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YES ENERGY

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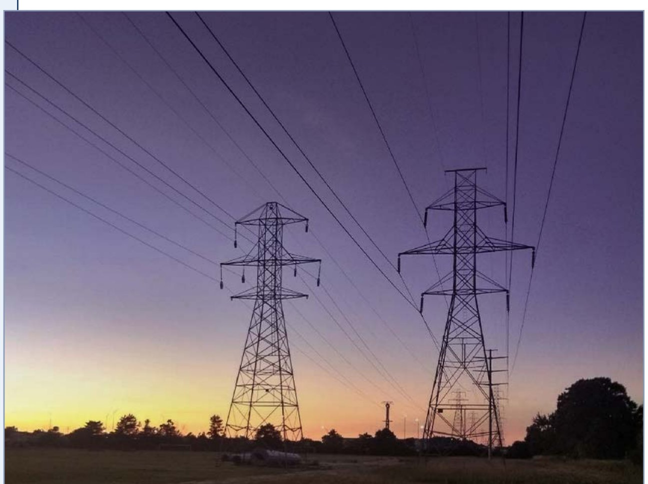
FERC Issues Order 1920-B Upholding States' Role in Cost Allocation



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Ensuring that state cost allocation agreements are filed with FERC is a major focus of Order 1920, and its two iterations, which face review at the 4th U.S. Circuit Court of Appeals.

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MISO

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MISO: DR to Face More Stringent Testing by 2026 Capacity Auction (p.28)

MISO is set on abolishing the hypothetical testing of capabilities of its demand response fleet by the 2026 capacity auction, in response to five recent instances of disciplinary action for allegedly deceitful activity.

PJM

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PJM CEO Manu Asthana Announces Year-end Resignation (p.43)

Asthana joined PJM as CEO five years ago, just as it was emerging from controversy related to FTR trading.

NYISO

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NY Energy Summit: Patience Trumps Angst (p.35)

Constraints and uncertainty face New York's ambitious energy plan as President Donald Trump revises the parameters on which it is based.

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In this week's issue

Groove on the Rubble

By Steve Huntoon

Steve Huntoon

The last couple weeks remind me of the 1971 comedy record by David Frye during the Nixon administration. Richard Nixon (Frye) hosts yippie Jerry Rubin (Gabe Kaplan) in the White House, trying to make a political connection.

And I need to stop to clarify that "yippie" back then meant members of the Youth International Party.

Nixon asks, "Tell me, Mr. Rubin, what would you do after everything was torn down?" And Rubin replies, "I don't know, man, maybe we'll just sit there and groove on the rubble."

Yeah man, just groove on the rubble.

We'll skip over everything else in the past couple weeks and ask what to make of the Trump administration's latest *executive order* directing FERC, an independent agency, to sunset its regulations in no more than five years (or explain why not). In apparently unintended irony, this is "to provide certainty and order."

The *"fact sheet"* for the executive order talks repeatedly about "energy production," which suggests the Trump Administration doesn't know what FERC does. FERC has no direct role in the production of energy except for the licensing of hydroelectric plants (and arguably qualifying facilities under the Public Utility Regulatory Policies Act, which the executive order inexplicably excludes).

FERC is told to sunset all its regulations implementing the Federal Power Act of 1935 and the Natural Gas Act of 1938 in one year but no more than five years. But these statutes don't exist in any intelligible way without the implementing regulations that have been promulgated and judicially affirmed over the last 80-some years.

Most recently we have the long-term transmission planning regulations in Order 1920. So let's see how this works: they govern transmission planning for the next 20-plus years, but they're terminated in one year or five years?

FERC headquarters in D.C. | © *RTO Insider*

The executive order requires FERC to issue a "sunset rule" for each of its regulations by Sept. 30, 2025, to eliminate each of its regulations by Sept. 30, 2026, except for such regulations that FERC finds should be extended based on "costs and benefits."

How can FERC get rid of regulations it is required by statute to have? How can FERC amend each of its regulations to add a sunset date without conducting formal rulemakings to do so? How can FERC apply a "costs and benefits" standard (whatever that might be) to its regulations rather than the statutory standards?

FERC is required to coordinate all this with its "DOGE team lead" and with the Office of Management and Budget (OMB). Does FERC have a DOGE team lead employee, as it apparently is required to have per an earlier *executive order*? How can the DOGE team lead, a FERC employee, coordinate with DOGE, and how can FERC coordinate with OMB, on rulemakings to sunset FERC's regulations without violating FERC's ex parte rules?

This comes on the heels of a February *executive order* regarding FERC and other "so-called independent agencies" (note the "so-called" pejorative) that:

- gives OMB control of FERC resources.
- requires the FERC chair to "regularly consult with and coordinate policies and priorities with the directors of OMB, the White House Domestic Policy Council and the White House National Economic Council."
- gives the attorney general control of all "questions of law" involving FERC.
- subjects all draft FERC regulations to review by OMB.

Good luck to Chair Mark Christie, his FERC colleagues and our industries.

(P.S. And let us pray for the return of *Kilmar Armando Abrego Garcia* so none of us have to fear arbitrary U.S. government kidnapping to foreign gulags where we must spend the rest of our lives.) ■

— Columnist Steve Huntoon, a former president of the Energy Bar Association, practiced energy law for more than 30 years.

FERC Issues Order 1920-B Upholding States' Role in Cost Allocation

By James Downing

FERC issued *Order 1920-B* on April 11, denying rehearing requests on its previous iteration that mostly sought to overturn requirements that transmission planners file cost allocation methods agreed on by state regulators and that they are consulted on future reforms.

Order 1920 gave states in a planning region six months to work on a cost allocation methodology, but it declined to require that they be filed by the ISO/RTO or other planning entity. That changed with Order 1920-A, which did require any agreed-upon cost allocation methods to be filed.

Edison Electric Institute, WIRES, and some regional transmission owner groups argued in separate rehearing requests that forcing transmission owners to file state cost allocation methods, even if they disagree with them, intrudes on their filing rights under the Federal Power Act's Section 205. That part of the law gives public utilities unilateral and exclusive filing rights to propose rates, terms and conditions of service that essentially places FERC in a reactive role.

But FPA Section 205 is complemented by Section 206, which provides FERC with the authority to modify any existing rates after a finding that they are unjust, unreasonable or unduly discriminatory.

A group of MISO transmission owners argued that the requirement to file state agreements disrupts the balance set by those two sections of the law — "allowing FPA Section 206 to usurp FPA Section 205," the order said.

"The compliance filings required by Order Nos. 1920 and 1920-A are a tool to implement the commission's authority under FPA Section 206 and do not implicate public utilities' rights and obligations under FPA Section 205," FERC said.

FERC issued Order 1920 and 1920-A under a Section 206 process that it initiated, which included a finding that its existing regional planning and cost allocation rules were unjust and unreasonable. The submission of compliance filings assists in implementing FERC's authority under Section 206.

"The express text of FPA Section 206 does not provide public utilities with statutory filing rights with respect to the just and reasonable replacement rate following a finding that existing rates are unjust, unreasonable, or unduly discriminatory or preferential," the order said. "Rather, the authority to 'determine the just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed and in force' is vested in the commission, and — in commission-initiated proceedings under FPA Section 206 — the commission must find that the replacement rate it determines and fixes meets the statutory criteria."


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Why This Matters

Ensuring that state cost allocation agreements are filed with FERC is a major focus of Order 1920, and its two iterations, which face review at the 4th U.S. Circuit Court of Appeals.

The law does not preclude FERC from requiring transmission providers to file state cost allocation methods. And just because a public utility has to file a compliance filing does not transform that into a Section 205 filing.

"A contrary conclusion would fail to recognize and give effect to the distinct and express statutory authority afforded to the commission in FPA Section 206, which arises pursuant to specific statutory findings and which, once triggered, is subject to different requirements than FPA Section 205 filings," the order said.

While Section 205 does give public utilities exclusive filing rights, when considered in the correct statutory context the arguments that require them to file state cost allocation agreements are not persuasive.

"FPA Section 205 is not implicated by these aspects of Order No. 1920-A, and arguments to the contrary conflate compliance filings to assist the commission in implementing its authority under FPA Section 206 with public utilities' rate filings under FPA Section 205," the order said.

Part of the debate goes to a court case from Atlantic City where FERC tried to require public utilities to cede their Section 205 filing rights to an RTO (PJM in the court case). The court found that FERC could not deny utilities statutory rights given to them by Congress.

Order 1920 does not remove those filing rights, because the requirement to file state cost allocation agreements falls under FERC's authority to set a replacement rate under Section 206.

Transmission owners also made arguments that imposing the state filing requirements goes against the Administrative Procedures Act. FERC responded that given how important state engagement is to getting large, regional transmission lines built, it makes sense to ensure they have meaningful participation in the process.

"The commission found that the additional requirement would allow it to better evaluate whether transmission providers have complied with Order No. 1920's requirement to provide a forum for negotiations that enables meaningful participation by relevant state entities during the engagement period," the order said.

A group of PJM transmission owners argued the requirement goes against the First Amendment to the Constitution by compelling speech.

"Order No. 1920-A imposes no actual burden or limitation on transmission providers' speech but instead requires nothing more than the attachment of one or more files, containing the information provided by relevant state entities, to transmission providers' compliance proposals under FPA Section 206," the order said.

Another item that transmission owners filed for rehearing was the requirement that regional planners consult state regulators before amending long-term cost allocation arrangements, making similar arguments about the FPA.

FERC disagreed again, saying the consultation requirement does not regulate Section 205 filing rights but rather addresses the practices through which cost allocation methods are developed, which is tied to the likelihood such lines actually get built.

"In Order No. 1920-A, the commission determined — and we here sustain — that requiring transmission providers to consult with relevant state entities will provide an opportunity for state input, which 'has the potential to minimize additional costs and delays in the siting process and to facilitate the development of long-term regional transmission facilities,'" the order said.

One area where FERC did tweak Order 1920 was to clarify that regional transmission plans can consider the needs of non-jurisdictional utilities if they voluntarily agree to pay their fair share under regional cost allocation.

The National Rural Electric Cooperative Association and transmission owners in the WestConnect regional planning area argue the previous language could be interpreted to ban any planning around non-jurisdictional utility needs.

If a non-jurisdictional utility has not voluntarily enrolled in a transmission planning region, its needs cannot be addressed. But if they have signed up for a region, then they can as long as the compliance filing can show FERC there is no free ridership issue. ■

ACP Road Map Suggests Market Changes to Increase Storage Participation

By James Downing

The American Clean Power Association on April 8 released a report produced by The Brattle Group laying out how organized markets can replicate the success CAISO and ERCOT have had in deploying energy storage resources.

The "*Energy Storage Market Reform Roadmap*" includes detailed changes for the energy, capacity and ancillary services markets, with individual "road maps" for MISO, NYISO and PJM guiding how to grow storage in their territories.

The report and road maps focus on those grid operators because they have "opportunities for market reform," their states are pursuing decarbonization, and they have a mix of central planning and market-based investment.

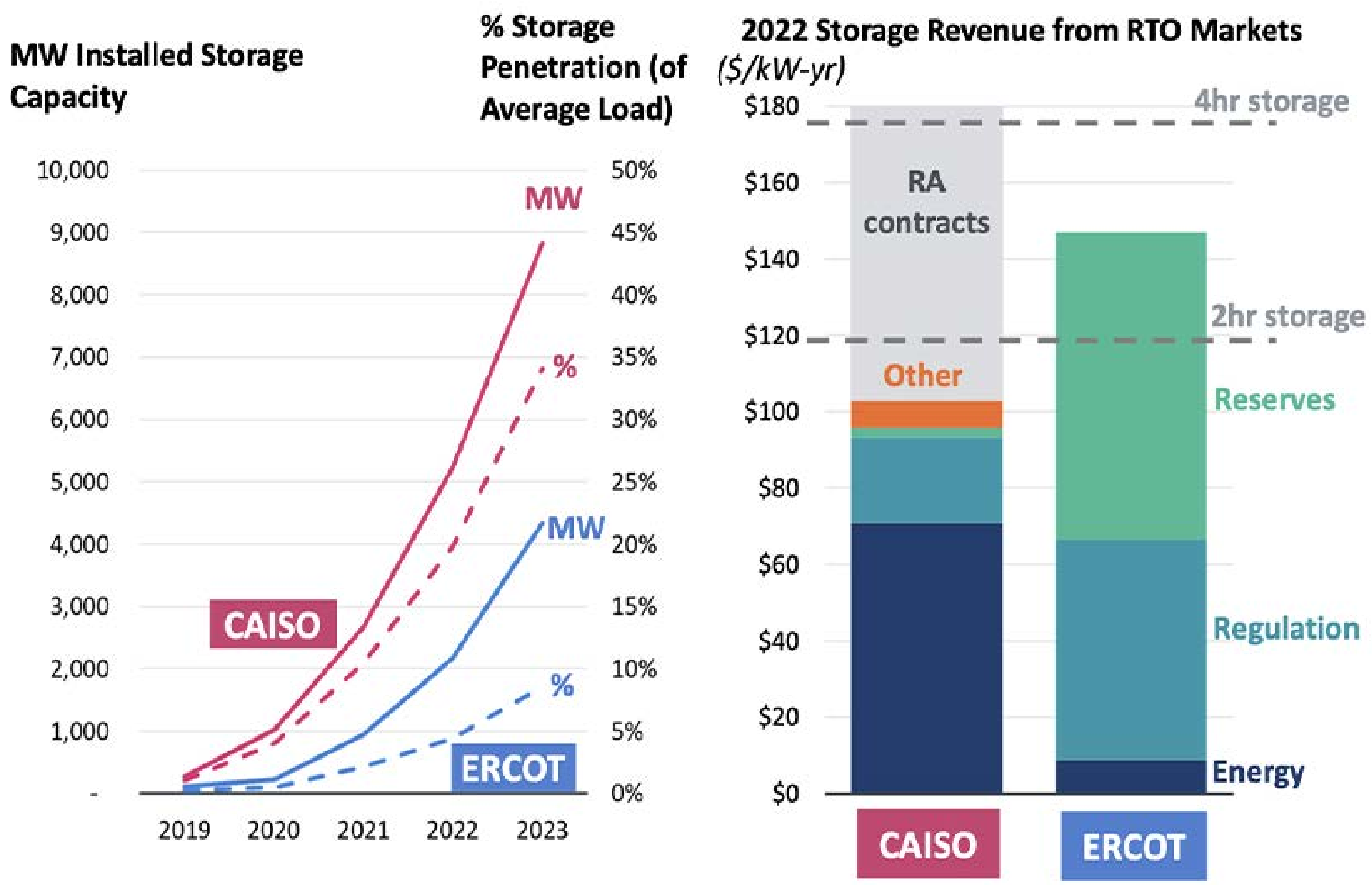
CAISO and ERCOT have shown that with updated market rules, energy storage delivers substantial value and complements both thermal and renewable generation to help meet reliability needs.

"Energy storage technologies add a new dimension of flexibility and efficiency to our electric grid," ACP Vice President of Energy Storage Noah Roberts said in a statement. "Energy storage has proven to boost reliability and lower energy costs. In Texas, the state added 5 GW of energy storage in one year, eliminating calls for customers to reduce electricity use during historic summer heat, stabilizing the grid through volatile winter storms, all the while delivering more than a billion dollars in energy cost savings. This road map outlines actionable steps to better utilize energy storage to deliver reliable and affordable power across the United States."

Why This Matters

CAISO and ERCOT have seen storage grow significantly in recent years. ACP's report offers ways to replicate that success in MISO, NYISO and PJM.

Before FERC issued Order 841 in December 2020 to open up the RTOs to energy storage, the resource faced barriers to participation in the markets, which were designed around the attributes of other generators. Where the organized markets have encouraged deployment and removed barriers, storage has helped prevent blackouts and reduced pressure on customers during tight operating con-



The growth of storage in CAISO and ERCOT and revenue streams from both markets | *The Brattle Group* ditions on the grid, while delivering cost savings, ACP said.

One of the areas the report and road maps focus on is the need to replace retiring generation while maintaining reliability and meeting growing demand in many parts of the country. Storage can help replace the reliability services retiring generation provided while keeping a lid on high capacity prices, ACP said.

Many generators were planned to support local transmission needs, especially when they were built in load pockets. Retirements will continue to trigger transmission violations, and some of those are too localized for capacity markets to solve.

The industry's historic answer for those situations is to build transmission, and sometimes to keep power plants running with out-of-market, reliability-must-run contracts while that is built. But storage, or non-wires alternatives, can contribute to solving those issues at lower costs to consumers, the paper says. "RTOs should identify solution(s) that lead to the lowest costs for ratepayers when procuring reliability solutions out of market."

Some RTOs, including PJM, do not consider non-wires alternatives for retiring generators. Others do, but they are rarely picked because of a lack of comprehensive benefit-cost analysis, which is exacerbated by the short notice period between the solicitation date and required online date, the report says.

On average in PJM, RMRs have cost $300/MW-day, which is well above the market clearing prices in the long term of $100/MW-day, according to the paper. Studies have shown the benefits of competitive solicitations both in transmission infrastructure procurement and generator procurement, it says.

Energy storage — especially long-duration and multiday — may be able to resolve both transmission security constraints and provide flexibility value to the grid, the report argues.

The report highlights how CAISO oversaw a process to replace the 165-MW Oakland gas plant that announced its retirement in 2016. The ISO picked Pacific Gas and Electric's Oakland Clean Energy Initiative, which included some transmission upgrades, storage and demand response that met the need at a lower cost than transmission or generation solutions alone.

It also pointed to NYISO's efforts to replace the dual-fuel Narrows and Gowanus plants that were slated for retirement this year. The plants were to be replaced by the Champlain Hudson Express Line to bring hydropower down from Quebec, but the line was delayed until 2027.

NYISO identified a short-term reliability need and issued a competitive solicitation for a solution, but none of the responses could solve it in time. Recently, NYISO said the peaker plants will still be needed for the next couple of years. (See related story, *NYISO Reaffirms Need for NYC Peakers in Summer*.)

"As electricity grids struggle to keep pace with the feverish growth in energy demand across the country, every electron of power counts," Eolian COO Stephanie Smith said in a statement. "Battery energy storage helps both thermal and renewable energy technologies optimize their participation and increase reliability and resilience by providing power when and where it is needed quickly. By updating existing rules to account for new technologies, regional electricity markets can enhance grid performance and lower costs for consumers." ■

Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies

By James Downing

President Donald Trump signed a series of executive orders April 8 that seek to keep existing coal-fired power plants running, ease regulations and permitting for coal mining, and remove "unlawful and burdensome" state laws that impede the industry.

The president also issued a *proclamation* that coal plants be exempt from the latest iteration of the Mercury and Air Toxics Standard, which the White House *said* will ensure they are not prematurely closed.

"For four long years, Joe Biden and congressional Democrats tried to abolish the American coal industry," Trump said at a White House ceremony flanked by coal miners. "They did everything in their power — while he was awake, which wasn't much — shutting down dozens of coal plants, upending coal leases on federal lands, and putting thousands and thousands of coal miners out of work."

Trump *ordered* the secretary of energy to use Federal Power Act Section 202(c), which is meant to be used as a backstop to keep plants running for reliability even if that violates environmental rules, in a much broader way than previously used.

The president also *called on* the Department of Justice to go after "unconstitutional" state laws that limit the use of domestic energy resources, including coal and other fossil fuels.

Why This Matters

This is Trump's second attempt to bail out the coal industry, akin to the failed DOE NOPR that FERC voted down in his first term. This time the president is using DOE, DOJ and other departments to help coal plants stay open and challenge state policies that are seen as anti-coal.

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The final *order* is titled "Reinvigorating America's Beautiful Clean Coal Industry" and includes measures to open more federal land to coal mining.

The White House's fact sheets tied to the announcements cite the recent return to demand growth from the expansion of data centers, which are expected to drive up overall demand by 16% in the next five years. They also call coal "essential" to the power grid, making up 16% of total generation, which is down from 52.8% in 1990, according to the Energy Information Administration.

Coal generation has been on a steady decline since 2007 when it produced 2,016 billion kWh, falling to just 675 billion kWh in 2023, according to EIA.

"It is highly unlikely, in fact, probably zero probability, that anyone will ever build a new coal plant," energy consultant Alison Silverstein said in an interview.

Coal generation is more expensive to build than natural gas, which is facing stiff competition on its own from renewables in the markets. The best any policies can do would be to keep coal plants running longer, and that means going against decades of efforts to clean up the grid, Silverstein said.

Silverstein wrote a report for the Department of Energy in Trump's first term when then-Energy Secretary Rick Perry submitted a Notice of Proposed Rulemaking with FERC that would have had grid operators pay coal plants their full operating costs. Her report said that was not needed, and FERC voted the proposal down unanimously 5-0 after several of Trump's appointees had taken office.

FERC is not the focus of the current efforts, though some of the executive orders indicate the cabinet secretaries could consult with the agency as the policies are implemented.

The executive order on "Strengthening the Reliability and Security of the United States Electric Grid" directs Energy Secretary Chris Wright to "streamline, systemize and expedite" the Department of Energy's process for issuing orders under Section 202(c). It gives the secretary 30 days to review and analyze forecasted reserve margins for all regions of the bulk power system regulated by FERC to identify those with margins "below acceptable thresholds as identified by the secretary."

DOE will have to release that analysis in 90 days and then use it to identify at-risk plants of 50 MW or above. It will then use its 202(c) authority to prevent them from leaving the grid, or from converting fuel sources if that leads to a net reduction in generating capacity.

Recent uses of Section 202(c) have focused on maintaining reliability in extreme weather, and in many cases it was only in effect for days, according to *DOE*. A famous case from 20 years ago kept a plant in Alexandria, Va., open to avoid blackouts in D.C., including the White House (*EL05-145*).

One issue that will have to be addressed is what compensation any coal plants required to stay online are due. Most of the existing coal fleet is already uncompetitive and most are inefficient, Silverstein said.

"Keeping them running is costing the local utility ratepayers money because it is more expensive to buy coal production and to keep the coal plants running than it is to buy in the market from renewables or gas," Silverstein said. "So, the thing that they are doing is essentially keeping these plants going by raising everybody's costs."

"Protecting American Energy from State Overreach" directs the Department of Energy to go after state policies that "target or discriminate against out-of-state energy producers." The order specifically calls out climate policies enacted by California, New York and Vermont.

"These laws and policies also undermine federalism by projecting the regulatory preferences of a few states into all states," the order says. "Americans must be permitted to heat their homes, fuel their cars and have peace of mind — free from policies that make energy more expensive and inevitably degrade quality of life."

The order calls on Attorney General Pam Bondi to identify all such state laws and to prioritize challenges to laws purporting to address climate change, environmental justice, carbon or greenhouse gas emissions, and funds to collect carbon penalties and taxes. "The attorney general shall expeditiously take all appropriate action to stop the enforcement" of such state laws and file a report in 60 days on those efforts, which will include recommendations for additional executive actions or legislative measures."

Reactions to the executive orders were mixed, with some saying they will help maintain reliability and others saying they are bad for the environment and consumers.

National Renewable Electric Cooperative Association CEO Jim Matheson and co-op executives from around the country were at the White House in support of Trump's actions. NRECA members own at least part of 79 coal units with 21 GW of capacity, and 11 of them, totaling 3 GW, are currently scheduled to retire between now and 2030.

"At a time when electricity demand is skyrocketing, we need to be adding more always-available energy to the grid, not shutting down power plants that have useful life left," Matheson said in a statement. "Electric co-ops provide reliable power to communities across the country. Today's announcements help drive home smart energy policies that will support efforts to keep the lights on at a price families and businesses can afford. We thank the administration for recognizing the continued importance of always-available resources in the nation's energy mix."

Rep. Julie Fedorchak (R-N.D.), who was president of the National Association of Regulatory Utility Commissioners before assuming office this year, also praised the action, having introduced a *resolution* warning about growing demand and retiring plants April 7.

"At a time when reliable baseload power is being shut down without adequate replacement, his executive orders are exactly what we need," Fedorchak said. "With electricity demand from AI and data centers surging, the U.S. urgently needs always-available power — and that's what coal provides, especially the mine-mouth coal power we produce in North Dakota."

