and timeline for what pieces need to be done next, and maybe some issue-spotting is brought there too."

Mereness said staff have filed a notice with the PUC alerting it to "likely" protocol violations in three of the RTC's 150 or so reports. One of the reports prints $9,000 prices at the cap, even though the cap was reduced to $5,000 after February 2021's Winter Storm Uri. Staff are working on an urgent Nodal Protocol revision request to remedy the problem.

"In the meantime, we're going to fix our systems to not print $9,000 prices as soon as we can after go-live," he said. "In a way, we're going live with something that may or may not show up because it only shows up in a load-shed type event."

"See you on the other side," Mereness said in closing his presentation.

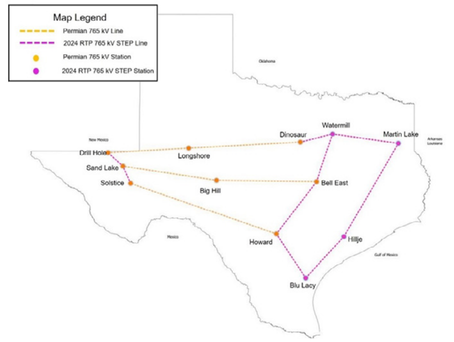
Large Loads 'Consuming' ERCOT

ERCOT has added 142.2 GW of interconnection requests by large loads during 2025, staff told TAC, pushing the total queue to 225.8 GW as of mid-November.

Over 193 GW of those requests are by standalone facilities, with co-located loads accounting for the rest.

"We thought [83 GW] was a lot," ERCOT's Julie Snitman said.

Nearly a quarter of the requests (91 of 366) are from loads larger than 1,000 MW apiece; the other 275 are at least 75 MW each. Developers submitted 78 requests during the second quarter and have already filed half of that midway through the fourth quarter. At the same time, staff said a little more than 5,000 MW of large



The 765-kV Eastern Backbone involves AEP, CenterPoint Energy, CPS Energy and Oncor. | *ERCOT*

loads have been "observed" as being energized.

"ERCOT is having a problem getting started with cluster studies because everybody keeps submitting new large loads to them," Longhorn Power's Bob Wittmeyer, who chairs TAC's Large Load Working Group, told stakeholders. "Large loads are effectively consuming all of their resources by adding more large loads."

"That's really heating up our bandwidth," ERCOT's Agee Springer, senior manager of grid interconnections, said in agreement.

Several stakeholders questioned how staff can be sure the large loads will eventually show up. Kristi Hobbs, vice president of system planning and weatherization, said she has been "very active" in the PUC's large load rulemaking process.

"It's very important that we work with the commission to get this rule right because that will indicate what we will include in our forecast going forward," she said.

ERCOT is partnering with Texas A&M's Engineering Experiment Station to develop detailed generic dynamic models of large loads and how they can change their power output during and after grid disturbances. Wittmeyer said he recently attended a *conference* on interconnecting large loads in ERCOT, held by the university's College of Engineering, that was "pretty well attended by a bunch of data center folks."

Ross' Last Meeting

The meeting marked the last for AEP's Richard Ross, the longest-serving TAC member. Ross has represented AEP on the Investor-Owned Utility segment for about 23 years, he said.

Richard Ross, AEP | © *RTO Insider*

"He's not going anywhere. He's not retiring," Smith assured members.

Ross said he will continue to supply a word or theme of the day — a staple at both TAC and SPP Markets and Operations Policy Committee meetings — in the future.

His final word of the month? "Ventilate."

"Gratitude" had been suggested before Ross joined the meeting. But "no, that's not the theme at all," he said. "If you want to go with it, that's fine, but the word of the month is 'ventilate' … you know, we've ventilated on ERCOT's opinion.

"Use 'ventilate,' 'gratitude,' whatever it takes to get us to 2 o'clock," Ross said, referring to the meeting's scheduled close.

"Unless anybody else has gratitude or ventilating or is retiring from TAC, I think we can adjourn," Smith said in ending the meeting.

NPRR Comments Rule

The committee endorsed a protocol change (*NPRR1298*) that would require comments on proposed rule changes to be delivered to ERCOT within 14 days of the revision request's posting. Comments posted after the 14-day comment period can be considered at the Protocol Revision Subcommittee's discretion.

The measure passed 21-1, with six abstentions. Ross was the only member voting against it.

"I don't think it was necessary," Ross, who said he doesn't like abstaining, observed in explaining his vote to Basaran. "We've worked well without this for many years … I don't know if we had this rule in place for the last 20 years if it would have adversely impacted anything."

TAC approved a request by BHER Power Resources for a permanent site-specific exemption from complying with metering protocols by placing it on the combination ballot. The company said its Falcon Seaboard facility in Big Spring was built in such a way that it can't meet a 500-kW maximum load limit requirement for auxiliary distribution factors. The facility has been operating for 35 years. ■

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

NRG Secures 3rd Loan from Texas Energy Fund

The Texas Public Utility Commission has signed a sixth loan agreement through the Texas Energy Fund's in-ERCOT loan program, up to $370 million for a new 455-MW gas-fired plant in the Houston area.

The unit would more than double the capacity of NRG Energy's existing Greens Bayou Generating Station. NRG has a large 78-MW steam turbine unit, three 54-MW gas or fuel turbine units and three 64-MW gas turbines, totaling 354 MW of capacity.

Greens Bayou Unit 6 is expected to come online in 2028. The TEF's In-ERCOT Generation Loan Program has now produced loans for more than 3,500 MW of dispatchable gas generation. That is more than a third of the way to the $10 billion fund's 10,000-MW objective.

NRG's president of business and wholesale operations, Robert Gaudette, said reliable power is "essential" to keep fueling Texas' "unprecedented" growth.

"Our investment at Greens Bayou reflects NRG's commitment to delivering dependable, dispatchable generation when Texans need it most," he said in a *statement* Nov. 20.

Total project costs under the loan agreement are estimated at less than $617 million. The PUC is providing a 20-year loan for up to $370 million, or 60% of total cost, at 3% interest. The loan's term runs through November 2045, and Greens Bayou 6 must meet *minimum performance standards*.

The loan is the third that NRG has secured from the in-ERCOT program, which has been allocated $7.2 billion of the total fund. The Houston-based generator's other projects were granted $778 million in loans for 1,177 MW of nameplate capacity. (See *NRG Energy Secures $216M Loan from TEF* and *NRG Secures $562M Loan from Texas Energy Fund*.)

The PUC is vetting 11 additional applications, representing 5,406 MW of gas generation, for TEF's in-ERCOT program. ■

— Tom Kleckner

NRG Energy has received three grants from the Texas Energy Fund. | *NRG Energy*

IESO Open to Broader Range of Storage Technologies in Long Lead-time Procurement

Hydro Redevelopments Ruled Out

By Rich Heidorn Jr.

IESO is considering a broader range of long-duration energy storage technologies in its upcoming long lead-time procurement but will not include hydroelectric redevelopments, officials told stakeholders at an *engagement session* Nov. 19.

ISO officials also *said* they are considering changes to a termination provision and additional flexibility on outages.

IESO created the long lead-time procurement (LLT RFP) because energy storage resources such as compressed air and pumped hydro require longer planning cycles than the four-year lead times for resources offering in the pending Long Term 2 (LT2) procurement. The ISO plans to seek 600 to 800 MW of capacity and up to 1 TWh of energy from resources requiring at least five years of lead time in a solicitation expected about Q4 2026.

The energy stream of the LLT RFP will be open to new build hydroelectric facilities with a nameplate capacity of at least 1 MW that do not include pumped storage. LDES projects will be eligible for the capacity stream.

Eligible Technologies

In response to stakeholder requests for greater flexibility, IESO said it is considering increasing the limit on Class II LDES technologies to 200 MW from 100 MW and lowering the minimum to 10 MW from 50 MW.

Stakeholders said the proposed 50-MW minimum project size and a 100-MW cap would limit the procurement to only one or two LDES projects. Stakeholders proposed minimum project sizes as low as 1 MW.

"Most likely, with the current setup, we would be procuring only one project," acknowledged IESO's Jasdeep Kahlon. "However, we maintain that the need for a cap is required to limit risk related to these less proven technologies."

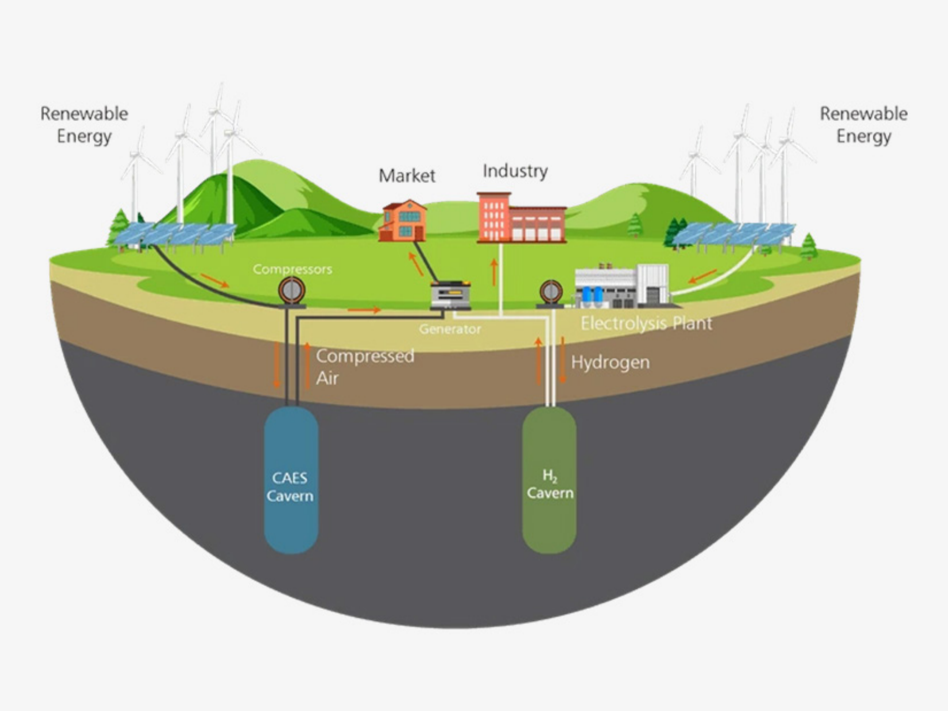


Diagram of a compressed air energy storage (CAES) system using renewable electricity to store compressed air in underground salt caverns, which can be combined with green hydrogen stored in co-located caverns to generate electricity. | *Corre Energy/Long Duration Energy Storage Council*

Why This Matters

IESO created the LLT procurement because storage resources such as compressed air and pumped hydro require longer planning cycles than the four-year lead times for resources offering in the pending Long Term 2 procurement.

Kahlon said the ISO doesn't see the benefit of dropping the minimum size below 10 MW, "as the minimum size requirement is intended to ensure participation from commercial-scale projects and not intended to procure less proven pilot-scale technologies."

Hydro Redevelopments

The ISO also rejected participation by hydro redevelopments, saying it has received limited information about potential projects and noting that "historical redevelopment timelines are highly variable," with some taking up to six years and others being completed in less than four years.

It also said there is "little evidence to justify" the 40-year contracts planned for the LLT procurement for hydro redevelopments and said such projects should seek 20-year contracts under the LT2 RFP scheduled for early 2026. (See *IESO Officials Deny Favoring Gas Resources in Upcoming Procurement*.)

Optional Termination

At an engagement session last month, the ISO said it would seek to reduce risks in the procurement by reserving the right to reject proposals that are too expensive and allowing the ISO and generation developers to cancel deals in the first few years. (See *IESO Seeks to Manage Risks in Long Lead-time Procurement*.)

The ISO said the termination option could be exercised by IESO or the project developer in the first two or three years after the contract date.

Stakeholders said the termination option would increase developers' risk and make financing more expensive, while reducing participation levels. They also said it could discourage participation by Indigenous communities that "typically invest in projects with a high likelihood of reaching commercial operation and generating long-term revenue."

The ISO said it would specify the circumstances that could result in a termination — such as failure to meet key milestones or obtain permits — and the date on which the optional termination right would lapse. It also is considering the termination payment that would apply when IESO or the supplier terminates and whether suppliers that terminate projects would be eligible for future procurements.

Reserve Prices

IESO proposed to use reserve prices — a confidential price threshold — to ensure it doesn't pay too much for energy or capacity in the solicitation. The ISO said the thresholds will be based in part on prices in the first window of the LT2 procurement and differences in the obligations of LT2 and LLT resources.

Many stakeholders opposed the proposal, saying prices from recent IESO procurements are not a good comparison due to the lifespans of the technologies procured.

The ISO said reserve prices will ensure the procurement is cost effective and broadens Ontario's supply mix while addressing the uncertainty of developing LLT resources. "The potential benefits associated with long lead-time resources, along with the longer lifetimes, will be considered in the determination of a reserve price," it said.

Outages

IESO said it is developing a proposal to provide additional flexibility for "midterm extended outages" and aligning them with annual planned maintenance outage requirements for LDES technologies. IESO had proposed a single outage of up to 12 months after the 20th anniversary of the contract. (See *IESO Ups Capacity Target for Long Lead-Time Resources*.)

Stakeholders told IESO it should consider permitting suppliers to take outages beginning after year 10 of the contract term and allow them to take multiple outages adding up to 12 months. Some said technologies using mechanical storage, such as compressed air energy storage (CAES) and pumped hydro, should be able to take an annual planned outage for up to 10 business days, similar to that for natural gas generators under the LT2(c-1) contract.

Early In-service Provisions

ISO officials said they may allow developers to begin commercial operation before the planned commercial operation date. The request would have to be filed no earlier than three years after the contract date and at least one year before the expected COD. Commercial operation could be no earlier than five years after the contract date.

IESO approval would depend on deliverability and system needs (e.g., Annual Planning Outlooks showing a need for energy arising earlier than capacity).

Environmental Approvals and Permitting

Because some LDES technologies are new to Ontario, the ISO said developers should consult early with the Ministry of Environment, Conservation and Parks regarding the environmental assessments and permitting requirements that will apply.

Team Member Experience


IESO's Jasdeep Kahlon | *IESO*

Kahlon said IESO is considering providing more flexibility to the team member experience requirements.

Under IESO's proposal, hydro developers must have at least two team members with experience with a hydro facility with a nameplate capacity of at least 1 MW that has achieved commercial operation in Canada or the U.S. within the past 15 years.

Stakeholders said the proposed requirement may create obstacles for mature resource types such as pumped hydro because no such projects have been commissioned within the past 15 years.

"For pumped storage projects, the requirement to have developed a 'same technology' project should include conventional hydroelectric facilities, as pumped storage is a direct variant of hydroelectric generation and the relevant development expertise is transferable," Andrew Thiele, senior director policy and government affairs for Energy Storage Canada, said in *written feedback*.

Jim Beamish, head of planning and analysis for Access Capital Corp., said requirements should be functional, as they were in the early 2000s when Ontario started procuring wind and solar generation.

"I recognize your concerns," Beamish said, "but the ISO really needs to look back at that and say, 'Well, what didn't work?' Because … there have been no CAES projects that reached commercialization in in the last 15 years."

"The intent here is definitely not to limit participation through team member experience," responded IESO's Danielle D'Souza. "It's really meant to just ensure that we have the best chance of these projects getting across the finish line."

Municipal Support Resolutions

Paul Ernsting, of Peterborough Utilities, said it may be challenging for developers to obtain required support resolutions from municipalities because of 2026 elections.

"If you've got less than three-quarters of council coming back, then that's a lame duck period. They don't do any decision-making during that period," he said.

"You've got your elections happening Oct. 26. Once everyone's elected, they don't start meeting until mid- to late November at the earliest. … That can be a tight timeline for this procurement, as well as for LT2 window two."

D'Souza welcomed the feedback. "We've heard that it's very different from municipality to municipality," she said.

