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# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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**COVER:** NCPA's Randy Howard used this graphic to explain the process for moving a CAISO governance bill through the California legislature in 2025. Pathways Initiative backers plan to start discussions with legislators this fall. (p.14) | *West-Wide Governance Pathways Initiative*

RTO Insider
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# In this week's issue

# FERC/Federal News

## FERC Observers, Stakeholders Lay out What is at Stake with Tx Rule Looming

*By James Downing*

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FERC is set to vote on its long-awaited proposed rule on transmission planning and cost allocation for regional lines at a special open *meeting* May 13, the commission announced last week ahead of this month's usual *meeting* (RM21-17).

Parties who have worked on the rule spoke with *RTO Insider* and in other venues April 22 about what they expect to see from the commission.

"I want to make sure that it's sufficiently strong so that planners really do plan for the anticipated resource mix; so they actually are required to consider all the factors of what that future resource mix looks like," Grid Strategies President Rob Gramlich said in an interview. "I want to make sure there's an actual decision that gets made about cost allocation."

States should obviously participate in the cost allocation process, Gramlich said, but if they cannot agree, the process should not end there; FERC should do something to move the ball forward.

The two biggest precedents in FERC's allocation regime can often come into conflict, former Arkansas Public Service Commission Chair Ted Thomas said on a webinar hosted by the Conservative Energy Network (CEN). The ideas that beneficiaries pay, and costs are commensurate with benefits, can often clash.

If a group is having dinner at a restaurant and only one diner orders dessert to share with the table, that person effectively caused the cost, but anyone who has a morsel will be a beneficiary, said Thomas, who runs a consulting firm.

"These two principles are in conflict," Thomas said. "Because it's really hard to get everybody on board in the same way on the front end so that they're all the cost-causers. But with 20/20 hindsight, when you can see that somebody benefits — well, under this other principle they're supposed to pay. But at the end of the day cost allocation is always about negotiation."

The rule will not change the fact that ultimately, states and other stakeholders need to negotiate over transmission cost allocation, Thomas said, but hopefully it will add guidelines to simplify that process.

The issue of cost allocation is one area where FERC's internal debates have spilled out into public somewhat, with Commissioner Mark Christie repeatedly saying he does not want to see one state pay for another's policies, most recently in response to a *letter* from a group of congressmen led by Rep. Andrew Garbarino (R-N.Y.).

"It would be grossly unfair for FERC to force consumers in other states to pay for projects implementing the policies of politicians they never got the chance to vote for, when their own states' policymakers have not agreed to pay for those projects," Christie said in his *response*. "Such an imposition is contrary to American principles of democracy, a core principle of which is that the people have the right to elect the policymakers who impose costs on them, so the people can hold them accountable."

Commissioner Allison Clements wrote less in *response* to Garbarino, but she argued that the costs of failing to invest in the grid, from customers facing huge bills from last-minute reliability needs to economic development going elsewhere, need to be considered.

"The risks and costs of declining to plan holistically for a modern grid may far outweigh the short-term lure for states to 'go at it alone' from a transmission planning perspective," Clements wrote.

While public policy has generated plenty of debate beyond two of FERC's three commissioners, Clean Energy Buyers Association Senior Director Bryn Baker told the CEN webinar that is not a focus of the proposed rule.

"Public policy — I think we need to be clear that unless there's a dramatic reversal, is not in the list of things to evaluate the need for these lines," Baker said. "It's not in the goal as one of those metrics. I think that was a smart decision."

State renewable portfolio standards are not driving as much of the need for new transmission as the corporate renewable energy buyers that CEBA represents are, she added. Coupled with growing demand, getting enough supply online to secure new industries that face international competition should be key goals when considering building out the grid, she said.

MISO's Multi-Value Project lines have helped bring online many new renewable generators, but those were much less focused on policy than reliability and economics, Gramlich told *RTO Insider*.

"The state policies, even in MISO, weren't even really binding," Gramlich said. "They would have had the same results even if they completely ignored them. So, the point is, look at the economics of generation and anticipated additions and retirements over this 20-year period. And then design the network that achieves the lowest delivered costs for consumers; and any region should be able to do that."

Thomas said that Arkansas did give up some of its authority when it pushed Entergy into MISO, but he said that the deal was worth it.

"Do I worry about state jurisdiction? I really don't," Thomas said. "Particularly if you're in a … market already, there's some jurisdiction you give up to save $50 million a year. … You've bound yourself to work with other states that share these resources. But for $50 million a year that goes straight into ratepayers' pockets, it's worth it."

MISO might be ahead of the other RTOs when it comes to planning, but Thomas said it was in a class of organizations that could all use improvements.

While the devil is in the details, the broad strokes of FERC's proposal requiring proactive planning have wide support, as 174 organizations, including 59 consumer groups, supported the rule in their comments to the commission, Gramlich said.

### The Future of Transmission Competition

Another issue dividing stakeholders is FERC's proposal to pull back on Order 1000's elimination of the federal right of first refusal for regional transmission lines, finding it caused incumbents to focus on local projects not subject to competition.

Many utilities want to see FERC at least stick with that proposal, while supporters of competition are going to appeal if the commission follows through with it.

"So, No. 1: FERC has got to tackle the competitive transmission issues they've teed up and re-examine rights of first refusal," WIRES Group Executive Director Larry Gasteiger said in an interview. "I think if that's not in there, it would kind of be a major disappointment."

FERC has acknowledged that Order 1000 is not working correctly and the policies around ROFRs need to be reformed, he added.

The opposite needs to happen, according to Paul Cicio, chair of the Electricity Transmission Competition Coalition, made up of firms engaged in competitive transmission development and consumer groups.

"If [FERC] doesn't embrace competition; if it doesn't enforce Order 1000, this will be most likely the most costly consumer rule in history," Cicio told *RTO Insider*. "And it's because of the sheer magnitude of the amount of capital that is and will be spent on transmission going forward."

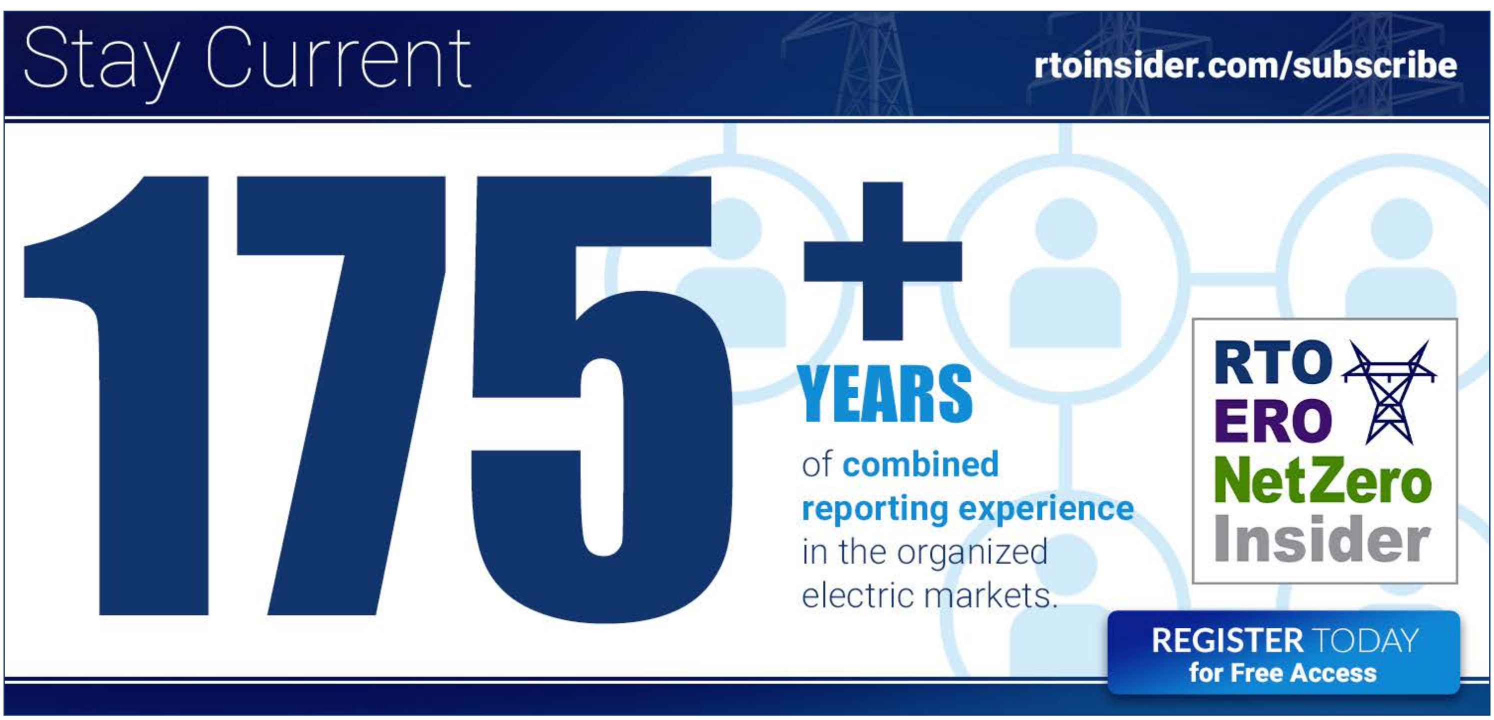
Competition can serve to contain the costs of transmission, which has granted very healthy returns that stay in place for decades, he added. The price of electricity has outstripped the Consumer Price Index in terms of inflation, and in cheap natural gas and other forms of generation, transmission and distribution costs have been rising, Cicio said.

The returns on investment of 10 to 12% are very high when compared to the manufacturing industry, which Cicio also represents, and he would like to see FERC tackle cost-containment issues more generally.

Cost containment came up in many of the comments, but Gasteiger said it was not really addressed in the proposed rule.

"We're hoping that they don't try to add it in now, given that they haven't really provided notice on it," Gasteiger said. "But I know there was a lot of pressure from different commenters for FERC to weigh in on that issue."

Any rule of this scope from FERC is guaranteed to be challenged in court; ETCC has already said it would appeal the final rule if the commission reinstates the federal ROFR, which Cicio reiterated. (See *Pro Competition Group Plans to Sue if FERC Reinstates Federal ROFR*.) ■



# FERC/Federal News

# DOE Issues Transmission Interconnection Roadmap

## *Document Complements FERC Order 2023, Seeks to Speed Clean Energy Transition*

*By John Cropley*

The U.S. Department of Energy has released its *roadmap* to speed interconnection of new clean energy projects to the nation's grid.

The framework announced April 17 is also intended to clear the queue of backlogs that have developed in the past decade, during which renewable energy interconnection requests have grown by 300 to 500%.

It is intended as a guide for stakeholders, including transmission providers, interconnection customers, regulators, manufacturers, consumer advocates and energy justice communities. It is a collection of potential strategies rather than a rigid list of prescriptive fixes.

DOE said its Interconnection Innovation e-Xchange (i2X) began working on the first-of-its-kind "Transmission Interconnection Roadmap" in June 2022. Midway through the process, in July 2023, FERC issued its landmark Order 2023, seeking to accomplish many of the same interconnection streamlining goals.

The DOE roadmap's authors indicate the new document contains some solutions that relate to Order 2023 while other solutions support a longer-term evolution of the interconnection process.

The roadmap is intended to complement and support implementation of Order 2023 by focusing on issues that Order 2023 may not resolve, such as balancing stricter requirements placed on interconnection customers with open access and equity considerations; incentivizing faster interconnection studies; and better coordinating affected system studies.

The roadmap also seeks to address issues not raised in Order 2023, such as data transparency, automation, cost allocation and workforce development.

The roadmap's authors anticipate further overlap as FERC completes its rulemaking on transmission planning. The interconnection process and transmission planning are so closely linked that some of the roadmap's solutions involve transmission planning, the authors write, but its focus is on interconnection reform.

DOE later this year expects to issue a draft of a companion roadmap focusing on the distribution grid.

"Clearing the backlog of nearly 12,000 solar, wind and storage projects waiting to connect to the grid is essential to deploying clean electricity to more Americans," U.S. Secretary of Energy Jennifer M. Granholm said in a *news release*.