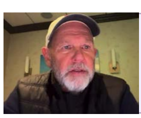
Environmental Defense Fund Director Ted Kelly blasted the orders, saying that they could not overcome the market realities faced by coal. He also took issue with the use of FPA Section 202(c) and vowed to oppose the White House's efforts.

"That law is designed for, and limited to, sudden emergencies creating an immediate risk of blackouts or other grid instability, such as storms, wildfires or sudden major infrastructure failures," Kelly said. "It is time-limited for the same reason, and it further limits any power generation that conflicts with environmental laws or regulations to the minimum hours needed to address the emergency. Changes to the power system over time, like load growth driven by data centers or power plant retirements driven by economics, are properly addressed by planning and action by utilities and their regulators — not by irrational and unlawful emergency actions."

Based on the market realities and likely challenges from EDF or Democratic state attorneys general, Silverstein predicted this second-term effort to bail out coal would wind up much like the failed NOPR from Trump's first term.

"This particular effort, I think, is going to have more grandstanding impact than actual impact," Silverstein said. "I think it will affect a few coal plants and a few coal-mining and coal-plant communities, and it's going to raise costs for everybody. But it's hard to imagine any data center wanting to sign a contract with a 60- to 80-year-old coal plant." ■

National/Federal news from our other channels



Robb: NERC Working with DOE on Energy Orders — ERO Insider

Texas RE Offers Compliance Help for New Registrants — ERO Insider

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Report Estimates Billions in Savings from More Interregional Transmission

Authors Outline Resistance to Creating Greater Levels of Market Integration

By John Cropley

The authors of a new report released April 4 say better market integration and reduced interregional constraints in the U.S. transmission network would have saved as much as $12 billion in 2022 and 2023.

They note the importance of achieving better grid integration in an era when increasing amounts of renewable generation is coming online but flag the difficulty of achieving it, given the financial incentive existing generators have to delay or block such integration.

The working paper, *"Power Flows, Part 2: Transmission Lowers US Generation Costs, But Generator Incentives Are Not Aligned,"* was written by Dasom Ham, Owen Kay and Catherine Hausman as part of *Resources for the Future*'s Obstacles to Energy Infrastructure research project.

They write that geographic constraints and mismatched supply and demand are growing as intermittent wind and solar capacity come online, often far removed from high-demand areas.

Better integration of electricity markets could allow systemwide cost savings and therefore lower consumer costs, the paper says. Integration of existing supply across regions could have saved $5.8 billion to $7.1 billion under 2022 conditions (which included higher natural gas prices) and $3.4 billion to $5 billion under 2023 conditions.

Other savings that could be created by intraregional integration were not estimated, nor does the report offer a full cost-benefit analysis of building new transmission or look at the cost versus societal benefit of building renewables.

But such integration would also create winners and losers, as existing generators in high-demand markets see their net profits drop and renewables in high-supply markets avoid curtailment.

The structure and processes of markets give those incumbents many opportunities to delay or block transmission construction projects that would run counter to their interests, and the report highlights case studies in multiple regions where they appear to have done just that.

This opposition can be hidden within workings of RTOs or it can be publicly visible, such as NextEra Energy's long-running but unsuccessful fight to thwart Avangrid's construction of the New England Clean Energy Connect, which will bring up to 1.2 GW of cheap Canadian hydropower to a region where NextEra operates multiple power plants.

The analysis showed these dynamics vary substantially by region: Greater market integration would benefit existing power producers in the Great Lakes, Great Plains and Rocky Mountain regions but hurt producers in the Northeast and Southeast.

Why This Matters

The anticipated benefits of interregional transmission and market integration in some cases would come at the expense of influential stakeholders.

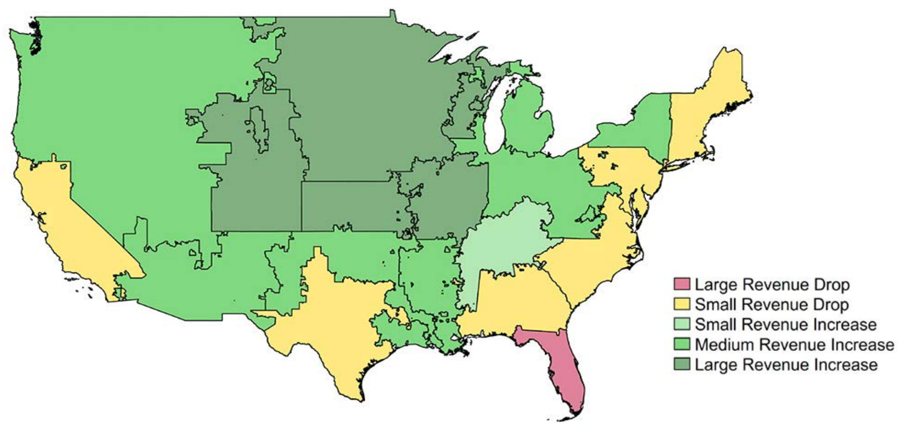
The barriers to siting, planning, permitting and construction of transmission are well known, and include cost allocation, land rights and environmental clearance. Importantly, transmission planning and changes to market structure for interregional electricity trade depends largely on the consensus of incumbent generation companies, who hold greater sway than stakeholders who would see cost savings.

Investment patterns in recent years show the result of these dynamics: Only 2% of new circuit miles installed from 2011 to 2020 were for interregional transmission lines, and the majority of all transmission investments were for local reliability concerns rather than generation cost savings.

The new report builds on *"Power Flows: Transmission Lines, Allocative Efficiency and Corporate Profits,"* a working paper written by Hausman and issued by the National Bureau of Economic Research in January 2024.

The earlier report focused on the MISO and SPP regions, but the new report looks at the entire continental U.S. The dynamics are similar and can be generalized, but MISO and SPP do have some distinctive features, and there were some limitations in extending the research design to the rest of the country.

Data was obtained primarily from the Energy Information Administration and EPA's Continuous Emissions Monitors Systems datasets. ■



Projected effect that market integration would have on net profits for a new natural gas generator in recent years. "Small revenue" changes are defined as up to $10 million per year, and "large" as more than $20 million. | *Resources for the Future*

CEC Approves Reliability Program Revisions After Pushback from CPUC

PG&E Distribution Service Customers Excluded from CEC Program

By David Krause

The California Energy Commission on April 10 approved revised guidelines for a reliability program after the state's utility regulator in March said the effort could undermine certain benefits of a separate reliability program run by Pacific Gas and Electric (PG&E).

The CEC program in question — the Demand Side Grid Support (DSGS) program — is part of the agency's Strategic Reliability Reserve (SRR) initiative, developed in 2022 as part of Assembly Bill 205. When the DSGS began in 2022, participants contributed 315 MW to help meet grid needs during a summer 2022 heat wave.

In March, the CEC planned to approve revised DSGS program guidelines, but held off on the decision due to a California Public Utilities Commission letter to the CEC saying the revised guidelines "overlap substantially" with PG&E's Automated Response Technology (ART) program.

The DSGS targets the same market segments and devices and is "likely to undermine the new resource adequacy benefits and other goals of the market-integrated ART program," Leuwam Tesfai, CPUC deputy executive director for energy and climate policy, said in the letter.

PG&E's ART program has begun enrolling customers and has capacity commitments under contract, Tesfai said.

The CPUC was specifically concerned that DSGS's Option 4, the Emergency Load Flexibility virtual power plant (VPP) pilot, conflicted with ART. The revised DSGS therefore excludes PG&E distribution service customers from participation in Incentive Option 4.

If a participant joins a conflicting program, such as ART, the participant's DSGS provider will be notified, and the participant will be suspended indefinitely until the conflict is resolved, the guidelines say.

In the DSGS, entities such as publicly owned electric utilities (POUs) and community choice aggregators (CCAs) are eligible to serve as load flexibility VPP aggregators, the revised guidelines say. A load flexibility VPP event contains up to two core hours, which are the peak price hours defined as the two consecutive hours in the daily availability window with the highest mean CAISO energy price, the guidelines say.

Stakeholders raised concerns with the delay in approving the guidelines, saying waiting interferes with providers' and participants' plans for program participation for 2025.

Why This Matters

The CEC's decision should strengthen the Demand Side Grid Support program's contribution to California's Strategic Reliability Reserve.

"It is especially concerning that the CPUC requested a delay on the date of the business meeting at which approval was to happen, given that the proposal to add Option 4 was publicly available and the CEC invited input beginning in October 2024," Kate Unger, senior policy adviser at the California Solar & Storage Association, said in a March 21 letter to the CEC. "PG&E and the CPUC had sufficient opportunity to raise concerns about the ART program throughout the revision process this year."

| © RTO Insider

CEC Approves Air Capture Grants

At the meeting, the CEC also approved three grants for companies working on direct air capture (DAC) methods. A major issue with DACs is that they require a large amount of water: 1.6 tons of water per ton of CO_2 captured for most commercial DAC systems, according to the CEC. To help solve this issue, the CEC awarded Circularity Fuels funding to improve its technology by eliminating the need for steam (and thus water). The project will also help the company demonstrate scalability from 5-kW to 50-kW systems and validate the product's performance in real-world conditions.

The second grant went to Noya, an Oakland-based company, to improve its product's materials and CO_2 regeneration. The third and final grant went to Berkeley-based AirCapture, allowing the company to design, develop and test a DAC system that uses microwave energy for sorbent regeneration. ■

Western Commissioners Ramp up Wildfire Efforts

Fire Prevention Must be 'Collective Responsibility,' Wyoming Regulator Says

By Henrik Nilsson

LA JOLLA, Calif. — Western lawmakers have advanced efforts to provide the power industry with guidance amid increased wildfire risk, regulators discussed during the joint spring conference of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB).

After California passed Assembly Bill 1054 in 2019, the Golden State has launched several initiatives aimed at ensuring the law is integrated with how utilities "build, operate and maintain California's electric system," Caroline Thomas Jacobs, director of the Office of Energy Infrastructure Safety at the California Natural Resources Agency, said during a panel discussion on April 2.

AB 1054 established a wildfire fund that paying utilities can tap into to pay claims for damages resulting from a wildfire caused by utility equipment. Money in the fund comes equally from utility ratepayers and shareholders. (See *California Wildfire Fund Could be Model for US, Panelists Say*.)

The law also established a fire certification element. Safety certification requirements in California include having a wildfire mitigation plan, safety culture assessments and evidence of making progress on previous plans. In addition, executive compensation must be based at least 50% on safety metrics.

Thomas Jacobs said utilities have made significant progress, but "clearly, the risk has not been eliminated."

"There's 150 years of infrastructure out there that is built to allow sparks," Thomas Jacobs said. "So, in today's given environment, we're not going to eliminate that risk overnight, but we are trying to layer that now into what the broader state effort is."

Why This Matters

As wildfire risks increase, state legislatures are seeking ways to mitigate utility-related fires while also enhancing collaboration within the power industry.

Recent efforts to integrate utility efforts with the broader state system under AB 1054 include developing partnerships "so that we can start leveraging the massive amounts of investments that the utilities are investing on wildfire and making sure that's paired with … the broader state system around wildfire resilience," Thomas Jacobs said.

Also, the state's Wildfire Mitigation Advisory Committee is coordinating initiatives with the Department of Insurance, communities and utilities to integrate wildfire mitigation work "into that broader state effort, Thomas Jacobs added.

'Collective Responsibility'

Wyoming has similarly stepped up its wildfire prevention work. The state's Legislature passed House Bill 192 in March following wildfires that burned thousands of acres in 2024.

The fires gave stakeholders a sense of urgency, said Mary Throne, a member of the Wyoming Public Service Commission and chair of WIRAB.

Wyoming's wildfire law, which goes into effect on July 1, does not create a wildfire fund, but it requires all utilities to file wildfire plans with the PSC, Throne said.

"The exchange for a wildfire plan that we approve, there's limited liability protection," Throne said. "It creates a presumption, a standard, a duty of care that applies as long as the company is in compliance with its wildfire plan and not engaged in gross negligence or malice."

Throne noted that wildfire mitigation is a "collective responsibility," adding that the utilities are not primarily responsible for the heightened fire risk.

Utilities "do have a duty of safe, adequate and reliable service for their infrastructure," Throne said. "But again, we cannot put what is really sort of a broader societal burden on an entity and entities that keep the lights on. There's got to be some collective skin in the game."

| Shutterstock

Wildfires also pose economic risks, and the West has already seen examples of utilities going bankrupt after being found liable, said Spencer Gray, executive director at the Northwest & Intermountain Power Producers Coalition (NIPPC).

NIPPC represents power producers and marketers. The organization's members "need entities on the other side of the contract who are going to attract capital, who are liable for the course of the contract, who don't face unexpected bankruptcy or a suspension of their ability to pay," Gray said.

"We're in a situation now, in many states, where the risk is not knowable," Gray said. "You can't mitigate it sufficiently to go back to your shareholders or to the debt markets to address it, and so that that really is an untenable situation," Gray added.

Efforts in Washington and Oregon are underway to address risk sharing, including enhanced wildfire planning requirements and the establishment of a fund for the benefit of wildfire victims, Gray said.

NIPPC has been supportive of these efforts and "we will continue to be supportive of creating a risk environment that's more knowable — not riskless — for our counterparties," Gray said. ■

Northwest's Only Nuclear Plant Could Get Uprate

Plan Would Boost Columbia Generating Station Output by 186 MW

By Elaine Goodman

Operators of the Columbia Generating Station (CGS) are seeking an extended power uprate for the facility, which is the Northwest's only commercial nuclear power plant and a supplier of electricity to the Bonneville Power Administration.

Energy Northwest's extended power uprate and efficiency improvement project for CGS would increase the power plant's electric generating capacity from the current 1,207 MW to 1,393 MW in 2031.

Energy Northwest, a consortium of utilities from across Washington state, owns and operates the plant near Richland, Wash. BPA markets the energy produced and pays all costs, which are included in the revenue requirements of its power services rate structure.

BPA and Energy Northwest hosted a meeting April 8 on the proposed uprate. Energy Northwest said it would seek BPA Finance Committee approval next month. The uprate also requires Nuclear Regulatory Commission approval.

Energy Northwest is also considering seeking a 20-year license renewal for CGS, which would extend operations through 2063.

Synergizing Projects

The uprate would coincide with so-called lifecycle management projects at the power plant, in which work on certain components is already scheduled. For example, replacement of the high-pressure turbine would cost the same with or without the power uprate, said Tammi Oldham with Energy Northwest.

In addition, the project could potentially take advantage of tax credits: either the production tax credit, an annual credit based on incremental generation, or the one-time investment tax credit.

"We see there is a growing demand for power, and we think an extended power uprate is a very [easy], cost-effective way to meet that growing need," said Energy Northwest's Jeff Windham.

"Overnight" direct costs, which don't include interest expenses, are projected at $465 million for the lifecycle management projects and an additional $670 million for the extended power uprate, for a total of $1.135 billion, according to an Energy Northwest presentation. Indirect costs are estimated at $30 million.

Work related to the uprate would occur during refueling and maintenance outages scheduled for 2027, 2029 and 2031, Energy Northwest said.

Although the lifecycle cost and benefits of the extended power uprate are expected to reduce rates, Energy Northwest noted that rate pressure would increase during construction until the project starts generating energy.

BPA's resource program includes the CGS extended power uprate in the least-cost portfolio for meeting future customer needs, a Bonneville representative said during the meeting. The uprate would reduce the amount of new solar and wind capacity BPA would otherwise need to acquire.

Columbia Generating Station | *Energy Northwest*

Why This Matters

The proposed uprate for Columbia Generating Station could provide a cost-efficient way to increase emissions-free baseload generating capacity in the Northwest.

Uprates on the Rise

Nuclear power plants across the U.S. have been turning to power uprates to meet soaring electricity demand. In one recent example, Georgia Power has proposed uprates to four of its nuclear reactors in its 2025 Integrated Resource Plan. (See *Georgia Power Proposes Nuclear Uprate, Delay in Fossil Retirement*.)

Since the 1970s, the NRC has approved 171 uprates totaling 8,030 MW of electric power, roughly equivalent to eight new reactors. Nuclear plants typically increase their output by using slightly more enriched uranium fuel or a higher percentage of new fuel, Energy Northwest said.

Power uprates fall into different categories based on the percentage by which power will be increased, according to the NRC. Stretch power uprates fall within the design capacity of the plant and are generally up to a 7% increase.

In contrast, extended power uprates require "significant modifications" to a plant's major equipment. Power increases in extended uprates may be as high as 20%.

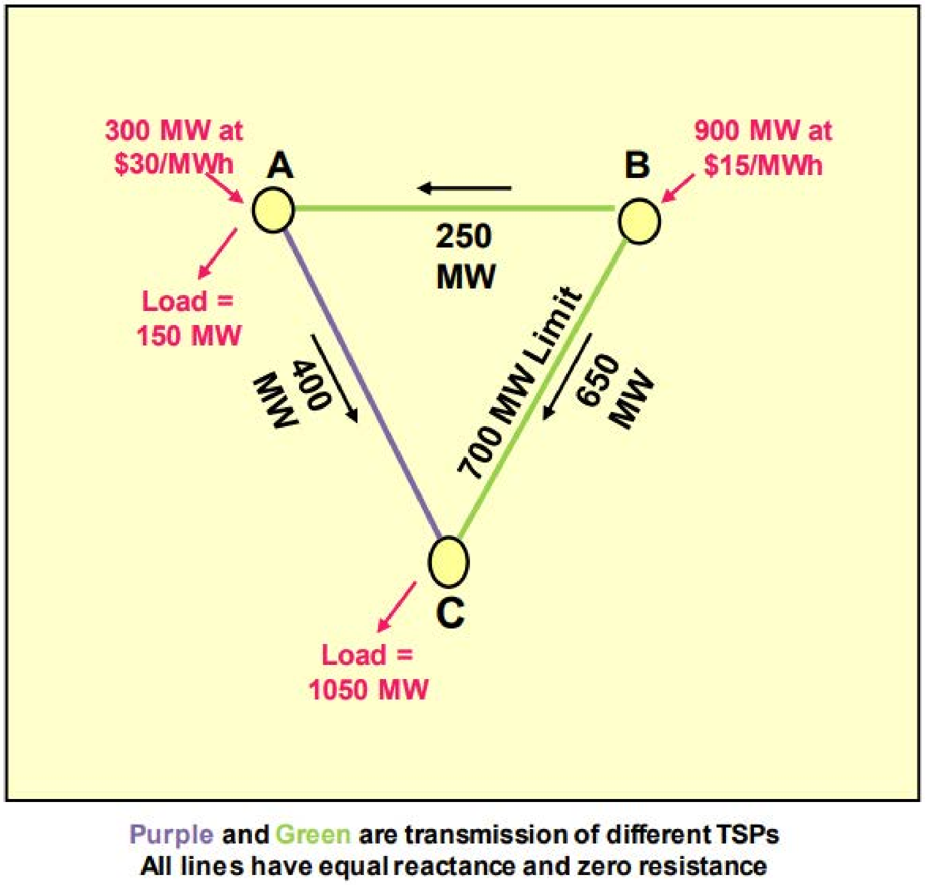
The NRC said it is preparing for more uprate requests.

"We're already looking at our past reviews to see how we can process these requests as efficiently as possible while maintaining safety," the agency said on its website. ■

Urgent EDAM Congestion Revenue Issue 'Will Take Time' to Address

CAISO Board Could Still Vote on a Proposal in May

By David Krause



This image shows the flow of electrons on parallel transmission lines from two generators to two loads. | *CAISO*

The complex issue regarding congestion revenue allocation in CAISO's Extended Day-Ahead Market (EDAM) continues to raise questions and cause some confusion for market participants, with a market expert reviewing possible solutions at an April 8 Western Energy Markets Governing Body meeting.

The issue is whether certain congestion revenues should be allocated to the balancing area in which the congestion costs accrued, or to the neighboring EDAM balancing authority area where the transmission constraint is located, specifically in cases in which parallel — or loop — flows occur.

In March, CAISO launched an "expedited" initiative to address stakeholder concerns. The ISO plans to release a full proposal on the issue in the coming week. (See *Fast-paced Effort will Address EDAM Congestion Revenue Issue*.)

Under current EDAM market rules, open access transmission tariff customers in one BAA will end up paying costs for congestion for parallel flows caused by binding transmission constraints in neighboring BAAs, CAISO market expert Susan Pope noted during the meeting. This requirement could make a system and its transmission users carry the costs of unexpected congestion.

OATT point-to-point (PTP) service is awarded without fully accounting for parallel flows, while management of infeasible OATT schedules today requires approaches such as curtailment of non-firm service and out-of-merit redispatch by the impacted BAA to manage congestion, Pope said.

"These congestion charges only occur when there are flows over binding constraints and the amount of the charges reflect the cost of managing the congestion on those constraints," Pope said. "So, if the cost of managing the congestion isn't that big, the charges aren't going to be that big."

There is strong justification for charging OATT customers for EDAM congestion costs, because the charges are tied to the marginal cost of redispatch to manage congestion on the binding constraints impacted by the OATT schedule, Pope added.

At an April 2 meeting on the subject, Anna McKenna, CAISO vice president of market design and analysis, also disputed the contention that EDAM's existing congestion revenue framework is inherently flawed. (See *EDAM Congestion Debate Builds Even as CAISO Moves to Address Issue*.)

However, Pope said the ISO could address stakeholder concerns by redesigning EDAM to include an avenue for OATT customers to more fully hedge or otherwise manage EDAM congestion cost charges.

More specifically, EDAM could adopt use of congestion revenue rights (CRRs), which would provide OATT customers with a hedge against EDAM congestion

Why This Matters

The "market expert" for the Western Energy Markets Governing Body added yet another voice to those who've acknowledged the complexity of dealing with congestion revenues in CAISO's EDAM.

charges. But the market design does not include CRRs, and CAISO would need to address core issues prior to including them, Pope said. Introducing CRRs would require new rules to establish transmission capability for CRRs while also enabling cost recovery for transmission service providers, she said.

In many RTOs and ISOs, such as NYISO, PJM, MISO and CAISO, OATT transmission reservations were infeasible when modeled, according to Pope's presentation. Furthermore, RTOs with CRRs have required lengthy stakeholder processes to design the market rules for converting existing OATT service arrangements into CRR allocations, Pope said.

Despite these challenges, introducing CRRs for hedging EDAM congestion costs would "likely enable more efficient scheduling and decrease the cost of serving EDAM load," Pope said. "But it will take time to design and implement CRRs when agreed upon by EDAM participants."

In the meantime, a transitional approach is needed to address concerns about OATT transmission customers' potential undue exposure to charges for parallel flow on binding constraints in other BAAs, Pope said.

One transitional solution is to enable PTP customers to "opt out" of EDAM settlements, which could allow them to avoid congestion charges under all grid conditions, such as by self-scheduling rights before or after EDAM without paying congestion charges, Pope said. But this approach could reduce efficiency and customer cost savings from EDAM and make it more difficult to maintain system reliability during stressed system conditions.

More Work Ahead

WEM Governing Body member John Prescott said the parallel flow congestion issue is "a very thorny problem."

"But I appreciate the fact that everybody is rolling up their sleeves and, I hope, working in earnest to solve this problem," Prescott said.

At the meeting, Alan Meck, principal market design analyst at Pacific Gas and Electric, asked if CAISO could break down the pros and cons of each possible solution to the matter.

"I think that I'm following this presentation, but it's been kind of difficult," Meck said. "It would be really helpful, I think, if you could add one additional slide synthesizing EDAM design pros and cons and where all of these different issues shake out."

Pope reminded attendees that a good solution to the issue "is probably one that doesn't make anybody happy."

"If everybody's complaining about something, that might be a good solution," Pope said. "There's a lot to gain by solving this problem. I just wanted to encourage everybody to sort of work together, be realistic and try to craft solutions."