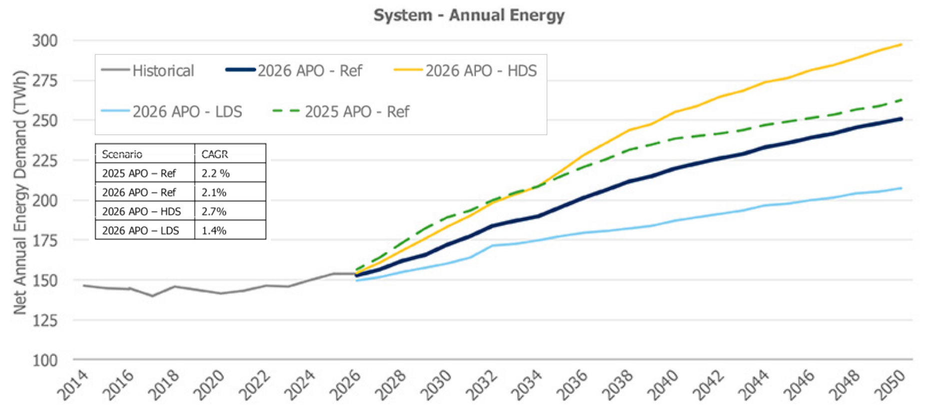
Next Steps

The IESO asked stakeholders to comment on the LLT RFP by Dec. 3 using the feedback form posted on the engagement *webpage*. ■

Citing Geopolitical Uncertainty, IESO Lowers Long-term Demand Forecast Slightly

ISO Still Expecting Rapid Load Growth over Next 25 Years, but Short-term Lag Expected

By Michael Brooks



IESO's Annual Planning Outlook will include high and low demand scenarios for the first time in its 2026 edition. | *IESO*

The *reference scenario* in IESO's 2026 Annual Planning Outlook indicates net annual energy demand growth of 65% by 2050, from just over 150 TWh in recent years to 250 TWh.

The figure represents "robust" load growth over the next 25 years, according to the ISO, but it is slightly lower than the 262 TWh (75%) predicted in *the 2025 APO*, released in April.

"While this APO reflects short-term impacts caused by current geopolitical uncertainty, the long-term forecast shows that Ontario is poised to continue growing through the 2030s and beyond — consistent with trends seen in the 2025 APO," IESO said in a presentation to webinar attendees Nov. 18.

Adam Kliber, IESO supervisor of planning models and forecasts, said there were four main drivers of the lower-than-expected demand. Among them are reduced adoption of electric vehicles and delays in large industrial "step loads" — projects typically over 20 MW that interconnect in large blocks, as opposed to slowly ramping up their growth over time.

IESO officials did not go into details about the delays, saying the underlying assumptions would be released alongside the full APO in the first quarter of 2026. The 2025 APO showed a rapid increase in two types of step loads: data centers, defined as commercial load, and the EV supply chain, including batteries. Data centers are still expected to be the main driver of load growth in Ontario.

Why This Matters

Ontario is expected to see a 65% increase in energy use over the next 25 years, but that is 4.5% less than what IESO previously predicted.

But several global situations have since led to delays in an expected ramp-up of EV production in the province. Chief among them is U.S. President Donald Trump's 25% tariff on imported auto parts, which led Honda to postpone a previously announced $11 billion expansion of its manufacturing plant in Alliston into an EV production hub.

And in late October, Honda slowed production at all its North American plants because of a dispute between the Netherlands and China over the Chinese-owned, Netherlands-based semiconductor manufacturer Nexperia. The dispute has thrown a *semiconductor supply chain* still recovering from the post-COVID-19 pandemic shortage into disarray. Honda has since *resumed normal operations* after securing enough chips, but that could change as the conflict continues.

Umicore Precious Metals Canada had also announced plans to build battery components for EVs at its Loyalist Township plant, with the federal and provincial governments contributing a combined $1 billion into the facility. That plan was paused even before Trump re-entered office, and the company has no intention of starting construction any time soon, as lower metal prices and EV demand globally led to *reduced revenue*.

Another factor leading to the lower growth is IESO's "new electricity demand-side management framework and its considerable contributions on slowing demand growth by helping families and businesses use electricity more efficiently." The ISO is also projecting lower population growth, though Kliber emphasized that the data "indicate a very high growth overall."

The geopolitical uncertainty is reflected in IESO's high and low demand scenarios, to be included in the APO for the first time to comply with a directive from the Ontario Minister of Energy and Mines. (See *Ontario Energy Plan Gives IESO Long 'To Do' List*.)

While the 2025 APO indicated a 2.2% compound annual growth rate and the 2026 reference scenario shows 2.1%, the high demand scenario shows 2.7%.

The ISO did not go into detail about the assumptions for each scenario, but officials also presented how it is developing the 2027 APO's scenarios, with explanations for each. The reference scenario represents "high-confidence policy, government announcements and continuing trends," while the high and low demand scenarios vary based on economic growth and consumer-driven electrification trends.

Under the reference scenario, EV adoption would continue to grow but is lower than the federal government's targets, with the low scenario reflecting even lower adoption rates. Under the high demand scenario, the government's targets are met. ■

IESO Tweaking Make-whole Payments for Operating Reserves

By Rich Heidorn Jr.

IESO is proposing rule changes to eliminate unwarranted make-whole payments (MWPs) to operating reserve (OR) providers under Ontario's nearly eight-month-old Market Renewal Program.

"These are very specific and limited circumstances and only became apparent after the Renewed Market 'go-live' and relate to the interaction between payments for energy and operating reserve," the ISO *said* at an engagement session Nov. 21.

MWPs are intended to incentivize market participants to follow their schedules by compensating a resource for the financial difference between its actual dispatch and what it would have been based on its offer curves and LMPs.

Although improved alignment between schedules and LMPs under the new market has reduced the need for MWPs, they still are needed because of manual out-of-market actions taken for reliability and differences between scheduling passes and pricing passes.

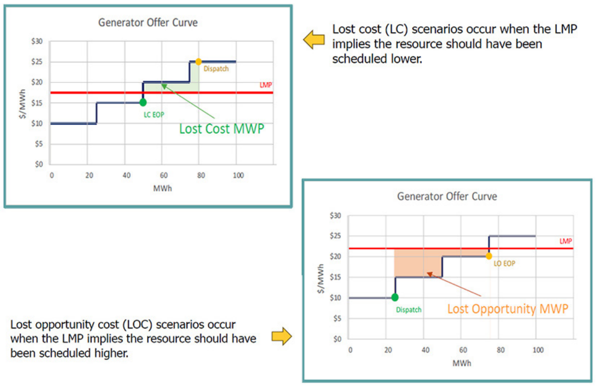
Real-time MWPs should represent a resource's physical capabilities and are calculated considering co-optimization of energy and OR. IESO calculates payments for lost costs and lost opportunity costs (LOCs) based on economic operating points (EOPs), which reflect the output a resource could have achieved based on its physical capabilities and LMP, under actual market conditions.

EOPs are based on offers and bids, resource-specific characteristics and LMPs. Lost cost scenarios occur when the LMP indicates a resource should have been scheduled lower.

The Renewed Market, which launched May 1, created a financially binding day-ahead market (DAM) and about 1,000 generation, load and intertie pricing nodes to replace its provincewide price. (See *Ontario Nodal Market Nearing 'Steady State' After Nearly 4 Months*.)

Why This Matters

Eliminating excess make-whole payments is important to IESO's Renewed Market, which the ISO says will save $700 million over a decade by reducing out-of-market actions and improving efficiency.



Lost cost and lost opportunity scenarios | *IESO*

Hok Ng, IESO's senior manager of market development, identified three types of inappropriate real-time make-whole payments:

EOPs and 'Forbidden Regions'

Some hydro generators have "forbidden regions" in which they cannot maintain steady operation without damaging their equipment and thus must ramp through.

Although the forbidden regions are considered in dispatch schedules, they are not reflected in determining the EOPs on which MWPs are based.

The energy market accounts for cases in which EOPs are physically unattainable with a settlement process that subtracts the portion of the MWP resulting from an energy schedule in a forbidden region or at the upper boundary.

IESO's proposed rule change (MR Ch.0.9 Section 3.5.6) would add a similar adjustment for OR MWP calculations.

OR Ramping in LOC EOP Calculations

An inconsistency between OR ramp constraints in the dispatch scheduling optimizer and EOP calculation engine is overstating EOPs beyond what resources can physically perform, resulting in unwarranted MWPs.

The EOP calculation engine is missing constraints containing the interval-to-interval energy ramp impact on available OR ramp.

IESO's proposed revision would add equations including the interval-to-interval change in energy to the LOC EOP OR calculations (MR Ch.0.7 App. 7.8).

MWPs not Offsetting Energy and OR Products

Make-whole payments are intended to keep a resource whole for following dispatch instructions that are co-optimized across energy and reserve products, such as 10-minute spin, 10-minute non-spin and 30-minute reserves.

But the current LOC MWP settlement is ignoring profits realized for the same capacity in the market, resulting in market participants being paid twice for the same megawatts.

The proposed Market Rule Amendment (MR Ch.0.9 Section 3.5) and Market Manual changes (MM 0.5.5 Section 2.7) will clarify how the offsetting should be calculated.

Next Steps

IESO requests comments on the Adjustments to RT MWP *engagement* by Dec. 1 via its *feedback form*. The ISO will respond to feedback and present a red-lined draft of the market rule amendments on Dec. 16.

IESO's Technical Panel will conduct an education session on the changes on Dec. 2 with a vote to recommend to the IESO board scheduled for Feb. 10, 2026.

Implementation is planned for April 2026. ■

Collaboration Key to Energy Affordability, Say U.S. and Canadian Officials

By Jon Lamson

BOSTON — Energy affordability and regional collaboration dominated talks at the New England-Canada Business Council's annual Executive Energy Conference on Nov. 19-20.

While the event featured similar themes and rallying cries as the 2024 conference, calls for collaboration have taken on a different tone amid heightened tensions between Washington and Ottawa. (See *US, Canadian Leaders Discuss Affordability of Energy Transition*.)

Massachusetts Gov. Maura Healey (D) and Nova Scotia Premier Tim Houston attended the event and emphasized the strong ties between the people and economies of the Northeast states and provinces.

"Our energy future is inextricably tied to Canada's," Healey said, noting that states and provinces are in regular communication on energy policy and planning through the Northeast International Committee on Energy, which reconvened in 2024.

She highlighted a *resolution* passed at the Annual Conference of New England Governors and Eastern Canadian Premiers during the prior weekend reaffirming "the importance of continued regional collaboration, including interregional information sharing, planning and analysis on energy matters."

"We look forward to continuing to build on that and to strengthen the ties that bind us, especially on energy transmission," she said.

Nova Scotia Premier Tim Houston addresses the conference. | © *RTO Insider*

Healey directly criticized the tariffs imposed by President Donald Trump for creating "needless friction" between the countries and driving up costs throughout energy infrastructure supply chains.

"Higher infrastructure costs ultimately make higher energy costs for our people, and it's our businesses, our consumers and our residents who lose out," Healey said. "Lift these tariffs, Mr. President, and lower housing costs and lower energy costs for the American people."

Houston touted the strength of cross-border relationships in the Northeast while emphasizing his commitment to transforming Nova Scotia into an "energy superpower." The province has outlined plans to scale up offshore wind and offshore oil and gas drilling, with an eye toward ramping up its exports.

"Nova Scotia is the next frontier in generation," Houston said. "As long as I'm in this chair, I will do everything I can to grow this industry."

Several presenters spoke about the massive potential for wind generation in the province. According to the *strategic plan* for the province's Wind West project, "Nova Scotia's already studied and identified sites [that] alone have the capacity to generate 62 GW of new electricity supply, with capacity factors of up to 60%," equal to about a quarter of Canada's total energy capacity.

The Canada-Nova Scotia Offshore Energy Regulator has *initiated* a process of issuing licenses to develop up to 3,000 MW across three areas, while leaving the door open for licenses of up to 5,000 MW.

Houston said he's confident about the viability of the sites, ports, workforce and matureness of the technology to support a large-scale wind buildout but acknowledged that questions remain about how to transport the power to markets in Canada and the U.S.

Dave MacGregor, associate deputy minister for the Nova Scotia Department of Energy, said he's "struck by the fact that we were talking about the exact same things 25 years ago — and I'm referring specifically to transmission."

But despite the challenges of the past, he expressed hope that renewed collaboration efforts finally could make transmission projects a reality.

"For the first time in close to three decades, the staff are coming to Nova Scotia to figure this out," MacGregor said. "I really have seen marked improvement, and I do see a path where New England can benefit and Canada can benefit."

Transmission paths to New England or Quebec could follow either submarine or overland routes. Several panelists at the conference advocated for a subsea path.

"We would say submarine cable all day long," said Donald Jessome, CEO of Transmission Developers Inc. "There's no engineering issues; the technology is there today."

Stuart Nachmias, CEO of Con Edison Transmission, agreed that the technology is available to support a submarine line but that there are challenges related to siting, permitting and offtake.

"Who's going to pay? That's always the issue," Nachmias said.

Phil Bartlett, chair of the Maine Public Utilities Commission, concurred, emphasizing the importance of understanding what the costs would be and how they would be shared.

Why This Matters

The large-scale development of renewable resources throughout the Northeast likely will rely in part on successful collaboration between states and provinces on transmission projects.

"It's going to take regional collaboration. I think you would need multiple states interested in a project to move forward," Bartlett said.

He expressed optimism about the recent increase in collaboration between the states on transmission issues, pointing to the ongoing ISO-NE Longer-term Transmission Planning (LTTP) procurement, which aims to reduce transmission constraints in Maine and help support the connection of 1,200 MW of onshore wind. (See *ISO-NE Provides More Detail on Responses to LTTP Procurement*.)

The newly established LTTP process includes a cost allocation framework, in which the costs of a solution selected by ISO-NE will, by default, be allocated by load share. The states have the option to submit an alternate cost allocation method or terminate the process.

In coordination with the LTTP solicitation, Maine has initiated a separate process to procure onshore wind in Northern Maine and a transmission line connecting the generation to a new substation that would be created through the LTTP process.

Bartlett said he expects at least five of the six New England states to participate in this separate procurement, adding that "having the states working together on these procurement issues really helps to get it done."

Bartlett said that 1,200 MW of onshore wind is just the "tip of the iceberg of what's available in Maine," and that "we consider this Phase 1 of that buildout, recognizing there's a lot more to do."

Massachusetts Gov. Maura Healey | © *RTO Insider*

'Build, Baby, Build'

Some speakers called for increased efforts to address the infrastructure constraints that limit the flow of gas into New England.

Toby Rice, CEO of the EQT, praised the Trump administration's energy policy approach and stressed the need to build more gas infrastructure to "win this AI race."

"I don't want to find out what happens if we don't win this race," Rice said.

It will be won, he said, by the country that can scale up generation most quickly. He noted that China is adding power at a far faster pace than the U.S.

"It's no longer about 'drill, baby, drill'; it's about build, baby, build, and we're hopeful that permitting reform will be a priority over the next 12 months," Rice said.

He said the growth of intermittent renewables has caused gas resource capacity factors to decline, putting strain on the economics supporting gas generation in some areas. To address the issue, he advocated for increased incentives for gas resources to be available on standby.

At the same time, he opposed capping capacity prices, saying, "We have to experience a little bit of pain for the market signals to be there."

John O'Brien, CEO of JERA Americas, said industry leaders should do more to advocate for adding gas pipeline capacity into the Northeast.

Business groups, such as the Associated Industries of Massachusetts and regional chambers of commerce, "have to be re-energized to actually take on those issues," O'Brien said. "You should take on an agenda, and the agenda might be controversial, but that's why you pay the big dues."

He said New England "should recognize that we need this infrastructure to continue to have our key industries" and pushed back on the idea that it is a foregone conclusion that the gas constraint will prevent the region from hosting data centers.

"Are we going to say, 'We're going to forgo that opportunity because we would have to expand the gas system?'" O'Brien asked.

Other speakers focused their comments on the importance of demand-side actions and reining in spending on upgrades to existing assets.

Weezie Nuara, Massachusetts' deputy secretary for federal and regional energy affairs, emphasized the "need to add transparency and scrutiny" to local transmission spending. She said ISO-NE's recent work to establish a new in-house asset condition reviewer should "help us get our hands around the largest component of [transmission] spending." (See *More Oversight Needed on Local Transmission Spending in NE, Panel Says*.)

Massachusetts Department of Public Utilities Commissioner Liz Anderson noted that, under state law, electric utilities cannot charge ratepayers for long-term gas pipeline contracts. She said the DPU is focused on addressing affordability through the means within its jurisdiction, including demand-side actions and scrutiny on infrastructure spending.

In recent years, the DPU has pursued an ambitious strategy promoting a phased electrification of the state's gas distribution network. (See *Outgoing Mass. DPU Chair Van Nostrand Discusses Gas Transition*.)

Advocates of this strategy argue that, without a focus on strategic electrification and pipe decommissioning, gas customers will be saddled with a rapidly increasing share of the gas network's fixed costs as electrification customers exit the system.

In an op-ed *published* in the *Boston Globe* on Nov. 17, former DPU Chair Jamie Van Nostrand wrote that gas supply, which accounted for about two-thirds of customer costs a decade ago, now makes up less than a third. Meanwhile, "roughly 70% of the bill pays for infrastructure, profits and taxes," he argued.

Anderson emphasized the importance of investment in energy efficiency and advanced metering infrastructure (AMI). The Massachusetts electric utilities aim to complete their deployment of AMI infrastructure by 2029. Once in place, the meters likely would enable development of time-varying rates that incentivize customers to reduce demand during peak periods.