### Goals and Suggestions

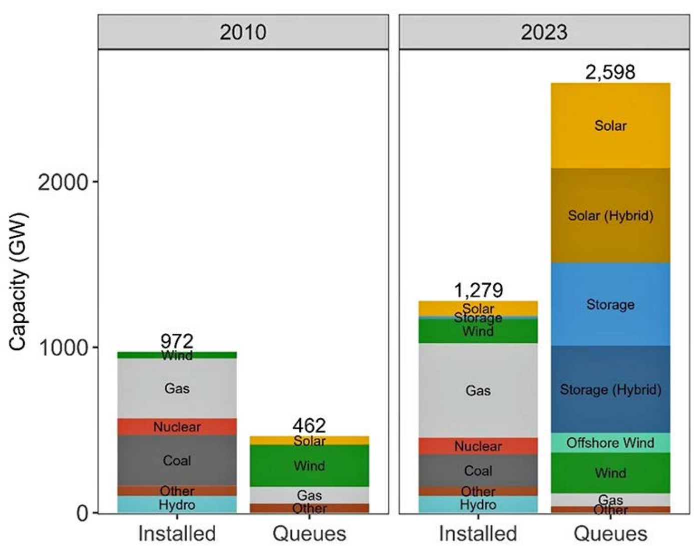
The roadmap frames the problem as one of volume: The U.S. grid saw fewer than 1,000 interconnection requests per year in the 2000s and as many as 3,000 per year in the past decade. The generation capacity represented in these requests has jumped from 150-200 GW per year to 400-750 GW.

The roadmap is framed around four primary goals, and it suggests solutions for each:

- Increase data access, transparency and security for interconnection by improving data on projects already in queues; enhancing interconnection study models and modeling assumptions; and developing tools to manage and analyze data.
- Improve the interconnection process and timeline through better queue management; improved affected system studies; a more inclusive and fair process; and workforce development focused on technical expertise needed in many industry professions.
- Promote economic efficiency in interconnection through better cost allocation; closer coordination between interconnection and transmission planning; and a revised model for interconnection studies.
- Maintain a reliable, resilient and secure grid by improving interconnection reliability assessment models and tools, and by developing comprehensive interconnection standards for things such as IBR capabilities and expected project performance.

The roadmap also includes four target metrics by which to judge improvements:

- An average time of less than 12 months for completed projects to move from interconnection request to interconnection agreement. As of 2022, this is averaging 33 months; the best performance since 2003 was 18 months in 2005-2008.
- A standard deviation of interconnection costs of less than $150/kW for all projects. As of 2020-2021, it was $551/kW; the best since 2007 was $154/kW in 2010-2011.
- A completion rate of greater than 70% for projects that enter the facility study phase. As of 2016, it was 45%; the best since 2006 was 55% in 2007.
- Zero annual NERC disturbance events involving unexpected tripping of IBRs not identified in offline analysis due to inaccurate IBR models. In 2022 there were four such events; the last time there were zero was in 2019. ■




The U.S. Department of Energy on April 17 issued its first-ever roadmap for speeding the interconnection of new clean energy generation to the nation's grid. | *DOE*

FERC/Federal News

# The Future of Natural Gas with Growing Demand and Climate Targets

By James Downing

The return to demand growth around the country has the industry considering how to meet it, with many utilities and states considering new natural gas-fired units, while others are trying to avoid growing carbon emissions while maintaining reliability.

The Department of Energy on April 17 released a report on "The Future of Resource Adequacy," which says firms investing in natural gas resources should make them able to be retrofitted with carbon capture and storage, or with the ability to burn clean hydrogen. (See related story, *DOE Urges Utilities to Embrace 'Holistic' Reliability Solutions*.)

"Building new natural gas plants without a strategy to address emissions risks infrastructure lock-in and stranded assets," the report said. "To help address these concerns, new gas capacity should be capable of achieving and supporting clean electricity systems. For example, gas generators should be designed to operate flexibly and at lower capacity factors to effectively support systems with increasing amounts of variable wind and solar generation."

Still, many utilities are trying to build new natural gas plants, with the Georgia Public Service Commission on April 16 approving Georgia Power's request to add three new dual-fueled combustion turbine units at an existing generation site between integrated resource plans because of unexpected load growth in its territory. The commission also authorized the utility to invest in new grid-scale batteries.

The new capacity was needed because Georgia Power found its 2030/31 winter demand projections had gone up by 5,900 MW since it issued its 2022 IRP, according to a brief the utility filed early this month with the PUC. The firm found it would need new capacity by winter 2025/26.

"Given the continued increase, progress and pace of committed customer load, the commission should have an extremely high degree of confidence in the forecast and should approve the company's load forecast as filed and agreed to in the stipulation," the utility said.

Overhanging the regulatory cases around new natural gas plants are EPA's looming rules under Section 111(d) of the Clean Air Act, which are expected to restrict fossil fuel emissions in the future. Ultimately, the rule's fate depends on the presidential election, as similar rules

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were overturned the last time Donald Trump was in the White House.

The Southeast in particular has been a hot spot for new demand from Georgia up to Data Center Alley in Northern Virginia, Luis Martinez, the Natural Resources Defense Council's lead for climate and energy in the region, said in an interview.

Dominion Energy has proposed building a major new natural gas plant in Chesterfield, Va., just south of Richmond.

"The troubling trend is the rush to build gas to meet it, which is what we're hoping won't come to fruition ... because it will derail our short-term and long-term, I'd say, climate emission-reduction goals," Martinez said.

Moving to more and more natural gas in the region also makes it more prone to sudden price spikes because of the commodity's volatile market, he added. North Carolina's Duke Energy has expanded its gas fleet in recent years, and customers have been pinched by spiking prices from recent winter storms and generally higher costs in 2022, which are now being felt on their power bills, Martinez said.

One reason the Southeast is seeing a flood of new natural gas plant proposals is that it relies on traditional regulation, meaning that as long as regulators approve the plant, it will get built.

"This risk of potentially having this new gas generation become a stranded asset, or not cost competitive, which you could see in other regions, is not present," Martinez said. "Once they're approved in the Southeast, then it'll be on ratepayers to pay for that whole thing, even if in 10 years these things are no longer useful because they have to add carbon capture and storage or they have to transition them to hydrogen, as the EPA 111 rule would require."

NRDC wants regulators around the region to evaluate all of the options they have to address the demand and pick the least-regrets ones, such as energy efficiency, before natural gas, he added.

California has long used the "loading order," where its Public Utilities Commission prioritizes efficiency and clean energy and places expanding natural gas capacity as a last resort to maintain reliability. While the different politics of the region mean that will never be a formal policy, it could serve as rule of thumb, Jackson Morris, NRDC's director of state power sector policy, said in an interview.

"There [is] tons of untapped energy efficiency on the system that needs to get tripled or quadrupled in scale. That's No. 1," Morris said. "Then you go to both utility-scale and distributed renewables projects. You also invest heavily in transmission and distribution investments, including both on existing reconducting efforts and things like that, as well as new lines and distribution infrastructure to maximize the capacity to move power around."

Natural gas should be the last resort to solve resource adequacy issues, he said. And NRDC would prefer utilities build CTs at this time because even though on a unit basis they are less efficient than combined cycle, they run much less often.

Other states around the country are dealing with similar issues. Harvard Law School's Electricity Law Initiative hosted a webinar this month with state regulators to discuss how to meet higher demand while staying on course for cutting emissions.

"I think the most important thing that we can do as states is to help to get the incentives right to balance the reliability and sustainability and clean energy goals that we've got," Illinois Commerce Commission Chair Doug Scott said.

A big part of Illinois' strategy is keeping its nuclear plants open. It pays them when natural gas is cheap, as it is currently, but customers actually received rebates in 2022 when the commodity's price spiked, Scott noted. As far as new capacity, Illinois is working to expand renewables.

Minnesota Public Utilities Commission Vice Chair Joseph Sullivan noted that the industry has dealt with even higher rates of demand growth in the past, such as when consumers adopted air conditioning *en masse* and demand grew from 7 to 9% every year.

"If you put on a data center, that's 10% of the entire system; it's a lot, and we've got to deal with that," Sullivan said. "But if we plan for it, and we use the processes that we have, I think we're going to get through it." ■

## FERC/Federal News

# EPA Rejects Stationary Combustion Turbine Emissions Request

## *Industry had Petitioned for Exemption from Hazardous Air Pollutant Regulations*

*By John Cropley*

EPA has rejected an industry petition to exempt stationary combustion turbines from hazardous air pollutant regulations.

EPA *announced its decision* April 15 and said it was part of a continuing, comprehensive approach to limit climate- and health-harming pollution from these sources.

EPA said stationary combustion turbines typically are located at power plants, compressor stations, landfills and industrial facilities, and burn a variety of fuels ranging from natural gas to distillate oil to landfill gas.

EPA said its regulations under Section 112 of the Clean Air Act limit emissions of air toxics, also called hazardous air pollutants, including formaldehyde, toluene, benzene, acetaldehyde and metals such as cadmium, chromium, manganese, lead and nickel.

In August 2019, the petitioners had asked EPA to remove stationary combustion turbines from the list of sources subject to Section 112 because they create a cancer risk of less than one in 1 million and therefore meet the statutory threshold to be delisted.

EPA said it rejected the petition because it was incomplete and because the agency could not conclude there was adequate data to determine that delisting thresholds were met.

EPA has denied a petition to remove stationary combustion turbines from the list of sources subject to regulation for emissions of air toxics. | *Shutterstock*

An EPA database last updated in October 2023 shows nearly 1,000 turbines at just over 500 facilities nationwide were subject to the regulations.

"Today's action will ensure people who live, work and play near these facilities are protected from harmful air pollution," EPA Administrator Michael S. Regan said in a *news release*. "EPA is committed to ensuring every community has clean air to breathe, especially those that have been overburdened and disproportionately impacted by poor air quality for too long."

The petitioners were the American Fuel & Petrochemical Manufacturers, the American Petroleum Institute, the American Public Power Association, the Gas Turbine Association, the Interstate Natural Gas Association of America and the National Rural Electric Cooperative Association.

American Petroleum Institute spokesperson Scott Lauermann said in a prepared statement: "While we are disappointed with this decision, we will continue to work with the EPA to ensure any new or revised emissions standards for combustion turbines are cost effective and technically feasible."

But Earthjustice and other environmental groups applauded EPA's announcement.

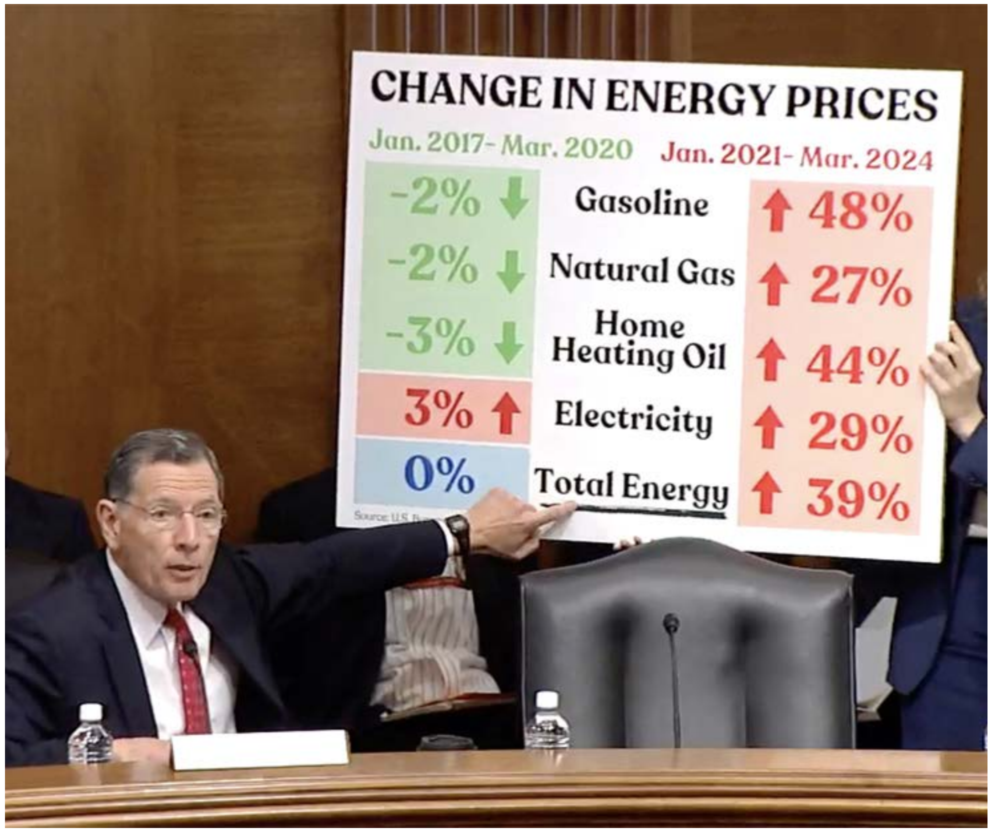
"Today's decision upholds critical environmental protections that are essential for safeguarding public health, particularly in communities that have historically borne the brunt of industrial pollution," Earthjustice Director of Federal Clean Air Practice James Pew said. "EPA did the right thing by rejecting industry's attempt to dodge these requirements and get a free pass to pollute."