CAISO is on track to publish a full proposal on the topic on April 14, spokesperson Jayme Ackemann said. Whether the CAISO Board of Governors will vote on the proposal at its May meeting is still under consideration, she said. ■

ERCOT Board of Directors Briefs

RMR Contract for CPS Energy Unit Faces Increased Costs, Delays

ERCOT's plans to continue running a 55-year-old San Antonio gas plant scheduled for retirement are being endangered by increased costs and timeline delays.

CEO Pablo Vegas told the Board of Directors during its April 8 meeting that "pretty significant findings" during CPS Energy's inspection of its Braunig Unit 3 found that the boiler superheater header must be replaced. What originally was thought to be a two- or three-month delay could be as long as 12 months, he said.

The cost to replace the heater header has not yet been estimated, but Vegas said the contractor inspecting the unit — built during the late 1960s and with a summer maximum rating of 400 MW — has found $2.7 million of incremental costs to repair and replace core components "of significant vintage." ERCOT and the market already are on the hook for $45.85 million under the terms of Braunig 3's reliability must-run contract. The budgeted amount is a 33% increase since CPS' first estimate in November.

Vegas said staff are working to validate the cost estimate of the heater header — "a fairly costly [replacement item]," he said — and other components with the original manufacturers and other potential suppliers.

"We have gotten signals that there may be some components that need to be replaced that have longer lead times to get those components in and get the unit up and running," he said. "We'll be looking at the impact of those delays to understand what that means in terms of the actual availability potential and then evaluate the cost benefit of continuing to work through this maintenance and repair cycle with Braunig Unit 3, versus looking at some other alternative. That data is very new."


Board Chair Bill Flores listens to the discussion during April's meetings. | *ERCOT*

The delays have placed added importance on the use of 15 mobile generators as an alternative to extending the life of V.H. Braunig Power Station's other two aging gas units, slated for retirement this year. The grid operator determined the generators and their 450 MW combined capacity is less risky and more cost-effective than using the two small units from the "Swinging '60s" with a combined summer maximum rating of 392 MW. (See *ERCOT Board OKs Mobile Generators in San Antonio*.)

Vegas said final negotiations are ongoing between LifeCycle Power, the mobile generators' owner; CenterPoint Energy, which leases the generators; and CPS Energy, which plans to deploy them in the San Antonio region.

"We are planning to do everything we can to incentivize bringing these units on as quickly as possible in the San Antonio area," he said. "Given the fact that we are seeing significant cost and potential schedule delays on the Braunig unit, it increases the importance of having these resources available during the peak parts of this summer."

"We're putting as much pressure on those parties to get those issues wrapped up, but I'm pretty optimistic that we should be able to get all this resolved," General Counsel Chad Seely said. "Getting those assets onto the grid sometime this summer … they're all kind of contingent on everything being folded up together."

LifeCycle's generators were projected in February to cost $54 million, including fuel costs and incentives. They can reach full output in 10 minutes, faster start times than the three Braunig units.

Seely said that as every day passes without an agreement with the parties, more risk is placed on their availability by August, "when we really need them."

Responding to questions from directors as to whether there is a drop-dead date before "punting" the generators, Vegas responded, "There isn't a scenario where we're going to punt this for this summer."

Kristi Hobbs, ERCOT's vice president of system planning and weatherization, told the board staff has been work with CPS, AEP Texas and South Texas Electric Cooperative to accelerate portions of a $435 million reliability project south of San Antonio. The rebuild addresses a transmission constraint that has led to Braunig 3's RMR contact and the mobile generator must-run alternative.

The CPS board on March 31 *agreed to a $150 million contract* with Quanta Services to work on 58 miles of energized transmission lines. Quanta has agreed to complete the work by December 2026, shortening the original 2029 timeline.

"We would be able to potentially exit both the Braunig 3 as well as the LifeCycle agreement as early as September of 2026," Hobbs said.

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 RMR contract ended in 2017, thanks partly to transmission facilities that increased imports into the region. (See *ERCOT Ending Greens Bayou RMR May 29*.)

CPS told ERCOT in 2024 that it planned to retire the Braunig units in March 2025. However, ERCOT said the plant's retirement would lead to reliability issues in the San Antonio area until the transmission constraint is resolved. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

Costs Increase for Permian EHV

Hobbs also told the board that staff has *filed* updated cost estimates for EHV transmission paths into the Permian Basin with the Public Utility Commission, which will determine whether to go with 345- or 765-kV lines. (See "EHV Lines Offer a Lifeline," *Texas Stakeholders Grappling with Tsunami of Large Loads*.)

The estimates provided by transmission providers have increased for both voltage options from the original May 2024 projections. The 345-kV option has increased 7.6% to $8.28 billion, while the 765-kV option has increased 11.6% to $10.11 billion.

"We recognize it's going to be an investment for the consumers to be able to get the transmission built that they need," Hobbs told directors. "We've often said that we feel like our current transmission system has maximized its capability, meaning we have squeezed all we can out of the current transmission system."

ERCOT said its analysis indicates that 765-kV circuits would provide "significant economic and reliability benefits" to the system because they are more efficient in moving power over long distances. Transmission providers and vendors said during a March 7 workshop that supply chain issues are not a concern.

The PUC is scheduled to take up the issue during its April 24 open meeting.

ERCOT CEO Pablo Vegas | © *RTO Insider*

Operations Vice President Dan Woodfin also updated the board on a "pretty eventful" March for renewable energy. Multiple wind, solar and total renewable records were set during the month:

- Wind generation: 28.5 GW, March 3.
- Solar generation: 26.3 GW, March 20.
- Solar penetration: 56.60%, March 20.
- Renewable generation: 39.99 GW, March 18.
- Renewable penetration: 76.11%, March 2.

Designing Residential DR Program

ERCOT is working with stakeholders to develop a residential demand response program to address short-time reliability problems, Keith Collins, vice president of commercial operations, told the board.

"We do think that there's an opportunity in terms of smart devices, thermostat, pool pumps, water heaters, things along that line, and to allow for a program that [focuses] on those types of resources," he said.

Collins said expanding the DR program is a top priority for ERCOT. As envisioned, it would provide an incentive payment to retail electric providers — and possibly public power entities in the competitive market — based on residential DR performance during highest net-load periods.

"The intent of the program is something that's quick to develop, simple in its administration, can be popular for folks to be a part of and ultimately is cost-effective in the end," he said. "We do think we have some novel concepts that we'll be able to accomplish."

ERCOT expects to complete the program's design this year, develop it in 2026 and implement it in 2027, Collins said.

Aguilar Resigns, R&M Dissolved

Board Chair Bill Flores opened the meeting by announcing Carlos Aguilar resigned as an independent director. Aguilar was one of the first two directors to sit on ERCOT's revamped board following Winter Storm Uri in 2021. His second term began in October 2024.

"His expertise and guidance have been instrumental in this board's decision-making," Flores said.

The ERCOT Board Selection Committee, composed of three members selected by Texas' governor, lieutenant governor and speaker of the House of Representatives, will begin the selection process in coming weeks, Flores said. Under state law, all board members must be Texas residents.

The board voted to dissolve its Reliability and Markets Committee and move its discussion to the full board. The R&M committee was created in 2022 and was responsible for core ISO functions and several technology-related functions that later were shifted to the Technology and Security Committee.

Flores moved the R&M's jurisdiction to allow all board members more direct participation in policy matters associated with the core functions of operations, planning and markets. He said future board meetings likely will be held over two days to manage business more efficiently.

Possible Admin Fee Decrease in '26

The board's Finance and Audit Committee began its review of the ISO's proposed 2026/27 budget, which could result in a 2-cent decrease in the system administration fee, said Flores, who presided over the committee meeting after Aguilar's resignation.

He said staff has proposed the fee be reduced from $0.63/MWh to $0.61/MWh, effective Jan. 1, 2026. The budget's total authorized spend is $474 million in 2026 and $557 million in 2027. The increase is due to the start of ERCOT's data center refresh project.

The F&A will review the budget again during its June meeting. Flores said the committee has asked staff to bake in several uncertainties during the planning process, including trade tariffs and disruptions and a potential economic downturn's effect on electric demand.

ERCOT to Sublicense Patents

Seely told the board the grid operator will enter into a *patent-license agreement with Lancium*, a Texas-based energy technology firm.

Seely said the company's patents may be a barrier to entry for increased market participation by controllable-load resources (CLRs) if that risks intellectual-property infringement disputes. Lancium is registered with ERCOT as a qualified-scheduling entity (QSE), load-serving entity and resource entity. It owns a portfolio that includes a patent focusing on determining performance strategies for loads using power option data based on a power option agreement.

"This is a longstanding issue that's been kind of playing around the surface in the stakeholder process for a couple of years," Seely said. There have been "arguments around the patents" with stakeholders. "ERCOT has been engaged with Lancium for quite some time trying to understand the impact of what those patents could mean to our CLR program."

Under the agreement, Lancium will license its relevant patents to ERCOT at no cost. The grid operator then will sublicense the patents to CLRs and any other applicable market participants or entities.

"This is a good outcome in which we can resolve this issue for the ERCOT region," Seely said.

Board Approves RTC Protocols

The board approved a key protocol change (*NPRR1269*) related to ERCOT's real-time co-optimization project, thought to be the foundation for future market improvements and scheduled to be deployed in December. (See "Stakeholders Approve Protocol Changes for Real-time Co-optimization," *ERCOT Technical Advisory Committee Briefs: March 26, 2025*.)

NPRR1269 determines and codifies policy changes that were deferred from the original RTC-related protocols developed after the project's inception in 2019: ramping scaling factor values; ancillary service (AS) proxy offer floor parameters; and ancillary service demand curves' (ASDC) use in reliability unit commitment (RUC) studies.

Two other RTC protocol changes, *NPRR1268* and *NPRR1270*, were placed on the board's consent agenda.

Benjamin Barkley, the Office of Public Utility Counsel's CEO, voted against the motion, saying setting the ASDC demand floor at $15 without seeing how it would perform with RTC is "premature."

"Set [the floor] at $0 just to see how the market would respond in that circumstance," he said.

Barkley again cast the lone dissenting vote against *NPRR1190*, which allows recovery of a "demonstrable financial loss" arising from a manual high dispatch limit override reducing real power output, when the output is intended to meet QSEs' load obligations. The Technical Advisory Committee lowered the $10 million threshold that would trigger a review to $3.5 million. (See "Amended NPRR Passes," *ERCOT TAC Opens Discussion on Proposed RTC Changes*.)

The directors also approved a *correction of real-time prices* for some operating days between Aug. 12 and Sept. 11 in 2024. A software update to ERCOT's energy management system resulted in stale telemetered MW values, leaving the ISO short $3.3 million in statement charges.

The board's consent agenda included six other NPRRs, two changes to the Planning Guide (PGRRs), single changes to the Nodal Operating and Settlement Metering Operating (NOGRR, SMOGRR), a system change request (SCR) and a modification to the Verifiable Cost Manual (VCMRR):

NPRR1234, *PGRR115*: Establishes interconnection and modeling requirements for large loads, defined as one or more facilities at a single site with an aggregate peak power demand of 75 MW or more.

NPRR1241: Clarifies the hourly standby fee clawbacks for firm fuel supply service during a winter weather watch by using a sliding scale.

NPRR1256: Changes language in adjustment period and real-time operations protocols related to must-run alternatives (MRAs), primarily in grey-boxed language from *NPRR885* (Must-Run Alternative Details and Revisions Resulting from PUCT Project No. 46369, Rulemaking Relating to Reliability Must-Run Service) to align the terminology for energy storage resources (ESRs) in the single-model era. It also specifies how qualified scheduling entities representing ESR MRAs would be settled for providing MRA service.

- *NPRR1268*: Defines the methodology for disaggregating the operating reserve demand curve into blended ancillary service demand curves.
- *NPRR1270*: Updates requirements for load resources that are changing under RTC and were not updated in earlier revisions; removes language associated with group assignments in the day-ahead market; and eliminates the automatic qualification of all resources to provide on-line non-spinning reserve and SCED-dispatchable ERCOT contingency reserve service, among other changes. Resources will be required to undergo a qualification test to provide each of these services.
- *NPRR1273*: Modifies ESRs' capacity to the amount sustained for 45 minutes included in the physical responsive capability's calculation.
- *NOGRR274*: Conforms the guide to *NPRR1217*'s (Remove Verbal Dispatch Instruction Requirement for Deployment and Recall of Load Resources and Emergency Response Service Resources) protocol changes.
- *PGRR119*: Codifies that a reliability margin will be used when limits associated with a stability constraint are modeled in the Regional Transmission Plan's reliability and economic base cases.
- *SCR829*: Adds an application programming interface to upload and download unit testing data from the net dependable capability and reactive capability application.
- *SMOGRR028*: Gives guidance for allowing loss compensation for current limiting reactors.
- *VCMRR042*: Adds seasonal sulfur dioxide and nitrogen oxide prices obtained from indices to calculate emission costs from May through September; annual prices would continue to be used from October through April. ■

— Tom Kleckner

Texas Loan Program Loses 2 More Gas Projects

By Tom Kleckner

Texas' loan program for gas generation has lost two more projects, marking the third and fourth companies to withdraw projects from the due diligence review process.

Constellation and WattBridge became the latest to pull projects from the Public Utility Commission's In-ERCOT Generation Loan Program, part of its Texas Energy Program. The companies took out four projects totaling 1,410 MW.

The 16 remaining applications total 8,346 MW of capacity and $4.46 billion in requested loan amounts. The TEF is a $5 billion, low-interest program designed by lawmakers to quickly add new natural gas plants.

PUC spokesperson Ellie Breed said staff intend to advance additional applications to the due diligence phase at a future open meeting.

Constellation was seeking financing for 300 MW of gas-fired generation at its Wolf Hollow III facility. It *told the PUC* in March it was unable to determine "with certainty" the project's overall costs because of the "uncertain timing" in receiving an air permit from the Texas Commission on Environmental Quality. That would prevent Constellation from signing a binding loan document.

WattBridge *withdrew* three projects totaling 1,110 MW of capacity. It said the TEF's financing terms "introduce risk and costs that result in lower than anticipated returns with elevated risks."

The company also said it was withdrawing a 510-MW project in the Houston region from the pool of remaining applicants.

Two other companies pulled their projects from the TEF earlier in 2025. They cited supply chain issues as delaying the projects and keeping them from meeting a December 2025 deadline for initial loan disbursements. (See *2 Companies Withdraw Texas Energy Fund Projects from Consideration*.)

More than 4,650 MW of capacity has been withdrawn or denied from the original submitted applications. Nearly a third (3,903 MW of 12,249 MW) of the projects that advanced to due diligence now have been withdrawn or denied.

Why This Matters

The Texas Energy Fund was created to set aside $5 billion in low-interest loans to quickly add new gas generation to ERCOT following 2021's Winter Storm Uri.

"Texas will get new gas resources … but gas plants take time," noted Stoic Energy principal Doug Lewin in his newsletter. "They can't be developed fast enough to ensure reliability or allow for economic growth in the next three or four years, and possibly longer than that."

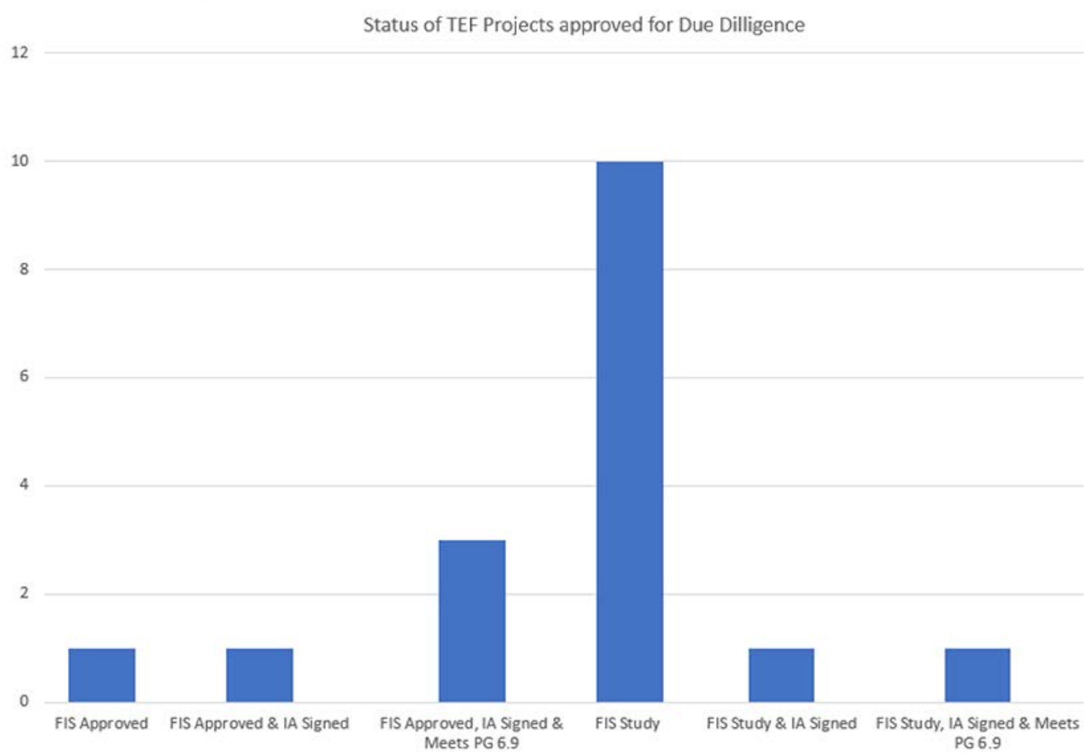
Kristi Hobbs, ERCOT's vice president of system planning and weatherization, told board members April 7 that all 16 Texas Energy Fund projects recommended for due diligence by the PUC have submitted full interconnection study (FIS) applications with the ISO and are in various phases of the generation-interconnection process. Seven applicants have completed the full study processes.

"Moving forward, a lot of progress on those," Hobbs told the board.

The *TEF* was created by the Texas Legislature in 2023 to add more dispatchable generation to the grid and was approved by voters later that year. Managed by the PUC, it is designed to provide grants and loans to finance construction, maintenance, modernization and operation of electric facilities in the state.

The fund is composed of four programs: In-ERCOT Generation Loans, In-ERCOT Completion Bonus Grants, Outside-ERCOT Grants and Texas Backup Power Package. ■

Texas Energy Fund Status



The TEF portfolio's 16 projects have all submitted full interconnection study (FIS) applications to ERCOT. | *ERCOT*

Texas Groups Ask FERC to Reject Puerto Rican Company Petition for Regulation

Late Comments Say Proposal Threatens State Jurisdiction over ERCOT

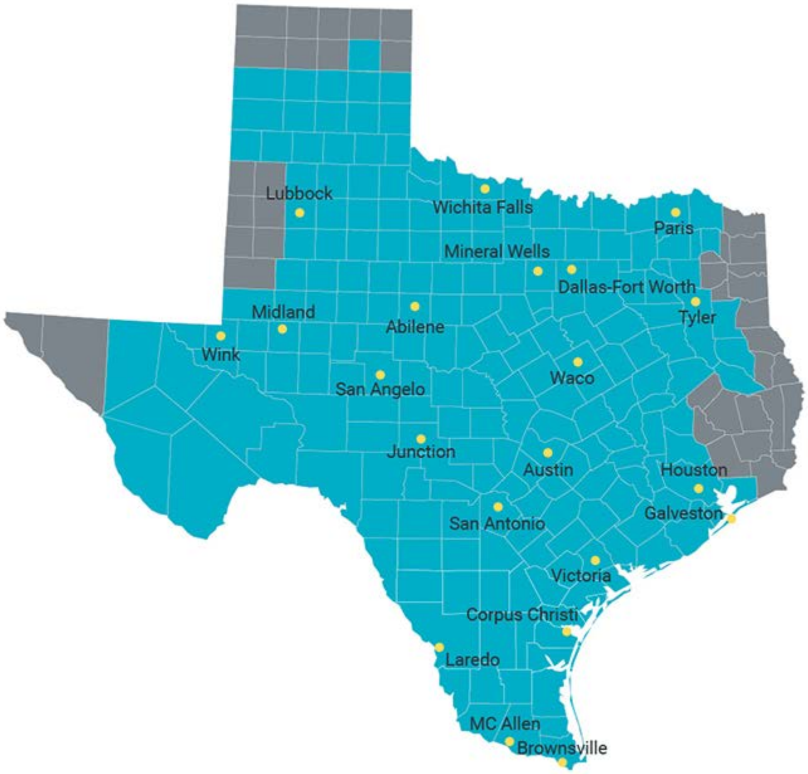
By James Downing

ERCOT, Oncor and the Texas Public Utility Commission have asked FERC to deny a petition from Puerto Rican company Pluvia to bring the territory under the commission's Federal Power Act jurisdiction (*EL25-57*).

Pluvia seeks a finding from FERC that its proposal to transmit power to Puerto Rico via batteries on cargo ships could make it subject to the commission's regulations. (See *Petition Asks FERC to Potentially Claim Jurisdiction over Puerto Rico*.)

The parties all filed similar motions, but none of them were aware of the petition, filed in early February, until after the due dates for comments, they said.

If the commission granted Pluvia's petition, the precedent would threaten ERCOT's jurisdictional status, in which its few connections to the rest of North America's grid do not give FERC jurisdiction over its markets, the Texas grid operator said April 8.



ERCOT service territory | *ERCOT*

"ERCOT recognizes the immense challenges the people of Puerto Rico have endured since Hurricane Maria and supports efforts to rebuild and modernize the island's electric grid," it told FERC. "Yet, as explained below, Pluvia's petition is not the right path to achieve these crucial goals."

Granting the petition would require an unprecedented reinterpretation and expansion of FERC's licensing jurisdiction under FPA Part I, which authorizes the commission to license non-federal hydroelectric projects on federal reservations or affecting navigable waters of the U.S., and under another section that gives FERC power to grant preliminary permits for such projects.

But using storage to transmit power is not a hydro project; the proposed sites in Puerto Rico are not considered federal reservations; and the transportation of cargo from the mainland to the territory would not involve crossing navigable waters of the U.S., ERCOT argued.

"Such a radical change could have serious implications for the jurisdictional independence of Texas's intrastate ERCOT grid," said the PUC, which oversees ERCOT's markets in the same way FERC regulates others in the U.S. All the transmission between it and other states is provided pursuant to FERC orders under sections 210 and 211 of the FPA.

"Because Pluvia's proposal does not involve any physical flow of electric energy between states, Pluvia presents no valid basis for the requested declaration," the PUC said. "What Pluvia requests would be a radical redefinition, contrary to precedent, of the meaning of 'electric energy' under the FPA to include stored potential energy that would later be converted into electric energy. And it would redefine 'transmission' under the FPA to include the shipment of charged storage devices that does not involve the flow or commingling of electric energy in interstate commerce. …

"This 'clarification'" — as Pluvia said in its request — "is contrary to law and totally unjustified: It would require the commission to ignore the plain text of the FPA and depart from well-established precedent analyzing the same issues in the context of the ERCOT market."

Oncor had filed to intervene in late March, making similar arguments, and Pluvia had asked FERC to deny the late intervention.

Oncor responded that while it was late, Pluvia's project is in early stages and FERC actually weighing the merits of its earlier filing would not burden it. FERC has been liberal in allowing late interventions in cases involving its jurisdiction, Oncor said.

"Even if Oncor had not moved to intervene in this proceeding, the commission still would need to assure itself that it has statutory authority to grant the relief Pluvia seeks," the utility said. "As such, Oncor intervening to raise jurisdictional arguments does not unduly prejudice or burden Pluvia." ■

ERCOT: 60 GW in Additional Demand by 2031

Grid Operator Adjusts Tx Load Forecasts to Reflect Reality

By Tom Kleckner

ERCOT unveiled a long-term load forecast for 2031 on April 8 that adjusts projections provided by transmission providers and accounts for the uncertain nature of data centers and other large users.

The numbers still are staggering. Even reducing the amount of utilities' projected loads based on historical data, the study forecasts demand to reach 145 GW in 2031. That is less than transmission providers' projections of 218 GW in 2031.