"That's a huge untapped resource, and I think that's something we can do at the state level," Anderson said. ■

ISO-NE Provides More Detail on Responses to LTTP Procurement

By Jon Lamson

ISO-NE has published a *summary* of proposals submitted for its first longer-term transmission planning (LTTP) procurement, which is aimed at reducing transmission constraints between Maine and southern New England and supporting 1,200 MW of new onshore wind in northern Maine.

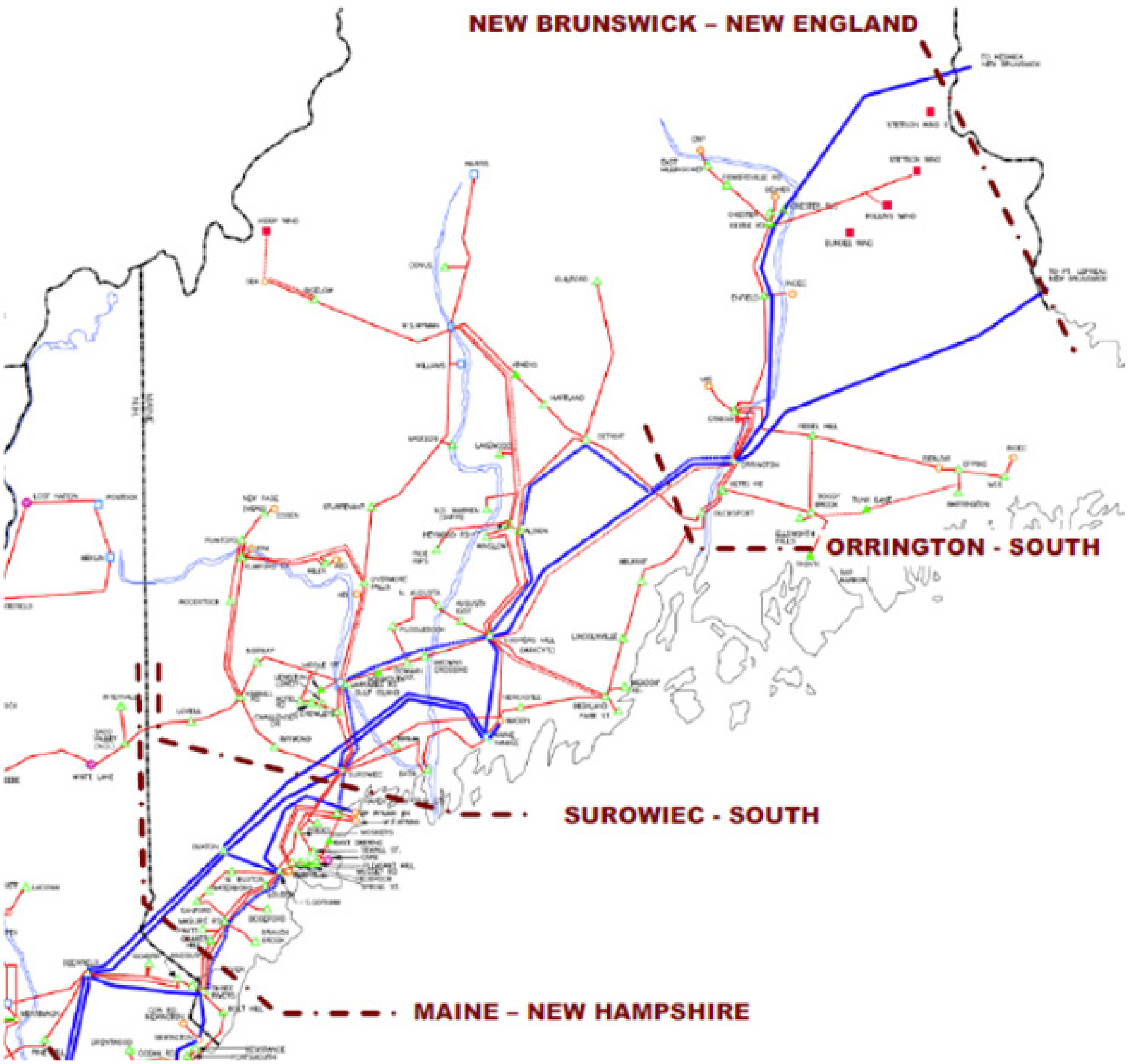
The solicitation is the first run of ISO-NE's new LTTP process, which the RTO and the New England states established to select solutions to needs identified in long-term transmission studies. (See *FERC Approves New Pathway for New England Transmission Projects*.)

Four project sponsors responded to the first LTTP procurement, submitting six proposals in total. The proposals represent "a good diversity of solution designs," ISO-NE said.

The cost projections range from $962 million to $4.04 billion, though these projections may change as the bidders and ISO-NE work to standardize the cost calculations. The expected in-service dates range from the fourth quarter of

Why This Matters

Along with easing longstanding transmission constraints in Maine, a successful first LTTP procurement could set the stage for subsequent efforts to address long-term transmission needs throughout New England.



ISO-NE Northern Maine interfaces | *ISO-NE*

2032 to the third quarter of 2035.

Four of the six projects are joint proposals submitted in collaboration with incumbent transmission owners. ISO-NE has not disclosed the identities of the companies that participated in the solicitation but noted that three of the lead project sponsors are incumbents and one is a non-incumbent.

Three of the submissions propose new HVDC lines running from Maine to Massachusetts, along with new and upgraded AC infrastructure. These proposals are:

- A 151-mile 400-kV line between Wiscasset, Maine, and Everett, Mass., with a total cost of $2.55 billion.
- A 144-mile 400-kV line between Wiscasset and Wakefield, Mass., projected to cost $2.6 billion.
- A 164-mile 320-kV line between the retired Maine Yankee Nuclear Plant (in Wiscasset) and the retired Mystic Generating Station (in Everett), with an expected cost of $4.04 billion.

The three other proposals rely on new AC lines and line upgrades. They are:

- A $2.2 billion proposal to build two new 345-kV lines totaling 70 miles, upgrade 16 miles of 115-kV line in Maine to 345 kV and upgrade existing 345- and 115-kV lines throughout Maine and New Hampshire.
- A $2.14 billion proposal that is nearly identical to the prior proposal, but with a reduction in total mileage of 345-kV upgrades.
- A $962 million proposal that includes a new 43-mile 345-kV line and three new substations.

ISO-NE said all the proposals claim to meet the minimum requirements of the RFP, which are to increase the Maine-New Hampshire interface limit to 3,000 MW and the Surowiec-South limit to 3,200 MW and support the interconnection of 1,200 MW of onshore wind in northern Maine.

For context, when the New England Clean Energy Connect transmission line is online — it is expected to achieve commercial operations this winter — the Surowiec-South limit will be 2,800 MW and the Maine-New Hampshire limit will be 2,200 MW.

ISO-NE said some proposals claimed to increase the limits beyond the minimum requirements. The RTO noted that it received proposals to increase the Surowiec-South limit to 3,800 MW and the Maine-New Hampshire limit to 3,600 MW.

All proposals would build a new substation near Pittsfield, Maine, to enable a 1,200-MW injection of onshore wind. No submissions proposed infrastructure that would accommodate more than the required 1,200 MW of offshore wind.

Separate from the LTTP process, Maine is seeking to procure 1,200 MW of wind in northern part of the state, along with transmission to connect the power to the proposed Pittsfield interconnection point in central Maine. Maine officials have expressed hope that other New England states will join in the solicitation.

Maine *issued* a draft RFP for this procurement in October (*2024-00099*), noting that the procurement "is designed to leverage the LTTP solicitation and is contingent on ISO-NE selecting a longer-term transmission upgrade project."

To select a preferred solution in the LTTP process, ISO-NE will review the projects to ensure they meet the minimum requirements, evaluate effects on other interfaces and screen for adverse system impacts.

ISO-NE also will rely on a consultant to evaluate the financial health of the project sponsors, the feasibility of the construction proposals and the cost estimates. The RTO will rely on the participating transmission owners to estimate the costs of corollary upgrades.

For projects that meet all the requirements, the RTO will quantify costs and benefits. (See *ISO-NE Releases Longer-term Transmission Planning RFP*.) Projects must have a positive benefit-to-cost ratio to be eligible to be selected by ISO-NE as the preferred solution.

ISO-NE said it expects to select a preferred solution by September 2026, noting that it is "cautious about committing to an earlier date" because the RFP "involves utilizing numerous new processes."

By default, the costs of a solution would be allocated by load, though the states could submit an alternative cost allocation methodology or opt to terminate the process following ISO-NE's selection.

If no proposals pass the benefit-cost threshold, the LTTP process allows one or more states to cover a project's costs that exceed the threshold, enabling it to proceed. ■

ISO-NE Outlines Accreditation for Active, Passive Demand Resources

By Jon Lamson

ISO-NE outlined proposed capacity accreditation for active and passive demand capacity resources at the NEPOOL Reliability Committee meeting Nov. 18.

The changes are part of the second phase of the RTO's wide-ranging Capacity Auction Reform (CAR) project, which aims to develop a seasonal capacity market and establish a marginal reliability impact (MRI) approach to accreditation that values resources based on their expected contributions to reducing energy shortfalls.

Passive Demand Capacity Resources

ISO-NE's passive demand capacity resource category is largely composed of energy efficiency resources but also includes some distributed generation.

Under the current accreditation process, ISO-NE determines seasonal qualified capacity based on estimated performance during a "fixed set of performance hours," which is intended to estimate resources' "expected contribution to resource adequacy during tight system conditions," the RTO noted in a *memo* issued prior to the RC meeting.

ISO-NE said the current set of performance hours "do not align well with hours when resource adequacy is at risk," noting that the most important hours for resource adequacy change as the resource mix changes.

Transitioning to a marginal reliability impact (MRI) accreditation process will better capture passive resource contributions during projected shortfall periods, said Clara Berger, senior market development analyst at ISO-NE.

The RTO plans to evaluate resources' MRI value based on "class-based hourly profiles for different technologies and end uses."

Each resource's final accreditation value would reflect the class values and maximum capabilities associated with each of its components, as passive resources often include multiple assets.

For distributed generation participating as passive demand capacity, ISO-NE plans to make resource-specific performance adjustments. These resources submit hourly data to the RTO, which will enable these adjustments.

Shutterstock

Berger noted that the new methodology would allow the RTO to account for performance differences between classes that are not captured under the existing rules.

"This approach incentivizes the development of PDR assets and measures that provide the greatest value to system reliability," ISO-NE said.

Active Demand Capacity Resources

ISO-NE's proposed approach to accrediting active demand capacity resources (ADCRs) is similarly focused on capturing the resources' ability to reduce shortfall.

Under the current rules, ISO-NE accredits its active demand resources based on information submitted when the resources enter the capacity market as new resources. The RTO does not update this information in subsequent auctions to account for actual performance.

"While the existing framework for ADCR qualification does not depend on ADCRs' demonstrated ability to reduce demand during stressed conditions, the proposed MRI framework for ADCRs will utilize both ADCRs' offered capability and actual performance for accreditation," ISO-NE *wrote*.

The RTO noted there is "a considerable amount of heterogeneity in ADCR performance," which creates risk that the market is procuring resources that are unable to perform at their full capacity during the most important hours.

Like passive resources, the contributions of active demand resources can depend on time of day, making it important for ISO-NE to evaluate accreditation at the most important hours for system reliability, ISO-NE said.

In the new accreditation process, the RTO proposes calculating MRI values using hourly profiles based on each resource's maximum reduction values offered over the past three years, with adjustments for the observed performance factor.

For new resources, the profile will be based on the performance of other resources in the portfolio of the lead market participant. If this data is not available, ISO-NE will base the profile on the performance of all existing active demand resources, with separate class averages for standalone resources larger than 5 MW.

Tie Benefits

Also at the RC, ISO-NE discussed how it plans to calculate tie benefits in a seasonal market.

Tie benefits are intended to quantify the reliability contributions of transmission lines connecting New England to neighboring regions. ISO-NE currently determines annual tie benefits based on summer values because the New England grid is a summer-peaking system.

The RTO noted that tie benefits associated with cross-border lines with Canada reflect "seasonal load diversity" associated with Quebec and the Maritimes' winter peaks, which enable the provinces to reliably export power when the New England grid is stressed in the summer.

In comparison, because New York and New England have similar load profiles, New York tie benefits "are mainly the result of diversity in resource outages or availability," ISO-NE noted.

As part of the CAR changes, ISO-NE plans to begin calculating tie benefits seasonally while maintaining the same basic modeling approach.

Under a seasonal framework, both New York and Canadian tie benefits will likely be driven by "diversity in resource outages or availability," instead of surplus capacity, which may reduce the overall amount of tie benefits the region can expect in the winter. ■

Unexpected Generation Loss Triggers Capacity Deficiency in ISO-NE

By Jon Lamson

ISO-NE declared a capacity deficiency on the evening of Nov. 23 after an unexpected loss of generation left the region short of its operating reserve requirements.

"The timing of the generation loss, coupled with consumer demand being slightly higher than expected, meant other resources could not immediately fill the gap," the RTO noted in a *recap* of the event, adding that its "highly trained system operators followed established procedures to maintain system reliability during the shortage period."

The deficiency conditions lasted from 5:41 p.m. to 7 p.m. The hourly real-time LMP shot up from $111/MWh prior to the event to $865/MWh between 6 p.m. and 7 p.m. The five-minute real-time LMP peaked at $2,665/MWh.

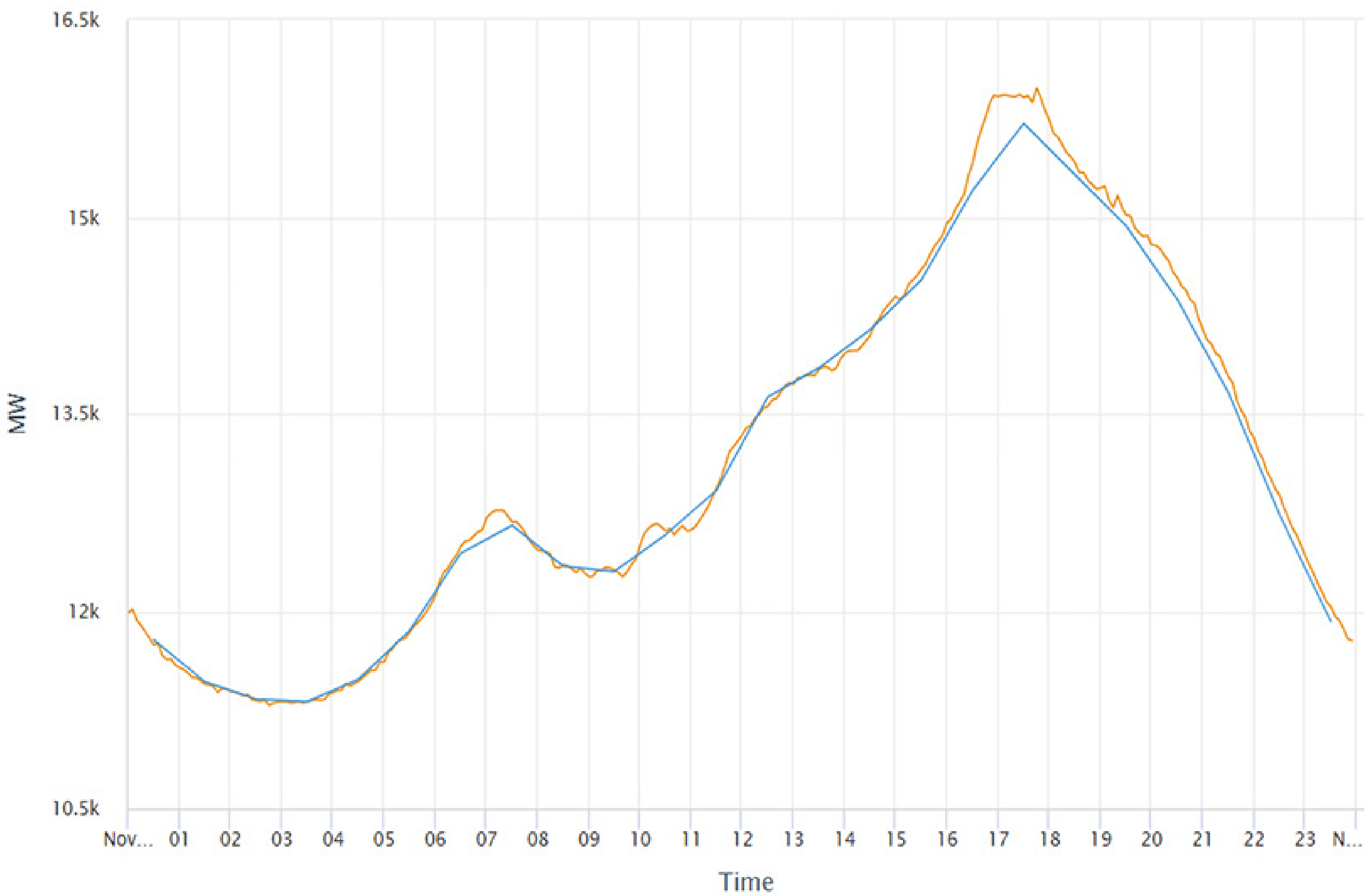
ISO-NE noted that "preliminary information indicates the system event will trigger the region's Forward Capacity Market Pay-for-Performance rules," which determine resources' charges and penalties associated with their performance during deficiency events.