The Sierra Club said it had been pushing back against the exemption request for five years.

"The EPA's denial of the petrochemical industry's bid to ease regulations for these major sources of toxic air pollution is a victory for public health and the environment," said Jane Williams, who chairs the organization's National Clean Air Team. "The EPA's commitment to upholding these standards reinforces the importance of robust regulatory frameworks prioritizing our planet's health and its people over industrial convenience." ■

## FERC/Federal News

# Granholm Defends DOE's 2025 Budget at Senate Hearing




Ranking Member John Barrasso (R-Wyo.) points to a chart showing recent increases in the cost of energy. | *Senate ENR Committee*

*By James Downing*

U.S. Energy Secretary Jennifer Granholm on April 16 *defended* her department's $51 billion budget proposal for fiscal 2025 before hostile Republicans on the Senate Energy and Natural Resources Committee.

Energy Secretary Jennifer Granholm testifies before the Senate Energy and Natural Resources Committee. | *Senate ENR Committee*

Granholm said companies have announced 600 new or expanded clean energy manufacturing sites in the country and nearly $200 billion in investment in the sector since the Infrastructure Investment and Jobs Act passed.

"Our commercialization tools are giving American businesses the confidence that they need to capitalize on this moment while deepening our energy security," Granholm said. "But deepening our energy security is an ongoing project, and we need to fund it year over year, and that's why the budget calls for significant appropriations for our demonstration and deployment programs."

While Granholm said DOE's efforts were leading to reindustrialization and new jobs, Republicans — led by Ranking Member John Barrasso (R-Wyo.) — tried to hang their worries about the cost of living on the Biden administration's energy policies.

"Prices are not only worse under Biden, they are significantly worse: gasoline up 48%, natural gas up 27%, home heating oil up 44%, electricity up 29%, total energy costs of 39%," Barrasso said as a staffer held up a chart with those numbers. "Since Joe Biden has come into office, this is a record failure."

Sen. Bill Cassidy (R-La.) said later in the hearing that the same numbers show how the administration has not been successful in cutting costs for consumers.

Granholm noted that the chart was comparing current prices to those at the height of the COVID-19 pandemic, when prices were depressed because of its impact on the economy.

"Natural gas is at very low prices," Granholm said. "Right now, the price of solar is very low. What's causing the increase in energy prices? One contributing factor is the investments in the grid that are necessary, this old grid that gets ratebased among ratepayers. And it's one of the reasons why it's so important for us all in leadership to take a look at how we invest in the national electric grid, so that we are not forcing ratepayers to bear that burden."

Cassidy also argued that the lack of pipeline development had been hindered by Biden administration policies.

DOE does not oversee pipeline siting, but Granholm noted that the budget request includes funding for the Low Income Home Energy Assistance Program for weatherization and other efficiency investments to help lower bills for customers.

Sen. Steve Daines (R-N.D.) asked when DOE expected to complete the study for which the administration has paused all new LNG export facility approvals.

"I look no further than the White House website where the first quote in their press release lauds — and let me quote — 'this administration's historic efforts to meet the global commitment to phase out fossil fuels,'" Daines said.

Granholm said she had not seen the White House's press release but noted that the industry has grown since the last time the impacts of LNG exports were studied.

"We were only exporting 4 BCF of LNG at that time, and now we are exporting 14 with another 12 BCF under construction, and 48 total authorized," Granholm said. "This pause doesn't affect any of that."

DOE expects to finish the study around the end of the year, and Granholm said staff working on it have been focused on how exports will impact domestic prices and what the future demand will be for LNG, especially given that many of the countries buying it today have their own commitments to net zero.

Sen. Angus King (I-Maine) was more supportive of the pause, noting it was prudent to examine exports' impacts given how quickly they have grown.

"Our low domestic gas prices are a huge asymmetric advantage around the world," King said. "And I'm concerned that we will, in effect, export that advantage." ■

FERC/Federal News

# Gas, Electric Trade Associations Call for More Gas Infrastructure

*By Jon Lamson*

ISOs and RTOs should take a more prominent role in expanding gas networks, gas and electricity industry representatives emphasized at a *webinar* April 15.

Convened by Texas RE, the talk focused on improving gas-electric coordination to prevent extreme weather risks like the issues that stemmed from Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022.

The FERC/NERC reports on power system performance during *Uri* and *Elliott* found that gas generators were the largest source of outages during the events. Gas supply issues accounted for about 27% of generator outages during Uri and 20% during Elliott, while mechanical and freezing issues accounted for about 65% of outages during Uri and 72% during Elliott. Mechanical and freezing issues accounted for about 65% of outages during Uri and 72% during Elliott.

"Organized power markets do not support the long-term commitments needed to expand gas infrastructure," said Joan Dreskin of the Interstate Natural Gas Association of America.

Dreskin said most contracts for firm gas capacity cover relatively short durations and do not provide the certainty needed for large, long-term investments. She added that RTOs should take steps to enable power generators to serve as anchor customers for pipeline expansion projects.

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"There's so many issues with getting a pipeline built," said Patricia Jagtiani of the Natural Gas Supply Association . Along with the difficulties of finding capacity offtakes, Jagtiani highlighted organized opposition, permitting delays and financing as major roadblocks to expanding gas networks.

The panelists said reliability issues could worsen as renewables proliferate and shift the role of gas generation from base load to peaking and balancing gaps left by clean energy, increasing power plant ramping requirements.

"We're going to need additional infrastructure on the power side and on the gas side," said Nancy Bagot of the Electric Power Supply Association. "It's probably the greatest challenge."

Gas expansion projects nationwide have faced opposition in large part due to the emissions associated with gas production, transport and combustion.

Gas generators accounted for about 43% of U.S. power plant emissions in 2022, according to *data* from the U.S. Energy Information Administration. Meanwhile, independent studies have shown repeatedly that U.S. emissions inventories *significantly undercount* emissions related to gas system methane leaks due to inadequate detection methods.

Beyond capacity additions, the panelists also called for market mechanisms to ensure generators secure adequate gas supply before extreme weather events, instead of as they occur.

In a *white paper* published in fall of 2023, the three associations wrote that most of the gas generator outages during Winter Storm Elliott occurred when RTOs called on the resources to run in real time. The groups noted that uncertainties related to when they will be dispatched and fuel cost recovery can dissuade generators from making gas purchases in advance.

To better incentivize generators to secure gas supply ahead of reliability events, RTOs should "develop market-based mechanisms to better signal expected power dispatch, avoid uplift and include fuel costs to reflect the cost of reliability in the market price," the coalition wrote.

If the market rules can be properly aligned with reliability risks, "the gas system is reliable [and] gas generators are reliable," Dreskin said. ■

# FERC/Federal News

# DOE Report Highlights Benefits of Advanced Grid Technologies

## *Report Follows AES, LineVision Case Study on Deploying DLRs*

*By James Downing*

Advanced grid technologies can help expand the grid quickly and relatively cheaply, according to a new report from the U.S. Department of Energy.

The *Pathways to Commercial Liftoff: Innovative Grid Deployment* report, released April 16, focuses on identifying ways to accelerate deployment of commercially available, but underused, advanced technologies over the next five years on existing transmission and distribution infrastructure. The technologies can quickly respond to accelerating grid pressures such as the need to expand capacity in the face of rising demand, enhancing reliability and supporting integration of clean energy.

"The majority of the nation's transmission and distribution lines are drastically overdue for an upgrade, which is why President Biden's Investing in America agenda is so critical to bring the grid up to date," Energy Secretary Jennifer Granholm said in a statement. "DOE's new Innovative Grid Deployment Liftoff report outlines the existing tools that can be deployed in less than five years to modernize the nation's power sector, making it more secure and reliable to deliver cheaper, cleaner power to American consumers."

The technologies covered include advanced conductors, high-voltage direct current lines, advanced distribution management systems, dynamic line ratings (DLRs), topology optimization, storage as transmission and distribution, data management systems and others. Deploying the advanced grid solutions could cost-effectively increase the capacity of the grid by 20 to 100 GW of incremental peak demand when installed individually, the report said.

Making sure the grid has enough capacity is important to many of the projects DOE has funded recently, Jigar Shah, director of the agency's Loan Program Office, told reporters.

"Our other manufacturing and energy generation applicants and grantees need to be able to connect to the grid," Shah said. "If our applicants can't connect to the grid quickly, that's going to meaningfully impact our ability to underwrite their debt."

The report was developed by staffers from around DOE with deep engagement from the private sector, said Vanessa Chan, director of the Office of Technology Transitions.

"The liftoff report breaks down the value chain of various portions of the economy and sketches a road map for the private sector to deploy the solutions that we need," Chan said. "So, in basic terms, [the report covers] things like: What cost do we have to hit in order for these technologies to take off? What are the technological and market-driven barriers that we have to overcome? What's the amount of investment that we need where and by when?"

While the grid needs to be expanded with new transmission and distribution investment, major new lines can take a long time to build and the GETs identified in the report can be deployed much more quickly, said Grid Deployment Office Director Maria Robinson.

"We're talking about three to five years deployment of key commercially available — but what we believe to be underutilized — advanced grid technologies and applications, and specifically how we can leverage existing transmission and distribution systems," Robinson told reporters.

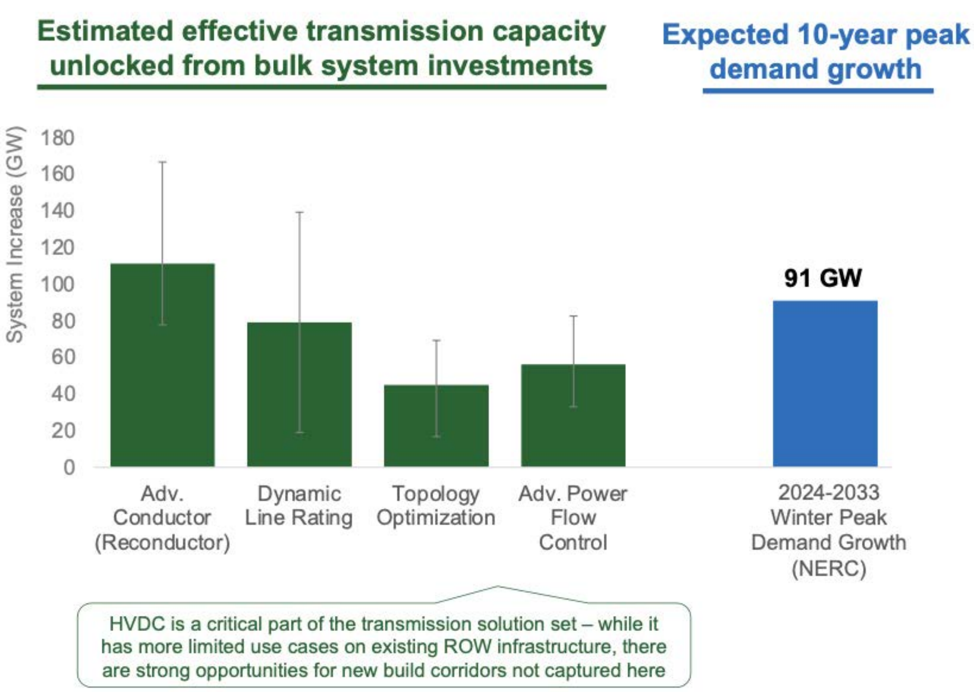
Most of the solutions cost less than a quarter of traditional alternatives and can be deployed quickly, since they use existing infrastructure.

DOE thinks the technologies can become a self-sustaining industry within three to five years, with "liftoff" happening when utilities and regulators comprehensively value and integrate advanced solutions as part of grid planning and operations. Pursuing between six and 12 operational deployments across a diverse set of utilities can cut risks enough to scale up the GETs industry, DOE said.

Besides building evidence for how the technologies work and getting utilities and grid operators comfortable with using new technologies, the industry's economic models and incentives must be updated for GETs to take off.

"For regulated utilities, this will require regulators to lead in aligning utility compensation models with the value generated from, and costs of, advanced grid solutions to deliver ratepayer benefits — e.g., implementing performance-based regulation, allowing some operational expenditures to be capitalized," the report said. "New mechanisms are needed that allocate costs in ways that better align with beneficiaries and equitably share benefits."

Grid operators also need to know how to




A chart from DOE's report showing the potential for various GETs compared to projected demand growth. | *DOE*

## FERC/Federal News

include GETs in system planning and prioritize them for investments, the report said. That requires a comprehensive understanding and method for evaluating the costs and benefits of the technologies.

The grid will benefit if the industry institutes the right reforms to use advanced transmission and distribution technologies to their full potential, it said.