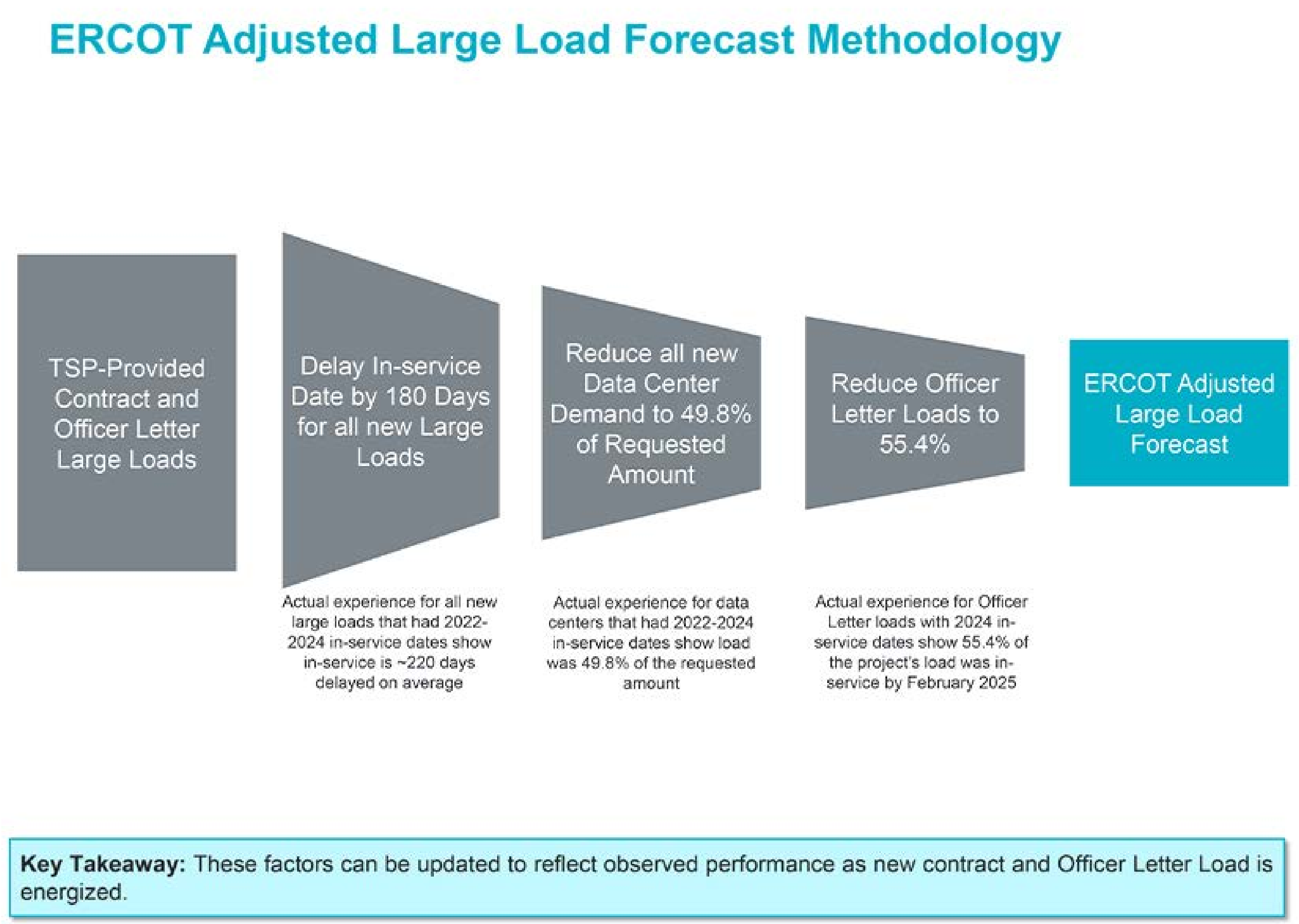
The grid operator's current peak demand is 85.5 GW, set in August 2023.

"Several people are looking forward to [this], with bated breath," Bill Flores, chair of ERCOT's Board of Directors, told COO Woody Rickerson before he presented the adjusted methodology to the directors.

The new treatment of load projections is a result of state legislation passed in 2023 (*House Bill 5066*) that updated regional transmission planning rules and required ERCOT to consider prospective loads identified by transmission provid-

Why This Matters

Even with downward adjustments, ERCOT's load forecast numbers are staggering. Transmission providers forecasted 218 GW of load by 2031. ERCOT reduced that to 145 GW, 60 GW above its current peak-demand record.



ERCOT's adjusted large-load forecast methodology uses historical data to modify load projections. | *ERCOT* ers. Previously, state laws prohibited the grid operator from factoring in load that was not financially committed or signed.

The legislation also directs ERCOT to file an annual report quantifying the capability of existing and planned generation and load resources. Staff plan to meet that requirement by using their semiannual *Capacity, Demand and Reserves* (CDR) report, as they did in December 2024 by using the TSPs' load forecast.

However, that CDR revealed negative planning reserve margins as early as 2026. (See *ERCOT's Revised CDR Report Met with Doubts*.)

"We're going to pivot away from using that forecast in this year's May CDR," Rickerson told the board. He noted the legislation's "most impactful difference" was ERCOT accepting transmission providers' officer-attested letters, which he attributes to much of the future data center load growth.

The *adjusted load forecast* is based on three adjustments:

- delaying the in-service date by 180 days for all new large loads;
- reducing new data center demand to 49.8% of the requested forecasts; and
- reducing officer-attestation loads to 54.55% of forecasts.

Rickerson said the reductions represent a "measured percentage of power being used" versus the forecasts.

"An important part to keep in mind here is that this is a forecast based on the most recent data we have, and we'll continue to update that as we move forward," he said. "Those numbers were derived from loads that had been forecasted that we can now see and measure. Those numbers, as we move forward, can change as forecasts become more accurate."

The problem, Rickerson said, is how to count the large loads (75 MW or more) that data centers, hyper-scalers and crypto miners are planning.

The board questioned Rickerson on the accuracy of data provided by transmission providers.

"Data centers are not something that we were forecasting or looking at four, five years ago, so this is new information. How fast it builds out is something we're all going to learn together," he said.

Rickerson said the quality of data needs to be adjusted "based on just the leading edge of historic numbers." As ERCOT gets more of those numbers, he said, the grid operator's adjusted load forecast and the transmission providers' aggregate projections likely will merge into one.

ERCOT CEO Pablo Vegas said *Senate Bill 6*, an omnibus energy bill being considered in the 2025 Legislature, includes provisions addressing the inputs into transmission providers' forecasts.

The ISO will begin incorporating the adjusted load forecast in transmission planning, resource adequacy and outage coordination analyses. Rickerson said a good-cause exception may be required from the Public Utility Commission.

There could be some good news in the future over the escalating demand ERCOT faces.

ERCOT COO Woody Rickerson | *ERCOT*

Pia Orrenius, a senior economist with the Federal Reserve Bank of Dallas, followed Rickerson's presentation by saying the Texas economy is "likely slowing."

"[Business] outlooks have recently turned pessimistic," she told the board, noting surveys of Texas businesses are "flashing some warning signs."

"Growth is likely to slow further … and will probably slow further than we're currently forecasting," she said. "The main reason is tariffs. They're going to lead to higher prices. Consumption and investment will slow and possibly decline." ■

GCPA Conference Examines the Biggest Change to ERCOT Market in 15 Years

By James Downing

HOUSTON — ERCOT this December will begin implementing a market design change that has been debated for more than a decade, experts said at the Gulf Coast Power Association's Annual Spring Conference on April 14.

The real-time co-optimization (RTC) of energy and ancillary services means that ERCOT's security-constrained economic dispatch will solve for both at the same time. Vice President of Commercial Operations Keith Collins said it could save billions of dollars a year in operating the grid, with a study finding RTC plus batteries (RTC+B) could save between $2.5 billion and $6.4 billion annually.

"Ultimately, there's a lot of benefit this is going to derive to the market, to the ratepayers and consumers," Collins said. "And you see that this is something that, while it's been in the works for a long time, we are essentially at the dawn of the RTC location."

The big difference in the potential benefits has to do with the years the market change was "back cast" for testing, which included the summer of 2023, when conditions in ERCOT were tight and prices were high, Collins said.

R Street Senior Fellow Beth Garza was a big supporter of the move when she was ERCOT's Independent Market Monitor, saying she got the grid operator and the Texas Public Utility Commission on board with the market change in 2018. The biggest change since that time has been the growth of storage, with 11 GW now competing in the markets.

Why This Matters

ERCOT is enacting a change that it says will help batteries serve the market and also move scarcity pricing toward market fundamentals and away from market participants' bids.

"This idea of 'RTC plus B,' in my mind, has become 'RTC because of B,'" Garza said. "For storage to be able to easily move into and out of providing energy versus capacity for ancillary services needed something different. And here it is."

The change will save money by dispatching a plant that had reserved some capacity for ancillary services in the energy market and then shifting the ancillary service to a more expensive plant, lowering the overall cost of power, according to ERCOT.

"We are getting more expensive ancillary services," ERCOT Principal of Market Design and Development Dave Maggio said. "So that can be a question of, is that necessarily a good thing? And the answer in this case is, yes, it is worth getting more expensive ancillary services because of the overall decreasing energy price."

The change also comes with a new offer cap in the energy markets, at just $2,000/MWh, down from the current $5,000/MWh. Prices can still go above $2,000/MWh, but as in the FERC-regulated markets, that will only happen when the market is running short. Scarcity pricing will be handled through the "ancillary services demand curve," which will replace the operating reserves demand curve (ORDC), Maggio said.

While RTC is set to go live Dec. 5, ERCOT is going to be spending the next seven months getting ready for it with market trials starting May 5, and a market notice explaining them is due soon, said Matt Mereness, the grid operator's senior director of market operations and implementation.

The training will involve weekly calls with market participants and, starting in September, trial runs of the new market design that will cover the morning ramps, Mereness said. ERCOT ran similar tests 15 years ago when it transitioned to a nodal design from zonal.

"Who was here for the nodal go-live 15 years ago?" Mereness asked the audience. "Now raise your hand if you did that. Well, the good news is it's not that big, but this is still the biggest paradigm shift we've had in 15 years."

ERCOT Vice President of Commercial Operations Keith Collins addresses the Gulf Coast Power Association's Real-Time Co-optimization Workshop. | © RTO Insider

The move to RTC is going to mean more efficient energy and ancillary services markets, which means that to drive more resource investments, the market will need to have more scarcity events that drive prices high and send price signals for investments, said NRG Senior Director of Regulatory Affairs Bill Barnes.

"We are becoming more dependent on the demand curve for price elevation," Barnes said. "I think that's a good thing. … When we first started, there wasn't an ORDC. We were solely dependent on submitting high offers. As we've evolved over the past 20 years, we've moved more towards a demand curve approach, which to me more aligns the price formation with the actual fundamentals of the market, versus one participant deciding to submit the price of the cap on a random day, which can be not a good thing."

While the move to RTC+B will influence price formation in ERCOT's markets, consultant Eric Goff said generation investments in the near future are going to be driven by large loads like data centers coming to Texas.

"The reason, among others, that large loads are attracted here is because you can transact in this market," Goff said. "You can get what you want without having to ask for too much permission, and if those large loads contribute to higher prices because of their demand, which they have been, in the long run, then you get to a price that reflects the cost of entry." ■

ISO-NE Outlines Market Power Mitigation Measures for CAR Project

By Jon Lamson

ISO-NE discussed its plans for preventing and mitigating market power as it overhauls its capacity market and resource retirement processes at the NEPOOL Markets Committee's meeting April 8.

The RTO's Capacity Auction Reform (CAR) project proposes to reduce the time between auctions and capacity commitment periods, transitioning the region from a forward market to a prompt construct. ISO-NE also plans to decouple resource retirements from the capacity offer process because the timing of the prompt market would not give the RTO enough time to address reliability issues created by retirements.

Under the new format, ISO-NE would require retiring resources to submit deactivation notices two years prior to their retirement from the market. As proposed, retirement notices would be binding and trigger an ISO-NE review process of potential reliability and market power issues. (See *ISO-NE Gives Updates on Prompt, Seasonal Capacity Market Changes*.)

The market power analysis would in-

What's Next

The market mitigation rules, like all aspects of the capacity auction reform project, are under development, and ISO-NE is open to alternative proposals to accomplishing its goals of mitigating and preventing the abuse of market power.

The Mystic Generating Station in Everett, Mass., retired in 2024. | *Fletcher6, CC BY-SA 3.0, via Wikimedia Commons* clude a conduct test to evaluate whether the resource is expected to be economic and a net portfolio benefits test to study whether a market participant's overall portfolio would benefit from the resource retirement.

If a resource fails both tests, ISO-NE would issue a penalty equal to 1.5 times the participant's expected portfolio-wide revenue increase from the retirement. These charges would be credited as a refund to all market participants.

"The market power charge is expected to be used infrequently," said Kevin Coopey, principal analyst at ISO-NE. "Ideally, the risk of being charged deters the exercise of market power."

The tests and charges would be based on expected market outcomes prior to the forward auction, instead of the actual market results.

"By evaluating market power at the notification deadline, we consider the perspective of the participant at the time of the deactivation notification," Coopey said.

Coopey said basing market power charges on the actual auction results would create a nearly two-year delay for participants to learn the actual charge amount, creating significant uncertainty associated with unexpected events distorting market results and risks of excessively large charges.

Some stakeholders expressed concern about reconciling differences between the market expectations of participants and the ISO-NE Internal Market Monitor.

"The IMM acknowledges that different assumptions may be reasonable when the market participant holds different market information or beliefs," Coopey said. "The IMM will accept different assumptions when they are reasonably justified."

Responding to stakeholder requests for ISO-NE to allow participants to withdraw retirement requests, Coopey said the RTO is "considering the feedback," adding that "the increased optionality of having withdrawable notifications must be balanced against the risk of increasing the likelihood of reliability retentions."

ISO-NE has expressed concern that participants could fish for out-of-market resource retentions if they are allowed to withdraw a retirement request when a resource is not retained.

Responses to the proposal for a market power charge have been mixed, with some stakeholders arguing the proposal may not be punitive enough to prevent exercising market power, while others made the case it would be too punitive and could create reliability issues by preventing deteriorating resources from retiring.

Ben Griffiths of LS Power advocated for more flexibility on the timing of retirement submissions, *proposing* that resources not needed for reliability should be allowed to retire with less than two years of advance notice.

"Without commenting on the merits of the two-year notice proposal, allowing for accelerated exit of resources determined nonessential for reliability would reduce market inefficiencies and resource owner concerns about forced market participation," Griffiths said.

"Optional, expeditious deactivation for non-reliability resources lets the region split the difference on notification: Longer notice period lets the region proactively explore reliability implications of each deactivating resource, while accelerated exit allows it to avoid a lengthy exit period when they aren't needed," he added.

Also at the MC meeting, ISO-NE *presented* its plans for mitigating market power concerns on offers within the capacity market. Andrew Copland of ISO-NE said that "in the ISO's current design, most key components of seller-side market power mitigation framework will remain substantively unchanged."

He said ISO-NE will run a conduct test and a pivotal-supplier test to evaluate market power, and it plans to impose a "binding offer ceiling at the IMM's estimated competitive offer price" for resources that fail both tests. Copland said ISO-NE will publish a capacity cost review threshold; all offers that surpass the threshold will be subject to cost review by the IMM.

Copland also noted that ISO-NE is updating its auction participation rules for the prompt market and will require "all commercial resources capable of providing capacity … to offer it into the auction."

He said resources that hold unused capacity interconnection rights pose a barrier for other resources looking to enter the market and could cause these resources to incur significant interconnection costs. He noted that participants can include multiple cost levels within a capacity offer from a single resource to account for the potential added costs of offering a resource's full capacity. ■

NEPOOL Markets Committee Briefs

The NEPOOL Markets Committee held a two-day meeting focused on ISO-NE's capacity auction reform (CAR) project. (See related story, *ISO-NE Outlines Market Power Mitigation Measures for CAR Project*.)

Ambient Temperature Derates

In other business, Hannah Johlas of ISO-NE presented an analysis of how ambient temperatures affect the performance of non-nuclear thermal resources, which the RTO developed in response to stakeholder requests. The analysis included an evaluation of third-party studies, capacity audit data and historical operational data.

All three components of the study showed a significant decline in the capacity of thermal resources as temperatures increased, equal to about a 3-4% decline in performance between 90 and 100 degrees Fahrenheit. The analysis did not evaluate the effects of ambient temperatures on fuel availability or resource outages.

While ISO-NE plans to calculate resource capacity accreditation at 90 F in the summer and 20 F in the winter, some stakeholders express concern that temperatures beyond this range could affect reliability.

ISO-NE does not plan to include modeling of ambient temperature effects in the CAR project because of the limited impacts and challenges of incorporating the additional modeling into the project. Johlas said it's uncommon for the entire resource fleet to face temperatures above 90 F, even as climate change increases temperatures.

Some stakeholders pushed back on this conclusion, making the case that extreme heat often coincides with stress on the grid, and that a 3-4% reduction in the capacity of a 22,000-MW thermal fleet could cause a capacity reduction of up to 880 MW.

Demand Response Distributed Energy Resource Aggregations

Also at the MC, Dennis Cakert of ISO-NE presented *conforming changes* for FERC Order 2222, focused on demand response distributed energy resource aggregations (DRDERAs), which are aggregations of DERs that can reduce demand and inject energy into the grid.

Order 2222 requires transmission operators to eliminate barriers for distributed energy resource aggregations to participate in wholesale markets.

ISO-NE proposes to make DRDERAs eligible to participate in the day-ahead ancillary services market and to receive net commitment period compensation (NCPC). Including DRDERAs in NCPC would prevent "economic incentives to not offer true costs or follow dispatch instructions" in the energy market, Cakert said.

ISO-NE also proposes to reduce the minimum size requirement for resources participating in the regulation market from 5 MW to 100 kW "to align with the approved Order No. 2222 design."

The changes would take effect in November 2026. ISO-NE will continue discussions on the conforming changes at the MC in May, targeting a vote on the proposal in June.

Tie Benefits

Matthew Ide, representing the Interconnection Rights Holders Management Committee, presented on the value of tie benefits and pushed back on the New England Power Generators Association's arguments in March that including tie benefits in the installed capacity requirement (ICR) creates reliability risks. (See *ISO-NE Gives Updates on Prompt, Seasonal Capacity Market Changes*.)

The ICR determines the amount of capacity ISO-NE must procure in the capacity market, while tie benefits refer to the emergency support New England can expect to receive from neighboring regions during a capacity shortage.

At the MC in March, Bruce Anderson of NEPGA said the "current market design 'assumes away' approximately 2,000 MW of capacity demand based on the belief that system energy from neighboring control areas is equivalent to 'firm capacity,'" creating risks of under-procurement and price suppression.

At the April MC meeting, Ide *emphasized* that tie benefits are not a market product, and instead are "the reasonably assumed reliability benefits that come from transmission infrastructure that enables emergency assistance between regions."

Tie benefits "are a reasonable and appropriate input into the ICR calculation," he added.

Ide said tie benefits are supported by contracts ensuring ISO-NE will receive tie benefits from neighboring regions if this support does not jeopardize reliability in the neighboring region. Even if weather conditions are similar across regions, it's highly unlikely for regions to experience resource outages threatening reliability at the same time, he said.

"Network load customers pay for all the tie benefits that come from the [pool transmission facility] ties through regional transmission rates. In return, load receives the benefit of a lower ICR and less need to procure capacity to meet the ICR," he added.

He noted that FERC has found including tie benefits in the ICR to be just and reasonable, and that a recent ISO-NE analysis found the "underlying methodology is robust and thorough in the capacity quantification of tie benefits."

ICR in a Prompt Auction

Manasa Kotha of ISO-NE *discussed* how the transition to a prompt market will affect the RTO's methodology for establishing the ICR. He said ISO-NE will begin the ICR process about a year prior to each capacity commitment period.

"The primary conforming change for the ICR setting process is mainly the time frame," Kotha said, adding that reducing this timing from four years to one year will allow ISO-NE top use more up-to-date data, load assumptions and interface limits.

"Under CAR-Prompt, the data will all be provided closer in time to the commitment period, which is expected to enhance the accuracy of the ICR-related values," Kotha said. ■

— Jon Lamson

FERC Authorizes NYISO, ISO-NE to Collect Tariffs on Electricity

By Jon Lamson

FERC on April 14 approved filings by NYISO and ISO-NE authorizing them to collect tariffs on electricity imports from Canada, if the "relevant federal authorities" deem them responsible for doing so (*ER25-1462*, *ER25-1445*).

The grid operators have said President Donald Trump's tariffs on energy imports do not appear to apply to electricity. However, to prevent potential financial consequences, both saw the need to establish a framework for collecting them.

The commission accepted both grid operators' proposed open access transmission tariff revisions for allocating Trump's tariffs. NYISO proposed to charge the "financially responsible party," while ISO-NE proposed to charge "the entities selling the assessed electricity into the ISO-administered market." (See *ISO-NE Braces for Tariffs on Canadian Electricity* and *NYISO Preparing to Collect Duties on Canadian Electricity Imports*.)

Both grid operators wrote that their cost collection methods would allow importers to include the costs of the duties in market offers. The mechanisms could change if the federal government gives clear instructions to them to collect the tariffs differently. ISO-NE included in its proposal a provision allowing it to collect the duties "in accordance with any federal regulations or guidance," while FERC directed NYISO to add a similar provision in an additional filing.

FERC emphasized that it makes "no finding regarding whether import duties imposed pursuant to the Canadian tariff executive order apply to Canadian electricity or whether [the grid operators are] required to pay them," and similarly declined to rule on whether it is legal to apply the import duties to electricity.

Because of the "exigent circumstances present," FERC directed both grid operators to file "any legal and/or technical guidance and related documentation from the relevant federal authorities showing that a federal agency has assessed an import duty on Canadian electricity imports" that triggers the grid operator's collection authority, "as soon as practicable after receiving such invoice."

If they do start collecting the tariffs, the grid operators must provide informational filings to FERC every six months for three years about the costs of the duties.

ISO-NE's proposal is intended to be a temporary mechanism; if the RTO anticipates tariffs lasting longer than 120 days, it must file a permanent cost collection method within 120 days of the first import duty invoice. ■

Why This Matters

The approvals do not mean that tariffs on electricity will take effect but create mechanisms for collecting the tariffs if the grid operators are directed to do so.

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MISO: DR to Face More Stringent Testing by 2026 Capacity Auction

> ## Why This Matters
>
> MISO is set on abolishing the hypothetical testing of capabilities of its demand response fleet by the 2026 capacity auction, in response to five recent instances of disciplinary action for allegedly deceitful activity.

By Amanda Durish Cook

CARMEL, Ind. — MISO said its next capacity auction in spring 2026 will feature more rigorous testing for its demand response that registers to provide capacity.

The grid operator said it will discontinue its practice of allowing its demand resources to provide hypothetical, mock tests as a performance indicator, except where state regulations might allow, for the 2026/27 Planning Resource Auction.

The end of mock testing follows MISO enforcing stricter registration requirements ahead of the 2025/26 capacity auction offer window, which ran March 26-31. (See *Following DR Exploitation, MISO Announces Stiffer Requirements Before Capacity Auction*.) Taken together, the more unyielding rules are a response to five recent instances of disciplinary action from FERC regarding companies allegedly misrepresenting demand response in MISO's capacity auctions. (See *Voltus Agrees to $18M Fine to Settle DR Tariff Violations in MISO*.)

"There are concerns about the mock test, how it's being used and the information around it," MISO Market Design Economist Joshua Schabla said during an April 9 Resource Adequacy Subcommittee. "Frankly, it's something we're uncomfortable with."

Schabla said at times, mock tests are "little more than a function in an Excel file."

MISO said all demand resources that plan to provide capacity beginning in June 2026 should be prepared to prove their capabilities via actual demand reductions to at least 50% of their stated seasonal values or down to a firm service level, if they specified one. Tests that show less than a 100% result need to be backed up with documentation explaining why a full reduction wasn't possible.

Joshua Schabla, MISO | © *RTO Insider*

MISO said it wasn't foreclosing the possibility that mock tests won't ever be allowed among its demand response fleet in the future. So far, the testing requirement would apply only to the 2026/27 capacity auction.