This was the second capacity deficiency event of the year; the first occurred during a period of extreme heat June 24. (See *Extreme Heat Triggers Capacity Deficiency in New England*.) While the June event coincided with a peak load of more than 26,000 MW, the highest experienced in the region since 2013, the Nov. 23 event coincided with a moderate peak of about 15,980 MW, which occurred around 5:45 p.m. This peak was about 270 MW higher than the peak forecast by ISO-NE.

While ISO-NE does not identify specific resource outages, data from the RTO show declining gas generation before and after the evening peak load. Gas generation dropped by roughly 1,400 MW between 5 p.m. and 6:30 p.m. Meanwhile, nearly 700 MW of oil generation kicked in during the event.

The two capacity scarcity events experienced so far in 2025 highlight what some market participants view as growing Pay-for-Performance risk in the ISO-NE capacity market. ISO-NE has experienced eight deficiency events since the start of 2016, with five occurring over the past three years.

An increasing number of capacity scarcity events, coupled with higher PFP rates implemented by ISO-NE in recent years, could lead to higher capacity prices in future auctions if participants price increased PFP risks into their capacity offers. ■



ISO-NE actual load (orange) and forecasted load (blue) for Nov. 23 | *ISO-NE*

MISO South Regulators Ready to Strike Out on Their Own for Tx Cost Allocation

By Amanda Durish Cook

MISO South states have signaled their intent to strike out on their own on a cost allocation design for long-range transmission projects located exclusively in the South subregion.

South regulators proposed their own cost allocation design *process* under FERC's Order 1920, which could produce a cost-sharing plan that could override MISO's recommended allocation for new transmission projects. (See *State Regulators Weigh Drafting Alternative to MISO Tx Cost Allocation*.)

During a Nov. 18 MISO teleconference, New Orleans City Council attorney David Shaffer, representing MISO South states, introduced the proposal Southern regulators put together.

"What's envisioned is the state agreement process would apply to long-range transmission projects in the MISO South region," Shaffer explained.

Shaffer emphasized that the MISO South state agreement process document is simply a framework to be used to design a cost allocation, not a cost allocation methodology itself.

According to the document, the South's design process would last no longer than six months after the MISO Board of Directors approves a slate of long-range projects.

The document instructs MISO South states to devise cost allocations that are roughly commensurate with estimated benefits. It also stipulates that benefit estimations should meet the Entergy Regional State Committee's criteria of "accurate, objective, measurable, quantifiable, non-duplicative, forward-looking, replicable and supported by data."

Participation in the development of and votes on cost allocation methods would be limited to relevant state entities, Shaffer said. However, state entities could agree unanimously to designate more organizations to participate in the process.

Some MISO stakeholders said the document was ambiguous as to when the design process would start.

FERC's Order 1920 directs RTOs to involve states when developing or amending a long-term regional transmission cost allocation. It gives states the go-ahead to meet independently to negotiate and devise cost allocation methods to offer to FERC in place of RTOs' methods.

MISO must file the state agreed-upon allocation alongside its own suggested allocation, even if it doesn't agree with it. MISO previously said its established, 100% postage stamp to load allocation could work for South long-range planning. The RTO changed its stance after it announced that the first MISO South long-range planning effort would be limited to Louisiana and a portion of Texas. MISO leadership said they couldn't picture using a subregional postage stamp allocation on a load-ratio basis for projects limited to just two states.

Entergy Louisiana rebuilding a 230-kV line over the Mississippi River in 2022 | *Entergy*

Why This Matters

The process document MISO South states presented provides a pathway to regulators designing their own transmission cost allocation.

MISO South's Entergy Regional State Committee has said it won't support any postage stamp aspect in MISO's long-range transmission allocation.

Prior to Order 1920, the Entergy Regional State Committee Working Group proposed an allocation in early 2024 for upcoming MISO South long-range transmission plan portfolios. It involves assigning 90% of costs based on adjusted production cost savings and avoided reliability projects; the remaining 10% would be charged to new generation that interconnects in MISO South based on a flow-based methodology. (See *Entergy States Debut Long-range Tx Cost Allocation Proposal, MISO Members Unconvinced*.)

Clean energy nonprofits have said Entergy and MISO South's preferred approach isn't broad enough and will leave the South continuing to build expensive local projects that don't yield regional benefits. (See *Clean Energy Orgs Push Entergy Players to Consider Broader Cost Allocation*.)

MISO's Jeremiah Doner said MISO will review the South state agreement process when it's finalized around March 2026. He said the South's allocation process will "have to be memorialized" in MISO's tariff as part of Order 1920 compliance.

MISO's Order 1920 compliance filing is due to FERC in June 2026. ■

MISO TOs Oppose Tx Cost Containment Suggestions

By Amanda Durish Cook

© RTO Insider

Multiple transmission owners have questioned the need behind a suggestion that MISO work more checks into its process for reviewing troubled transmission projects.

MISO transmission customers have asked MISO to use a 20% cost overrun on transmission projects in progress to trigger the RTO's variance analyses. That would take the place of the RTO's existing 25% over-budget threshold. MISO uses its variance analysis to reassess transmission projects that experience significant cost increases or other obstacles.

The group of transmission customers asked MISO to involve its Board of Directors with project reviews and decisions on transmission projects. They've also suggested MISO draw on third-party experts to decide projects' fate.

After it wraps up a variance analysis, MISO can decide either to let projects stand as-is, develop a mitigation plan for them, cancel projects or assign them to different developers if possible.

At a Nov. 18 stakeholder cost allocation meeting, Ken Stark, with the Coalition of MISO Transmission Customers, said that although transmission construction is needed, it must be done affordably. Stark has advocated for tighter rules around the variance analysis since late 2024. (See *End Users Push MISO for More Intensive Cost Overrun Evals on Tx Projects*.)

What's Next

The MISO Planning Advisory Committee will hold a special meeting Dec. 16 to discuss a stakeholder ask for a lower cost overrun threshold to trigger transmission project reviews and a recommendation that the MISO Board of Directors be more involved in said reviews.

"It's top of mind for regulators right now," Stark reasoned. He pointed out that SPP uses a 20% cost overrun to trigger reviews.

ITC's Cynthia Crane criticized the proposal for borrowing some of SPP's transmission cost containment process while ignoring key components. For instance, she said the 20% threshold SPP uses to re-examine projects is applied later, only after cost estimates are much more concrete than MISO's preliminary estimates.

Further, Crane said the SPP board is much more directly involved with day-to-day operations, having to sign off on tariff changes before they're submitted to FERC. The MISO board, on the other hand, takes a self-proclaimed "noses in, fingers out" governance approach, she said.

Stark said the board could have a "discreet and focused" role that doesn't drastically expand its authority.

MISO's Jeremiah Doner said the RTO provides frequent updates on the status of transmission projects. He said the board is not "hands off" when it comes to transmission development.

Stark said it then "makes sense" for the board to have a say in transmission projects that have hit a snag, given that the board approves MISO's annual transmission expansion plans.

Crane said MISO's End-Use Customer sector is "cherry picking" pieces of SPP's process.

"I fail to see how the proposal you're proposing is adequate," Ameren's Justin Stewart added.

Other stakeholders said MISO's 25% cost overrun threshold had stakeholder backing and would be more appropriate than borrowing another RTO's approach just for the sake of it.

The Planning Advisory Committee will take written stakeholder opinions on the proposed variance analysis edits through early December and hold a special meeting Dec. 16 for further discussion on the topic. ■

MISO Draft Tx Planning Futures Envision 400-GW Supply or More by 2045

By Amanda Durish Cook

MISO predicts it will have anywhere from 383 GW to 454 GW of installed capacity in its footprint by 2045, according to a preliminary version of its 20-year planning futures.

MISO charted resource totals at 383 GW, 403 GW, 446 GW and 454 GW for its Futures 1-4, respectively. The grid operator makes capacity expansion predictions under its 20-year planning scenarios, which help decide which long-range transmission projects are useful. This time around, MISO's predictions contain more natural gas generation and fewer renewable energy resources.

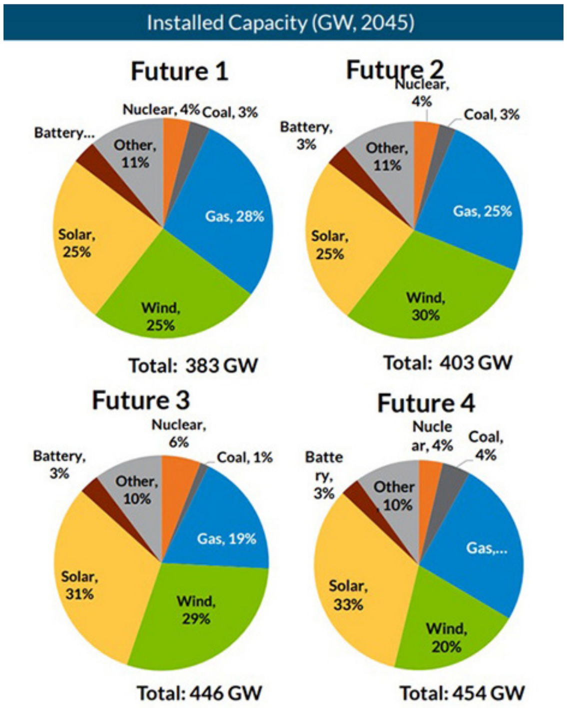
At a Nov. 18 stakeholder teleconference to debate the futures, Director of Economic and Policy Planning Christina Drake said they "limit all-in costs to members" while respecting states' and utilities' decarbonization goals and still being able to serve peak demand and meet planning reserve margin targets.

MISO has been constructing its planning futures for more than a year. It paused in mid-2025 to recalibrate the generation expansion assumptions in its futures after the Trump administration revoked tax credits for renewable generation. (See *MISO Seeking Realistic Gen Buildout for Tx Planning Futures*.)

Drake said MISO will perform more sensitivity analyses to test whether the four futures are "broad enough." MISO plans to use sensitivities to test other assumptions, like more load hyperscalers than MISO anticipates in its updated load forecast, a drop in cost for small modular reactors or long-duration storage, the reinstatement of renewable tax credits or natural gas prices that rise faster than expected.

Drake said MISO would not adjust members' stated resource plans to test assumptions, considering those plans set in stone. She has said "MISO will not be putting its finger on the scale" by changing planned units.

MISO Independent Market Monitor David Patton has suggested MISO introduce a sensitivity that contemplates cost caps on members' decarbonization goals. Patton reasoned that utilities would not spend infinite amounts of money to meet their clean energy goals when they have shareholders to answer to.



Preliminary capacity totals in MISO's four transmission planning futures | *MISO*

Drake said MISO will share its chosen sensitivities in December.

MISO said it will incorporate its growing load into the futures and plans to include data from its long-term load forecasting pilot program. (See *MISO Rationalizes Load Forecasting Pilot Program*.) According to early results, MISO could have an additional 64 GW to serve within 20 years.

Sustainable FERC Project's Natalie McIntire asked how MISO would capture the "uncertainty" behind the rise in large loads, where some may not materialize.

Clayton Mayfield, manager of MISO's economic planning team, said MISO would evaluate its stakeholder sources of data to figure out which large-scale load projects plan to minimize their needs. He also said MISO would use a project certainty ranking for loads, with a "high" classification for publicly known load projects in development with known locations, a "medium" ranking for loads under study and included in MISO's long-term forecast and "low" for loads still in talks and unreported in the long-term forecast.

MISO's first, most conservative future would include only high-certainty loads, while the second, middle-of-the-road future would include high- and medium-certainty projects. MISO's most aggressive fleet change scenario would include all potential load growth.

Mayfield said MISO is using a siting process for load additions similar to its capacity expansion process to depict load locations.

Bryn Baker, senior director at the Clean Energy Buyers Association, requested MISO consider that some large loads bring their own co-located or behind-the-meter generation to the table to aid their needs.

WPPI Energy's Steve Leovy similarly asked MISO to consider that some loads might be interruptible or construct onsite generation.

Finally, MISO won't include Louisiana's previous goal to reach net-zero greenhouse gas emissions by 2050 in its futures. At a late October workshop, Drake said MISO had "active discussions" with Louisiana officials and was told the Louisiana goals have been discontinued.

"Probably for the entire expansion, it's not going to move the needle much," Drake said.

MISO will hold more futures stakeholder workshops Dec. 17, Jan. 29 and Feb. 26. ■

What's Next

MISO plans to finalize its 20-year transmission planning scenarios by March 2026.

DOE Issues 3rd Emergency Order to Keep Michigan Coal Plant Open

By Amanda Durish Cook

The U.S. Department of Energy has reupped a coal-fired power plant in West Olive, Mich., for another 90-day period, preventing its planned retirement for a third time.

DOE issued another *emergency order* to MISO and by extension, plant owner Consumers Energy, to keep the 1,420-MW J.H. Campbell plant running from Nov. 19, 2025, to Feb. 17, 2026.

U.S. Secretary of Energy Chris Wright once again said that an "emergency exists in portions of the Midwest region … due to a shortage of electric energy, a shortage of facilities for the generation of electricity and other causes." He directed MISO and Consumers Energy to take "all measures necessary to ensure that the Campbell Plant is available to operate" and told MISO to write DOE by Dec. 3 to describe its efforts to keep Campbell running.

Consumers Energy originally planned to wind down operations at the plant in late May 2025, but DOE delivered its first emergency order on the eve of its retirement date. A second order in August followed on the heels of the first. The newest order brings prolonged operations to 270 days past the plant's planned retirement date.

DOE framed its order as strengthening Midwestern grid reliability as MISO enters winter weather. The department also argued that Campbell would have retired "15 years before the end of its scheduled design life" if it were allowed to power down.

What's Next

The third emergency order handed down from the DOE will keep the J.H. Campbell plant running another 90 days until Feb. 17, 2026. Plant owner Consumers Energy expects the orders to continue; environmental nonprofits pledged to keep fighting the series of orders in court.

As of the end of September, the plant's extended operations cost about $80 million, according to Consumers Energy's financial disclosures. (See *J.H. Campbell Bill Rises to $80M on DOE's Stay Open Orders*.)

The Environmental Defense Fund and Earthjustice continued to call the series of orders illegal and vowed to keep fighting them in the courts.

"Consumers Energy committed to retire the plant in 2022 under a settlement approved by Michigan state regulators, finding that replacing the plant with a variety of cleaner resources — including wind, solar and storage — would reduce costs for Michigan customers. DOE's series of emergency orders ignore those decisions and are now putting consumers across the Midwest on the hook to keep this aging, expensive and highly polluting plant online," EDF lead counsel Ted Kelly said in a statement.

Kelly said keeping the plant open is a "guaranteed way to needlessly" raise customer bills and worsen air pollution and pointed out the plant has "burned through over $600,000 in losses every day."

DOE claimed that Campbell has been "critical" to MISO operations during its deferred retirement. It said it operates "regularly" during high demand and low renewable energy output.

But EDF said the plant suffered a partial breakdown in June, and Campbell Units 1 and 2 were completely offline when demand peaked during the month. What's more, the nonprofit said NERC's *annual winter reliability assessment*, released Nov. 18, concludes MISO is resource adequate "even in situations with extreme levels of demand and generator outages."

Michael Lenoff, Earthjustice senior attorney, called the plant a "jalopy" that's "prone to breaking down."

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

During a third-quarter earnings call at the end of October, Consumers Energy CEO Garrick Rochow said he expects the emergency orders to continue in the long term and Consumers to comply with them.

Rochow said the utility has "a very flexible workforce that is committed … [to] following through with this order through the Department of Energy."

Rochow said Consumers agrees with FERC that costs of the plant should be allocated across MISO Midwest. He said the region benefits from the continued operation of the plant, not just Consumers ratepayers. Consumers has "great confidence in our ability to recover" costs and will "continue to invest in the plant thoughtfully," Rochow said.