"Using just one-fifth of the current investment in conventional transmission and distribution asset replacement to instead upgrade assets with advanced grid solutions could nearly double industry investment in advanced grid solutions, driving greater grid impacts without increasing costs to ratepayers," the report said.

Maintaining reliability and keeping the grid's frequency at 60 Hz are vitally important, and one way of showing utilities and grid operators the technologies can do those things while enhancing capacity is through demonstrations, including one DOE has funded at Philadelphia-area utility PECO, Robinson said.

"A lot of this is just increasing awareness and making sure that the regulators also feel comfortable with taking these approaches as well," she added.

### AES and LineVision Case Study on Dynamic Line Ratings

Segments of the industry have been working on rolling out the technologies, with LineVision and AES releasing a *case study* April 15 on the use of DLRs on five high-voltage lines across AES' utility territories in Ohio and Indiana. DLRs can increase reliability by giving operators a better sense of how their lines are operating, LineVision CEO Hudson Gilmer said in an interview.

"It's providing utilities better data with which to do their jobs," Gilmer said. "In the absence of monitoring of these lines that are really the backbone of the grid, utilities are guessing; they're making conservative static assumptions about how much power they can put through the lines. And what this technology does is for the first time, it really allows them to see actual conditions and know precisely how much power they can put through those lines."

While the case study found that, on average, DLRs can increase a line's capacity by 9 to 27% in the summer and up to 81% in the winter, Gilmer said they could sometimes help grid operators recognize when their assumptions are too generous and prompt them to dial back a line's capacity, such as on a hot summer day with no wind.

The case study involved installing LineVision's monitoring technology on major backbone lines, but results indicated it could benefit lower-voltage transmission as well, although the biggest savings were on the 345-KV lines.

The project involved installing 42 sensors in just eight weeks, with individual installation times of just a half-hour without considering travel time to the location. The quick installation time means they can easily be moved around as the grid changes, but Gilmer believes they might become standard across the entire system in the long term.

"There's one approach, which is deploying it almost like Band-Aids on that small number of problem lines," Gilmer said. "But another philosophy is to say, 'Why wouldn't I want this data on my entire transmission system?' So, these are the high-voltage lines that form the backbone of the grid. Wouldn't your operators want to know exactly how much power they can put through, and if there are any anomalies that they need to be concerned about?" ■

## CAISO/West News

# WRAP Participants Seek 1-Year Delay to 'Binding' Operations

### *RA Program Members Cite Big Challenges to Obtaining Resources in Coming Years*

*By Robert Mullin*

Citing "significant new headwinds" to securing energy resources, participants in the Western Resource Adequacy Program (WRAP) are seeking to delay the program's "binding" penalty phase by one year, to summer 2027.

Members of the voluntary program run by the Western Power Pool (WPP) are facing a May 31 deadline to commit to binding operations for summer 2026.

Once committed, participants will be at risk of incurring significant penalties for coming into a binding season with capacity deficiencies compared with their "forward showing" of promised resources for that season. The penalties are based on a formula set out in the WRAP *tariff*, which FERC approved in February 2023.

"Some WRAP participants have expressed concerns about their ability to meet WRAP forward-showing requirements in the next few years," members of the WRAP's Resource Adequacy Participants Committee (RAPC) said in an April 22 letter addressed to "Western Stakeholders."

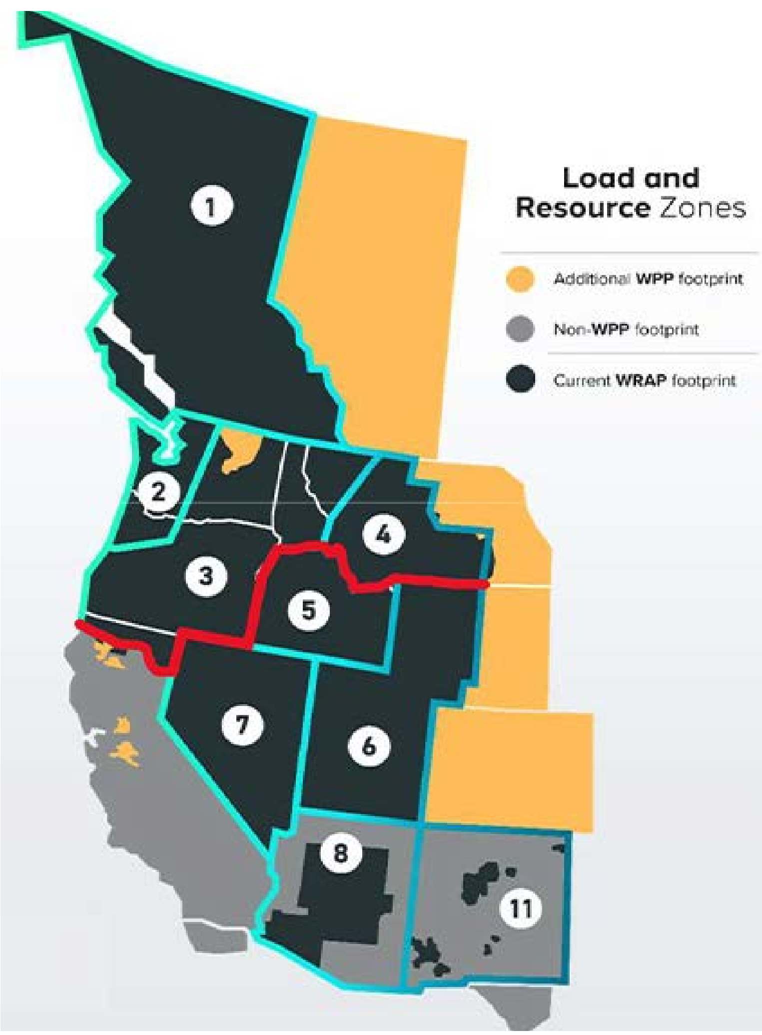
"They are understandably concerned, due to the reasons outlined [in the letter], about moving into binding operations given the potential magnitude of deficiency charges currently included in the tariff," the RAPC wrote.

Those reasons include:

- "supply chain issues and other challenges" that "have slowed our ability to deliver and interconnect new resources";
- regional peak load growing at a rate "faster than previously expected, driven primarily by electrification and data center expansion"; and
- "extreme weather events" that have "further challenged" the region's assumptions about the volume of resources necessary to maintain reliability.

The RAPC wrote that the WRAP "remains a critical tool" for addressing those challenges, having "shown its value by helping quantify where we stand and where we need to go."

"We plan to continue our best efforts to acquire and interconnect sufficient new resources to meet load growth as we strive to meet WRAP's regional resource adequacy metrics," it said. "We have been actively engaged in




| Subregion | Zone | Geographical Description |
|---|---|---|
| MidC | Zone 1 | British Columbia |
| | Zone 2 | West of Cascades |
| | Zone 3 | East of Cascades |
| | Zone 4 | NorthWestern |
| SWEDE | Zone 5 | Idaho Power |
| | Zone 6 | PacifiCorp East |
| | Zone 7 | Nevada |
| | Zone 8 | Arizona |
| | Zone 11 | New Mexico |

The summer load and resource zones for the Western Resource Adequacy Program | *Western Power Pool*

# CAISO/West News

conversations with each other and Western Power Pool about when a critical mass of participants can enter binding operations of WRAP together."

The WRAP tariff gives the WPP the flexibility to begin binding operations between 2025 and 2028. That means the RAPC's request to shift the start date to 2027 will be subject to stakeholder approval but will not require a tariff change.

"Once the revised transition plan is ready, we will submit the plan for consideration by stakeholders and the WRAP Board of Directors, following the WRAP governance process," the RAPC wrote.

## Seeking 'Critical Mass'

In a statement responding to the RAPC letter, WPP CEO Sarah Edmonds said her organization has "worked closely" with WRAP members as they've considered their decision and will continue to work with them on a proposal for transitioning to binding operations.

"Our goal has always been to have a critical mass of participants in a binding program so that the West will be able to address urgent reliability needs," Edmonds said. "That has not changed, though when and how we get there may look different than planned. Like the participants, our efforts will be focused on gaining commitment from a critical mass of participants for summer 2027."

In a March 2023 briefing of the WECC Board of Directors, Edmonds said she hoped to see the WRAP become binding as soon as possible, but she acknowledged that the binding phase could still be years away. (See *WPP CEO Looks to 'Earliest Possible' Binding Season for WRAP*.)

"To be candid, some load-serving entities are in better shape to go binding than others. Others need a little more time to adjust their procurement strategies and their positions relative to what they see coming at them," she had said.

The WRAP participants' move for a one-year delay indicates the RA situation in the West has likely deteriorated significantly since then.

"There is a legitimate question about whether the West will have adequate resources in the years to come. WRAP is the only regional program that specifically addresses that question," Edmonds said in her April 22 statement.

She said WPP will now focus on how to "collect more and better data from participants" for use in "more transparent regional discussions about events where capacity is constrained as we work toward going binding."

## Role in Broader Markets

While the WPP developed the WRAP and oversees its governance, the program's technical operations fall to SPP, whose Markets+ day-ahead offering is currently competing for Western participants with CAISO's Extended Day-Ahead Market (EDAM).

Under the tariff SPP filed with FERC last month, Markets+ participants would be required to participate in the WRAP. That integration was cited by Bonneville Power Administration staff in their recommendation this month that the federal power marketing administration choose the SPP-run market over EDAM. (See *BPA Staff Recommends Markets+ over EDAM*.)

"WRAP has become the dominant resource adequacy program outside of California," BPA staff said in their recommendation. "The EDAM proposal does not propose a uniform adequacy metric or require EDAM entities to participate in a resource adequacy program. Bonneville staff supports and prefers the clear and consistent requirement that all Markets+ [load-responsible entities] must participate in WRAP, which better supports regional reliability."

The WPP has not weighed in on the competition between Markets+ and EDAM, instead emphasizing the need for the West to have a sound platform for reliability.

"We welcome the various markets in development or under discussion in the West, but their benefit comes with the efficient and economic dispatch of resources at times of need," Edmonds said in her statement. "That only works if there are adequate planned resources available to dispatch." ■

## CAISO/West News

# Past Opponents Now See Legislative Pathway to CAISO Regionalization

### *Labor, Public Utility Reps Say Pathways Initiative 'Fundamentally Different' from Previous Efforts*

*By Robert Mullin*

Representatives from two groups that blocked past efforts to "regionalize" CAISO predict success for an upcoming campaign to change California law to allow the ISO to participate in the kind of independent RTO envisioned by the West-Wide Governance Pathways Initiative.

The reps from labor and California's publicly owned utilities shared their views April 19 at a virtual meeting of the initiative's Launch Committee. The committee discussed its recent straw proposal for a "stepwise" approach to transitioning CAISO's state-run governance to an independent body. (See *Western RTO Group Floats Independence Plan for EDAM, WEIM*.)

"Frankly, I wouldn't be spending this much time if I thought this was going to crash and burn," committee member Marc Joseph, an attorney who represents the International Brotherhood of Electrical Workers (IBEW), said during the meeting.

Step 1 of the straw proposal entails making the Governing Body of CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market as independent as possible "within the current CAISO structure in a way that presents little or no" risk to prompting challenges under California law.

Step 2 looks to fulfill the Pathways Initiative's "primary goal" by "creating a durable governance structure with a fully independent board that has sole authority to determine the market rules for EDAM and WEIM." A key action is creating a new "regional organization" (RO) separate from CAISO that would become successor to the WEIM/EDAM Governing Body.

That step would require changes to California law, which Joseph is confident will happen next time around.

That confidence stems in part from the fact that the powerful constituency he represents won't oppose the bill, something Joseph shared in an interview with *RTO Insider* in January. (See *Former Opponents Shift Position on CAISO 'Regionalization'*.)