Schabla said MISO plans to require a real test of its load-modifying resources (LMRs) once per year. The tests can be completed on the resource owner's time and would count as one deployment. MISO's LMRs currently are bound to deploy if necessary five times apiece in the summer and winter and three times apiece in spring and fall.

Erik Hanser, of the Michigan Public Service Commission, said the new testing requirements won't give resource owners much time because real power tests for the 2026/27 planning year begin in summertime up until LMR registration for the 2026/27 Planning Resource Auction begins Dec. 15.

Schabla said MISO has not called LMRs since December 2022. The three-year downtime provides further justification that it's time for LMRs to make a demonstration of their abilities, he said.

"We need to see something positive, that this demand resource is real and can perform to requirements. … We need to see that it can do what we're paying it to do," Schabla said.

MISO Independent Market Monitor David Patton said terminating the mock test practice is critical because the IMM has noticed mock test results submitted from LMRs with reduction levels that are "difficult to believe." He said in some cases, LMRs appeared to fail a real power test and then decided to conduct a mock test instead. Patton said at this point, MISO likely is hosting and paying several megawatts of LMRs that either aren't real or can't achieve what they say they can.

Patton said it's "entirely fair" for MISO to provide notice now that it will enact stricter testing requirements, even if it doesn't yet have FERC approval to end mock testing. He said LMRs should use the time to prepare for actual testing.

Patton said MISO's proposed 50% benchmark testing is "far too lax." MISO pays LMRs too much to accept a 50% performance, Patton argued.

"We're going to continue to talk to MISO and stakeholders about that dimension of this proposal," he said.

MISO to Allow LMR Capacity Substitutions

MISO also said it will permit load modifying and demand response resources to replace their auction-cleared capacity with other, uncleared capacity in the event they're unable to deliver promised load reductions. The change would also take effect in the 2026/27 planning year auction.

MISO allows its more traditional resource types to replace zonal resource credits, but that allowance doesn't extend to demand response resources and LMRs. In MISO, resources' accredited capacity values are converted to zonal resource credits that are used in auction trading.

MISO said it will allow LMRs to make similar, limited replacements if: the end-use customers it contracted for reductions must terminate contracts; regulations prevent the LMR from performing; or a change in ownership occurs in an end-use facility that the resource was banking on to shrink load. For behind-the-meter generation registered as LMRs, MISO said a planned outage longer than 31 days or a catastrophic outage would present the opportunity for replacements.

MISO said in all cases, it may require documentation or evidence.

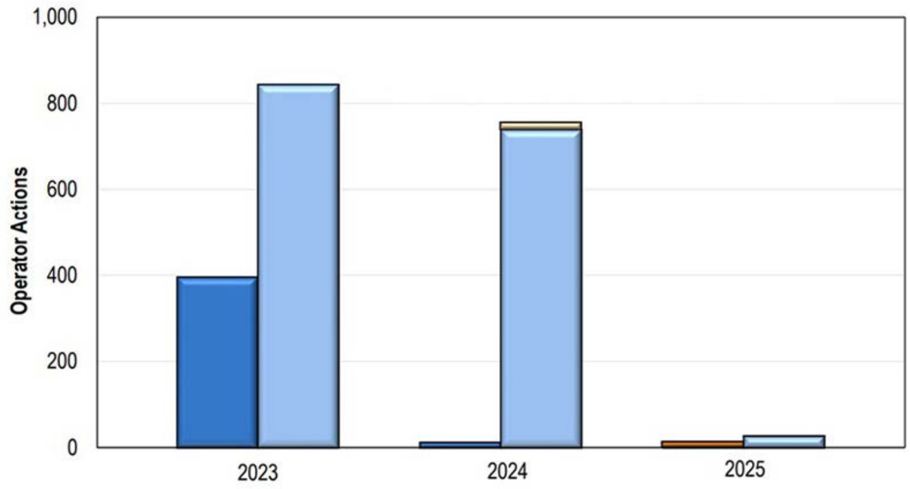
Schabla said resources "must have a good reason to replace" and must be prepared to explain their situations to MISO and the IMM.

MISO staff said they intentionally drafted narrow criteria for replacement conditions so auction commitments remain binding, and market participants don't have a route to avoid obligations.

Some stakeholders have said MISO's replacement proposal is encouraging and will be helpful if facilities close and zonal resource credits need to be replaced. ■

IMM Praises MISO for Fewer Out-of-market Actions

By Amanda Durish Cook



Winter Totals		2023	2024	2025
MRD: Wind	(unit-hours)	394	14	3
MRD: Solar	(unit-hours)	0	0	11
Caps: Wind	(unit-hours)	842	738	27
Caps: Solar	(unit-hours)	0	17	1

MISO operator actions to manage congestion over winters 2023-2025 | *Potomac Economics*

CARMEL, Ind. — After years of its Independent Market Monitor critiquing MISO for making too many out-of-market actions to tame congestion, the IMM congratulated the RTO for dramatically reducing such actions over this winter's sustained cold.

Speaking at the Market Subcommittee's meeting April 10, IMM Carrie Milton said MISO operators' manual actions for congestion management fell dramatically over the winter. She said despite record peak loads over the winter, MISO trusted its markets more and paid minimal uplift payments. (See *MISO: Better Preparations Clinched Winter Storm Operations*.)

The IMM has long advocated for the MISO control room to allow market-based interventions rather than operators making what it calls inefficient, out-of-market actions to manually redispatch or cap generation output.

By the IMM's count, MISO operators ordered just 42 manual redispatches and generation caps over winter 2025, compared to 769 in winter 2024 and 1,236 in winter 2023 that the IMM previously cataloged.

"It almost looks like we're missing data," Milton said of the IMM's striking graph comparing the instances of actions in winter 2023, 2024 and 2025. Milton called it a "very impressive result."

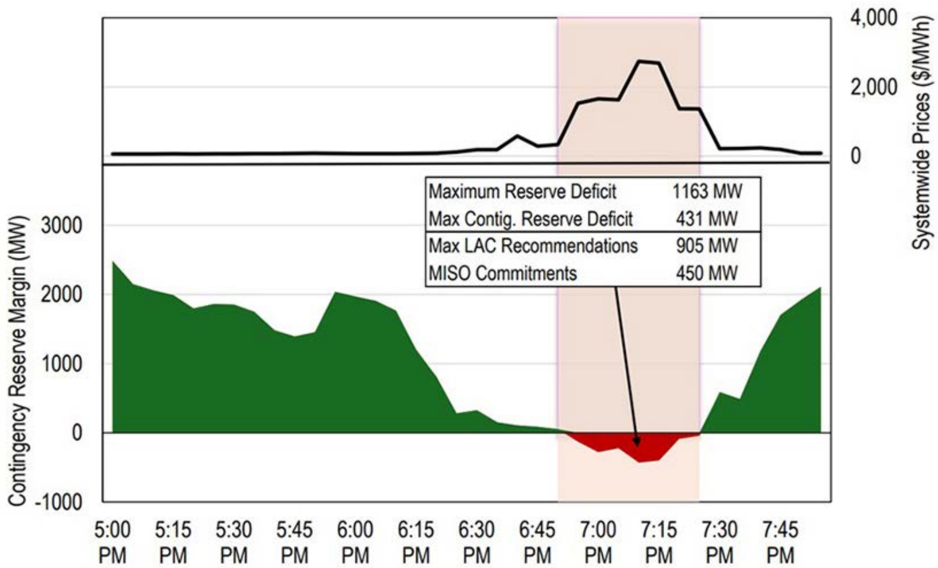
Milton said MISO has worked to make better data available and has congestion management guidelines among control room operators.

Stakeholders asked if the IMM believed that the minimal out-of-market actions could be an enduring trend.

Milton said she thought MISO can reduce its extraneous actions in the long run, even if actions outside of the market tick up during spring. She said maintenance outage season combined with volatile spring weather and high wind likely will lend itself to more out-of-market interventions March through May.

"We understand if we don't see the same result in the spring quarter," Milton said.

Finally, Milton advised the MISO operations team to put more trust into its look-ahead commitment tool to call up units. If control room operators had followed the tool's recommendation to procure and committed an additional 905 MW around 7 p.m. ET on Feb. 19, they could have avoided a contingency reserve shortage that day, Milton said. MISO committed only 450 MW, she said. ■



An illustration of the contingency reserve shortage on Feb. 19 | *Potomac Economics*

Why This Matters

MISO's IMM says a combination of operator training, improved data and more trust in its markets got the RTO to a record low number of manual market interventions to manage congestion.

MISO Fast Lane Proposal Disadvantages IPPs, Retail Choice States, Critics Tell FERC

Plan Draws Rebuke from Former FERC Commissioners

By Amanda Durish Cook

MISO's proposal to use a temporary "fast lane" in its interconnection queue to speed up necessary resource additions would give utility-owned generation preferential treatment, according to protesters' comments filed with FERC on April 7, with a group of former commissioners saying it should be a nonstarter.

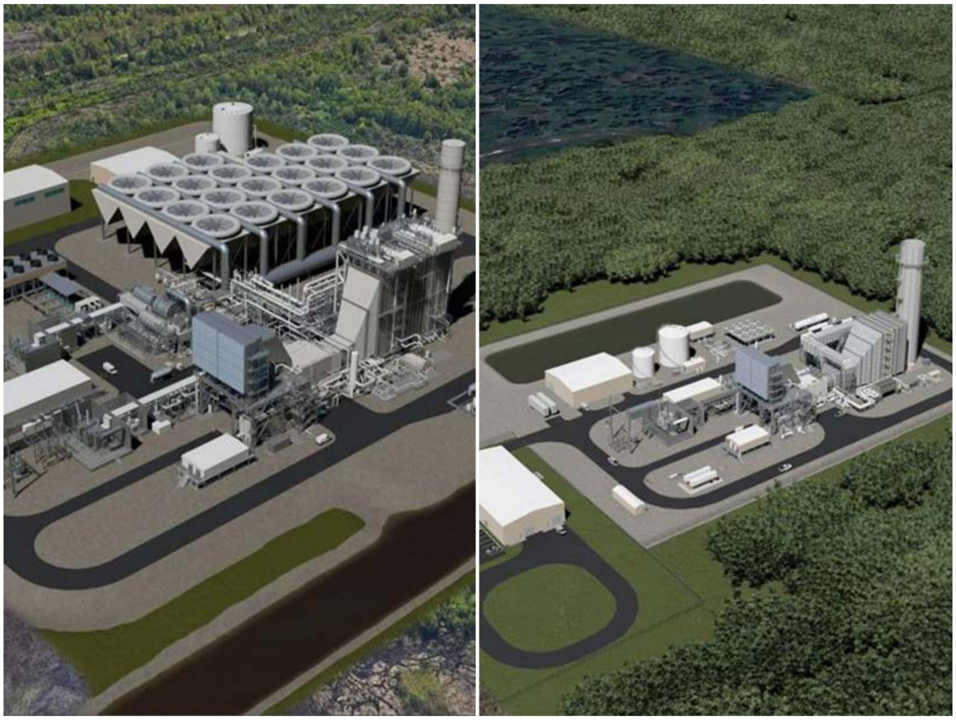
The RTO filed its proposal to install the fast lane by the beginning of summer with FERC on March 17. (See *MISO Says Queue Fast Track Design Settled, Ready for FERC*.) The plan would have projects designated as essential by regulators traversing a separate queue equipped with dedicated, individual studies instead of the cluster-style studies MISO uses in its ordinary queue (ER25-1674).

MISO staff have said its current interconnection procedures are not up to the task of processing new projects expeditiously because of a buildup of projects with study delays. The grid operator has proposed using the special process for the next four years to overcome capacity deficits.

The plan drew a *letter* from eight former FERC commissioners — Democrats and Republicans alike — to express "deep concern." The group, which includes past Chairs Richard Glick, Neil Chatterjee, Joseph T. Kelliher and Pat Wood III, said creating a special, expedited interconnection study treatment in the queue "presents the opportunity for self-dealing by utilities to advance their affiliated generation."

The former commissioners said the fast lane's process, in which a proposed generating facility must either be owned by a load-serving entity or have a power purchase or similar agreement with proof of load, appears unworkable. The group pointed out that independent competitive generation projects have historically been unable to finalize offtake terms and arrangements in contracts until they are assigned network upgrade costs in the queue. They called the plan a threat to FERC's policy of open-access transmission.

They also questioned whether regulators would use an independent process or seek to avoid undue discrimination when selecting projects for special study treatment. They said PJM and CAISO's recent adoption of queue expressways differ from MISO's, which is "not narrowly tailored and allows affiliated generation to receive preferential treatment."



Rendering of Entergy Texas' proposed Legend and Lone Star power stations | *Entergy Texas*

Why This Matters

Rarely do former FERC commissioners band together to call an interconnection queue proposal from an RTO a bad idea. Eight of them have written a letter laying out why MISO's plan to install a separate fast-tracked queue lane could threaten FERC's open access transmission tenet.

"It has been nearly 30 years since FERC first planted the flag of open access when the commission issued Order No. 888. We have come too far to reverse course now, especially when, as other regions have demonstrated, more narrowly tailored options to expedite the generator interconnection process for resource adequacy purposes are available," warned the former commissioners, which also include James Hoecker, Donald Santa, Nora Mead Brownell and John Norris.

States Divided

Support for the proposal among MISO's states fell along retail choice lines.

The Illinois Commerce Commission said it believed the fast lane would discriminate against retail choice jurisdictions and give preferential treatment to vertically integrated states. While state identification of need would work for those that use integrated resource plans, it wouldn't work for Illinois, which relies on competitive markets to ensure resource adequacy, the ICC said.

Illinois is MISO's only true retail choice state; Michigan allows up to 10% of a utility's retail electric sales to be purchased from alternative suppliers.

"Unless the proposal is amended, the projects in Illinois will be at a disadvantage," the ICC argued. MISO's proposal as is does not contain "workable language" to include Illinois or Michigan in short-term reliability considerations, it said.

Rolling out the special queue lane in a staggered manner wouldn't be a solution, either, the ICC said, because by the time MISO established specialized rules for Illinois, the state would have suffered "irreparable economic harm" from the delay.

Vistra, which operates resources in downstate Illinois' Zone 4, agreed. The company said the fast lane would bestow undue preference for generation in vertically integrated states, violating the Federal Power Act, and give LSEs a leg up over independent power producers.

Vistra said MISO is failing to ensure the fast lane would be limited to interconnection requests needed to meet resource adequacy or reliability requirements. The company argued that a request from a regulatory authority to study a resource does not mean it will meaningfully contribute to resource sufficiency.

"If MISO is going to take the exceptional step of allowing select resources to bypass the queue in the name of meeting near-term reliability needs, then there must be a reasonable basis for concluding that these resources can meet the specific reliability needs identified by MISO," Vistra said.

The Michigan Public Service Commission expressed concern that the plan could worsen "inherent inequities" unless applicants for expedited treatment show they have analyzed whether existing projects in the queue could solve the resource adequacy problem they seek to address. Absent that step, MISO could facilitate discriminatory practices and "do grave harm to fundamental principles of open-access transmission that have been core tenants of FERC's regulatory framework since the issuance of Order 888 in 1996," the PSC said.

Alliant Energy battery storage in Portage, Wis. | *Alliant Energy*

It also said it doubted MISO's commitment to bringing projects online as soon as possible because its plan includes a three-year grace period beyond its proposed three-year-out commercial operation date for expedited projects.

Earthrise Energy, which also owns generation in southern Illinois, said FERC should direct MISO to amend its filing so it includes a separate plan for Illinois and Michigan.

But the proposal drew plenty of support from vertically integrated states, including two governors.

Missouri Gov. Mike Kehoe, whose state turned up a capacity deficit in MISO's 2023/24 Planning Resource Auction, said it is "committed to swift action to meet the needs of this moment." He said that the express lane can help the industry meet unprecedented load growth reliably.

Indiana Gov. Mike Braun also supported the fast lane, saying it's "essential for energy development" in his state.

"We are committed to providing reliable, affordable energy to all Hoosiers, but we cannot move as swiftly as necessary without MISO being equally as swift," Braun wrote. MISO is right to recognize it needs urgency and a unique means to manage a confluence of accelerated load growth, a rash of resource retirements and lagging resource additions, he said.

The Organization of MISO States framed the plan as a "necessary but limited mechanism" to maintain reliability across the footprint. OMS said most of its members support "enabling an alternative pathway other than the standard queue to meet immediate resource adequacy needs."

The Arkansas, Louisiana, Mississippi and Texas commissions supported the proposal. Entergy operating companies, which make up the lion's share of MISO South, were similarly on board.

Entergy Texas noted that it needs to bring its Legend and Lone Star gas plants — worth 1.2 GW collectively — online by 2028 to serve growing demand. Entergy

Louisiana noted that it needs three new gas plants of its own at 2.26 GW to serve a new Meta data center. Entergy Arkansas said MISO's queue backlogs "unreasonably impede" new generation coming online.

Questions over Fairness for IPPs

IPPs predicted that the fast lane, which wouldn't use a megawatt cap to limit entries, would soon form a "second, unmanageable queue that would paralyze the MISO interconnection process."

They also echoed Vistra's concerns that regulators could make errors deciding which projects are essential and questioned "MISO's decision to delegate many of the key terms and conditions of interconnection service to state and local regulatory authorities outside of FERC's jurisdiction and leave those processes ripe for arbitrary and unduly discriminatory outcomes in violation of the FPA."

They echoed the former FERC commissioners' discrimination arguments and said the plan would put those developing competitive generation at a disadvantage while creating opportunities for LSEs to engage in self-dealing.

Public interest organizations, including the Sierra Club, Natural Resources Defense Council and Union of Concerned Scientists, called the proposal a "queue-jumping mechanism for preferred projects."

"In MISO's own telling, such a proposal is necessitated by MISO's failure to maintain a process that timely processes interconnection requests from new generation. And as a result of this failure, MISO now claims that it needs to create a separate interconnection process to ensure that these preferred projects are able to come online by the time they are needed for grid reliability," the groups said. They added that MISO was missing a "technical quantification" of its RA need in its proposal.

NextEra Energy said the "gravity of harm that will be caused … cannot be overstated" and predicted that the proposal would give vertically integrated utilities free rein to "self-build their own generation solutions, bypassing gigawatts of independent generation stranded in MISO's legacy interconnection queue."

The Coalition of Midwest Power Producers (COMPP) lambasted the filing as well. It said MISO didn't quantify its resource inadequacy and wrongly omitted Michigan's Zone 7 and Illinois' Zone 4 from the plan. COMPP said together, those two zones contain about 31 GW of load, just 3 GW less than the whole of MISO South. It asked FERC to reject the filing.

The Clean Grid Alliance (CGA) said the expedited proposal is redundant because MISO already has efforts underway to speed up its queue, including study automation help from tech startup Pearl Street, higher fees and the capping of annual entrants at 50% peak load.

CGA said expedited generation would be allowed to claim transmission capacity that otherwise could be available for projects in the traditional queue, causing harm to developers. It also said MISO didn't seem to be considering that some of its 56 GW with signed generator interconnection agreements would overcome delays to come online and handily manage a projected shortfall of a few gigawatts. (See *MISO Members Grapple with 54 GW in Incomplete Gen, Predict Storage Expansion*.)

"Rather than meaningfully parsing out data from its queue and even attempting to match queued generation to sub-region resource adequacy shortfalls, MISO merely makes conclusory statements and cites to its reports that claim there is a resource adequacy shortfall," CGA argued.

LSEs: RA Needs Above All

Michigan-based Consumers Energy said that even though the 1,603-project, 296-GW interconnection queue appears to be able to deliver on resource adequacy, more than 70% of projects drop out of the queue.

Consumers said the high withdrawal rate, coupled with supply chain, permitting and study delays, translates into waiting times for projects that regularly exceed three years. On the other hand, a fast lane is a "tool that can help identify necessary projects and provide a path for a limited number of these resource adequacy projects to get connected in time to meet customer needs."

Duke Indiana said the fast track would be a solid plan, pointing out that NERC's 2024 Long-Term Reliability Assessment indicated that MISO may experience a 4.7-GW shortfall in 2028 "if the current expected generator retirements occur without the addition of significantly more generation."

DTE Energy, Alliant Energy, Ameren and WEC Energy Group likewise filed in support, all stressing MISO's resource adequacy needs.

Transmission owners said the proposal is "tailored" to avert conflicts between expedited projects and those in the queue's usual definitive planning phase by allowing both to be processed in tandem. TOs also said the plan is "intentionally targeted and time-bound with a built-in sunset date, at the latest, by the end of 2028."

MISO has acknowledged its stakeholders are concerned over the potential for discrimination between generation projects and whether a need really exists to create a dedicated fast track in the queue. But staff maintain the proposal is necessary and won't be unduly preferential.

"We have a significant resource adequacy need we've been projecting for a few years," MISO's Andy Witmeier said at a Dec. 6, 2024, workshop. He pointed to the warnings MISO delivers on a quarterly basis in front of its Board of Directors.

Witmeier said MISO is confident that it has enough "inherent barriers" in place to the fast lane that there won't be a "mad rush" where developers enter projects "willy nilly." He said projects must be recognized and accepted by a state to meet a known need before they are able to gain entry.

"MISO has always been open to queue reform and trying to make the process better … and more efficient for all users," Witmeier said, noting that in the five years he has worked on the queue, the RTO has continually made improvements.

He said it is prepared to hire additional consultants, contractors or temporary personnel to take on the additional work of the fast lane, resulting in higher processing fees for interconnection customers, though it should be straightforward. MISO won't create special studies; it will just conduct its usual interconnection studies on a condensed timeline by focusing on a single generating unit, he said. "We know how to study interconnection requests." ■

MISO Discards Interim Participation Option from Order 2222 Plan

By Amanda Durish Cook

MISO on April 7 announced it will scrap its plan to use an existing demand response participation category to get aggregators of distributed energy resources participating on a limited basis a few years ahead of its full implementation of FERC Order 2222 in 2030.

During a DER Task Force meeting, MISO counsel Michael Kessler said the RTO decided that trying to bend the interim plan to all Order 2222 requirements as FERC recommended would be "unduly burdensome." Kessler said MISO plans to inform FERC by July that it will abandon its DR participation idea rather than try to make it fully compliant with the rule.

FERC accepted MISO's second try at Order 2222 compliance Jan. 16, granting the RTO until mid-2029 to prepare before fully accepting DER aggregators into its markets in 2030. (See *FERC Permits 2030 Finish Date for MISO Order 2222 Compliance*.)

The commission accepted MISO's explanation that its underlying computer systems need work over the next four years. However, it told the RTO its plan to allow DER aggregations in its markets earlier in a two-phase rollout needed to be either deleted or revised significantly.

MISO proposed to use a two-stage approach to Order 2222 compliance. First, it would use an existing DR resource participation category to get DER aggregations participating sooner — albeit on a limited basis — and providing energy, contingency reserves and capacity through behind-the-meter generation or controllable load. MISO would have begun registering DER aggregations under its DRR Type I model by Sept. 1, 2026, and would have allowed participation to begin by June 1, 2027. DER aggregations would have been limited to 1 MW or larger under the model.

But in its Jan. 16 order, FERC said MISO's proposed 1-MW size threshold is too large, as Order 2222's minimum for participation is only 100 kW.

The commission also said MISO's DR placeholder doesn't address the coordination, data requirements or means to discourage double-counting of resource contributions required under Order 2222. It decided the RTO missed the mark on using an existing participation model to eke out partial compliance.

FERC gave MISO 180 days to either explain how the DRR Type I participation model could comply with Order 2222 or strike the first phase of participation from its compliance plan. MISO decided over the last few weeks that it would not salvage that aspect for a separate filing to allow DER aggregations to provide some services by the middle of 2027.

Kessler said MISO attempting to make its planned, interim step complaint with Order 2222 would likely require the same system changes that aren't doable until full compliance with the rule in late 2029 through mid-2030. ■

| © RTO Insider

NY Energy Summit: Patience Trumps Angst

State Stands by Green Goals as Whirlwind of Federal Uncertainty Makes Them More Challenging

By John Cropley

Why This Matters

Constraints and uncertainty face New York's ambitious energy plan as President Donald Trump revises the parameters on which it is based.