Rejji Hayes, CFO of Consumers parent CMS Energy Corp., said Consumers is treating all costs associated with Campbell's extensions as a regulatory asset. He said so far, there has been "minimal" capital investment. Hayes said once Consumers starts receiving cost recovery from MISO Midwest customers, the company would refund Michigan customers.

"We're trying our best to make sure that Michigan customers are held harmless as we continue to operate the plant to the benefit of the region as noted," Hayes said during the earnings call. ■

$12B MISO 2025 Tx Portfolio Close to Final Approval

By Amanda Durish Cook

A MISO board committee advanced 432 projects from transmission owners at a cost of almost $12.3 billion under the RTO's 2025 Transmission Expansion Plan.

The System Planning Committee voted unanimously to approve the MTEP 25 *package* at a Nov. 17 teleconference. The plan now moves to the full Board of Directors for consideration at its final meeting of the year Dec. 11.

The projects, which total 1,901 miles, would support 11.6 GW of spot load additions. Louisiana contains the most investment at $3.4 billion. Wisconsin follows with $1.8 billion and Indiana with almost $1.7 billion. (See *MISO 2025 Tx Expansion Estimate Drops Slightly to $12.4B*.)

MISO Executive Director of Transmission Planning Laura Rauch said large loads seeking to reserve spots on the grid influenced the sizeable investment.

MTEP 25's most expensive project — Entergy Louisiana's $1.2 billion Cargas 500-kV and Smalling 500-230-kV stations in northeastern Louisiana — is planned to support a new $10 billion Meta data center.

Southern Louisiana's Babel-to-Webre 500-kV line project is the second-most expensive MTEP 25 project at $1.066 billion. Entergy Louisiana said it's needed to meet NERC reliability criteria.

The Missouri Multi-Entity New Transmission (MoMENT) project, a $604 million joint venture between Ameren, Evergy, MISO, SPP and Associated Electric Cooperative, is the third-most expensive. The 345-kV and 161-kV lines and substation in central Missouri are meant to improve reliability and be in service by December 2030.

Rauch told board members that MISO emphasized the collaboration behind the MoMENT project in its MTEP 25 report.

MISO's Jeremiah Doner said load growth, AI data centers and economic development — all the "hot button issues" — influenced MTEP 25.

"The common theme this year is around those large load additions," Doner said during a Nov. 3 gathering of the Planning Advisory Committee (PAC).

PAC's 11 membership sectors *voted* in early November to approve MTEP 25. Six sectors voted in favor of the portfolio, two abstained from voting and three sectors didn't respond to the emailed ballot.

MISO's state regulatory sector typically abstains from voting on MTEP portfolios, reasoning that it's improper for state commissioners to preemptively judge the projects that will come before them later for separate approvals.

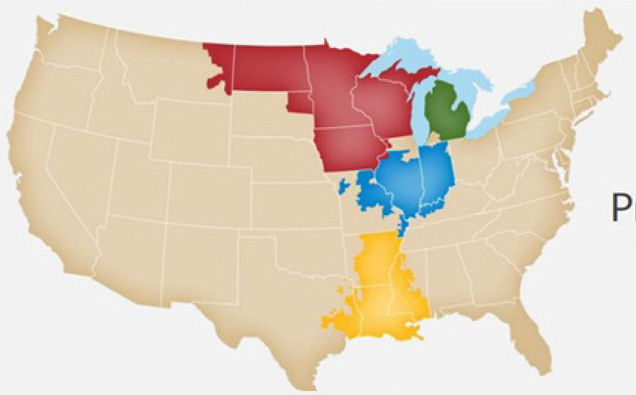
MTEP 25 still contains a $92 million maintenance project for a 345-kV line that was part of MISO's 2011 Multi-Value Project portfolio. Xcel Energy will replace cracking davit arms on a multi-value project in Minnesota. Any maintenance on multi-value projects must be classified under the multi-value category. ■

What's Next

MISO's 2025 Transmission Expansion Plan includes 432 projects at a cost of almost $12.3 billion. The portfolio moves to final board approval Dec. 11.

Subregional Project Breakdown

	West	East	Central	South	Total
Line miles	849	137	546	370	1,901
Large load additions (MW)	2,376	20	4,329	4,924	11.6 GW
Expedited projects	10	1	24	14	49



Projects submitted by 33 Transmission Owners

MISO's 2025 Transmission Expansion Plan statistics by subregion | *MISO*

FERC Gives Go-ahead on Tougher MISO DR Testing Rules

By Amanda Durish Cook

FERC has greenlit MISO's plan to require its demand response to make real-world demand reductions to fulfill the RTO's testing requirements.

FERC said the "modifications more clearly define and standardize the existing testing procedures" in a Nov. 17 order (*ER25-2845*).

MISO now can mandate DR to make actual megawatt reductions for testing instead of submitting mock tests to prove capability. MISO worked on the proposal over 2025. (See *MISO Tries to Ward Off DR Fraud with New Testing Regime*.)

"[W]e find that establishing stricter testing waiver criteria and adding specific testing parameters for demand resources in the tariff will provide greater certainty that demand resources will be available when called on by MISO," FERC said, adding that the rules should diminish the "likelihood of market participants registering resources into the auction in a manner that does not accurately reflect the true capability of their resources."

Alcoa's aluminum smelter facility in Newburgh, Ind. | *Alcoa*

The commission granted MISO's requested effective date of July 15, 2025, so the new testing regime is in place by the 2026/27 capacity auction. It said it weighed the quick turnaround time against the importance of accurate testing. It pointed out that MISO allows market participants to use "operational data gathered in the ordinary course of business" to prove full demand reduction or allows resource owners to defer testing until May 29, 2026.

MISO has about 15 GW of DR as of late 2025. But MISO has said its experience shows that only about half of the DR fleet is available when needed.

Why This Matters

With FERC approval, MISO can largely do away with mock tests and require its demand response resources to make real megawatt reductions to prove their effectiveness.

Under the new MISO paradigm, DR resource owners must demonstrate they can honor their notification time while dropping demand within the time-of-day periods that match with hours that MISO expects system risk to occur. The resources must hold their demand reduction for 15 minutes, covering at least two meter intervals. Owners must show a full reduction of all the megawatts they specified in registration during a real power test. MISO said it would allow some resources that experience a weather impact during testing to demonstrate a bit less than their full stated capability.

MISO will allow select DR owners to proceed with a mock test if a state authority expressly allows it or if it's a proven resource that has responded to a MISO call in the past three years and has not changed its specifications since.

DR and distributed energy resource aggregators argued before FERC that MISO's plan allows discriminatory treatment between load-serving entities' DR programs and aggregators of retail customers.

Voltus and Advanced Energy United said MISO's testing waivers for load-serving entities' DR programs amounted to aggregators' DR groupings being held to a different standard. MISO included testing waivers for retail DR programs overseen by state regulatory authorities. It didn't extend the possibility of waivers to aggregators.

FERC said the testing exceptions aren't discriminatory and recognize "states' interest and expertise in ensuring that the demand response programs under their jurisdiction are effective." The commission further pointed out that MISO's tariff already contains the potential for testing exemptions for retail programs managed by state regulators. It said it was "reasonable for MISO's testing requirements to account for relevant testing provisions in retail programs."

The testing rules are part of a myriad of new restrictions MISO has placed on its DR since the RTO, its Independent Market Monitor and FERC staff discovered multiple instances of fraud, misrepresentation or rule violations among its DR fleet. (See *MISO Tries to Clear Up Assortment of New DR Rules*.) ■

PJM Stakeholders Reject All CIFP Proposals on Large Loads

By Devin Leith-Yessian

The PJM Members Committee voted against each of the dozen proposals brought to address rising data center load as part of the RTO's Critical Issue Fast Path (CIFP) process. (See *PJM Stakeholders to Vote on Large Load CIFP Proposals*.)

The *proposal* from the Southern Maryland Electric Cooperative (SMECO) was the highest vote-getter at a special MC meeting Nov. 19, receiving 46.66% sector-weighted support, still falling short of the two-thirds required for endorsement. It was followed by the Independent Market Monitor's proposal at 39.88% and PJM's at 38.66%. The voting was advisory to the RTO's Board of Managers, which expressed its intent to file changes with FERC in December to be effective for the 2028/29 Base Residual Auction (BRA).

PJM CEO Manu Asthana | © *RTO Insider*

Addressing the committee after the vote, PJM CEO Manu Asthana said those goals stand, and more detail around timing will be forthcoming. Though there was no winner among the packages, Asthana said there was plenty of information for the board to review from the input shared during the meeting preceding the vote, the last to be held as part of the process.

The CIFP meeting, during which each of the sponsors presented their proposals to the board, lasted much of the day, beginning at 9 a.m. and stretching past its 2 p.m. scheduled end time, pushing the MC's meeting to start at 3:45 p.m. The CIFP meeting was closed to the media, and there was no discussion on the packages themselves during the MC meeting before the vote opened.

RTO spokesperson Jeff Shields said the board plans to act in the next few weeks.

"PJM opened this conversation about the integration of large loads and greatly appreciates our stakeholders for their contributions to this effort," he wrote in an email statement. "The stakeholder process produced many thoughtful proposals, some of which were introduced late in the process and require additional development. This vote is advisory to PJM's independent board. The board can and does expect to act on large load additions to the system and will make its decision known in the next few weeks."

The SMECO package adopted the changes sought by PJM, including changes to the pricing and dispatch of price-responsive demand (PRD), the addition of state reviews of large load adjustments and an expedited interconnection track (EIT) for state-sponsored projects. Both SMECO's and PJM's proposals would shift PRD to an energy market strike price, rather than a dynamic retail rate, but SMECO proposed a $1,000/MWh limit and PJM would set it at $1,849/MWh.

The PJM proposal would also align PRD dispatch with demand response by requiring it to respond regardless of bid price, subject it to performance assessment interval (PAI) penalties and mirror their 30-minute energy bid price caps. SMECO would only subject PRD participants to Capacity Performance penalties if the resource is dispatched when the strike price or PAI conditions have not been met and require that they have supervisory control over the load and the ability to curtail.

The EIT would create a 10-month process for resources of at least 250 MW and nonrefundable study deposits of $10,000/MW for projects paired with large loads and doubled for standalone development. They would require letters of support from the governor or utility commission for the state they are sited in, which is intended to avoid expending limited resources for studying requests on projects that will be mired in permitting and siting challenges at the state level. Only 10 projects would be allowed to proceed each year.

The RTO's *executive summary* of its package included a request for the board to initiate a second phase of the CIFP process focused on changes to the reliability backstop and incentives for large loads to bring their own generation or participate in DR programs.

Why This Matters

The PJM Members Committee's vote was only advisory to the Board of Managers, which means the board will need to decide itself what to file with FERC in December.

Board Chair David Mills said it will endeavor to assemble a proposal that makes sense of all the information provided throughout the CIFP process.

"It's been an arduous journey to get to this point. I'm actually not surprised we got such disparate accounts on all of these proposals. … Just because none of these passed does not mean the board will not act," he said.

During an open-ended discussion following the MC's regular monthly meeting Nov. 20, Mills said he could envision changes to the CIFP process in the future. One possible change could be adding milestones throughout the process if there are many proposals being considered.

Tom Rutigliano, senior advocate at the Natural Resources Defense Council, said the board has hard decisions ahead of it to ensure that data center growth is not subsidized by the public.

"The growth of data centers is colliding with the reality of the power grid. PJM members weren't able to see past their commercial interests and solve a critical reliability threat. Now the board will need to stand up and make some hard decisions. We hope they fulfill their obligation to 67 million people and commit to protecting reliability, not subsidize data centers at public expense, and treat all customers fairly," he said in a statement.

"The public faces a $163 billion bill through 2033; and the region could suffer multiple rolling blackouts each year. If the board doesn't step up, the region won't be able to meet record demand and will suffer declining reliability for years to come." ■

Voltus, Mission:data Argue Data Access Issues Stymie Residential DR in PJM

By James Downing

Why This Matters

Expanding residential DR could help with major issues like affordability, but FERC will have to decide whether that is worth it with PJM and others arguing against widening the use of statistical modeling to get around data access issues.

Voltus and Mission:data pushed back on opposition to their complaint against PJM from the RTO and others on using statistical modeling for residential demand response customers, saying the current rules have residential customers providing just 0.4% of registered DR in the market (*EL26-4*).

"Complainants wish to make it completely clear for the record: Voltus and Mission:data's complaint is limited to residential customers," they said in an answer filed Nov. 18. "Voltus and Mission:data are not proposing that statistical sampling be employed for any other class of customer, or to sample across customer classes."

PJM argued in its response that the complaint was trying to get around state rules, which have made it hard to access interval meter data for residential customers for legitimate reasons. The RTO also said it lets DR aggregators use statistical modeling when interval metering data is not available at all for residential customers. (See *PJM Asks FERC to Deny Demand Response Metering Data Complaint*.)

Allowing DR aggregators to use those statistical modeling techniques when interval meter data is made unobtainable by state rules would unlock residential DR in PJM, Voltus Chief Regulatory Officer and former FERC Chair Jon Wellinghoff said in an interview Nov. 19.

"I would say there's probably several thousand megawatts of DR that could be brought into PJM if we could access those residential customers, but this is the block," Wellinghoff said. "We are being blocked by the fact that we don't have reasonable access to interval meter data."

The original complaint detailed Voltus' efforts to procure the needed data from utilities for residential customers and how that proved difficult enough to be infeasible. It did that after FERC rejected a similar complaint from CPower on the grounds it had not filed enough information to prove data access rules were a hindrance to signing up customers for wholesale DR.

Voltus has no problem going through information security regulations to access the data where they are available, but it showed in the original complaint that many utilities across PJM make it very difficult for any third parties to get access, he added.

FERC granting the complaint could lead to states making their rules more workable, Wellinghoff said.

"It will give money in the pockets of residential consumers who are hurting from utility bills," he added. "It will provide money to them for participating in these programs."

Two of the biggest issues facing the industry are interconnecting large loads and affordability, which can be in tension. DR can help free up space on the grid to connect additional loads, and it can save customers from paying for extra investments to the grid, while directly giving money to participants.

"All the governors in PJM should be all over this complaint, telling FERC you should approve it immediately," Wellinghoff said.

These kinds of DR programs for residential customers get around resistance to more economically elegant price-responsive demand, which could be a grid resource given the right price signals such as time-of-use rates, Wellinghoff said. But PRD has not proved popular among consumers, even as technology has advanced.

"It's simply because consumers would much rather have some third party provide some service to them that can control independently their devices in ways that will help the market but also preserve the comfort in their home and provide them money in their pocket," Wellinghoff said. "But they don't want to do anything actively, because they've got other things to do."

Having a third-party aggregator handle the optimal charging for a plug-in car or when to moderate air conditioning demand makes it easier for consumers who need to focus on their family life or jobs, he added.

The utilities with interval meters for residential customers have unfettered access to the data and could set up these programs themselves, but they lack the incentives to do so, Wellinghoff argued.

"They have no interest or incentive to have consumers go on time-of-use rates," Wellinghoff said. "They have no interest or incentive to help customers participate in wholesale markets because they don't make any money doing that. In fact, they lose money by doing that, because what that does is it allows consumers to help the system run more efficiently."

That means less investment in the system, and less investment means fewer returns for shareholders, he added.

In addition to opposition from the RTO and member utilities, PJM's Independent Market Monitor opposed the complaint on the grounds that the statistical modeling methods were by nature less accurate than the real data, which would degrade the RTO's ability to track Capacity Performance and its ability to maintain resource adequacy.

"What the IMM also does not acknowledge is that PJM, in fact, accepts this 'uncertainty' and lack of precision for financial settlements today, where interval meters do not exist, as outlined in Manual 19," Voltus said in its answer. "PJM's statistical sampling process is designed to be rigorous and requires [that] 'samples must be designed to achieve a maximum error of 10% at 90% confidence.' The IMM does not explain how complainants' proposal would introduce unacceptable certainty beyond what is established practice today." ■

PJM Stakeholders to Explore DR Performance

By Devin Leith-Yessian

Monitoring Analytics President Joe Bowring | © *RTO Insider*

The PJM Markets and Reliability Committee endorsed by acclamation an *issue charge* to explore how the performance of demand response and price-responsive demand (PRD) resources can be improved.

According to the accompanying *problem statement*, the six load management deployments in this summer had a weighted average performance of 67%, which is "significantly lower" than was observed during tests conducted in the 2024/25 delivery year and the actual performance in past years. It states that shrinking reserve margins are likely to require more regular DR and PRD dispatching. The committee approved the document during its Nov. 20 meeting.

"PJM seeks to ensure that stakeholders understand the existing load management dispatch process (and PRD required response) and the measurement and verification calculations used to determine Capacity Performance and real-time energy settlements," it says.