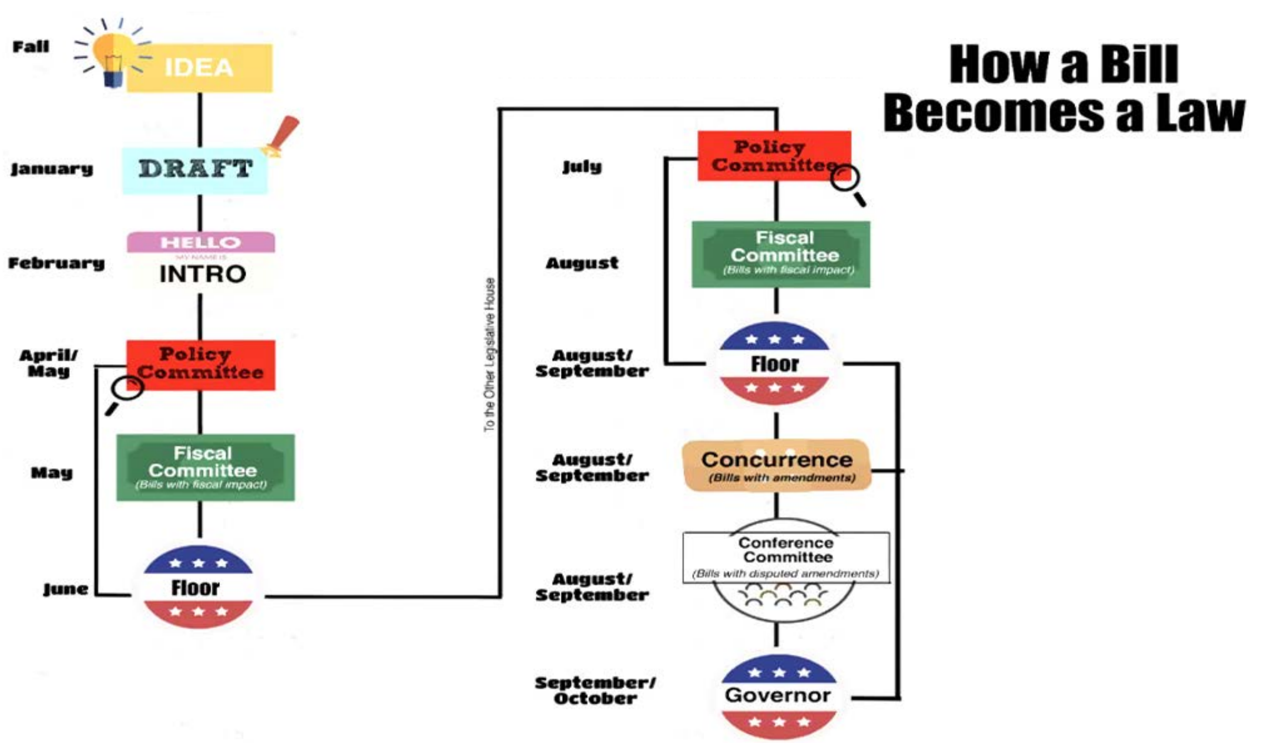
In the interview, he explained the IBEW opposed the three previous legislative efforts to convert CAISO into a multistate entity because the plans, as proposed, would have expanded the boundaries of the ISO's balancing authority area. Under California law, that could've meant the portion of projects that California's renewable portfolio standard required to be interconnected directly to the ISO's BAA could be built outside the state, reducing job opportunities for members.

But the Pathways Initiative plan would allow the ISO to preserve its BAA while still integrating more closely with the rest of the West.

Still, skeptics have continued to express doubts the initiative will produce the kind of California legislation needed to transform the ISO's governance.

"So many people outside of California asked me, 'So what's different this time?' Or more pointedly they ask, 'Why should we expect any different result this time?'" Joseph said during the call.

He pointed to the makeup of the effort's Launch Committee. In addition to Joseph, it includes public power representatives Jim Shetler, general manager of the Balancing Authority of Northern California (BANC), and Randy Howard, GM of the Northern California Power Agency (NCPA) — all of whom are "spending lots and lots of time and effort to craft a proposal that will succeed."




NCPA's Randy Howard used this graphic to explain the process for moving a CAISO governance bill through the California legislature in 2025. Pathways Initiative backers plan to start discussions with legislators this fall. | *West-Wide Governance Pathways Initiative*

# CAISO/West News

A "more substantive" reason for Joseph's confidence is that he sees the Pathways proposal as being "completely and fundamentally different" from past proposals in both "structure and detail."

Prior proposals would have replaced CAISO's Board of Governors with an independent body "not connected in any way to the state of California," he said, providing "absolutely no guarantees" California consumers or policies would be protected.

In contrast, "we will know the details" about the outcome of the Pathways plan, Joseph continued.

"CAISO would remain intact, the CAISO balancing authority area would remain intact, the incentives to create jobs in California would remain intact," he said. "And the thing that changes is the governance just of the market functions now currently housed within ... CAISO, with the door left open for more incremental changes in the future."

For those reasons, Joseph expects any future bill to alter the ISO's governance will look much different from the past failed bills.

"Obviously, I can't speak for the California legislature, but given the fundamental differences in both structure and detail [of Pathways], and the demonstrated benefits for California consumers and for workers ... I think there's every reason to think that the outcome can be different," he said.

## Legislative Approach

NCPA's Howard said California's publicly owned utilities opposed previous regionalization efforts for many of the same reasons laid out by Joseph. They've altered their stance in part due to their success in participating in CAISO's Western Energy Imbalance Market, and they want to build on that.

"We like what we see in the [EDAM], but we know overall market conditions have changed dramatically throughout the West in the last couple of years, and we see that change continuing," Howard said. "And so the do-nothing strategy, or staying as we are today, doesn't make a lot of sense."

Howard said the framework in the Pathways proposal resolves many of the issues the public had with earlier attempts to change CAISO governance.

He noted that while the Launch Committee won't directly lobby California lawmakers, some of its members already are starting to engage with the legislature in their organizational capacities with the aim of moving a bill through the 2025 session.

"There's already been an effort to get out and have some informational sessions with some key legislative staff [and] walk through what we've been working on [and explain] why it is different" from past efforts, Howard said, adding that he saw some of those staff listening in on the call.

Pathways backers will begin meeting with legislators in the fall to discuss the type of legislation needed and "hopefully work on draft language," Howard said, with the expectation of having a bill submitted into either the California Assembly or Senate at the start of the next session in January.

"I agree with Mark. With the framework that's here and that we're proposing, I don't see ... difficulty ... in moving this forward. But again, I can't speak for [legislators]; they will have that opportunity to vote," he said.

## Funding Update

Launch Committee co-Chair Kathleen Staks, executive director of Western Freedom, updated meeting participants on the status of the Pathways Initiative's financial status after the U.S. Department of Education rejected its January application for $800,000 in grants. (*See Pathways Initiative Rejected for $800K in DOE Funding*.)

Staks said DOE declined to select the project because the agency lacked details about the scope of the activities to be funded by the grants, which would have consisted of $400,000 annually for two years.

"Back in January, we were still very early in our work, and it was difficult to provide details at that point about the direction and the ultimate structure that we're still frankly working to develop with input from stakeholders," she said.

The funding assumptions for Phase 1 of Pathways, expected to conclude this month, did not include the DOE money.

Staks said DOE is putting out another round of funding for wholesale electricity market studies and engagements this spring and the Launch Committee "is evaluating potential proposals for that funding opportunity and how beneficial those funds would actually be."

"We're also pursuing other funding opportunities, and we'll continue to provide information about the budget and the various tasks that we need to be able to fund and how much money and where that money is coming from," she said. ■

## West news from our other channels

*Wash. Council OKs Reduced Version of Horse Heaven Hills Project* — NetZero Insider

*Calif. Senate Committee Passes Energy-related Bills* — NetZero Insider

*Wash. Cap-and-invest Supporters Launch Anti-repeal Effort* — NetZero Insider

*FERC OKs Pipeline Expansion Despite West Coast States' Opposition* — NetZero Insider

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# CAISO/West News

# Pathways Initiative Rejected for $800K in DOE Funding

## *Group Sought Federal Grants for Multiple 'Support Functions,' Including Outreach*

*By Robert Mullin*

The West-Wide Governance Pathways Initiative has potentially lost a key source of financial backing after the U.S. Department of Energy rejected the group's application for $800,000 in grants to support its initial operations.

"The Pathways Initiative did not receive DOE funding in the last round," Western Freedom Executive Director Kathleen Staks, co-chair of the initiative's Launch Committee, told *RTO Insider* in an email April 17. "We plan to share more information and potential next steps during our [April 19] stakeholder call and [will be] happy to answer additional questions at that point."

The group applied for the money in January in response to a DOE Funding Opportunity Announcement (FOA), seeking two tranches of $400,000 each to be disbursed over two years. The initiative was launched last July by energy officials from five Western states to develop the framework for an independent RTO that pointedly includes California and builds on CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). (See *Regulators Propose New Independent Western RTO*.)

"This funding is necessary for major Pathways support functions — development of informational materials; outreach to key stakeholders; regular convenings through virtual and in-person gatherings; and facilitation to ensure meaningful participation by those who wish to engage," the group said in a concept paper included in the grant application. (See *Western RTO Group Seeking $800K in DOE Funding*.)

The funding would be "essential to performing outreach to states and groups not yet aware of, or able to participate in, the new nonprofit independent governance entity envisioned by" the initiative's backers and make it more accessible to a larger set of stakeholders, the paper said.

Speaking at the Launch Committee's last monthly update March 15, Jim Shetler, co-chair of the committee's Priority Administrative Work Group, expressed confidence that Pathways would win the DOE funding. (See *Pathways Initiative Discloses Funders, Reiterates Goals*.)

Shetler, general manager of the Balancing Authority of Northern California, said the federal money would likely arrive in June or July, possibly leaving a funding gap in late spring that would likely be covered by the group's original budget of $570,000 needed to fund Phase 1 of the effort through the end of April.

It's now unclear how Phase 2 will be funded. During the March update, Shetler said the initiative had raised about $430,000 from 24 stakeholder donors to cover the initial budget, with more pledges on the way.

As of April 17, a "pledge summary" spreadsheet maintained by the group showed the list of donors had expanded to 32. It now includes the Interwest Energy Alliance, Western Resource Advocates, Primergy Solar, Solariant Capital, Pattern Energy, Brookfield Renewable Partners, Engie North America and one "individual contributor." But the spreadsheet shows only pledge ranges, not donors' specific contributions.

NOTE: This is a living document and updates will be posted periodically. Donations support the work of the Pathways initiative

| Organization | $ 1-5,000 | $5,001-10,000 | $10,001-20,000 | $20,001-30,000 |
|---|---|---|---|---|
| Apex Clean Energy | | x | | |
| Avangrid | x | | | |
| Avista Corp. | | | | x |
| Balancing Authority of Northern California | | | | x |
| California Community Choice Association | | | | x |
| EDP Renewables | | x | | |
| Invenergy | x | | | |
| NextEra Energy | | | x | |
| Northern California Power Agency | | | | x |
| NW Energy Coalition | | | x | |
| Orsted Wind Power North America | x | | | |
| Pacific Gas & Electric | | | | x |
| PacifiCorp | | | | x |
| PNGC Power | | | | x |
| Portland General Electric | | | | x |
| Public Service Company of New Mexico | | | | x |
| Puget Sound Energy | | | | x |
| Seattle City Light | | | | x |
| Southern California Edison | | | | x |
| Turlock Irrigation District | | x | | |
| Union of Concerned Scientists | x | | | |
| Western Freedom | | | x | |
| Western Power Trading Forum (AES, Calpine, Constellation, Shell, Vistra) | | | | x |
| NIPPC | x | | | |
| Interwest Energy Alliance | x | | | |
| Western Resources Advocates | | x | | |
| Primergy Solar | | | x | |
| Individual Contribution | x | | | |
| Solariant Capital | x | | | |
| Pattern Energy | | x | | |
| Brookfield Renewable | x | | | |
| Engie North America | x | | | |

While the Pathways Initiative was rejected for $800,000 in DOE grant funding, the group's list of donors has grown from 24 to 32 over the past month. | *West-Wide Governance Pathways Initiative*

The denial of federal funding comes just a week after the initiative released its straw proposal for tackling a "stepwise" transition of CAISO's WEIM and EDAM to independent governance and could represent a setback for the EDAM in its competition for participants with SPP's Markets+. (See *Western RTO Group Floats Independence Plan for EDAM, WEIM*.)

SPP officials, meeting in Denver, declined to comment on the development.

CAISO spokesperson Anne Gonzales said the ISO would defer comment to the Launch Committee. ■

*Tom Kleckner contributed to this article from Denver.*

# GCPA Spring Conference Reckons with Texas-sized Load Additions

*By Amanda Durish Cook*


GCPA Spring Conference underway at Hilton Americas Houston on April 16 | *© RTO Insider LLC*

HOUSTON — The Gulf Coast Power Association's 37th annual Spring Conference on April 16-17 tackled the vexing assignment of how to reliably serve Texas' unprecedented surge in demand with a cleaner energy supply.

The two-day event, held at the Hilton Houston Americas, featured experts from both the organizations trying to rise to the challenge and the companies behind the soaring demand.

"I just got to say it loud and clear: Since Uri, we're too much talk and not enough cattle," Hunt Energy Network CEO and former FERC Chair Pat Wood said during a keynote speech. "The fundamental fact is: We have told the world that Texas is 'open for business.' Everyone in this room believes it, and the world is responding. Companies are moving here in droves. People are flooding the state from both coasts.

"We've said we're open for business, but we haven't stocked the shelves. … We've invited gigawatts of new business and residential demand to come to our store, but we are woefully short on serving them."