ALBANY, N.Y. — Energy and transmission development in New York can be an exercise in patience and persistence, with supportive policy messages counterbalanced by complex regulations, high costs and long timelines.

The annual New York Energy Summit often is a showcase of this dichotomy, a chance to catch up on the latest developments in the Empire State and share thoughts on how to build on those changes or get around them.

The 2025 edition of the event could have been more of this, given the important policy decisions being hashed out a block away in the state Capitol. But they often seemed overshadowed by national developments — a brewing global trade war, trillion-dollar hourly swings in the financial markets and murmurs of a recession or stagflation bearing down on the U.S. economy.

Clearly the need to expand and modernize New York's grid persists regardless of who is in the White House, and the timelines will extend beyond the term of any one president, or any three.

But as recent weeks have shown, a president can change the landscape markedly in much less than a single term — or even worse, shroud the landscape in a fog of uncertainty.


New York PSC Chair Rory Christian | © *RTO Insider*

As New York Public Service Chair Rory Christian noted in a keynote address: "Difficult times lie ahead."

"Inaction is not an option," he said. "I encourage you to lean into this moment, not despite the uncertainty, but because of it."

New York's grid is like most others — it needs extensive and expensive modernization and expansion as it faces potentially huge load growth. The state also has some of the most ambitious plans in the nation to decarbonize the power portfolio feeding that grid, as well as some of the highest costs and most rigorous processes for carrying all these plans out.

Rapid-fire directives coming from the White House since Jan. 20 have made the prospect more daunting.

Inflation and interest rate fluctuations have created new financial risks, as have President Donald Trump's repeated tariff threats. Previously committed grants and tax incentives remain under threat.

An executive order issued on Day 2 of the *New York Energy Summit* targets key policy decisions in climate-focused states and calls out New York by name.

State officials speaking at the Infocast event acknowledged the uncertainty facing everyone in the room but said it has not changed New York's vision.


Georges Sassine, NYSERDA | © *RTO Insider*

"If there's one message to take away today it is that the state of New York is fully committed to our clean energy goals," said Georges Sassine, vice president of large-scale renewables for the New York State Energy Research and Development Authority, which is leading the efforts to decarbonize the state, particularly its generation portfolio.

Christian heads the Department of Public Service, which leads regulatory efforts to put the infrastructure in place to accomplish these policy goals.

"[The goals] require, above all, a modernized grid," Christian said. "We're entering an era where our history of flat demand and flat load growth is no longer the norm. We're in an era where need for interconnecting multiple resources in a short period of time is no longer a luxury but a necessity."

Christian laid out some of the steps being taken toward this Grid of the Future, as the proceeding is named, and toward the flexibility needed to make it meet the needs at an affordable cost.

Like any long-running process with thousands of stakeholders, there is not unanimous agreement on the details, nor universal satisfaction with the pace.

The state has seen slow buildout of renewables in the nearly six years since passage of its landmark climate law mandated the transition, and multiple panelists said state regulators need to adjust their approach accordingly — fossil fuels will be needed longer than the state hoped.


Matt Schwall, Alpha Generation | © *RTO Insider*

Matt Schwall, director of regulatory affairs for Alpha Generation, said all six of his company's plants in New York are operating with Title Five state air permits that are expired and awaiting renewal.

"And that's not just unique to us; that's every generator in the state. It's tough to convince an investor to put money in the state when you don't know if you can even get a permit."


IPPNY CEO Gavin Donohue | © *RTO Insider*

Independent Power Producers of New York President Gavin Donohue, whose members produce much of the state's electricity, said reliability concerns are growing.

"The state needs to be realistic about what it takes to keep the lights on, on a day-to-day basis, and there needs to be a recognition that permits need to be issued in an effort to maintain that reliability," he said.


Shaun Johnson, NYISO | © *RTO Insider*

NYISO Vice President of Market Structures Shaun Johnson said: "Particularly in some areas of the state, we have razor-thin margins. We, at the moment, don't have a lot of flexibility to be able to ramp up new generation quickly and meet those future demand needs."

The solution, he added, is not simple; it is a mix of load demand, market signals and state policy that will attract investors. "Because at the end of the day, they can choose — am I going to come to New York? Am I going to go to Virginia? Am I going to go to Texas? Where am I deploying my capital? And in some ways, we're all competing against each other for that capital."

New York has had some very visible problems adding generation — 88 renewable projects canceled their offtake contracts after cost escalations swept the industry in 2023. Those projects would have provided sizable progress toward the state's clean energy goals and toward meeting the need for more gigawatts of capacity. The contracts are gone but the projects themselves are not necessarily dead, and the state will try to draw them and others back into its portfolio.

Sassine said more requests for proposals are in the works, along with requests for information (RFI) to shape those RFPs.

"We very much look forward in these RFI processes to get feedback from all stakeholders on how we should be thinking about risk-sharing, going forward in light of all this federal uncertainty," he said.

The state-owned New York Power Authority has begun working in its new role as a renewables developer, and the vice president leading the effort, Vennela Yadhati, said renewables have a key advantage over the fossil fuel generation that suddenly is in favor in Washington: speed of deployment.

Multiple speakers at the summit noted the yearslong wait for a newly built gas


Vennela Yadhati, New York Power Authority | © *RTO Insider*

turbine. Yadhati contrasted the relative speed with which solar and onshore wind generation are being built and cited the resilience those industries have developed.

"The renewables industry has been through administration changes in the past," she said. "We have been through uncertainty in the past, but we continue to strive and thrive, actually, in this market."


Marguerite Wells, ACE-NY | © *RTO Insider*

Marguerite Wells, executive director of Alliance for Clean Energy New York, placed some of the onus for moving ahead on the renewable energy developers themselves.

Some developers, she said, have submitted "tire kicker" proposals they were not fully committed to, contributing to the sluggish nature of the NYISO interconnection queue, and others have cut corners on their community outreach efforts — a potentially serious mistake in a home-rule state where local opinion can slow or block a proposal.

As the level of public opposition and concern around projects and politicization of renewables grows, it is more and more incumbent on developers "to do a better and better job with community relations and stakeholder work," Wells said. "I think that often gets short shrift."

New York's infamously slow timelines, she added, are getting better, through the state's streamlined regulatory processes and through NYISO's newly revamped interconnection process.

"I think we can see that the new process is doing what it's supposed to do," Wells said. "It's painful to go through it now. It's much more expensive and it's faster, and it's more technically challenging to get all that work done in a shorter period of time. But the end goal is to have an interconnection process that more similarly mimics what Texas has done, which is get a project through in a year or two. Used to be five to seven in New York, and that's


U.S. Rep. Daniel Goldman (D-N.Y.) | © *RTO Insider*

not necessary."

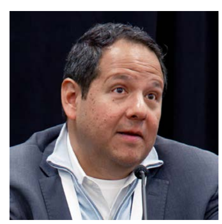
U.S. Rep. Daniel Goldman (D) conceded that his opinions hold no sway with Trump and that he is worried about the fate of renewable projects both present and future.

But he said the country's need for electricity and the benefits renewables have provided for red congressional districts will be more influential than the opinions of a congressman representing a deep-blue New York City district.

Goldman urged listeners to stick with the approach that most of the renewable energy community seems to have adopted the day after Election Day, emphasizing the good of the nation rather than the good of the planet.

"Let's set aside the climate benefits as we are making this case right now, because the economic and national security case for clean energy is stronger than ever."

He added: "We absolutely cannot give up with this administration — even if those wind turbines are unattractive."


Sergio Garcia, Rabobank | © *RTO Insider*

Sergio Garcia, executive director of project finance at Rabobank, counseled patience and a longer view. Financial planning is difficult until budget and policy negotiations produce a firm picture of the tax incentives that grew from the Inflation Reduction Act.

"Right now, we're all distracted with the IRA," he said. "It'll change — in what form, I have no clue. Until we have visibility in there, it makes your jobs a lot harder, because you need to deploy capital."

Garcia added: "It's a reality check, right? It did work before the IRA, and it'll work again in one form or another, and renewables will continue to strive because it is the lowest levelized cost of energy. So I think there's plenty to do. I think that banks are all active, and we're all like looking for projects to finance." ■

NY Energy Summit: Making the RAPID Act Live up to its Name

Stakeholders Excited by Prospect of Faster Transmission Development

By John Cropley

ALBANY, N.Y. — Speeding up the construction of new transmission and other energy infrastructure is a recurring topic of conversation each year at the New York Energy Summit.

The 2025 edition of the Infocast event included standard complaints and constructive criticism, but there also seemed to be more progress to report than in some years.

The April 7-9 Energy Summit fell shortly before the one-year anniversary of the Renewable Action Through Project Interconnection and Deployment Act.

The RAPID Act expanded the powers and responsibility of the Office of Renewable Energy Siting, in hopes ORES could create for major transmission proposals some of the same streamlining it has done for proposed large-scale renewables: a standardized and expedited permitting process that can override local authority if needed.

Recently appointed ORES Executive Director Zeryai Hagos brought the audience up to speed on the work of what officially now is the Office of Renewable Energy Siting and Electric Transmission but still is known as ORES.

"We've got a much larger volume of transmission projects that we already know exist and are coming, and we have many, many more that are going to get approved by the [Public Service] Commission, I think, in the coming years, as the [Coordinated Grid Planning Process] begins to develop its first real big slate of projects at the end of next year," he said.

"And so primarily the purpose of the RAPID Act was to ensure that we could keep moving at the pace necessary to achieve the climate goals and not let transmission be a barrier."

Why This Matters

New York is trying to ease factors that make its energy goals slow and expensive to pursue.

Zeryai Hagos, executive director of the New York Office of Renewable Energy Siting and Electric Transmission, is shown at at the New York Energy Summit on April 7 in Albany, N.Y. | © *RTO Insider*

Hagos recalled coming to New York in 2019 and discovering what everyone else discovers: It was a slow and expensive place to build generation and transmission.

Long-running efforts to address this have been complicated by events at the local and global level. Hagos recalled several such events during his tenure in New York:

Later in 2019, the state passed its landmark climate law, with statutory requirements that will radically increase the amount of electricity used in New York and radically decrease the amount of greenhouse gases emitted. (And radically increase the amount of generation and transmission capacity needed.)

In 2020, the COVID-19 pandemic altered energy use patterns as people began to stay at home.

In 2022 and 2023, global supply chain and cost factors eviscerated New York's portfolio of contracted clean-energy projects, likely making the first target of the climate law — 70% renewables by 2030 — unreachable.

Now in 2025, Hagos said, federal policy changes could actively thwart New York's energy agenda, or make it more expensive to achieve, or both.

Interconnection queues are crowded and permitting reviews can be slow anywhere in the nation, not just in New York.

U.S. Rep. Daniel Goldman (D) focused on federal sluggishness in his remarks. "We really need to continue to streamline the process of getting clean energy up and running and on the grid. We need permitting reform," he said, calling out specifically the irony of environmentally beneficial renewables being subject to the lengthy and rigorous reviews originally designed for environmentally unfriendly fossil fuel projects.

Max Luke, National Grid's director of transmission and wholesale market policy, said the utility is optimistic about changes wrought by the RAPID Act as well as by FERC orders 1920 and 2023, and will work with NYISO and other stakeholders to continue refining the process.

The draft regulations promulgated through the RAPID Act are not complete — public comments are being accepted through April 18 — so their exact impact remains to be seen, Luke added.

"But National Grid is hopeful that that they will expedite transmission development considerably," he said. "We're faced with needing to build a lot more transmission in the state for a whole bunch of reasons, but a lot of that is driven by the state's public policy objectives."

ORES is not a magic bullet. It was intended to streamline the permitting process and limit the ability of local governments to stand in the way of policy goals, but it is not "drill, baby, drill," a rubber stamp or a carte blanche. The application process is rigorous and complex, the pre-application process can take longer than the application process, and local opinion still matters.

One after another, developers, advocates and officials speaking at the summit warned against scrimping on community outreach or ignoring public opinion when pursuing energy projects.

Boralex public affairs manager Zack

Zack Hutchins, Boralex | © *RTO Insider*

Max Luke, National Grid | © *RTO Insider*

Hutchins said public outreach is even more important in the ORES era.

"The ORES structure has been extremely helpful as far as providing certainty and helping with timelines and all of that," he said. "One of the unfortunate side effects of it has been that it's created this tension between developers and local officials who feel that they don't have a say."

Boralex gets feet on the ground early and often when it is advancing a project, Hutchins said.

"And if we can prove that we provide value and that we can answer questions that [local officials] receive from angry citizens, then that gives us a leg up when it comes time to actually move into the development phase, the construction phase and then the operation phase of these various projects."

Joel Thomas, who leads East Coast development for the AES Corporation, said a developer that waits until the permitting process to start pitching the project to the community has waited too long and can find themselves being reactive to people who already have made up their minds.

Alliance for Clean Energy New York Executive Director Marguerite Wells also emphasized proactive outreach. "You should be having dozens and dozens of community meetings before any public decisions get made," she said.

Wells warned that the various streamlining efforts that ORES, NYISO and other New York entities are making are not simple changes:

"The promise and the challenge of the revised approach to managing the queue

Joel Thomas, AES | © *RTO Insider*

is that it's going to deliver us projects out the other side that have been fully vetted in a much shorter period of time, but it is more expensive, and it requires a higher level of rigor going in and a higher level of financial commitment on the part of the developers throughout the process."

As the one-year anniversary of the RAPID Act nears and the comment period on its draft regulations ends, ORES is trying to balance the many demands and expectations placed on it.

New York does not speak with one voice: It is a deep blue state by population but a heavily red state by geography. The red areas often are prime targets for energy development; some of them resent that fact and resent that ORES can override their objections.

More than 200 comments have been submitted about the RAPID Act draft regulations (*24-M-0433*), ranging from it being another dictatorial power grab to ORES not going far enough to shorten the permitting and pre-permitting processes.

"We recently extended the comment period because many stakeholders just thought that this was such a substantial change, and there was so much happening in the regulations," Hagos said.

"We understand that there is a tradeoff between having really, really strong environmental protections and making sure we do it right, and also time — time and feasibility."

And that provides a hint about a likely theme of conversation at the 2026 New York Energy Summit: How can we tweak New York's permitting just a little further, and how can we assuage local discontent just a little more effectively? ■

NYISO's Firm Fuel Proposal Criticized by Market Monitor

Says Incentive for Generators to Rely on 'Inferior Types' of Service

By Vincent Gabrielle

NYISO's market monitor *claims* the ISO's firm fuel capacity accreditation proposal would incentivize generators to rely on inferior types of firm fuel service that could undermine the winter reliability benefits of firming up.

"The current tariff is enforced through documentation, the need to obtain agreements that commit to firm fuel obligations," said Pallas LeeVanSchaick, vice president of Potomac Economics. "The NYISO proposal fundamentally changes the obligation … by switching to something with a performance-based rule."

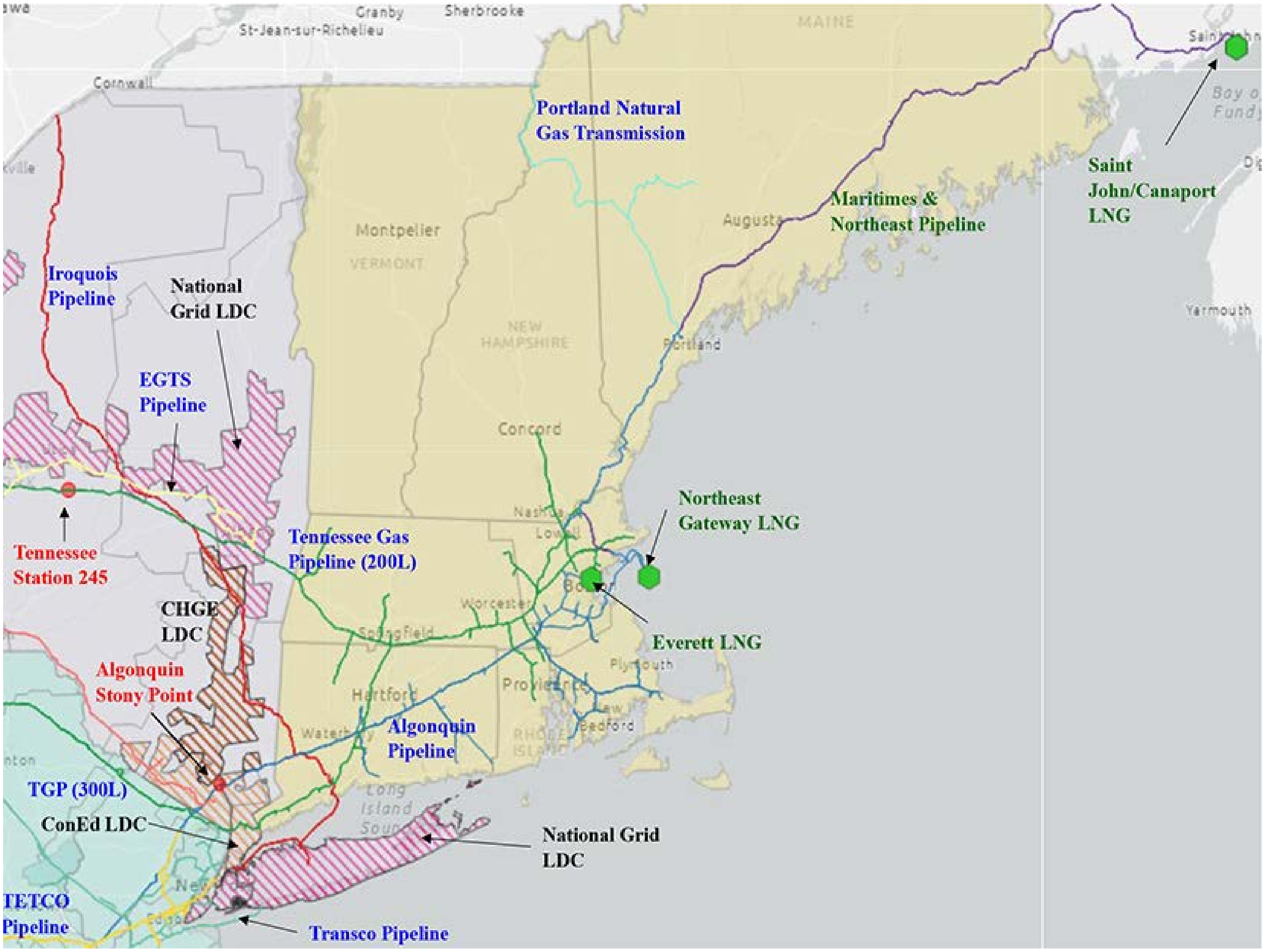
Why This Matters

NYISO is running out of time to file its firm fuel capacity accreditation project this year but the market monitor has found some major issues.

The NYISO proposal asks that generators elect as firm or non-firm roughly 16 months in advance of the capability period they are electing for. The proposal requires that generators electing firm notify the ISO they have secured firm contracts by Dec. 1 of the capability year.

Generators that elect firm need to have fuel supply, transportation and replenishment strategies in place by the December deadline to ensure they can operate 56 hours over a consecutive seven-day period during the winter. Failure to perform during the capability period could result in sanctions.

LeeVanSchaick said in a presentation April 9 to the Installed Capacity Working Group (ICAP WG) that NYISO's current proposal creates an incentive for generators to rely on "inferior types of firm fuel



Pipeline network in N.Y. and New England | *Potomac Economics* service" to qualify as firm. That's because of the way it interacts with the natural gas import infrastructure.

During most periods, "firm" gas used by generators is made available on the system through capacity release, LeeVanSchaick said. Capacity release is the reselling of firm fuel rights to another entity. These can be pre-arranged for set terms of time.

"Most of the gas that's available during winter is mostly a function of capacity release," LeeVanSchaick said. "It's not something that's going to be available under all circumstances."

During the worst winter periods, more generators are called on, reducing available fuel. If more generation is called on than there is natural gas available, then they must rely on fuel injections at the LNG ports in New Brunswick and the Boston area. These periods are infrequent. Most generators, LeeVanSchaick said, don't bother coming up with firm fuel transportation contracts.

"A performance-based penalty doesn't provide a very strong incentive to do this," LeeVanSchaick said. "You're sort of relying on generators to ignore their incentives."

LeeVanSchaick said the purpose of firm fuel capacity accreditation is to try to incentivize generators to have capacity for infrequent conditions. He said it requires either verification of firm fuel and transport contracts on the front end, which the NYISO proposal does not do, or extreme penalties to make a violation too risky.

He proposed levying an additional firm fuel penalty on any generator that notifies the ISO of failure to contract by Dec. 1. For generators that are discovered to have not informed the ISO of a failure to get firm fuel contacts in place, he recommends a financial sanction and FERC referral. He also recommended moving the deadline up to March before the capability period.

Representatives of the generator sector took issue with this analysis, saying there were penalties beyond the firm fuel sanction that they would be exposed to if they misrepresented how firm their fuel was. Specifically, misrepresenting how firm a contract was already could get a generator in trouble with FERC for a tariff violation.

"I think the concern you raised is that this (getting firm fuel) is not a black-and-white behavior and therefore the ISO should allocate penalties," said Mark Younger of Hudson Energy Economics. "I think if we've got issues that need to be evaluated where it's not black and white, that FERC is the appropriate place to do that."

Younger said he was more comfortable with the clarity of the ISO proposal and there was nothing in it to prohibit the ISO from asking generators what they did to secure a firm resource.

Doreen Saia, chair of the energy law practice at Greenberg Traurig, said she wasn't comfortable with a system that forced generators to declare they could lock down fuel supplies 15 months in advance, combined with a penalty if they couldn't secure a contract because of market reasons.

"It's like having a cop on a road seeing a car go really fast and not know if it went 70 or 90 and therefore not know what kind of ticket it should get," Saia said. "I think that's a FERC question and FERC should decide whether any additional penalty should be required or not."

NYISO staff attending the working group disappeared during the lunch break to confer in private on the MMU proposal and the discussion it generated. They came back with an ellipsis.

"We'd like to get any additional feedback or thoughts on the proposal that was put forward today," said Shaun Johnson, vice president of market structures for NYISO. "We'll take that feedback, process it and consider our next steps going forward."

Zack Smith, senior manager capacity and new resource integration market solutions for NYISO, said they would move "rapidly" with their considerations.

Julia Popova, chair of the ICAP WG, asked about the timing of NYISO returning with an answer. The ISO is running out of time to file with FERC and avoid jostling the current Aug. 1 deadline.

Smith said the ISO would return "soon" but didn't provide a clearer timeline.

"The message is clear. Stay tuned," Popova said. ■

NYISO Reaffirms Need for NYC Peakers in Summer

By Vincent Gabrielle

NYISO continues to find a reliability need for New York City this summer and two peaker plants in the city should be allowed to continue operations into 2027 if necessary, according to sensitivity results for the first-quarter Short Term Assessment of Reliability (*STAR*), presented April 7 to the Transmission Planning Advisory Subcommittee.

Ross Altman, NYISO senior manager of reliability planning, said the city would be deficient by 281 MW for five hours on a hypothetical summer peak day during normal weather conditions if the Gowanus and Narrows peaker units are offline. Both barge-borne floating plants were built in the early 1970s and are owned by AlphaGen.

The ISO said it continues to believe the plants should be allowed to operate beyond their planned retirement in May, until May 2027 or a "permanent solution" is in place.

But NYISO is also concerned about unplanned outages at aging plants; the accelerated retirement of other, smaller New York Power Authority gas plants; the impact of heat waves; and delays on the Champlain Hudson Power Express transmission project.