It notes that the circumstances under which DR and PRD could be used were expanded in the 2024/25 delivery year to allow deployments outside a performance assessment interval (PAI). When a PAI is not active, demand-side resources are not subject to CP penalties if they do not perform and they can use historic test results to replace actual performance during a non-PAI event. The Independent Market Monitor has pointed to the lack of penalties and the ability to substitute actual performance with test results as part of its opposition to expanding load flexibility as part of the Critical Issue Fast Path (CIFP) process focused on how to address rapid large load growth.

"Demand-side response when called is effectively voluntary based on the relatively weak incentives to respond, despite the fact that the tariff states that reductions are required. If demand-side resources do not respond when called, any actual performance penalties can be overridden by test results, if the performance issue is not during a PAI event," the Monitor wrote in its State of the Market *report* for the third quarter.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said the poor performance of demand-side resources casts a cloud over the CIFP proposals voted on by the Members Committee during its Nov. 19 meeting. (See related story, *PJM Stakeholders Reject All CIFP Proposals on Large Loads*.)

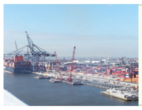
The issue charge envisions "solutions that will improve performance when load management is dispatched, or PRD is required to respond, and ensure applicable tariff requirements associated with performance are met."

The expected changes the issue charge lists are fairly broad, leaving the door open to "process and/or system changes" and corresponding changes to the governing documents and manual language. Implementation is targeted for the 2028/29 Base Residual Auction, which is scheduled to be conducted in June 2026, and a tariff filing is expected in late April.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said his client J-Power USA could not support the issue charge without a wider scope inclusive of how DR participates in the energy market. Adding a requirement that demand-side resources offer into the energy market should be on the table, he said.

Aaron Breidenbaugh, senior director of regulatory affairs at CPower Energy Management, said the energy and capacity markets do not always provide enough compensation to cover the costs of a curtailment. Trying to develop a cost-based offer structure for the resource class could take as long as a year. ■

Northeast news from our other channels



Nonprofit Groups Sue N.Y. and N.J. over Pipeline Approval

NetZero Insider

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

PJM Presents 1st Read on Minimum Capitalization Requirement Proposal

PJM *presented* its Markets and Reliability Committee with a first read on a proposal to increase the minimum capitalization requirements to participate in its markets.

| © RTO Insider

It was supported by 84% of stakeholders in the RTO's Risk Management Committee in an October poll.

Under existing policy, entities participating in financial transmission rights markets must have either $1 million in tangible net worth (TNW) or $10 million in tangible assets. For those not involved in FTRs, the requirement is $500,000 in TNW or $5 million for tangible assets.

The proposal would increase the TNW threshold to $2 million for all participants with a 3% fixed rate escalation annually. It includes a transition period in which the TNW for non-FTR participants would first increase to $1 million and double over five years.

The TNW and tangible asset minimums have not been changed since they were instituted in 2011. PJM's Ryan Jones said minimum capitalization requirements are meant to ensure that market participants can handle the risk associated with their activities and reduce the risk of default shifting costs to others.

An earlier version of the proposal would have required $5 million in TNW, but PJM decreased that after stakeholders voiced concern that it would create too big a barrier to participation, increase market concentration and reduce competition.

Independent Market Monitor Joe Bowring said he views the proposal as a modest requirement which would protect members against defaults by market participants who cannot meet their obligations. ■

— Devin Leith-Yessian

Enviros Challenge MISO, SPP Queue Express Lanes

By Amanda Durish Cook and Tom Kleckner

The Bottom Line

Environmental groups hope to deliver a one-two punch to SPP and MISO's interconnection queue fast lanes, challenging both at the D.C. Circuit Court of Appeals in a pair of lawsuits.

Environmental groups are further pressing their opposition to MISO's and SPP's fast-track studies for primarily fossil fuel projects, challenging both in the D.C. Circuit Court of Appeals in a pair of lawsuits.

The petitions for review, filed with the court Nov. 18, contest FERC's separate approvals of MISO's Expedited Resource Addition Study and SPP's Expedited Resource Adequacy Study (ERAS) processes, allowing load-responsible entities to nominate qualified projects for fast-track reviews to maintain resource adequacy.

Earthjustice filed the MISO *petition* on behalf of environmental groups Clean Wisconsin and Natural Resources Defense Council. It was joined in the filing by the Sierra Club.

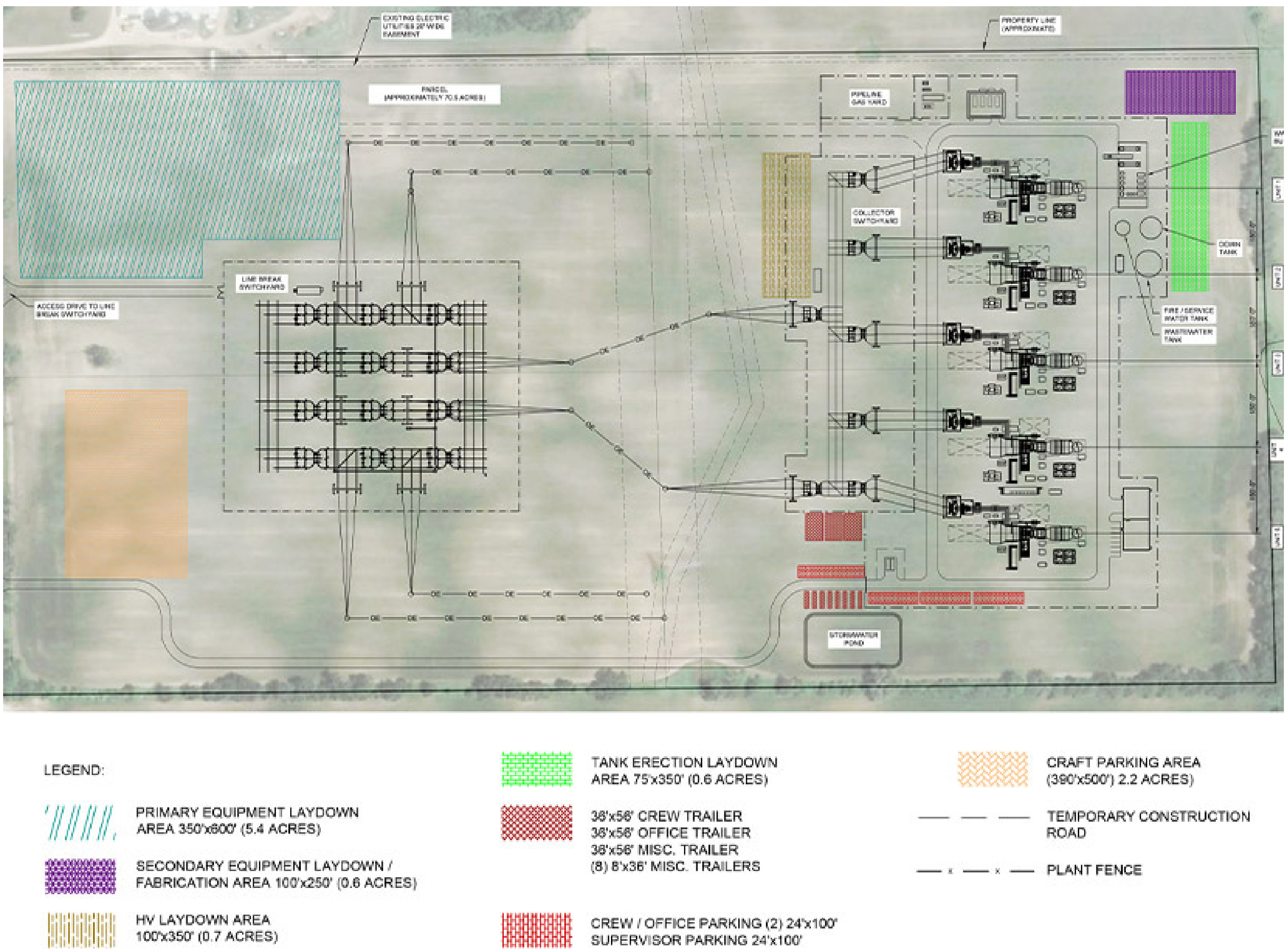
Separately, the Sierra Club filed a *petition* with the court against SPP's "unnecessary" proposal. The organization said the ERAS proposal favors gas generation at the expense of wind, solar and battery storage projects.

The filings came one day after the Sierra Club and NRDC, represented by Earthjustice, were party to a similar request to the D.C. Circuit over SPP's accreditation methodology for clean energy resources. (See related story, *SPP's ELCC Methodology Contested at Appeals Court*.)

The groups said MISO's interconnection-queue express lanes bestow an "undue advantage" for fossil fuel generation, with ratepayers funding the grid upgrades needed to accommodate them. They asked for a reversal of FERC's approval order.

They argued FERC incorrectly brushed aside the potential for the fast lanes to aggravate wait times and complicate studies for regularly queued resources.

"FERC is letting grid operators like MISO rewrite the rule book to the benefit of



Invenergy's proposed Red Oak Ridge Energy Center in Wisconsin is one of MISO's ERAS applicants | *Invenergy* fossil fuel and data center companies, and at the expense of everyone else," Ada Statler, a senior associate attorney at Earthjustice, said in a statement. "FERC is sidelining cheaper clean energy projects and allowing utilities to pass on the higher costs of methane gas to other customers, despite its legal mandate to ensure just and reasonable rates."

Caroline Reiser, an NRDC senior attorney, said the fast lanes create an environment where a handful of mostly gas plants can cut in line to their financial benefit.

Sierra Club Senior Attorney Greg Wannier added that MISO is "spending too much time trying to benefit monopoly utilities and the gas industry at the expense of clean energy and independent producers."

The Sierra Club said MISO's process allows fast-tracked projects to "pass on significant upgrade costs to residential customers and to skip over clean energy projects that have been waiting for years to connect to the grid." It argued that the clean energy waiting in MISO's 175-GW interconnection queue is more affordable than the 18 GW of gas generation under study in the fast lane.

The Sierra Club and Natural Resources Defense Council objected to MISO's design while it was pending before FERC. (See *MISO Fast Lane Proposal Disadvantages IPPs, Retail Choice States, Critics Tell FERC*.)

MISO has received 49 project applications representing more than 26 GW for its expedited queue. Most proposals entail natural gas-fired units. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class*.)

MISO Vice President of System Planning Aubrey Johnson said during a Nov. 11 Entergy State Regional Committee meeting that MISO believes the fast lane already has met its objectives to accelerate resource additions.

Altogether, MISO's temporary process would enable 68 projects, with 10 slots reserved for submissions from independent power producers and eight reserved for entities serving MISO's retail choice load in downstate Illinois and a percentage of Michigan.

Sierra Club Appeals SPP ERAS

The Sierra Club said that despite no "solid evidence" of a capacity shortage, SPP claimed its ERAS proposal was necessary to address rising capacity demands. It said SPP has a history of *favoring thermal projects* over renewable energy and that the ERAS process' structure would make it virtually impossible for wind or solar facilities to participate in this new process.

The organization said the ERAS allows the fast-tracked projects to pass upgrade costs to residential customers and clean energy projects that have been waiting for years to connect to the grid. It said it previously alleged at FERC that SPP "improperly" dismissed the potential for fast track to exacerbate challenges in processing and connecting the rest of the RTO's queued resources.

SPP spokesperson Seth Blomeley told *RTO Insider* that staff are reviewing the Sierra Club's filing. "We remain confident in the merits of our plan, which was approved by FERC," he said in an email.

The Sierra Club argues that SPP claims ERAS is necessary to meet increased demand from data centers but that SPP suggested in other regulatory contexts that other reforms to the queue would address resource shortfalls.

The Sierra Club pointed to Duke University *research* that found new demand for electricity from data centers and other large loads can be flexed to avoid building expensive new gas plants while maintaining electric grid reliability.

FERC approved SPP's ERAS proposal in July. It was conditional on making a compliance filing within 30 days of the order's issuance (*ER25-2296*). (See *FERC Approves SPP's ERAS Process, Accreditation*.)

The Sierra Club's rehearing request was rejected in November, "deemed to have been denied" after no FERC action was taken. ■

SPP's ELCC Methodology Contested at Appeals Court

Environmental Organizations Request D.C. Circuit's Review of FERC Orders

By Tom Kleckner

The Sierra Club and Natural Resources Defense Council have filed a *petition* with an appeals court to toss two recent FERC orders that granted SPP's request to modify provisions for clean energy resources' capacity accreditation.

The two organizations, represented by nonprofit advocate Earthjustice, filed the request with the D.C. Circuit Court of Appeals on Nov. 17.

At issue is FERC's July approval of SPP's tariff revisions to implement an effective load-carrying capability (ELCC) for wind, solar and storage resources, and a performance-based accreditation (PBA) methodology for conventional resources (*ER24-1317*). (See *FERC Approves SPP's ERAS Process, Accreditation*.)

The Sierra Club and NRDC also are appealing FERC's denial of a rehearing request for the order. The commission said in August that in the absence of FERC's action in response to the request, the rehearing "may be deemed to have been denied."

In approving SPP's ELCC and PBA methodologies, FERC said the gird operator's tariff change was a "new data-driven approach to resource accreditation." Commissioners David Rosner and Judy Chang filed a joint concurrence, noting "numerous" parties raised several methodological concerns with SPP's proposal.

"However, despite the concerns, commenters nonetheless appear to universally recognize that SPP's proposal is an improvement over the status quo," they wrote. "Given the growing urgency of the resource adequacy challenge in SPP, we are persuaded that the commission should accept this just and reasonable improvement."

The RTO said in its filings that it will be able to more accurately measure generators' reliability and ensure they are dispatched and compensated for their "real-world performance."

"This gives utilities and grid operators better tools to plan for and maintain a reliable grid," SPP said.

The environmental groups say SPP's proposal "holds renewable energy sources to a significantly higher standard than fossil fuels" and doesn't consider thermal generation's "poor reliability during extreme weather." They cited a report from the Union of Concerned Scientists that found thermal plants as "disproportionately vulnerable to failure" during recent winter storms.

Why This Matters

The environmental groups say SPP's ELCC capacity accreditation allows the RTO to artificially entrench fossil fuel generators at the expense of clean, reliable, renewable energy. They cited a report that found thermal plants "disproportionately vulnerable to failure" during recent winter storms.

Deriva Energy's Frontier II wind farm in Oklahoma must now meet ELCC capacity accreditation. | *Duke Energy Renewables*

"Power outages were avoided because SPP's wind fleet significantly outperformed its expected value," Sierra Club and NRDC said in a *news release*.

SPP spokesperson Seth Blomeley said staff are reviewing the appeal filing.

"We continue to have confidence in the merits of our [ELCC] plan," he said.

Sierra Club senior attorney Greg Wannier said that "fair and accurate resource evaluation should be the minimum expectation for any grid operator."

"Unfortunately, SPP decided instead to artificially prop up the value of coal and gas," he said. "This double standard will force customers to pay more money for less reliable electric service and increases the risk of life-threatening power outages during the next heat wave or winter storm."

"FERC has allowed SPP to put their thumb on the scale to artificially entrench fossil fuel generators at the expense of clean, reliable, renewable energy," Earthjustice seniorattorney Aaron Stemplewicz said. "We look forward to exposing FERC's misguided approval in court." ■

SPP: 'High Likelihood' to Meet Winter Demand

SPP said it expects a "high likelihood" of meeting demand during the upcoming winter season.

Bruce Rew, senior vice president of operations, told stakeholders during a Nov. 17 winter readiness webinar that SPP does not anticipate "major concerns" during the season, which runs from December through February.

"Our studies show we'll have sufficient generation to meet peak demand, and that's before considering resources such as demand response, energy imports or voluntary conservation programs," he said. "While our forecasts are dependable, they're not perfect, so we also work to be prepared in case of an unexpected event."

Rew assured his audience that SPP has "robust" tools and procedures in place to maintain reliability, "even when real operating conditions deviate from our forecast."

"Thanks to the dedication of our staff members and stakeholders, we're all well positioned to meet the challenges of the upcoming winter season," he said.

SPP is predicting what Rew called a three-way weather forecast split across its footprint: colder than normal temperatures across the northern section, near normal conditions in the central areas and warmer than normal conditions slightly more likely in the South.

"An isolated extreme event cannot be ruled out," Rew said.

Staff said SPP expects peak demand to exceed 48.8 GW during the winter. It has more than 64 GW of accredited capacity, a reserve margin of 35% and about 1.2 GW of DR to work with.

The RTO's load-responsible entities are required to meet a 15% planning reserve margin for both the summer and winter seasons in 2025. The winter PRM ratchets up to 36% for the 2026-27 winter season.