Wood said ERCOT needs to build a system that won't "fail catastrophically from the center" but one that's "redundantly resilient" to protect from overlapping risks. And Texas needs to unveil an "ERCOT 3.0" that adopts a "wartime-level sense of urgency," upgrade the grid, streamline the interconnection queue and design pricing that inspires investors to build dispatchable generation without taxpayer subsidies. "Trucks and cranes from the Red River to the Rio Grande," he said.

Wood also said Texas risks its "envy of the world" status in industry if it cannot employ creative solutions, including energy efficiency, load participation, and multidirectional flows on the transmission and distribution systems to unlock behind-the-meter generation.

"To paraphrase my old boss, we want no electron left behind. Let's get back to work," he said.

Wood said ERCOT's future supply will be "digitalized, decentralized, diversified, democratized, dependable and decarbonized." He said it's ironic that Texas is at the vanguard of clean energy in a state that's "almost embarrassed to talk about" climate change.

Outgoing Calpine CEO Thad Hill said it's obvious that Texas' load is growing from data centers, manufacturing, natural gas and "maybe hydrogen."

"This is more big-load-driven than it's ever been. We're talking about 300 to 400 MW hooking up to the grid at a time," he said.


Calpine CEO Thad Hill | *© RTO Insider LLC*

Hill said, however, he isn't anxiety-ridden over the future.

"What you're going to hear from me is more hopeful," he said. There's cause for optimism because additions of price-responsive load are outstripping traditional load additions, and solar-and-storage combinations are blossoming, helping to solve ERCOT's summer reliability issues.

Hill said ERCOT's "major to do" should be creating a formal program for price-response load, more comprehensive than its existing Emergency Response Service. The hot summer and high prices in Texas in 2023 prodded new investment in dispatchable resources. He said gas plant plans in the ERCOT queue have doubled, with battery storage rising fivefold.

"Capital is flowing to dispatchable resources. … Gas is up; batteries are up. But man, we've got to find a way to institutionalize price-responsive load as a resource," he said.

Hill also acknowledged that additions of short-duration battery storage have a ceiling on their usefulness.

"What happens when reserve events outlast the resources?" he asked, noting that ERCOT experienced two events upward of seven hours in which it needed consistent reserves, once in early September and once in early November. He said ERCOT should evaluate the duration it needs its ancillary services to last.

"Storage is doing great things for this market," Hill said, but he urged market designers to be realistic about how long it can deliver. He said storage in ERCOT has already been found short of state of charge when called upon.

Hill advised Texas lawmakers to "take a legislative breather and let the experts work." The legislature, which has been active the last two sessions, now needs to allow the Public Utility Commission's and ERCOT's plans to "take root."

"We've got a good thing, though there's been trauma along the way," Hill said, referencing Winter Storm Uri. "I think we're going to be just fine."

# GCPA 37th annual Spring Conference

Entergy Texas CEO Eliecer Viamontes | © RTO Insider LLC

On a panel concerning the "insatiable" demand for power, Entergy Texas CEO Eliecer Viamontes said his territory is seeing "once-in-a-generation load growth" that must be met with aggressive capacity buildout to elude load shed.

"This is game changing. We cannot propose incremental generation," he said.

"I've been astounded at load growth. It's something [that] 10 years ago, I wouldn't have predicted," said Jack Farley, HIF USA's executive vice president.

Farley predicted that about "one in five" of the approximately 60 GW of flexible load projects lined up in ERCOT's queue will reach commercial operation.

"Nonflexible loads will have to become somewhat flexible going forward," said Jeff Hanson, Digital Realty's senior director of energy supply chain. It's the "only way to address" infrastructure expansion failing to keep up with climbing load, he said.

Hanson said industry will remain drawn to Texas because of the welcoming regulatory climate that allows renewables to be built quickly, the "deep, deep pools" of sunshine and wind, the vastness of the state and the "lack of NIMBY-ism."

Farley said behind-the-meter generation can help moderate runaway demand. Hanson added that large loads might consider adding their own onsite generation.

CenterPoint Energy Vice President of Regulatory Affairs Jason Ryan said Texas needs to employ an "all-of-the-above" strategy "to the max" to meet demand. With Houston's energy needs set to double by 2050, he said the state is already behind in mounting major infrastructure buildouts. He asked the audience to consider the "100-plus years" it took for Houston to assemble its current grid.

Hanson predicted ERCOT will "be dancing on the edge" for a few tough years until infrastructure expansion can catch up.

Bryan Fisher, managing director of climate aligned industries at RMI, said industrial decarbonization alone could double the nation's demand for power.

From left: Ali Amirali, Lotus Infrastructure Partners; Kip Fox, ETT; Kris Zadlo, Grid United; and Brian Hudson, Priority Power | © RTO Insider LLC

"Texas and the Gulf Coast are ground zero for industrial decarbonization," Fisher told attendees. He said the Houston area alone has the potential to serve not only national demand for hydrogen, but the world's market as well. He said RMI's preliminary analysis shows that Houston could be confronting 2.5 times its peak demand today by 2050 because of the added demands of industrial electrification, hydrogen production, and carbon capture and sequestration.

### Calls for ERCOT Transmission Planning

Priority Power Director of Development Brian Hudson said a decade ago, forecasters were talking about 300 to 500 MW of load growth. He said those figures exploded in recent years to gigawatts.

"It's got to be stuff that we haven't tried before to keep up with the pace," he said.

He said in addition to dynamic line ratings, Texas should consider making it easier for behind-the-meter generation projects of 10 MW and above to interconnect to the distribution system and lighten load.

Kip Fox, president of Electric Transmission Texas (ETT), an American Electric Power and Berkshire Hathaway Energy partnership, said he is trying to energize a new line but cannot get approval from ERCOT for the necessary outage of nearby equipment because of current levels of demand. He said if ERCOT doesn't give the go-ahead for an outage soon, ETT will likely have to wait through the summer moratorium to energize the line.

"We're not fast enough to build. … It's not like we haven't submitted ideas to build transmission. But at the end of the day, someone in the regulatory space is going to have to realize we need it," Fox said.

Kris Zadlo, chief commercial and technology officer at Grid United, said it's no longer the pandemic causing supply chain woes, but skyrocketing load growth.

"We have unprecedented demand for equipment, and that's not dawning on some," Zadlo said. He said data centers are even procuring transformers, making it more difficult for a small Texas electric cooperative to secure equipment.

Multiple panelists said ERCOT should move away from planning for spot solutions and examine what transmission will be necessary longer term.

"Long-term transmission plans have been shelved, and we need to act on them today,"

# GCPA 37th annual Spring Conference

Zadlo said. He also said someone needs to "challenge the utility mindset" and say, "'Look, what you built yesterday will not work.'"

"Data centers go up faster than transmission does," noted Ali Amirali, senior vice president of Lotus Infrastructure Partners.

Amirali said developers should prepare lines today to be high-voltage-ready, with insulation and right-of-way procurement, and find "patient" investors who see the value in having the option to easily size up transmission capacity.

Zadlo said the mindset that HVDC lines are novel and untested should be scrapped.

"It's not that complicated," Amirali agreed. He joked that he became a power systems engineer when he was young because he was "lazy," and he figured the last great technological advancement in the field was transformers. Now he lamented that he was proven right and there haven't been more advancements.

"We cannot solve today's problems using yesterday's technology, and to be honest, we're still in the '60s," he said. He later laughed and added a disclaimer that his views are "mine and mine alone."

## The Lure of Gas

In an earlier panel, CPS Energy Chief Supply Officer Benjamin Ethridge said there are opportunities in the future for zero-emission dispatchable generation. For now, he said gas plants will be the dominant on-demand power source for growing load, and gas infrastructure needs major expansion.

"It's great to have 2035 or 2040 goals, but we need to be able to weather the next winter storm, the next Uri," said Michael Enger, Austin Energy's vice president of energy market operations and resource planning.

Scott Harlan, Rockland Capital | *© RTO Insider LLC*

Rockland Capital co-Managing Partner Scott Harlan said his company is interested solely in gas-fired facilities to bolster dispatchable resources. However, he said gas supply can be uncertain with intrastate pipeline companies that function as unregulated monopolies without transparency.

All agreed that the Texas Energy Fund, which provides as much as $10 billion in subsidies to fund dispatchable resources, is a welcome development.

Kathleen Smith, president of Aegle Power, said she was "very pleased" to see the subsidized loans approved by Texas voters and is excited to see what projects are submitted next month.

Smith also predicted that the Texas Legislature will be relatively quiet on the energy front this session barring any new emergency events.

"I really hope the legislature stands down, maybe does a few tweaks but not anything massive," Harlan said. He added that he's also concerned about EPA's power plant emissions rule, expected to be released at the end of the month. He said if gas facilities are required to install carbon capture, it will add years to commercial operation dates.

"I'm hoping they take a more tempered approach. If they're aggressive and require carbon capture on gas plants, there are going to be lawsuits," he predicted.

Enger said he is hoping for a trouble-free, windy summer. Ethridge said that though Austin is gearing up for another hot summer, his utility has more wind, solar and storage, and he's "bullish" on ERCOT market dynamics.

Martin Pasqualini, managing director and partner of boutique investment firm CCA Group, said Texas law shouldn't be hostile to wind and solar project financing.

"I think the renewable market can deal with neutrality but not outright antipathy," he said.

Pasqualini pointed out that Texas is no longer the only market experiencing load growth. It might be more difficult to build in other regions, he said, but it's possible for renewable developers to withdraw from ERCOT.

Dean Tuel, vice president of Goldman Sachs-backed compressed air storage company Hydrostor, said his company takes advantage of low-cost excess and furnishes grid reliability — effectively capacity, though ERCOT doesn't have a capacity market.

Tuel said he would like utilities to look further on the horizon for procurement plans. Utilities shouldn't simply plan on erecting solar panels and short-term energy storage for the next few years but should also procure dispatchable resources for beyond 2030. He said for his company, whose assets have a 50-year lifespan, long-term offtake agreements are key.

OnPeak Power Managing Partner Ingmar Sterzing also said ERCOT no longer has the market cornered on fastest queue processing time.

"The load is coming in so quickly that it could definitely be a challenge," he said.

Pranay Reminisetty, a lead interconnection engineer with DNV, said constraints on the ERCOT grid are piling up and the state needs new transmission so it doesn't hamstring new generation.

"You have significant load growth in hours that you're not really building generation for," said Luis Lugo, head of ERCOT trading at Mercuria. He said April's prices have already been high on unseasonably warm weather.

"Fundamentally, we've done nothing to build generation for hot weather," Lugo said.

During a panel concerning corporate sustainability goals, Chris Dorow, regional manager of power and utilities for BASF, said that although some companies have recently pushed out sustainability goals, those timelines were always "aspirational" because they were made when technology feasibility wasn't fleshed out.

Tina Moss, senior director of net zero strategy for LyondellBasell Industries, said her company's climate goals still boil down to matching the targets laid out in the Paris Agreement on climate change.

Alex Beck, co-founder of renewable financial firm GoodLynx, said companies' sustainability offices are often "kneecapped" and not bestowed the budgets or power to enact their goals. "Corporate America needs to reframe" how it incorporates zero-emission energy and buy tax credits to finance clean energy projects, he said. ■

## National/Federal news from our other channels

*Biden Announces $7B in IRA Funds for Low-income Solar*

NetZero Insider

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

## ERCOT News

# ERCOT Technical Advisory Briefs: April 15, 2024

### *Staff Say No Further Changes to ECRS Methodology*

ERCOT last week told stakeholders that its staff are not supportive of modifications to the calculation of ERCOT contingency reserve service (ECRS) after recent changes resulted in lower quantities of the product this year.

ERCOT's Nitika Mago told the Technical Advisory Committee on April 15 that last year's annually required review of ECRS methodology, reduced 2024 quantities by an average of 442 MW in each hour. That is about a 21% reduction in the service, she said.

"We, as we do every year, will continue to see if there are any improvements that can be made," Mago said. "We'll continue to work on the analysis ... but at least we're getting ready for where we want to be."

ERCOT has drafted a nodal protocol revision request (*NPRR1224*) creating a trigger allowing staff to manually release ECRS from dispatchable resources earlier than they did last summer. Stakeholders have requested additional analysis on the measure and have tabled it at the Protocol Revision Subcommittee, pushing off any likely decision until midsummer. Staff said that without the guidance on an "appropriately balanced ECRS deployment trigger," they will release the product in a similar manner to last year.

"I think we do see this as a good step forward," Jeff Billo, ERCOT's director of operations planning, said of the NPRR. "We see other steps being necessary, but we see this as a good initial step forward."