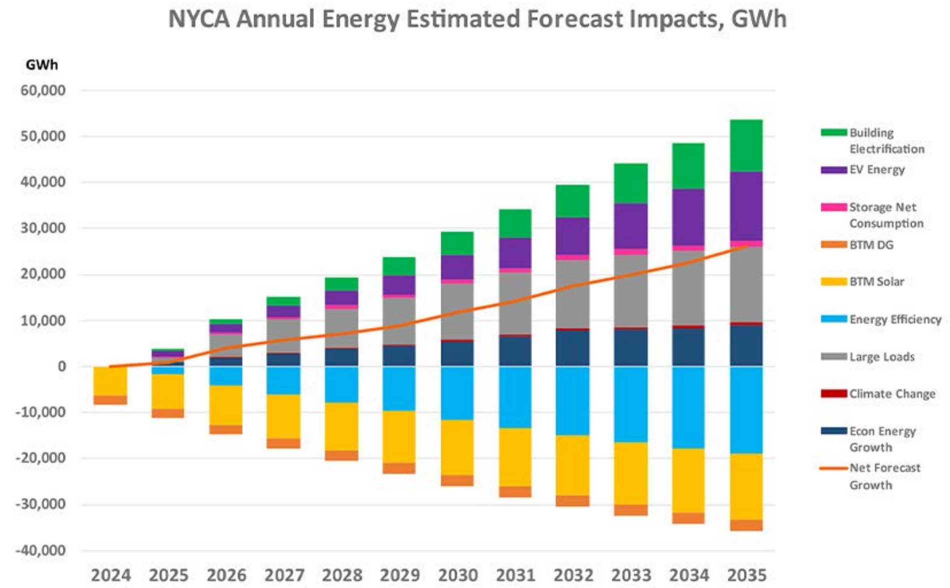
The status of the fossil fuel fleet and NYISO's assumptions about their retirements occupied much of the discussion. Altman said the ISO was not forecasting retirements; rather, the intent of the analysis was to understand how many old plants were at risk of failure.

"What we're showing with aging fossil fuel [power plants] isn't purely economic or policy driven," Altman said. "As complicated, spinning heavy machines age, they are more likely to fail."

Chris Casey with the Natural Resources Defense Council asked NYISO to make it clear in the final Q1 STAR report, due

What's Next

NYISO will release the full Q1 STAR report on April 14.



	Economy	Large Loads	Climate	EE	BTM Solar	BTM DG	BTM Storage	EV	Electrification	Net Impact	Forecast Growth
Annual Impact:	0.5%	1.0%	0.04%	-1.1%	-0.9%	-0.2%	0.1%	0.9%	0.7%	1.1%	1.6%

| NYISO

to be released by April 14, that it wasn't talking about normal retirements. He said the language of the presentation made it confusing as to whether the "deactivations" were a normal process or from catastrophic failure.

Doreen Saia, chair of the energy law practice at Greenberg Traurig, asked whether the ISO was implying with this analysis that it was worried that if a fossil fuel generator went offline, it would not get it back.

"If that's part of your analysis, it needs to be said someplace because I think it's an absolutely fair assumption," Saia said. "I don't know why you would think you could get them back in this environment where gas turbines aren't favored and the owner could very well sell or repurpose their very attractive real estate."

NYISO also presented its 2025 *preliminary* baseline forecast for the next 10 years of load growth for both the winter and summer capability periods.

The ISO is projecting roughly 3,700 GWh of large load growth in 2025, mostly concentrated in the North Country and Buffalo. In 2026, roughly 7,800 GWh of large load is forecast to be on the grid.

These large loads constitute the greatest driver of growth in New York. In the near term, they dwarf both electric vehicle and building electrification forecasts. Economy-driven demand growth is projected to remain relatively low through 2035 because of poor economic forecasts.

Without the large loads, New York would likely see declines in overall energy consumption because of outmigration and slowing economic growth through 2031. The forecasts did not consider the Trump administration's tariffs.

The ISO also expects energy efficiency gains to mitigate load growth, with strong support from behind-the-meter solar and energy storage.

Casey said he agreed with several skeptical stakeholders that some of the sensitivity scenarios did not present credible possibilities. He went further, saying that given the tariffs from the Trump administration, the baseline forecast could be "way above" reality.

"There is a realistic possibility that things will stay as they are," Casey said. "A lot of economic development and large loads that we anticipate coming are not going to come, or are not going to come when they are expected." ■

FERC Sustains Order Rejecting Expanded Susquehanna Co-located Load Arrangement

By Devin Leith-Yessian

FERC sustained its rejection of amendments to the Susquehanna nuclear plant interconnection service agreement (ISA) to increase the amount of power serving a co-located data center (*ER24-2172*).

The changes sought by Talen Energy would have increased the scale of the Amazon Web Services data center operating behind the fence of Susquehanna from 300 MW to 480 MW. That was rejected by the commission on Nov. 1 on the grounds PJM had not demonstrated the proposal was "necessary for any interest unique to the interconnection of the Susquehanna customer facility." (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

The April 10 rehearing order defended the commission's earlier finding that the proposed ISA amendments were not based on "*specific* reliability concerns, *novel* legal issues and *unique* factors" as demonstrated by it being based on PJM's generally applicable guidance document for co-located configurations. While the RTO since has rescinded that document, the commission noted that portions of the proposed amendments to Susquehanna's ISA mirrored the guidance and comments debating the proposal referred to it repeatedly. The rehearing order argued that allowing a standardized practice to be the basis of ISA language that does not conform to the *pro forma* interconnection service agreement (ISA) would weaken the commission's necessary standard.

Why This Matters

Energy companies and data centers want FERC to clarify how they can move ahead to co-locate data centers. The commission said the Susquehanna rejection order does not prejudice any future co-located load configurations.

In its request for rehearing, Susquehanna said the commission's rejection was not based on the unique configuration Talen sought, but rather that it could create a precedent for other resources that would not be reflected in the *pro forma* ISA. The company argued that being the first of its kind is not a valid reason for denying the application.

The commission wrote that reliance on the guidance document "raised the question of whether PJM intended to offer certain terms to all similarly situated interconnection customers."

"Creating a requirement that the commission wait for a pattern to emerge before rejecting a non-conforming provision, as Susquehanna requests, would meaningfully weaken the necessary standard and meaningfully increase the possibility for disparate treatment that the necessary standard is designed to diminish," the commission wrote.

Susquehanna also argued that reliability concerns "haunt" the rejection order despite PJM stating that necessary studies had not identified any issues with the configuration.

In the rehearing order, the commission wrote the study findings are not relevant to the rejection order, which hinged on a determination that PJM had not shown that the non-conforming language was necessary.

Vistra requested the commission clarify whether its rejection establishes a blanket limit on amending ISAs to co-locate data centers. If the intention was to hold that such amendments are not appropriate, Vistra said the underlying issues should be outlined so Susquehanna could refile without those provisions and others could do so as well. The commission responded that the rejection order does not prejudice any future co-located load configurations.

Phillips Dissents

The rehearing order was approved on the same lines as the original rejection, with Commissioners Mark Christie and Lindsay See in support and Willie Phillips dissenting. Commissioners David Rosner and Judy Chang did not participate.

Talen Energy's Susquehanna Steam Electric Station located in Salem Township, Pa. | *Talen Energy*

Phillips wrote that he's hopeful the commission's order that PJM show cause investigating whether PJM's tariff is just and reasonable without language addressing co-located load will allow such configurations to proceed. He repeated arguments he made opposing the original rejection that data centers represent an "era defining technology" that requires regulatory leadership. (See *FERC Launches Rulemaking on Thorny Issues Involving Data Center Co-location*.)

"Notwithstanding my disagreement with these orders' rationale and determination, I remain hopeful that the Commission's recently issued order … will soon result in solutions to address what I regard as unnecessary roadblocks to the continued maturing of an industry that is vital to our economic prosperity and national security," Phillips' dissent on the rehearing order said.

PJM's response to the show cause order said more FERC guidance is needed on how the RTO should allow co-located configurations to proceed and laid out several possible pathways. It also noted challenges that remain unsolved, such as how to account for ancillary services the RTO maintains are consumed by co-located loads and whether protective schemes can be adequate for preventing the load from inappropriately taking energy from the grid. (See *PJM Responds to FERC Co-located Load Investigation*.)

Proponents of co-location have argued that in some instances the load should be considered separate from the wholesale grid and should not be charged for services such as regulation and black start. ■

PJM CEO Manu Asthana Announces Year-end Resignation

Plans to Stay on as Adviser to RTO Through June 2026

By Devin Leith-Yessian

PJM CEO Manu Asthana on April 14 *said* he will resign from his position at the end of 2025 after more than five years of leading the RTO.

"My five-plus years at the helm of PJM have been some of the most fulfilling of my career," Asthana said in a statement. "I am especially appreciative of the opportunity to have led PJM's remarkably talented, diligent and committed people, who work hard every day to keep the power flowing for 67 million people.

"The time has now come for my wife and me to move back to be closer to our family and friends in Texas. I look forward to continuing to lead the organization through the end of the year and to helping facilitate an orderly transition to my successor."

Asthana relocated to Pennsylvania when he took over as the head of PJM on Jan. 1, 2020, in the wake of the GreenHat Energy default, which led to the resignation of several PJM executives. (See *PJM Taps Ex-Direct Energy Exec as New CEO*.)

Mark Takahashi, chair of the PJM Board of Managers, said Asthana guided the RTO through several significant changes, including the shift to studying interconnection requests with a cluster-based approach and an overhaul of capacity market rules following Winter Storm Elliott in December 2022. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

"The PJM board is grateful to Manu for his strong leadership during a time of tremendous change in the electricity industry," Takahashi said in a statement. "Under his leadership, PJM successfully navigated the COVID-19 pandemic, significant market reforms, interconnection process enhancements, the buildout of a robust risk management function and the delivery of world-class grid reliability through a variety of extreme weather events."

Why This Matters

Asthana joined PJM as CEO five years ago, just as it was emerging from controversy related to FTR trading.

PJM CEO Manu Asthana | © *RTO Insider*

Takahashi said Asthana has worked with the board to develop "PJM's internal succession pipeline."

"We have a strong executive team, including internal succession candidates. We will also consider external candidates for this role," Takahashi said.

The board has formed a search committee to identify a replacement in the next year. That process will be aided by consulting firm Korn Ferry with input from the RTO's membership and stakeholders. Asthana is set to stay on as a senior adviser until June 2026.

Electric Power Supply Association CEO Todd Snitchler said Asthana led PJM through a time of rapid change.

"We have appreciated working with him and his willingness to listen to the input of the generator community as he navigated how to deliver reliable power while addressing the challenges posed by varying state and federal policy preferences; a rapid rise in energy demand; and external factors like supply chain hurdles and onerous permitting policies that impede infrastructure development," Snitchler said.

He said EPSA hopes to see PJM continue to address planning and interconnection queue issues, and "strongly support" a market that balances input from stakeholders and market participants and "provides reasonable certainty and a fair opportunity for a return on investment for resource developers."

Glen Thomas, president of GT Power Group, said "leading PJM is a challenging job, and Manu led PJM through some very challenging times, from COVID to the data center demand boom. He remained calm, accessible and diligent no matter what the challenge. We look forward to working with PJM to find a successor that can lead PJM to meet its mission to deliver reliability through markets."

D.C. Public Service Commission Chair Emile Thompson, current president of the Organization of PJM States Inc. (OPSI), pointed to several capacity market changes PJM pursued in recent months that consumer advocates have argued would ward off inappropriately high prices. (See *PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor*.)

"CEO Asthana has been a tremendous partner to work with during my tenure as the president of OPSI," he said. "Together, we worked to implement a number of reforms in response to the most recent Base Residual Auction. I look forward to continuing to work with him through the remainder of his tenure as we tackle issues such as resource adequacy, sub-annual capacity markets, transmission planning and issues surrounding co-location." ■

PJM, Alphabet Partnering on AI Tools to Speed Interconnection

By Devin Leith-Yessian

Why This Matters

The pace of generation interconnections is projected to lag behind load growth and resource retirements in the PJM footprint. The RTO says expediting interconnection studies is one piece of getting new resources online faster.

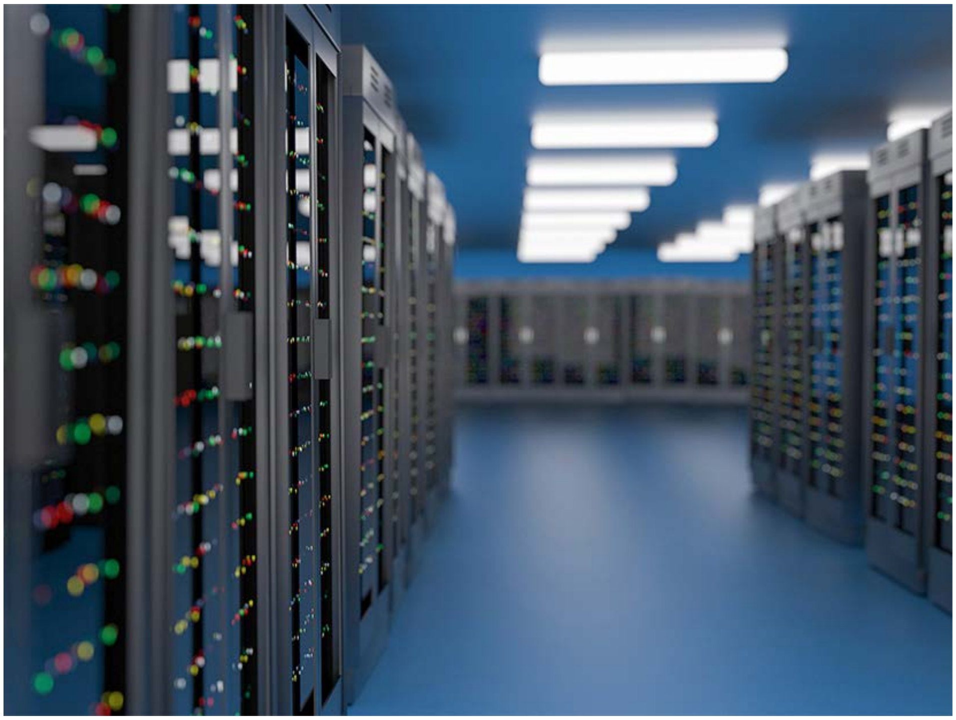
PJM and Alphabet on April 10 announced a partnership to develop a suite of new tools using artificial intelligence to speed the RTO's generation interconnection process.

Amanda Peterson Corio, head of data center energy at Google, said grid planners face an explosion in the number of new service requests they have received, straining their ability to process applications. Google sister company X Development is leading the initiative to build on its Grid Planning Tool and Grid Aware software to create a streamlined work environment PJM can use to more quickly bring new generation onto the grid at a time when the RTO is sounding alarm bells about future resource adequacy.

The planning tool has been deployed in Chile to simulate the grid 20 years into the future with hourly granularity, while Grid Aware uses visual information from sources like Google Maps to facilitate inspections and identify where repairs may be needed.

"This initiative brings together our most advanced technologies to help solve one of the greatest challenges of the AI era: evolving our electricity systems to meet this moment," Corio said. "We see the opportunity to help secure America's electricity needs with the many resources seeking to provide energy to the grid and believe this work with PJM is a great catalyst for innovation across the United States."

The sluggish pace of new entry is one of three contributors to a potential capacity deficiency that PJM has identified in the 2029/30 delivery year, alongside generation deactivations and ballooning load largely fueled by data centers. Executive Vice President of Operations, Planning & Security Aftab Khan said the RTO's shift to a cluster-based approach to studying interconnection requests is allowing it to more expeditiously work through its backlogged queue, but it still will take about two years for projects to go through the process. Integrating more artificial intelligence into those studies can add more efficiency and quality to studies, he said. (See *PJM Reaches Milestone on Clearing Interconnection Queue Backlog*.)



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"Innovation will be critical to meeting the demands on the future grid, and we're leveraging some of the world's best capabilities with these cutting-edge tools to further reduce completion times for new service requests," Khan said. "PJM is committed to bringing new generation onto the system as quickly and reliably as possible."

Renewable developers and consumer advocates have pointed to PJM's interconnection queue as a central obstacle to getting clean energy onto the grid and allowing generation owners to respond to high capacity prices. In a complaint filed at FERC, Pennsylvania Gov. Josh Shapiro (D) argued for a lower maximum capacity price on the grounds the new generation cannot respond to price signals sent by upcoming Base Residual Auctions. PJM has defended the process, saying more projects are clearing the queue but are becoming mired in other issues challenging development, such as supply chain constraints and permitting requirements. (See *PJM Presents Capacity Price Cap and Floor to Members Committee*.)

Page Crahan, general manager of X's electric-oriented *Tapestry*, said a core challenge grid operators face is information being siloed across disparate information streams and tools, an environment she said could be streamlined through using Google's expertise in data management to create a unified model of the grid, pulling together the output of existing tools to create a "knowledge graph." She said the name Tapestry was chosen to represent the goal of creating a platform that can stitch together the fragmented elements of the grid.

Speaking during a press conference ahead of the announcement of the partnership, Crahan said one area that could be improved by adding AI is processing PDF applications submitted by generation owners with new projects. Assessing the information in those files creates a bottleneck in the study process, where planners have to consult multiple tools, models and datasets when modeling how a new generator may impact existing equipment. She also gave the example of using AI to aid in validating information provided in interconnection applications; rather than planners having to refer to multiple documents to determine whether the land rights are associated with the correct builder, she said Tapestry software could sift through those files.

Tapestry already has partnered with system operators across the globe, including developing "near real-time grid virtualization" software to simulate AES' distribution grids in Ohio and Indiana, as well as advanced inverter technology working with Australia's Commonwealth Scientific and Industrial Research Organization.

Crahan said Chile's National Electric Coordinator (CEN) has deployed the Grid Planning Tool to allow planners to simulate its grid 86% faster, allowing 30 times the number of scenarios to be run. Google's DeepMind software has also improved CEN's weather forecasting for wind.

Unlike those other projects, Crahan said the work with PJM will be the "first of its kind" to integrate AI into the modeling interconnection study process of a large grid coordinator. X aims to deliver the first tools to PJM in 2025, she said.

In response to questions on how the effort to speed interconnections may interact with President Donald Trump's executive order April 8 seeking to ease regulations on coal generation, Khan said PJM is fuel agnostic and will welcome any resource that can improve reliability. He added there are many factors that can impact the viability of coal, including the growth of gas generation. (See related story, *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

Corio said Google remains dedicated to its climate goals and will continue to seek clean energy sources that can provide firm capacity. She specified that coal is not a clean technology under that framework. ■

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Md. Consumer Advocate Seeks Price Cut in PJM 2024 Capacity Auction

OPC Contends 'Flawed' Auction Will Drive 24% Price Increase for Some Ratepayers

By Devin Leith-Yessian

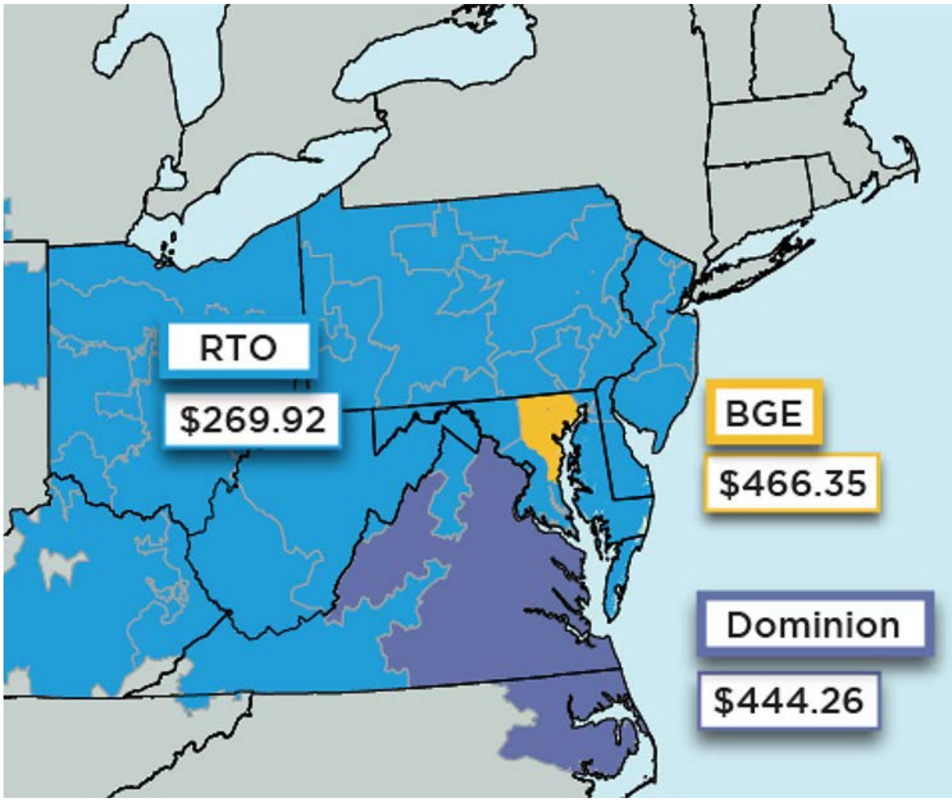
The Maryland Office of People's Counsel has filed a *complaint* against PJM alleging the rules used in the 2025/26 Base Residual Auction would require consumers to pay twice for capacity provided by generators operating on reliability-must-run agreements.

The auction conducted in July 2024 resulted in a nearly 10-fold increase in capacity prices. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

"PJM ran a flawed auction resulting in prices that — unless corrected — will cost Maryland residential electric customers hundreds of dollars per year in unreasonable and unnecessary capacity costs," People's Counsel David Lapp said in an *announcement* of the complaint April 14. "We are asking FERC to undo those unjust results and direct PJM to reset the prices for the 2024 auction by correcting the same flawed rules that FERC has already accepted the need to fix for future auctions."

Pointing to a Synapse Energy Economics *report* commissioned by the OPC, the complaint said excluding RMR units from the supply stack would inflate costs by more than $5 billion. That report found that the 2025/26 BRA design would increase monthly costs by as much as 24% for some Maryland ratepayers. (See *Maryland Report Details PJM Cost Increases for Ratepayers*.)

OPC also contends that the auction allowed market manipulation, improperly exempted 1,600 MW of generation from being required to submit offers and produced prices incapable of incentivizing new entry because of the confluence of long development timelines and a compressed auction schedule. It notes the auction was conducted within a year of the start of the corresponding delivery year on June 1.



PJM capacity prices increased nearly tenfold in the 2025/26 Base Residual Auction, with two regions reaching their zonal caps. | *PJM*

"The [FERC] and the courts have made clear that high prices are unjust and unreasonable if they do not reflect market fundamentals or cannot induce a market response. The 2025/2026 BRA results fall short on both grounds," the complaint says.

The complaint argues that revising the auction results would not violate the filed rate doctrine as they are "intended to govern future performance" that has yet to begin. It pointed to a 2021 remand from the D.C. Circuit Court of Appeals directing FERC to reopen an investigation into MISO's 2015/16 capacity auction, which set a $150/MW-day clearing price in its Zone 4. (See *FERC to Take 2nd Look at 2015 MISO Capacity Auction*.)

The complaint would effectively expedite implementation of a change the commission approved in February, granting a PJM request to model the output of RMR units as capacity as long as the resources could meet certain criteria, including being available to RTO dispatchers when called upon.

The proposal is set to go into effect for the 2026/27 and 2027/28 delivery years, with PJM intending to develop a long-term solution with stakeholders. Comments on the docket centered around two Talen Energy resources: the 1,289-MW Brandon Shores coal-fired generator and 843-MW H.A. Wagner oil-fired plant. Both facilities are located near Baltimore and are slated to deactivate after operating on RMR agreements through Dec. 31, 2028 (*ER25-682*, *ER24-1787*, *ER24-1790*). (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

"The 2024 auction results ignore the significant ratepayer-funded reliability contributions of the Brandon Shores and Wagner plants — with devastating consequences to customers from the resulting extraordinarily higher capacity market costs," Lapp said. "The Federal Power Act prohibits requiring captive utility customers to pay twice for the same service." ■

SEEM Members File Market Agreement Update

Changes Incorporate Requested Pseudo-tie Language

By Holden Mann

Alabama Power, on behalf of other members of the Southeast Energy Exchange Market (SEEM), has submitted a FERC-ordered filing detailing changes to the market's agreement intended to comply with a March 14 order from the commission (*ER21-1111*).