The grid operator set a record winter peak of 48.1 GW in February 2025. Its all-time peak is 56.2 GW, set in August 2023. ■

— Tom Kleckner

SPP says staff and its operations center are ready for the winter season. | *SPP*

PUCO Fines FirstEnergy $250M After Investigation into HB 6 Scandal

By James Downing

The Public Utilities Commission of Ohio approved $250 million in fines for FirstEnergy, which comes after a federal investigation in 2020 found the utility had bribed lawmakers to secure a bailout for its nuclear plants. (See *Feds: FE Paid $61M in Bribes to Win Nuke Subsidy*.)

The bribes went chiefly to state legislators including former House Speaker Larry Householder (R), but former PUCO Chair Sam Randazzo was also charged with taking bribes before he killed himself in 2024. (See *Scandal-ridden Former PUCO Chair Sam Randazzo Found Dead*.)

PUCO issued two separate orders, finding that FirstEnergy's utilities in the state (Cleveland Electric Illuminating Co., Ohio Edison and Toledo Edison) violated state law, PUCO regulations and orders, and ordered them to pay a combined $250.7 million in restitution to customers and civil forfeitures.

"The commission has remained steadfast in ensuring that we have followed the facts wherever they may lead," PUCO Chair Jenifer French said in a statement. "Our hope is the events underlying these proceedings will remain a cautionary lesson of accountability and honesty in utility regulatory matters."

FirstEnergy has already paid a fine to the U.S. Treasury over the bribery allegations, and the $250 million resolves issues PUCO uncovered after it launched investigations into the utility after the federal probe became public.

PUCO found that the FirstEnergy utilities failed to show that they adhered to a 2016 order it approved authorizing them to collect a "distribution modernization rider" to update their distribution grids. Instead, FirstEnergy took some of the money to subsidize its unregulated generation affiliate between 2017 and 2019. The company has since sold off its unregulated generation.

The utilities will have to return $179.99 million over three billing cycles for that activity, which PUCO arrived at by tripling the $59.996 million the company spent in bribes to get House Bill 6 passed. The law provided a subsidy for the company's nuclear plants.

"These funds represent an unnerving shadow over our regulatory role in this state and have harmed each and every consumer whose interests we aim to protect in proceedings before us," PUCO *said* about the $60 million. "There have been many actions intervenors have called upon us to take in response to these events that lie outside of our authority to provide; however, when we do have the authority to order restitution for all Ohioans harmed by the companies' actions discussed in these proceedings, we must do so in the interest of justice."

FirstEnergy must refund an additional $6.64 million plus interest for some transactions it billed to customers but lacked supporting documentation or that were misallocated to customers, as identified in an audit by PUCO.

Davis-Besse nuclear plant in northern Ohio | *FirstEnergy*

Why This Matters

The case was the biggest utility corruption scandal in recent history, and PUCO has finished its probe, resulting in some restitution to ratepayers.

The rest of the $250 million is due in the form of civil forfeitures after PUCO found FirstEnergy violated Ohio's corporate separation laws when it entered into a consulting agreement with the Sustainability Funding Alliance in 2013. Regulated utilities were allocated costs for a consulting deal that benefited its generation affiliate, and the company owes $21.78 million in restitution.

The commission found FirstEnergy failed to disclose a side deal with the Industrial Energy Users – Ohio during a 2015 proceeding. The commission ordered the utility to pay a civil forfeiture of $18.93 million.

The last chunk is from a 2021 corporate separation audit, which found seven areas of violation between the company's regulated and unregulated affiliates including a lack of a chief compliance officer and missing cost allocation information. FirstEnergy owes $23.36 million for that behavior, which PUCO said "contributed to the conduct giving rise to the HB 6 scandal."

PUCO said FirstEnergy's utilities have worked to fix their culture since the scandal and have new leadership that was not involved in the bribery, but the commission said it would remain vigilant to ensure compliance going forward.

"These proceedings were the first, and we trust the last, of their kind," French said. "It is our responsibility and duty to impose appropriate remedies so as to ensure that they are." ■

FERC Greenlights LS Power to Sell CPower, 12.9 GW to NRG

By Devin Leith-Yessian

FERC has approved LS Power's deal to sell 12.9 GW of its gas generation in PJM, NYISO and ISO-NE, as well as its 6-GW demand response business, CPower, to NRG Energy for $12 billion (*EC25-102*).

The transaction, approved Nov. 14, was opposed by PJM's Independent Market Monitor, as well as the New Jersey Division of Rate Counsel and Maryland Office of People's Counsel, which argued it would harm competition and lacked safeguards against market power manipulation.

The Monitor urged the commission to condition its approval on requirements around how NRG could structure its cost- and price-based offers, subject them to the requirement that they offer into the day-ahead and real-time energy markets, base the DR strike price on the cost of dispatch and commit to not removing the generators' capacity status to serve co-located load. (See *NRG, PJM IMM Disagree on LS Power Deal's Market Power Impact*.)

NRG submitted analysis on how the deal would affect prices and ownership concentration, finding that the Herfindahl-Hirschman Index (HHI) for the New York City local capacity market is moderately concentrated and would increase from 1,085 points to 1,122 for the 2026 summer auction and go up from 1,157 to 1,214 in the 2026 winter auction. It determined the PJM capacity market is unconcentrated, with an HHI that would increase from 563 points to 565 across the RTO and would decrease within the MAAC zone from 851 to 840. They argued the increases in NYISO are small and below the commission's threshold for rejecting a transaction and that the units in New York City would be considered pivotal and therefore subject to mitigation rules.

Commission staff issued a deficiency letter Aug. 13, requesting that the companies file more information about whether the DR resources were included in the horizontal market screens for PJM and NYISO. The companies responded with additional sensitivities showing there would be a "trivial impact" in the city and that the sensitivities for PJM and MAAC likewise found little impact.

The Monitor argued that the three-pivotal-supplier test would more accurately represent the impact to market power than the HHI, particularly given how tight PJM's capacity market is.

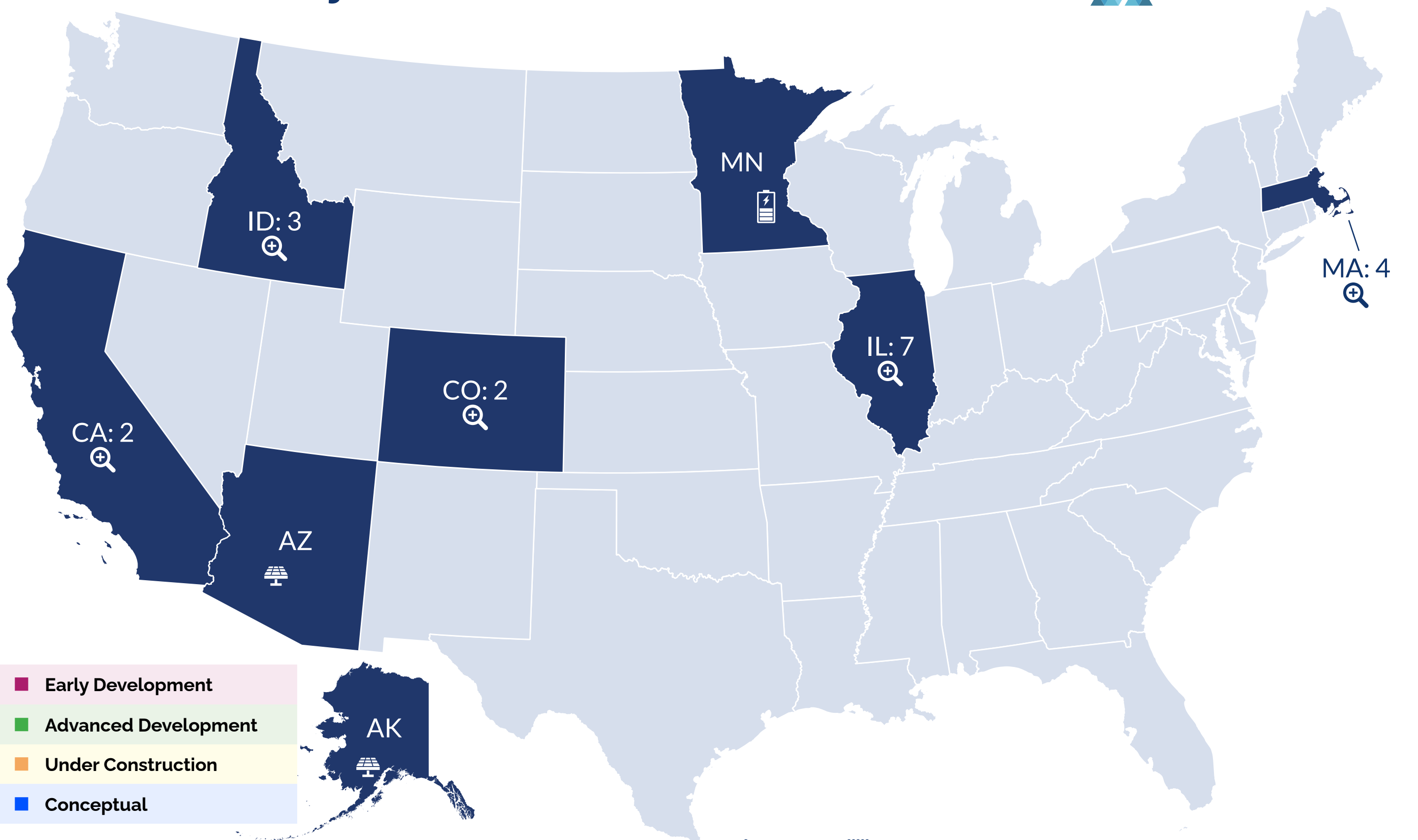
"Regarding the PJM IMM's arguments that the proposed transaction will increase market power in PJM, we find that the PJM IMM has not demonstrated that the proposed transaction will have an adverse effect on horizontal competition," FERC wrote. "Although intervenors may submit alternative competitive analyses, accompanied by appropriate data, to support their arguments, the commission historically has not relied on three-pivotal-supplier test results or hourly market share analysis for its analysis of [Federal Power Act] Section 203 transactions, and we decline to do so here. Neither the three-pivotal-supplier test results nor hourly market share analysis cast doubt on the results of applicants' [delivered price test], which indicates that the proposed transaction does not increase market concentration in any relevant market."

During NRG's third-quarter earnings call, CEO Larry Coben said the company expects the deal to close in the first quarter of 2026. It includes $6.4 billion in cash and NRG purchasing about 11% of LS Power's shares, though it would only directly receive less than a 10% holding to avoid the commission's threshold for determining when a party holds functional control. The remainder will be transferred to an independent trust. ■

LS Power's Ravenswood Generating Station in Queens, N.Y. | © *RTO Insider*

Generation Projects Added in the Past Week

YES ENERGY



Solar Wind Energy Stoarage Natural Gas Geothermal Nuclear Coal

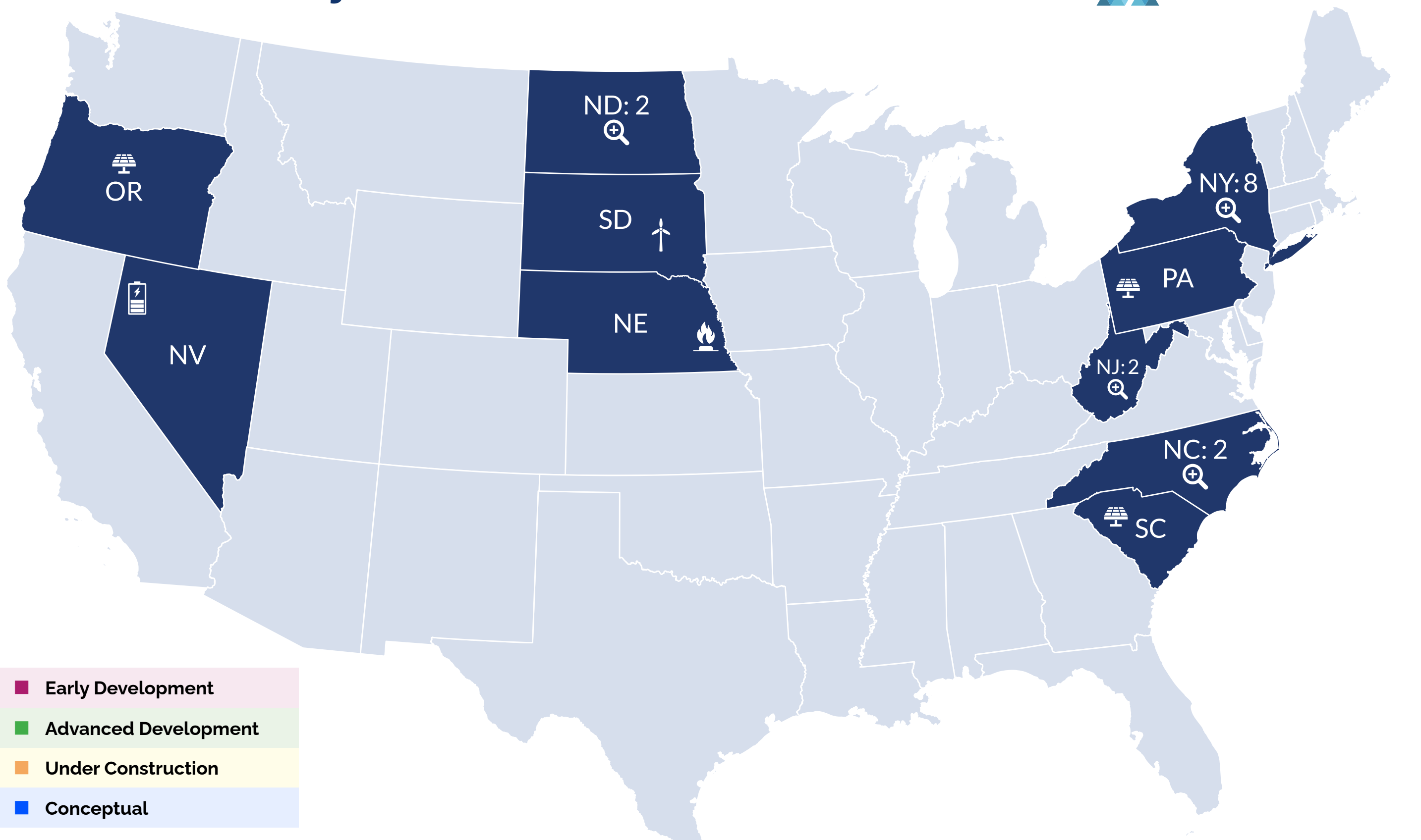
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Beluga Solar Project	Chugach Electric Association, Inc.		AK	10	2028
	Olas S-thon Solar	GRICUA		AZ	20	2026
	Athos Storage	Softbank Group Corp	SB Energy	CA	450	2030
	Nevada Union Solar	Total S.A.	Totalenergies Distributed Generation	CA	1	2026
	Spud Valley Solar	Nextera Energy, Inc.		CO	600	2031
	Spud Valley Solar BESS	Nextera Energy, Inc.		CO	600	2031
	Blacks Creek Storage	Gardner Group	rPlus Energies	ID	200	2027
	Bluebird Solar (ID)	Gardner Group	rPlus Energies	ID	200	2028
	Bluebird Storage	Gardner Group	rPlus Energies	ID	100	2028
	IL Solar Bonacci Project1	Generate Capital		IL	3	2026
	IL Solar Bonacci Project2	Generate Capital		IL	2	2026
	Cincinnati CSG 1	Dimension Renewable Energy	Dimension Energy	IL	5	2027
	Cincinnati CSG 2	Dimension Renewable Energy	Dimension Energy	IL	5	2027
	Crete Goodenow Solar 1	Soltage		IL	3	2026
	IL Forefront - Lena site 1	Brookfield Asset Management	Luminace	IL	2	2025
	IL Forefront - Lena site 2	Brookfield Asset Management	Luminace	IL	2	2025
	VS Great Western Dennis SMART	Valta Energy		MA	2	2028
	VS Hedges Plymouth SMART II	Longroad Energy	Valta Energy	MA	4	2027
	Millbury Landfill Solar	Ameresco		MA	2	2025
	Millbury Landfill Solar BESS	Ameresco		MA	1	2025
	Blue Lake BESS	Xcel Energy	Northern States Power Co	MN	136	2027