ECRS was deployed last June as ERCOT's first new ancillary service in 20 years. The grid operator's Independent Market Monitor said in December that ECRS has created artificial supply shortages producing "massive" inefficient market costs, totaling about $12.5 billion last year through November.

Staff promised last year to re-evaluate ECRS and share the results with stakeholders by April 30. They said a holistic review of the entire ancillary service methodology could soon be necessary. That same review would better address some of the IMM's concerns, Mago said. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

Mark Dreyfus, representing a coalition of Texas cities, urged for a deeper review of the IMM's $12.5 billion figure to determine whether ERCOT induced congestion by holding excess reserves out of the energy market.


TAC Chair Caitlin Smith guides the committee through its April meeting. | *ERCOT*

"I've asked, and I think others asked way back when this issue first started: Let's all drill down; this is so important," Dreyfus said, noting the wholesale market's "potentially unnecessary expense."

"Let's drill down and find out if that really happened or what were the circumstances. I don't think we did that drill-down, and this conversation has suffered from that," he said.

ERCOT has disputed the IMM's analysis, calling the numbers "unknowable." Billo said the long-term cost is really the cost of capacity being set aside.

"We all understand that $12.5 billion is not a real number," he said. "I think the calculation was probably correct, but it's not a real number or indication of what actual costs are. We don't even know if it's even the right magnitude of cost. That that's an unknowable number, because we don't know how bidding and offer behavior would have changed.

"We don't know what capacity may have decided they didn't want to be there because of that change. So, I think we need to focus more on the fundamentals of what do we need and what are the cost[s] from a capacity standpoint," Billo said.

Michele Richmond, executive director for the Texas Competitive Power Advocates trade association, argued that there would have been behavioral changes "because when you change how something works within the market, that is just a natural result."

"What we have seen is that ECRS has sent a signal to the market that investment in dispatchable generation is needed in ERCOT. Investment decisions are not based on what happened in the past; they're based on what the expectations are for the future," Richmond said. "I think we need to be really cautious that we don't chill that investment or send a message that we want reliability, but it can't cost anything, because that's also not realistic. A balance needs to be struck. I think that making sure what we do is the right thing for the market — not just this summer and next summer, but in the long term — is really critical."

### ERCOT: Remand IBR Rule

ERCOT plans to recommend that the Board of Directors this week remand a controversial rule change to TAC, against stressing the risk to grid reliability, staff told members.

"We still have concerns about the reliability implications of [NOGRR245] endorsed by TAC," Dan Woodfin, ERCOT's vice president of system operations, told TAC.

Woodfin said staff will recommend that TAC address the reliability concerns and either modify stakeholders' proposed language or explain how the NOGRR addresses ERCOT's reliability issues.

The NOGRR is intended to align the grid operator's rules with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers *standard* for IBRs interconnecting with the grid. Two IBR-related voltage disturbances in West Texas in 2021 and 2022, dubbed the Odessa Disturbances I and II, have added urgency to the measure's eventual passage. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

Stakeholders have proposed software changes to fix the issues NERC and ERCOT have identified. They have said ERCOT's proposals, if approved, "will implement the nation's most aggressive ride-through performance requirements to date."

TAC in March approved *amended language* that stakeholders pushed through despite ERCOT's objections. Stakeholders said the language was "carefully crafted" to reach a solution balancing risk mitigation with "economic, technological and operational realities." (See *ERCOT Technical Advisory Committee Briefs: March 27, 2024*.)

"We would like to see this matter be resolved

# ERCOT News

and the ERCOT board endorse the TAC-recommended comments," said Eric Goff, who has led the stakeholder group opposing staff's recommendation. "We might be in opposition to further remand and delays in limitation of these renewable resources. This is affecting real-world investment decisions every day, and we would like to get this matter resolved as quickly as possible."

"Working towards more consensus is always beneficial. If there is a remand, does this end up just becoming an appeal back to the board, or is there a path to further consensus or possibly strumming the ukulele singing 'Kumbaya?'" Luminant's Ned Bonskowski asked Woodfin. "We made a recommendation to the board, and the presumption was for a lot of us that there were going to be folks on both sides, and then the board would end up taking some action, and then there may be action further taken at the [Texas Public Utility] Commission level. I want to make sure that we're moving forward in a way that will continue to sharpen the pencil, if it's possible."

"Part of the benefit of this remand will be to further flesh out all of the pros and cons of the different approaches on each of the many issues that we're talking about," Woodfin responded. "That will be in the record out in public, so that both the board and the commission will have all that in front of them and be able to see all the different moving parts as this goes forward."

ERCOT's Jeff Billo (upper right) explains staff's thoughts on ECRS. | *ERCOT*

Goff said his group already has an "extensive and well developed record" addressing those questions and argued against further delays. A remand could push the NOGRR to the June or August board meetings. It will then still have to go before the PUC for final approval.

"The effective date for new resources could potentially be pushed even further, and we would really like to see this pass," Goff said.

## Key Date for RTC+B Project

Members endorsed a white paper detailing changes to the reliability unit commitment process necessary to co-optimizing energy and ancillary service procurements to meet forecasted load and ancillary service requirements.

The paper sets the guardrails for the Real-time Co-optimization plus Batteries (RTC+B) Task Force's design work and its scope. The document has gone through three reviews without changes, said ERCOT's Matt Mereness, the RTC+B's chair.

"The white paper has dealt with the design elements we need to finish our design and begin building software. It sets the foundation that we will build from," he said. "We don't want to slow things down waiting to get the principles defined so the NPRR doesn't get pulled in different directions other than this white paper."

The white paper is the first of 20 issues the RTC+B team has identified and is addressing. Mereness said the task force is wrapping up its work on requirements and hopes to release a program timeline in September laying out the schedule for the remaining work. The project remains on track for delivery in 2026.

"At this point, 2026 is still the placeholder until told otherwise," Mereness said.

ERCOT held the first of four technical workshops on the project April 19, sharing expected dispatch and data control changes. "These are really very technical workshops, which is why they have the word 'technical' in them," Mereness said.

## Hanson Rejoins Committee

National Grid's Kevin Hanson has rejoined TAC in the independent power marketer segment. He received support from Pedernales Electric Cooperative's Eric Blakey, who kiddingly said the "ever dependable" Hanson should be up for TAC's Spirit Award.

"He has earned it," said Blakey, chair of TAC's *Wholesale Market Subcommittee*. "He's currently chair of three working groups. We're trying to take away one of his responsibilities, but he's just done an amazing job stepping in."

Hanson replaces Seth Cochran, who recently took a position with energy trader Vitol after 13 years at DC Energy. Cochran served on ERCOT's board for five years (2016-2020).

## $435M San Antonio Project OK'd

By unanimously approving its usual combo ballot, the committee endorsed ERCOT's proposed $435 million San Antonio South Reliability II project addressing reliability issues south of the city.

The area has been plagued with significant congestion. The grid operator in February created *four new generic transmission constraints* in the area to limit power transfers in north-to-south and south-to-north directions.

The project will now go before the board for approval, as its price tag easily exceeded the $100 million threshold, requiring the directors' approval.

ERCOT staff identified the project while studying a different proposal. ERCOT's independent review found the project necessary under its and NERC's planning criteria. Staff analyzed 15 options and shortlisted four before finding its preferred option.

The combo ballot also included NOGRR and Planning Guide changes (PGRR) that, if they go before the board and are approved, would:

- *NOGRR255*: establish high-resolution data requirements.
- *PGRR112*: set requirements for interconnecting entities to submit dynamic data models and for transmission service providers to submit final full interconnection studies for approval at least 30 business days before the quarterly stability assessment deadline.

A second combo ballot was conducted to allow for members' abstention on two measures related to the use of electric service identifier IDs (ESI ID). The NPRR (*NPRR1212*) would clarify a distribution service provider's obligation to provide an ESI ID for a resource site that consumes load other than wholesale storage load and is not behind a non-opt-in entity tie meter.

The cooperative segment abstained from the vote, which also included *PGRR114*, over complaints that the NPRR pre-empts the rights of co-ops and municipalities over access to their distribution systems. ■

*— Tom Kleckner*

# ISO-NE News

## ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points

*By Jon Lamson*

Relocating two offshore wind points of interconnection (POIs) from Maine to Massachusetts could substantially reduce New England's transmission upgrade cost requirements in the coming decades, ISO-NE told its Planning Advisory Committee on April 18.

Shifting the points of interconnection would *decrease the need* for north-to-south transmission upgrades, cutting the overall cost range for transmission upgrades to $19 billion to $22 billion by 2050 compared to the original $22 billion to $26 billion estimate from ISO-NE's *2050 Transmission Study*. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

| Year/Load Level | Maximum Load Served (MW) | Original Total Cost Range ($) | After Relocation Total Cost Range ($) | Roadmap | Original Scenario -Total Cost ($B) | After Relocation – Total Cost ($B) | Cost Savings ($B) | Cost Savings (%) |
|---|---|---|---|---|---|---|---|---|
| 2035 | 35,000 | $6-9 Billion | $5-9 Billion | AC | $7.6 | $7.7 | -$0.1 | -1.32% |
| | | | | DC | $8.2 | $8.2 | $0 | 0.12% |
| | | | | Minimize AC | $5.8 | $5.8 | $0.1 | 1.32% |
| | | | | Offshore Grid | $7.4 | $5.6 | $1.8 | 24.54% |
| 2040 | 43,000 | $10-13 Billion | $9-12 Billion | AC | $11.8 | $11.4 | $0.4 | 3.69% |
| | | | | DC | $12.1 | $11.9 | $0.2 | 1.81% |
| | | | | Minimize AC | $10.7 | $9.8 | $0.9 | 8.38% |
| | | | | Offshore Grid | $11.4 | $9.4 | $2 | 17.86% |
| 2050 51 GW | 51,000 | $15-17 Billion | $13-16 Billion | AC | $15.5 | $14.5 | $1 | 6.21% |
| | | | | DC | $15.9 | $15.4 | $0.5 | 2.95% |
| | | | | Minimize AC | $15.6 | $13.9 | $1.7 | 10.62% |
| | | | | Offshore Grid | $15.7 | $13.6 | $2.1 | 13.29% |
| 2050 57 GW | 57,000 | $22-26 Billion | $19-22 Billion | AC | $22.6 | $20.5 | $2.2 | 9.55% |
| | | | | DC | $25.3 | $21.2 | $4 | 15.86% |
| | | | | Minimize AC | N/A | $19.8 | N/A | N/A |
| | | | | Offshore Grid | $23.4 | $20.8 | $2.6 | 11.13% |

Summary of estimated ISO-NE transmission costs through 2050 | *ISO-NE*

"Location of offshore wind POIs are important, and results can vary significantly based on these locational choices," said Liam Durkin of ISO-NE. "The offshore wind POI screening analysis will be one important step towards refining assumptions around offshore wind POIs."

The analysis used the same methodology as the 2050 Transmission study, shifting just two of the POIs in the study. One of the key findings of the original study was the need for increased transmission capacity from northern New England to the Boston area.

Moving the two POIs south would reduce flows along the Maine-New Hampshire interface and the North-South interface in the winter, while the shifts would minimally impact summer flows, ISO-NE found.

The lack of summer effects stemmed partly from ISO-NE's expectation that offshore wind output would decline significantly during the summer.

The 2050 Transmission Study considered four pathways to meet the transmission needs: an AC road map, a DC road map, an offshore grid road map and a plan focused on minimizing the need for new lines by upgrading existing infrastructure.

The POI analysis showed that shifting the two offshore wind interconnections would benefit all four pathways, saving the AC road map an estimated $2.2 billion, the DC road map an estimated $4 billion and the offshore grid road map an estimated $2.6 billion.

While ISO-NE initially found it could not meet its expected 2050 peak load of 57 GW through the "minimization of new lines road map," the RTO found the POI shifts would make this road map possible, with an estimated cost of $19.8 billion.

Although this pathway relies the least on new lines, it still would include a few, as well as substantial line rebuilds.

"Rebuilds alone cannot successfully serve a 57-GW winter peak load along the North-South and Boston Import interfaces," Durkin said.

ISO-NE projects a 57-GW winter peak but also emphasized the potential benefits of lowering the peak through demand-reduction efforts. The original analysis from the 2050 Transmission Study found that limiting the peak to 51 GW would reduce transmission costs by about $8 billion.

The updated analysis also found benefits of the POI shift with a 51-GW winter peak; taking the interconnection changes into account, the lower peak reduced the overall cost estimate to $13 billion to $16 billion. ■


## ISO-NE News

# Northeast States Apply for Federal Money for 2 Tx Projects

By Jon Lamson


| © RTO Insider LLC

The six New England states report they've submitted two applications for federal funding for transmission projects aimed at improving grid reliability and enabling interconnection of clean energy resources.