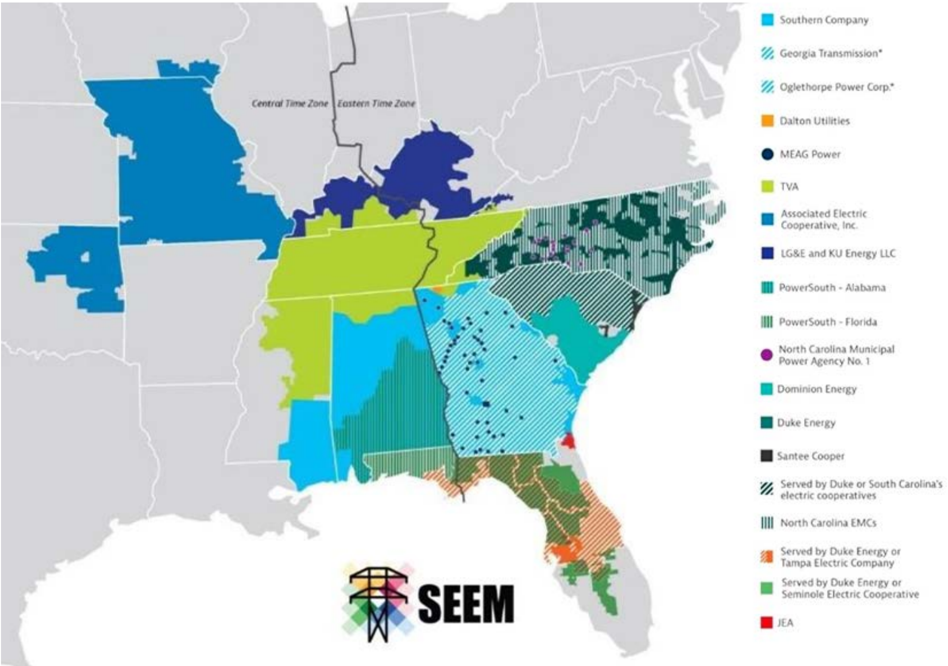
The proposed changes to the agreement detail the ability of utilities to participate in SEEM via pseudo-ties, which are used to represent interconnections between two balancing authorities where no physical connection exists between the load or generation and the power system network. SEEM members proposed the changes take effect April 15.

FERC directed SEEM to update the agreement after members argued in an earlier filing that pseudo-ties offered a means for loads and resources outside the SEEM territory to participate in the market. (See *SEEM Members Respond to FERC Briefing Request*.) This claim came in response to the commission's request for briefings after an order from the D.C. Circuit Court of Appeals remanded the commission's approval of the market in 2021.

One of FERC's questions concerned whether entities with a source or sink outside SEEM's territory could meet the technical requirements of the market's matching platform. SEEM's supporters have argued the territorial requirement was needed to implement the market platform that matches excess supply with free transmission every 15 minutes. But the court claimed the limitation resembled "discriminatory practices against third-party competitors by monopoly utilities." (See *DC Circuit Sends SEEM Back to FERC*.)

FERC's March 14 order acknowledged "an external source or sink could be a participant in SEEM if it used a pseudo-tie," but observed that such a practice would significantly affect "rates, terms or conditions of service" to such an extent that it should be included in the market agreement rather than a business practice manual. In their response, SEEM members agreed "there is not a SEEM entity that … would have the authority to evaluate and approve or reject creation of a pseudo-tie" under the current market agreement.

To address this, members proposed amending the agreement in several places. First, the new agreement adds the words "including through the use of a pseudo-tie" to language in the market rules that says a participant must own or control a source, and/or "be contractually obligated to serve a sink," within the SEEM territory. A new footnote in the same section specifies that a prospective participant seeking to establish a pseudo-tie must coordinate with relevant BAs, transmission providers and reliability coordinators, along with the SEEM Operating Committee.



Map of Southeast Energy Exchange Market's footprint | *SEEM*

Why This Matters

The proposed changes to the market agreement detail the ability of utilities to participate in SEEM via pseudo-tie, addressing issues raised by FERC in an earlier order.

Members said that "a pseudo-tied resource or load, once established, would appear no differently from any other resource or load registered as a valid source or sink" participating in SEEM.

A change to Article 5 would establish the Operating Committee's obligation to coordinate with efforts to participate via pseudo-tie. The language of the new section 5.11 requires the committee not to reject a pseudo-tie that has been accepted by the relevant TP, BAs and RCs.

Similar language is found in proposed changes to section 3.4, adding that TPs "shall have a duty to coordinate and act in good faith in interactions with any prospective participant … utilizing a pseudo-tie," and with all relevant BAs and RCs. Such good-faith interaction must include transparency about the reason for any denial of participation.

The updates also added definitions of the terms "pseudo-tie" and "reliability coordinator" to be consistent with definitions in the SEEM market rules.

"These changes appropriately commit SEEM to working with potential participants on pseudo-ties, including coordinating with the other identified entities necessary to the establishment of any such pseudo-tie," members said. ■

BPA Flooded with Comments on Draft Day-ahead Market Decision

Roughly 150 Submissions from Utilities, Interest Groups, Tribes and Others

By Robert Mullin and Henrik Nilsson

The Bonneville Power Administration elicited nearly 150 comments in response to the March 6 draft policy outlining its decision to join SPP's Markets+ rather than CAISO's Extended Day-Ahead Market.

BPA's tentative decision in favor of Markets+ offered little surprise to Western electricity sector stakeholders involved in the development of day-ahead markets in the West.

Still, the draft's release ended nearly two years of speculation about a potential surprise — or whether the agency might succumb to political pressure and delay its choice to let developments play out around the West-Wide Governance Pathways Initiative's efforts to bring more independent governance to CAISO's markets. (See *BPA Selects SPP Markets+ in Draft Policy*.)

The torrent of *comments* (so far) have offered few surprises as well, with supporters of each market staking out many of the same positions they've voiced since BPA kicked off its day-ahead market participation stakeholder process in July 2023.

RTO Insider's round-up of the comments is by no means a comprehensive one, but we have sought to include many from key players in the industry and important constituencies. More comments were being posted to the BPA site throughout the day, and we will continue to review them for inclusion in future articles.

BPA officials have said they will respond to the comments and expect the agency to issue its final record of decision in early May.

'Compelling' Choice

Unsurprisingly, the consumer-owned utilities (COUs) that make up BPA's base of "preference" customers largely supported the draft policy and urged the agency to finalize its decision without delay.

> **What's Next**
>
> BPA officials have said they will respond to all stakeholder comments and plan to issue the agency's final record of decision in early May.

A common thread among the COUs backing the draft policy was the market governance issue, with some contending the Markets+ framework provides an independent governance structure that EDAM lacks.

For example, Gary Huhta, general manager at Cowlitz County Public Utility District, urged BPA "to proceed without delay" instead of waiting for the Pathways Initiative to wrap up "development of a partial independent governance structure."

Pathways is developing a "regional organization" (RO) that will assume governance over EDAM and CAISO Western Energy Imbalance Market.

"BPA's choice of Markets+ over CAISO's EDAM is compelling, as its superior independent governance, uniform resource adequacy requirements, [greenhouse gas] design and a congestion revenue mechanism that promotes transmission investments," Huhta wrote.

Snohomish County PUD shared Huhta's sentiment. Snohomish noted that for Pathways to succeed, the California Legislature would have to support the initiative. And even if lawmakers back the proposal, Pathways "would not achieve full independence due to the remaining significant intertwining of CAISO and the new regional organization, including shared staffing and a shared tariff."

"Under the proposal, CAISO would retain the dual roles of a participating balancing authority for one part of the footprint and the market operator for the full footprint that could result in a conflict of interest," Snohomish contended. "Given the magnitude of trade likely to occur within day-ahead markets, and the potential influence of market rules and market operations over the allocation of costs and benefits of market participation, Snohomish has a strong preference for the fully independent governance structure of Markets+."

Snohomish also is one of the signatories to the so-called "issue alerts" published recently to highlight the purported advantages of Markets+ over EDAM. (See *7th 'Issue Alert' Highlights Markets+ Footprint*.)

The Western Public Agencies Group (WPAG), which consists of 27 COUs in Oregon and Washington, supported the draft policy. The organization noted the policy comes as utilities prepare to sign new long-term provider-of-choice contracts slated to go into effect in 2028 and set the conditions under which BPA sells federal power to customers.

"BPA's proposal to participate in a day-ahead market is the type of strategic progression needed to meet the moment and to secure the region's long-term future," WPAG wrote. "What is more, based on BPA's extensive analysis, Markets+ appears to be the market for the job."

Vancouver, British Columbia-based energy trader Powerex, a key Markets+ backer, said it "strongly supports" BPA's draft policy, writing that it "reflects thorough analysis, extensive stakeholder input and a clear understanding of the long-term structural, operational and economic implications of organized day-ahead market participation."

The company also said it agrees with BPA's conclusion that the SPP market is the best option "to protect the value" of the federal hydroelectric system and "uphold its statutory obligations, and promote a durable, fair and transparent market platform for Bonneville, its customers and the region."

'Ignores the Facts'

But the region's two largest consumer-owned utilities by number of customers

— Seattle City Light and Eugene Water and Electric Board (EWEB) — stood out among COUs in opposing BPA's draft decision.

"BPA's decision to join Markets+ does not comply with the agency's statutory obligation to provide 'the lowest possible rates to consumers consistent with sound business principles.' Rather, BPA's premature decision ignores the facts presented by its own record and analysis," City Light wrote in comments that extended to 114 pages.

City Light reiterated the key concerns it expressed in a letter to BPA Administrator John Hairston last November after the agency played down the value of the results of a study it had commissioned to compare the potential economic benefits of participating in either market. (See *Markets+ Leaning 'Alarming,' Seattle City Light Tells BPA*.)

"BPA's own economic analysis indicates that joining the California Independent System Operator's Extended Day Ahead Market offers the largest benefits to its customers, followed by choosing to not join any day-ahead market," the Seattle utility said.

City Light said Markets+ "is worse for BPA customers than EDAM by $165 million to $221 million annually — and these losses persist indefinitely into the future," while continued participation in the WEIM would provide only $79 million to $130 million in greater benefits than joining the SPP market.

The utility also contended "all available analysis" indicates Markets+ will not provide the "well connected and integrated market footprint of diverse loads and resources" needed to deliver the maximum benefits for BPA customers.

"BPA's decision eschews objective analysis and chooses which factors it elevates based on whether they support its preferred outcome. This is not consistent with sound business principles," City Light said.

Oregon-based EWEB said it agreed with BPA about the need for independent market governance but contended that issue should not be the "sole factor" in the agency's decision and "must be carefully weighed alongside the critical elements of transmission connectivity and market footprint."

EWEB expressed concern about what it said are "the inefficiencies associated with a smaller, disconnected market like SPP's Markets+."

Like City Light, EWEB encouraged BPA to continue participating in the WEIM over joining Markets+, giving the agency time "to observe the ongoing evolution of EDAM and its progress toward independent governance."

"By waiting, BPA can make a more informed, strategic decision that not only aligns with its operational goals but also strengthens regional collaboration. This measured approach ensures that BPA chooses the best long-term market option for both its stakeholders and the broader region," EWEB wrote.

'Narrow Set of Interests'

The draft policy also found little support among environmental organizations, with many urging BPA to pause or withdraw its draft decision.

In a joint letter, Earthjustice, the Northwest Energy Coalition and Idaho Conservation League said the proposed decision violates the National Environmental Policy Act and the Pacific Northwest Electric Power Planning and Conservation Act.

The trio argued BPA failed to consider the environmental impacts of its choice in violation of NEPA, noting the agency has committed "up to $40,000,000 as part of the collateral for a bank loan to support the development of Markets+. The promise to pay these funds is irre-

Spillway at BPA's Bonneville Dam | © *RTO Insider* vocable, and they will be forfeited if BPA withdraws from Markets+. This commitment of resources prior to any environmental review is contrary to NEPA."

The groups argued BPA violated the latter act by ignoring the "substantial cost savings of a decision to join EDAM" and instead prioritizing Markets+'s governance design. They pointed to two production cost studies showing that EDAM could provide significant savings for BPA customers under certain scenarios. (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits*.)

In urging BPA to withdraw its draft policy, the groups wrote that the agency's "response to public input has been minimal, and its decision-making process has been opaque and appears more focused on catering to a narrow set of interests rather than the broader public good. BPA, however, has a legal duty to serve the best interests of the entire Pacific Northwest, including, among others, the region's energy, environmental and economic interests."

Other environmental groups similarly opposed the draft decision. Save Our Wild Salmon Coalition, Sierra Club, Oregon Clean Grid Collaborative and Renewable Northwest all opposed the draft decision in separate letters.

The Washington BlueGreen Alliance, a coalition of labor unions and environmental groups, said BPA did not "fully consider" how its decision would affect not just preference customers, but the Northwest region at large.

"We are concerned that the BPA draft decision to join Markets+ is based on an inadequate analysis of each day-ahead market's governance structure and economic costs to the region, which will have significant consequences for our region's climate policies and workers," the group said.

They also argued the "fragmented nature" of the Markets+ footprint is likely to result in a less reliable system or require customers to pay more to ensure uninterrupted delivery.

"Substantial increases in BPA's costs have a direct effect on industrial manufacturing growth and job creation in our states. These costs will likely be passed on to ratepayers, and the impact will be felt most acutely by large energy users, such as industrial and commercial ratepayers," the group wrote.

Tribal Perspectives

Many of the region's tribes had their own reason to oppose BPA's decision and urge postponement, saying they were unable to provide informed — and legally required — consent because of the agency's lack of "government-to-government consultation" with tribal representatives.

"The federal government's trust responsibility obligates BPA to ensure that tribes are full partners in managing the lands and resources that are our ancestral inheritance," the Snoqualmie Tribe in Washington wrote, adding that "tribal values, priorities and rights must be integrated into the" day-ahead market.

Washington's Yakama Nation urged BPA to delay until it "has engaged in full in meaningful consultation" with the tribe to ensure that participation in a day-ahead market does not "negatively impact" the Yakama's treaty-reserved resources and rights.

The Confederated Tribes of the Umatilla Indian Reservation expressed similar concerns, pointing to potential risks to its members' fishing rights on the Columbia River from changes in BPA's operations.

The Alliance for Tribal Clean Energy echoed those concerns, while also contending BPA's decision was "rushed."

"BPA's accelerated timeline precludes the thorough evaluation of alternative market options that might better align with tribal interests and environmental considerations," the alliance wrote.

Tech Views

Tech companies and data center developers, including Google, Amazon, Microsoft and Rivian, signed a letter by the Clean Energy Buyers Association asking BPA to postpone its decision.

The companies contended more analysis is needed to consider studies that show a "wide range of potential outcomes, especially the potential for increased systems costs, creates confusion and significant uncertainty for ratepayers."

"Retail customers in Bonneville's service territory deserve greater assurance that participation in a [day-ahead market] will not drive undue costs, ultimately borne by ratepayers," the companies wrote.

They also wrote BPA should wait until the outcome of Pathways, while noting that staffing issues at BPA pose challenges. (See *BPA to Restore 89 'Probationary' Staff, Agency Confirms*.)

Amazon, which has invested billions of dollars toward the development of data centers in Oregon, issued a separate letter. The company said BPA's justification for its draft policy "is not sufficient to meet the important threshold of ratepayer protection, particularly in light of other market options available, some of which have been reported by Bonneville studies to save customers hundreds of millions compared to the Southwest Power Pool's Markets+."

The company said BPA should hold off on joining a day-ahead market and remain in CAISO's WEIM while it evaluates its options.

'Seamless' Market

CAISO weighed in as well, noting the estimated $97 million in benefits BPA has earned since joining the WEIM in 2022 and pointing to that market's contribution to increasingly coordinated transmission flows across the Northwest, which it said has resulted in $1.5 billion in estimated benefits for the entire region.

"The seamless real-time operational market created between the Pacific Northwest and other WEIM balancing areas in the West has also become an invaluable tool in supporting system reliability, especially during stressed system conditions, which have increased in frequency and intensity in recent years," CAISO wrote.

CAISO also questioned BPA's treatment of the governance issue in its draft, saying the document does "not fully present and consider the enhancements to the ISO's market governance that will take effect upon implementation" of the Pathways Initiative's "Step 1" changes to that governance.

The ISO said BPA's draft also neglected to discuss "limitations" SPP has placed on the governance authority of the Markets+ Independent Panel, an issue important for "comparative governance analysis."

"While the [Markets+] tariff contemplates that the SPP board will give significant deference to the MIP's decisions, the SPP board nonetheless retains broad authority to overturn such decisions," CAISO wrote. ■

Company Briefs

Occidental Awarded Permit for Direct Carbon Capture Project

EPA last week approved Occidental Petroleum's application to capture carbon dioxide from the atmosphere and inject it underground.

Occidental Petroleum, a Houston-based oil firm, will start storing 500,000 metric tons of carbon dioxide in deep, non-permeable rock formations 4,400 feet underground as soon as this year. The facility will be located 20 miles southwest of Odessa.

More: *Texas Tribune*

Chevron Ordered to Pay More than $740M to Restore Louisiana Coast

Oil company Chevron must pay $744.6 million to restore damage it caused to southeast Louisiana's coastal wetlands, a jury ruled following a trial more than a decade in the making.

Jurors found that Texaco, acquired by Chevron in 2001, had violated Louisiana regulations governing coastal resources for decades by failing to restore wetlands impacted by dredging canals, drilling wells and billions of gallons of wastewater dumped into the marsh. The jury awarded $575 million to compensate for land loss, $161 million for contamination and $8.6 million for abandoned equipment.

The case was the first of dozens of pending lawsuits to reach trial in Louisiana against the leading oil companies for their role in accelerating land loss along the state's rapidly disappearing coast. The verdict, which Chevron said it will appeal, could set a precedent leaving other oil and gas firms on the hook for billions of dollars in damages tied to land loss and environmental degradation.

More: *The Associated Press*

EVelution Energy to Break Ground on Cobalt Processing Facility

EVelution Energy last week said it plans to begin construction of its cobalt processing facility in Arizona later this year.

It would be the only cobalt processing facility in the U.S.

Cobalt is a mineral in high demand for its use in EV batteries, aerospace products and defense technologies.

More: *Arizona Republic*

Federal Briefs

Report: Clean Energy Powered 40% of Global Electricity in 2024

The world used clean power sources to meet more than 40% of its electricity demand last year for the first time since the 1940s, according to a report by thinktank Ember.

The report found that solar farms have been the world's fastest-growing source of energy for the last 20 consecutive years. Overall, solar power made up almost 7% of the world's electricity, while wind power made up just over 8%. Hydropower accounted for 14%.

The report, which accounted for 93% of the global electricity market across 88 countries, also found that a surge in demand pushed emissions from the global power sector up by 1.6% to an all-time high last year.

More: *The Guardian*

NRC Renews Duke Energy's Oconee Nuclear Station

The U.S. Nuclear Regulatory Commission last week renewed the operating licenses for Duke Energy's Oconee Nuclear Station for an additional 20 years through 2054.

Oconee is the first of Duke's nuclear facilities to reach the milestone of extending its license and receiving approval to operate for 80 years.

More: *Greenville Business Magazine*

Senators Introduce TVA Salary Transparency Bill

Sens. Marsha Blackburn and Bill Hagerty last week introduced a bill in the Senate that would require the Tennessee Valley Authority to make more salaries available to the public.

The bill would require TVA to report salaries of employees making more than $123,041 per year. Currently, TVA reports only the salaries of its five highest-paid executives. The utility had 11,312 employees last year, according to its latest annual financial report, and reported the median total compensation for all employees was $163,779.

More: *Knoxville News Sentinel*

BLM Approves Nevada Gas Pipeline

The Bureau of Land Management has approved a new gas pipeline in Humboldt County, Nev.

An environmental analysis of the Pinyon Pipeline found no significant impact to burying the line between the existing Ruby Pipeline and the Valmy Power Plant.

The pipeline will be 16 miles long and support the conversion of the North Valmy Generating Station from a coal-fired plant to a natural gas-fired plant.

More: *KOLO*

Sources: More than 2,600 DOE Staffers Accept 2nd Offer to Resign

More than 2,600 DOE staffers have opted to take the Trump administration's second round of resignation offers, two sources said.

The number is more than double the 1,217 staffers that took the first round offered in January, according to a document. It could go significantly higher in coming weeks as staffers over 40 years of age get an additional 45-day period to consider the offer.

More: *Reuters*

State Briefs

ARKANSAS

Senate Passes Bill to Regulate Wind Power

The Senate last week voted 29-1 to pass a bill that will establish a new regulatory framework for future wind energy projects.

The bill would give county and city governments the ability to regulate new wind projects while also establishing minimum standards for the construction of turbines. It would require the Public Service Commission to develop rules regulating and permitting future projects, including standards for decommissioning projects, studies for impacts on wildlife and potential public safety issues, among many other provisions.

The bill now heads to a committee of the House of Representatives.

More: *Arkansas Times*

COLORADO

Montezuma County Enacts 6-month Solar Moratorium

The Montezuma County Board of County Commissioners last week unanimously agreed to place a six-month moratorium on large scale solar developments.

Commissioner Jim Candeleria said the board was considering the moratorium "just to pause, to make sure we have better language in land use code." As it stands, there's "nothing specific" to solar in the county code, said Planning and Zoning Director Don Haley.

The moratorium will not bar existing applications from moving forward.

More: *The Journal*

CONNECTICUT

House Approves 2 PURA Commissioners

The state House last week voted to advance two of Gov. Ned Lamont's nominees to serve on the Public Utilities Regulatory Authority.

Marissa Gillett, the chair of the PURA, cleared the chamber on a vote of 91-52, while David Arconti received a 136-9 vote.

Both nominations now head to the Senate.

More: *CT Mirror*

MAINE

Bill Removing Referendum for Nuclear Plants Fails in House

An effort aimed at removing obstacles for the development of nuclear power failed an early test in the House of Representatives last week.

The measure would overturn a 40-year-old requirement that proposed nuclear power projects be subject to a statewide referendum. Lawmakers adopted the requirement in 1983 as a response to public concerns about nuclear power following the partial meltdown of the Three Mile Island power plant in 1979.

The bill failed an initial vote along party lines in the House. It now moves to the Senate.

More: *Maine Public Radio*

PUC to Investigate Versant Power

Following issues uncovered in an independent audit of Versant Power, the Public Utilities Commission launched a formal investigation focused on the utility's management practices and oversight by its Canadian parent company ENMAX.

The PUC said the audit, which was conducted last year, looked at the company's operations, management structure, customer service and collections practices and the reliability of its distribution system. PUC Chair Philip Bartlett said the report "raised a number of questions regarding the judgment of Versant's management."

Versant Power is the state's second-largest investor-owned utility.

More: *Mainebiz*

MINNESOTA

PUC Approves Minnesota Energy Connection Tx Line

The Public Utilities Commission last week approved Xcel Energy's Minnesota Energy Connection Project.

The project includes the construction of a 345-kV, double-circuit, high-voltage transmission line, approximately 174 miles in length across several counties. It will also involve modifications to existing substations.

More: *West Central Tribune*

MISSOURI

Gov. Kehoe Signs 'Construction in Progress' Bill

Gov. Mike Kehoe last week signed a bill into law that will allow utilities to charge customers for power plants as they are being built, rather than after they are complete.

The bill also requires utilities to replace retiring power plants with a similarly sized energy source that can immediately be turned on. It also includes changes that will protect consumers by expanding the window of time when utilities cannot disconnect service.

More: *KCUR*

NEW MEXICO

Gov. Lujan Grisham Signs Electric Grid, Solar Power Bills into Law

Gov. **Michelle Lujan Grisham** last week signed two bills into law that will affect the state's power industry.

House Bill 128 will establish a $20 million dollar fund to provide grants for solar energy and battery storage for tribal, rural and low-income schools, municipalities and counties. House Bill 93 will allow larger utilities to incorporate advanced grid technology projects into their modernization plans and incorporate those plans into the ratemaking process before the Public Regulation Commission.

More: *Source NM*