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

Generation Projects Added in the Past Week

YES ENERGY



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

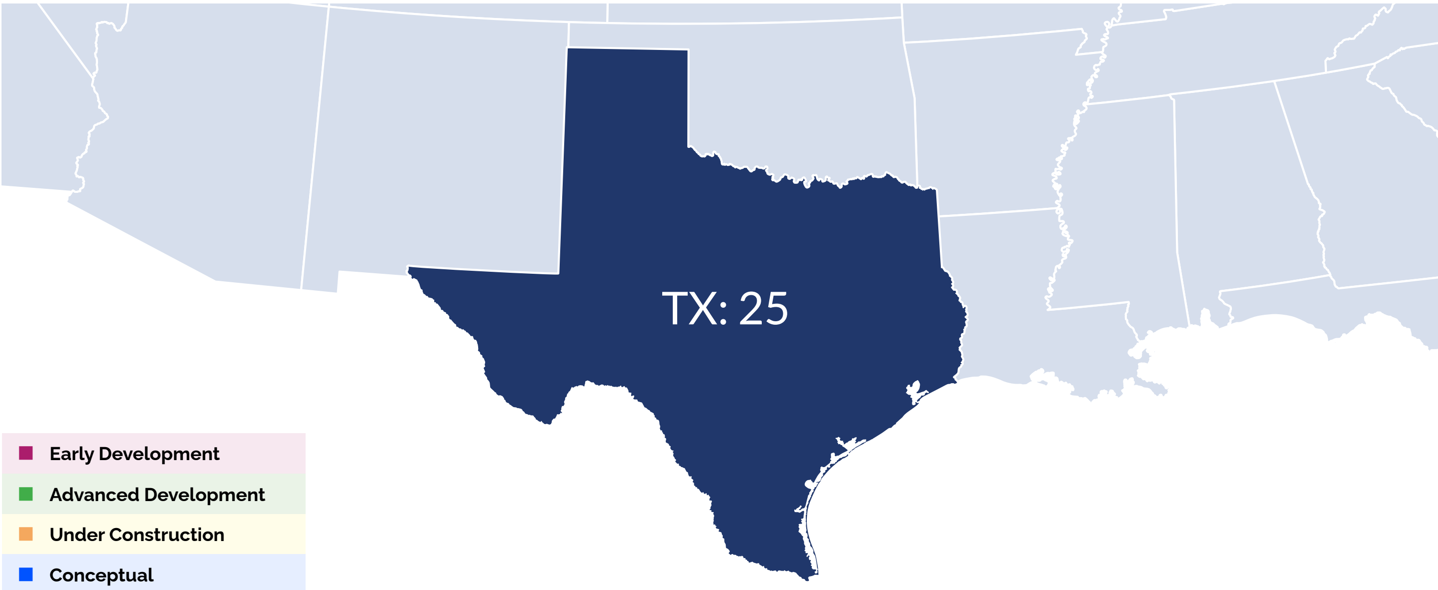
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
Solar	Swift Creek Solar	Enlight Renewable Energy	Clenera	NC	100	2029
Energy Storage	Swift Creek Storage	Enlight Renewable Energy	Clenera	NC	80	2029
Wind	PrairieWinds 1 Repower	Touchstone Energy Cooperative	Basin Electric Power Cooperative	ND		2028
Wind	Minot Wind Repower	Touchstone Energy Cooperative	Basin Electric Power Cooperative	ND		2028
Natural Gas	Cass County 4M	Omaha Public Power District		NE	273	2030
Energy Storage	South River BESS Phase II	American Electric Power	Aep Onsite Partners	NJ	10	2025
Natural Gas	Bergen Natural Gas Unit 1 Uprate	Alpha Generation		NJ	51	2028
Energy Storage	Dodge Flat Storage	Nextera Energy, Inc.		NV	150	2029
Solar	Dutch Hill Solar	Nova Infrastructure	Uge International	NY	5	2027
Solar	Perrysburg Solar	Nova Infrastructure	Uge USA	NY	4	2027
Solar	Kruger Energy Bhatti Solar	Kruger, Inc.	Kruger Energy	NY	4	2026
Solar	Lodi PV	Generate Capital		NY	5	2026
Solar	NY Lyons II	Generate Capital		NY	5	2026
Solar	South Green Haven Solar 1	Generate Capital		NY	3	2026
Solar	Vienna PV	Generate Capital		NY	5	2026
Solar	West Genesee Road Solar 1	Generate Capital		NY	3	2026
Solar	Cartwright Solar I	Ownership Undisclosed		OR	40	2026
Solar	Green Meadows Solar (Harlansburg PV)	LS Power	Rev Renewables	PA	40	2026
Solar	Pit Stop Solar	BNRG Renewables		SC	75	2026
Wind	Crow Lake Wind (PrairieWinds SD1) Repower	Touchstone Energy Cooperative	Basin Electric Power Cooperative	SD		2028

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

Generation Projects Added in the Past Week

YES ENERGY



Early Development

Advanced Development

Under Construction

Conceptual

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

Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
Gaines County CTG	Xcel Energy	Southwestern Public Service Co	TX	1,160	2032
Tolk Station CTG	Xcel Energy	Southwestern Public Service Co	TX	928	2033
Yellow House Wind at Tolk Station	Xcel Energy	Southwestern Public Service Co	TX	300	2030
Ciervo Wind	RWE AG	RWE Clean Energy	TX	302	2031
Barbara BESS	Ownership Undisclosed		TX	201	2030
Black Mountain Hale Gas	Ownership Undisclosed		TX	991	2034
Bunting Solar Project	Ownership Undisclosed		TX	126	2029
Caldwell County Energy Center	Ownership Undisclosed		TX	1,500	2035
Grayback Solar	Ownership Undisclosed		TX	222	2030
Jewett Energy Center 1 Gas	Ownership Undisclosed		TX	1,274	2033
Kilby1 Part 1 Small Block Simple Cycle	Ownership Undisclosed		TX	371	2030
Nabla Energy Storage I & II	Ownership Undisclosed		TX	750	2031
Neal Battery	Ownership Undisclosed		TX	121	2030
Neptune Gas Generation Plant	Ownership Undisclosed		TX	114	2029
Oakley BESS	Ownership Undisclosed		TX	201	2030
Reunion Solar	Ownership Undisclosed		TX	601	2031
Reunion Storage	Ownership Undisclosed		TX	200	2031
Roan Solar Phase 1 & 2	Ownership Undisclosed		TX	206	2031
Soluce Bravo Solar	Ownership Undisclosed		TX	81	2030
Soluce Bravo Storage	Ownership Undisclosed		TX	302	2030
Spurland Solar I & II	Ownership Undisclosed		TX	302	2032
Buffalo Jump Wind	Nextera Energy, Inc.	Nextera Energy Resources	TX	740	2033
Timmerman Power Plant Phase 2B	Lower Colorado River Authority		TX	94	2026
Riviera Gas	BKV Corporation		TX	942	2034
Chevron West Texas Natural Gas	Chevron Corporation	Chevron USA	TX	2,500	2028

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

Company Briefs

Rocky Mountain Power to Investigate Massive Power Outage

Rocky Mountain Power last week announced it is internally investigating a massive, multi-utility power outage that left more than 100,000 customers in Wyoming, South Dakota and Montana without electricity on Nov. 13.

Although several other utilities affected by the interruption noted it originated outside their systems, Rocky Mountain Power says it doesn't know if it originated within its system. The Western Area Power Administration, which was impacted by the interruption, initially described the cause as "triggered by two tripped 500-kV lines near Medicine Bow, Wyo."

It's unclear how much detail the company will offer to the public or when.

More: *WyoFile*

Exxon Halts Plans for Major Hydrogen Plant

Exxon Mobil has paused plans to build one of the world's largest hydrogen production facilities due to weak customer demand, CEO Darren Woods said last week.

"There's been a continued challenge to establish committed customers who are willing to provide contracts for offtake," Woods said.

Exxon announced plans in 2022 to build the plant at its refining and chemical complex in Baytown, Texas, with a goal of producing 1 Bcfd of blue hydrogen. The company and its partners have invested about $500 million so far into the project, which is estimated to cost several billion dollars. Exxon can restart the project when there is enough market demand, though it is unclear when that could be.

More: *Reuters*

First Solar Formally Opens 3.5-GW Factory

First Solar last week formally opened its new $1.1 billion manufacturing facility in Iberia Parish, La.

The plant is forecast to add 3.5 GW of annual production of the company's Series 7 thin-film modules.

The 2.4 million-square-foot facility, one of the largest manufacturing plants in the country, began production in July, several months ahead of schedule.

More: *Renewables Now*

Federal Briefs

EV Sales Plummet in October

U.S. EV sales fell 49% from September to October following the expiration of federal tax credits.

Estimated October new EV sales totaled 74,835 units – down 30.3% from a year earlier. EV share of total sales dropped sharply to 5.8%, falling nearly six percentage points from September's record of 11.6%.

Meanwhile, used EV sales reached 31,610 units, representing a 20.4% decline from September but still showing strong growth at 36.2% year over year.

More: *Cox Automotive*

Report: Industrial Decarbonization Investments Struggling

Between 2018 and the third quarter of 2025, U.S. companies have canceled $17 billion worth of projects in industrial decarbonization projects — exceeding the $15 billion invested in those technologies over the same period, according to a report by the Clean Investment Monitor.

Hydrogen, both green and blue, dominates the cancellations, with companies having scrapped $7 billion of projects.

Looking ahead, $136 billion in outstanding investment remains to be spent across 229 projects in the pipeline that have either not broken ground or are currently under construction. Of that total, at least $14 billion is tied to federal awards that have been revoked by the DOE or are at risk of being so.

More: *Clean Investment Monitor*

National/Federal news from our other channels

NERC Standards Committee Rejects Nuclear Reporting Carve-out — ERO Insider

ERO, Stakeholders Support Proposed Cybersecurity Standards — ERO Insider

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

State Briefs

CALIFORNIA

9th Circuit Pauses Climate Risk Reporting Law

The 9th U.S. Circuit Court of Appeals last week paused a state law set to take effect in January requiring large companies to report climate change financial risks every two years.

The Chamber of Commerce asked the court to pause the law, arguing it violates the companies' First Amendment rights. The state has argued that the law doesn't violate the First Amendment because commercial speech isn't protected the same way under the Constitution. The Air Resources Board estimated more than 4,100 businesses would have to comply with the legislation.

The Air Resources Board said it is reviewing the ruling.

More: *The Associated Press*

EJAC Co-chair Resigns, Cites ARB Conflict

Catherine Garoupa, executive director of the Central Valley Air Quality Coalition and one of two Environmental Justice Advisory Committee chairs, resigned from her role with the committee last week.

In her resignation letter, Garoupa said the Air Resources Board has increasingly dismissed science and shown a bias toward regulated industries "at the expense of low-income communities and communities of color." Martha Argüello, the other co-chair, said she would remain in place to help the transition for new committee members joining next year and to work with the ARB's new chair, but echoed Garoupa's concerns.

More: *Inside Climate News*

Gas Leak Caused Chino Hills Home Explosion

The Chino Valley Independent Fire District last week determined a gas leak was the cause of a home explosion, although they have yet to locate the source of the leak.

The incident, which occurred Nov. 16, left eight people hospitalized with non-life-threatening injuries. Sixteen homes were initially evacuated as the investigation got underway, but residents were able to return later that night.

More: *CBS LA*

IDAHO

High-ranking Officials Ousted from PUC Allege Misconduct in Lawsuit

Two officials ousted from the Idaho Public Utilities Commission filed a whistleblower lawsuit accusing the PUC of violating open meeting laws and wrongfully terminating them.

Maria Barratt-Riley, the former executive director of the PUC since 2012, and Joshua Haver, a former policy strategist, are suing the agency, saying they repeatedly voiced concerns and filed reports over misconduct before being wrongfully terminated. The lawsuit, which was filed in October, accuses commissioners and a senior staff member of violating the state's open meeting law, having *ex parte* communications with officials from companies with open rate cases, creating a hostile work environment, misusing public funds and retaliating against the two employees for reporting such misconduct.

The PUC declined to comment on the lawsuit.

More: *Idaho Statesman*

KENTUCKY

PSC, AG to Appeal FERC Complaint Dismissal

The Public Service Commission and Attorney General Russell Coleman last week said they will appeal the dismissal of a complaint they brought before FERC alleging that Kentucky Power customers were unfairly covering costs of transmission projects in other states.

The complaint said Kentucky Power customers were subsidizing — to the tune of $66 million from 2017 through 2022 —transmission projects "hundreds of miles away" because of a cost-sharing arrangement across seven states. The arrangement included various AEP subsidiaries that are part of PJM. FERC dismissed the complaint because the attorney general and the PSC failed to establish the cost-sharing arrangement for supplemental projects was "in a manner that is unjust and unreasonable or unduly discriminatory or preferential."

More: *Kentucky Lantern*

MAINE

PUC Rejects CMP's Proposed Rate Hike

The Public Utilities Commission last week rejected Central Maine Power's proposed rate increase, saying the utility needs to resubmit a plan that takes long-term resilience planning and the impact on ratepayers into greater consideration.

While the PUC opted to dismiss the request, the commission said it would provide CMP with guidance for developing another plan. The plan would have increased rates for the average customer by $35/month or $420/year by 2030.

More: *Maine Morning Star*

MONTANA

PSC Agrees to Partial NorthWestern Rate Increase

The Public Service Commission last week agreed to a rate increase for NorthWestern Energy of $246 million.

PSC staff last week recommended denying NorthWestern Energy's bid to recover $45 million in cost overruns for its Yellowstone County gas plant, saying the utility did not adequately evaluate more affordable options. The staff also said the utility didn't manage risks in a cost-effective way and likely could have avoided $45 million in cost overruns. It recommended the commission reduce NorthWestern's proposed $287 million rate base to $227.7 million.

More: *KTVH*; *Daily Montanan*

NEBRASKA

OPPD Again Delays Decision on North Omaha Plant

The OPPD Board of Directors again delayed their vote on whether to stick to the company's original plan for the North Omaha power plant by shutting

down three units that were converted to natural gas in 2016 and converting the two remaining coal-only units to natural gas. The board first delayed a decision in October.

OPPD CEO Javier Fernandez urged the board to keep the plant running, while residents voiced anger at Fernandez and board members for possibly going back on their original plans.

The board will take public comments for 30 days before voting in December.

More: *WOWT*

NEVADA

PUC Upholds NV Energy's Billing Change

The Public Utilities Commission last week reaffirmed its approval of NV Energy's daily demand rate design.

In September, the PUC authorized the utility to start basing customer bills on the maximum amount of electricity used during a single point of the day, rather than following the traditional practice of charging based on total electricity consumed. The PUC determined that because NV Energy's distribution facilities are built to handle the maximum amount of energy a customer requires at any point in time, it logically follows that a rate structure should be tied to a customer's max demand on the system, according to the draft order issued.

Groups submitted various requests for reconsideration, arguing state law prohibits the setting of residential rates based on the time of day, day of week or time of year. The groups are now considering legal options.

More: *The Nevada Independent*

OREGON

Gov. Kotek Wants Agencies to Speed up Permitting

Gov. Tina Kotek last week issued an executive order directing state agencies to speed up energy project permitting and processes to connect renewable energy to the state's grid.

Kotek wants state land and natural resource agencies to collaborate on strategies by September 2026 that will lead to policy proposals for the Legislature to take up in 2027. They must advance the state's target of reducing greenhouse gas pollution 50% by 2035 and 90% by 2050, as established in a 2021 executive order by former Gov. Kate Brown.

The state energy strategy also calls for the state to add 8 GW of energy storage by 2045.

More: *Oregon Capital Chronicle*

PacifiCorp Reaches $150M Wildfire Settlement

PacifiCorp last week announced it reached a $150 million settlement with 1,434 plaintiffs for the 2020 Labor Day weekend wildfires.

The utility has denied accusations it was negligent in failing to shut off power lines during a windstorm. Oregon and the U.S. government are also suing PacifiCorp over damage to natural resources.

The payout boosts the amount PacifiCorp has agreed to pay wildfire claimants to close to $1.7 billion.

More: *Reuters*

UTAH

Hi Tech Solutions, Holtec Partner with DNR to Manufacture SMRs

The state Department of Natural Resources last week announced it has partnered with Holtec and Hi Tech Solutions on a proposed hub for small modular nuclear reactor manufacturing, workforce training and power generation in Brigham City.

To reach the partnership's goals, the companies need to build multiple SMRs, with four in northern Utah and others in different sites across the state and the West, said Hi Tech Solutions co-founder Chris Hayter.

More details and project milestones will be announced in the coming months.

More: *Utah News Dispatch*

VIRGINIA

Spanberger Appoints Energy Policy Transition Team

Governor-elect Abigail Spanberger last week made three appointments to her energy policy team in Josephus Allmond, Will Cleveland and Angela Navarro.

Allmond is a staff attorney at the Southern Environmental Law Center and part of the Commission on Electric Utility Regulation. Cleveland is an energy and environmental lawyer through Lighthouse Policy & Law. Navarro was a member of the Corporation Commission before becoming the president of Align Energy Advisors.

More: *Virginia Mercury*