The applications are for the second round of funding from the U.S. Department of Energy's Grid Innovation Program, which offers up to $1.82 billion, capped at $1 billion for major individual transmission projects.

The application for the "Clean Resilience Link" project was submitted in conjunction with New York state. The project, backed by National Grid, would upgrade a 230-kV line between New York and New England to 345 kV, "increasing transfer capacity between the two regions by up to 1,000 MW."

A Brattle Group *analysis* commissioned by New York published in early April found the project's benefits would well exceed its costs.

"Even recognizing the large uncertainties, the ~$1.7b estimated system-wide benefits relative to the ~$600m net costs suggests that the project is highly favorable (with a ~$1b net benefit) from a systemwide perspective," the Brattle Group wrote.

The firm wrote that the project would address the need for increased transmission capacity between New England and New York, which has been documented in studies including the *DOE National Transmission Needs Study* and Massachusetts' *Energy Pathways to Deep Decarbonization* report.

The second project, titled "Power Up New England" is backed by developers including Eversource, National Grid and Elevate Renewables. The project is intended to upgrade and add points of interconnection in southern New England to unlock up to 4,800 MW of offshore wind and battery energy storage systems.

"As we work to achieve our climate goals and increase the generation of renewable energy in the region, we need to invest in our transmission system and storage resources to deliver clean energy to our residents and businesses," said Massachusetts Department of Energy Resources Commissioner Elizabeth Mahony in a press release.

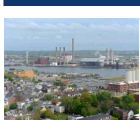
"This joint application to the Grid Innovation Program underscores the importance of continued collaboration with neighboring states and puts forth thoughtful proposals that will help strengthen and prepare our regional grid," said Dan Burgess, director of the Maine Governor's Energy Office.

The states noted in an April 17 announcement that the applications contain "robust Community Benefits Plans" focused on "community engagement, workforce development, and diversity, equity, inclusion and accessibility."

The projects were selected by the states through a joint solicitation of proposals in 2023, and the states submitted concept papers to DOE for the projects in January, with help from ISO-NE.

The first found of Grid Innovation Program awards ranged from $1.7 million for a synchronous condenser conversion project in Hawaii to $464 million for a new *interconnection collaboration* in the central U.S. ■

## Northeast news from our other channels



*Mass. AGO, DOER Call for Climate Guardrails on Everett LNG Contracts* — NetZero Insider

*NY Offshore Wind Plans Implode Again* — NetZero Insider

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

# ISO-NE Decreases Its 10-year Peak Load Forecast

*By Jon Lamson*

ISO-NE is decreasing its peak load projections slightly for the next 10 years due to slower-than-expected electric vehicle adoption, managed charging programs and changes to its modeling of partial building electrification.

The RTO *projects* a 2033 net winter peak of 26,768 MW and a net summer peak of 27,052, it told stakeholders at the NEPOOL Reliability Committee (RC) on April 17. ISO-NE reduced its 2032 projections by 1.8% for the net summer peak and 2.5% for the net winter peak.

The net peak projections include demand reductions associated with energy efficiency and distributed behind-the-meter (BTM) resources. The results will be included in ISO-NE's 2024 Capacity, Energy, Loads and Transmission report.

Both net peak demand and overall net energy have declined significantly in New England over the past two decades due to efficiency efforts and the proliferation of BTM solar. But as the New England states aim to electrify large parts of their transportation and heating sectors, ISO-NE projects load growth to accelerate in the latter part of this decade.

While the New England grid currently reaches its annual peak loads in the summer, ISO-NE anticipates electrification eventually will cause the region's winter peaks to surpass summer peaks.

"Beyond the forecast horizon, by the mid-2030s, electrification is expected to cause winter peak demand to become the typical, prevailing peak season," said Victoria Rojo of ISO-NE.

The increase in the winter peak could be partly mitigated by the warming climate, which is causing milder winter weather in New England — 2023 was the warmest winter on record for the Northeast according to *data* from the National Oceanic and Atmospheric Administration.

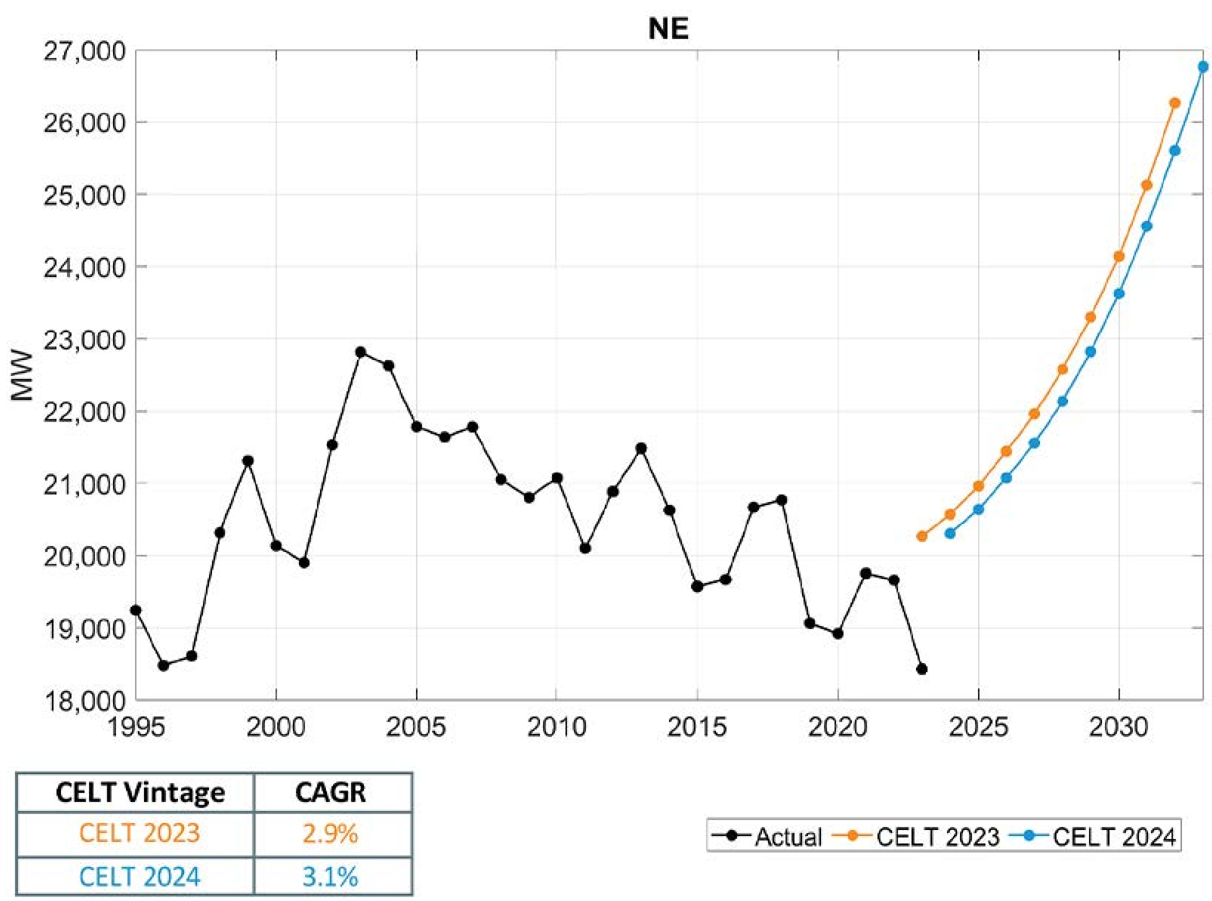
ISO-NE's load projections are based on weather data from the past 30 years and do not consider climate forecasts. Rojo said the RTO hopes to update its methodology to include climate projections in the 2025, 10-year load forecast.

## Distributed Energy Resource Data Collection

ISO-NE also *proposed* a new process to "formalize and standardize the data collection of size, location and characteristics of distributed energy resources."

The proposal would make distribution providers responsible for providing ISO-NE with data about individual DER installations, including size, fuel type, in-service date and location. The RTO currently collects DER data through voluntary disclosures from distribution providers.

Improved DER data collection would bring a range of benefits for the region, ISO-NE said.




ISO-NE net-peak forecast through 2033 | *ISO-NE*

"More accurate forecasts and historical accounting lead to more efficient market outcomes and less uncertainty in system operations and planning," said Dan Schwarting of ISO-NE.

Schwarting added that improved DER data would lead to "more accurate interconnection studies and more efficient/faster study timelines for FERC- and state-jurisdictional generation projects to interconnect to the transmission system."

ISO-NE also intends to develop a database collecting DER data so it can better access and use the data, Schwarting said. The RTO plans to present the RC with a draft procedure in May and aims for a vote in June. ■

## MISO News

# Louisiana PSC Adopts Nearly $2B Entergy Resilience Plan

### *Proposal Approved 4 Days After Submission*

*By Amanda Durish Cook*

State regulators voted 3-2 on April 19 to approve Entergy Louisiana's hotly debated $1.9 billion grid-hardening proposal to be funded by ratepayers, four days after the utility submitted it.

The utility filed the first phase of its Entergy Future Ready Resilience Plan with the Louisiana Public Service Commission on April 15 and requested fast-tracked approval on April 19 during the commission's Business and Executive Session (*U-36625*). The commission issued a supplemental *agenda* to its meeting to consider Entergy's ask.

The quick turnaround elicited criticism from Commissioner Davante Lewis, who expressed concerns that the final draft of the plan wasn't shared earlier with the public and commission staff.

"Like all Louisianans, I would love to see the kind of grid improvements that get us back on track faster after storms, but I need to be certain I am equipped to represent the public, who have no other choice but to buy their power from these companies from month to month," Lewis wrote in a press release prior to the meeting. "Transparent, deliberative decision-making is already difficult to achieve when specifics of this proposal are deemed proprietary and confidential to Entergy's outside contractors."

Lewis also said "substantial details" of the plan "are obscured by contractor confidentiality agreements."

"The public deserves to know more and have the chance to be heard in decisions of this magnitude," he wrote.

The 17 pages of potential transmission and distribution system projects listed in Entergy's filing are nearly illegible (see picture on next page) and provide few specifics on the projects.

Commissioner Foster Campbell joined Lewis in opposition. He said he could not vote in favor of the plan because it assigns the same costs to ratepayers over five years regardless of where they live, and the bulk of storm damages occur in the southern part of the state. He noted his district includes the "poorest place in America."

"I can't in good conscience vote to give them a higher utility bill when I don't think they get a fair share," Campbell said.


Commissioner Davante Lewis (center) speaks against Entergy's grid resilience plan at an April 19 meeting. | *Louisiana Public Service Commission*

Entergy Louisiana insists the resilience plan has not been rushed through the regulatory process and was in the works at the PSC for about a year and a half. Spokesperson Brandon Scardigli said the utility first filed its resilience application in December 2022.

"The record in that proceeding is complete, as the company and intervenors have filed several rounds of testimony and discovery throughout those 16 months, engaging stakeholders and responding to questions and concerns," Scardigli said in an email to *RTO Insider*.

He pointed out that the commission's approval could have Entergy getting a jump on improvements before the Atlantic hurricane season kicks off.

"June 1 marks the beginning of hurricane season — in just 45 days. Now is the time to take the necessary steps to harden Louisiana's electric grid, which will benefit residents and businesses by reducing the cost of future restoration and shortening the duration of outages following storms, allowing Louisiana to get back to normal faster," he wrote.

Entergy did not address *RTO Insider's* request to elaborate on which projects are in the proposal or how they might be prioritized. Scardigli said the plan includes "thousands of projects aimed at reinforcing critical structures on both the transmission and distribution systems."

Prior to the vote, Lewis said taking up Entergy's proposal could create a bad precedent in which utilities don't have to "make good faith efforts" to negotiate with staff or address the public's concerns. He said he received more than 90 emails in a single day from intervenors and constituents asking for more time to understand the proposal.

He said he saw no reason to address Entergy's plan "this month [or] this week." In fact, Lewis said the only reason he could fathom Entergy needing its plan addressed so soon is so it could deliver its shareholders some "good news" during an April 23 earnings call.

Campbell made a failed motion to defer Entergy's application for a month; only Lewis joined him in the vote. Commissioner Eric Skrmetta advanced Entergy's plan for consideration. Commissioners Craig Greene and Mike Francis voted with Skrmetta.

Skrmetta said he spent "an enormous amount

# MISO News

of time" talking with Entergy in recent weeks about the plan, which he said embodies the phrase "an ounce of prevention is worth a pound of cure."

He emphasized that Entergy's plan includes a pole performance metric that stipulates if 150 or more poles fail in a storm they were designed to withstand, a portion of the funds spent on them is returned to ratepayers. He called it "a *de facto* insurance policy" and said the plan is in the best interest of the company and ratepayers.

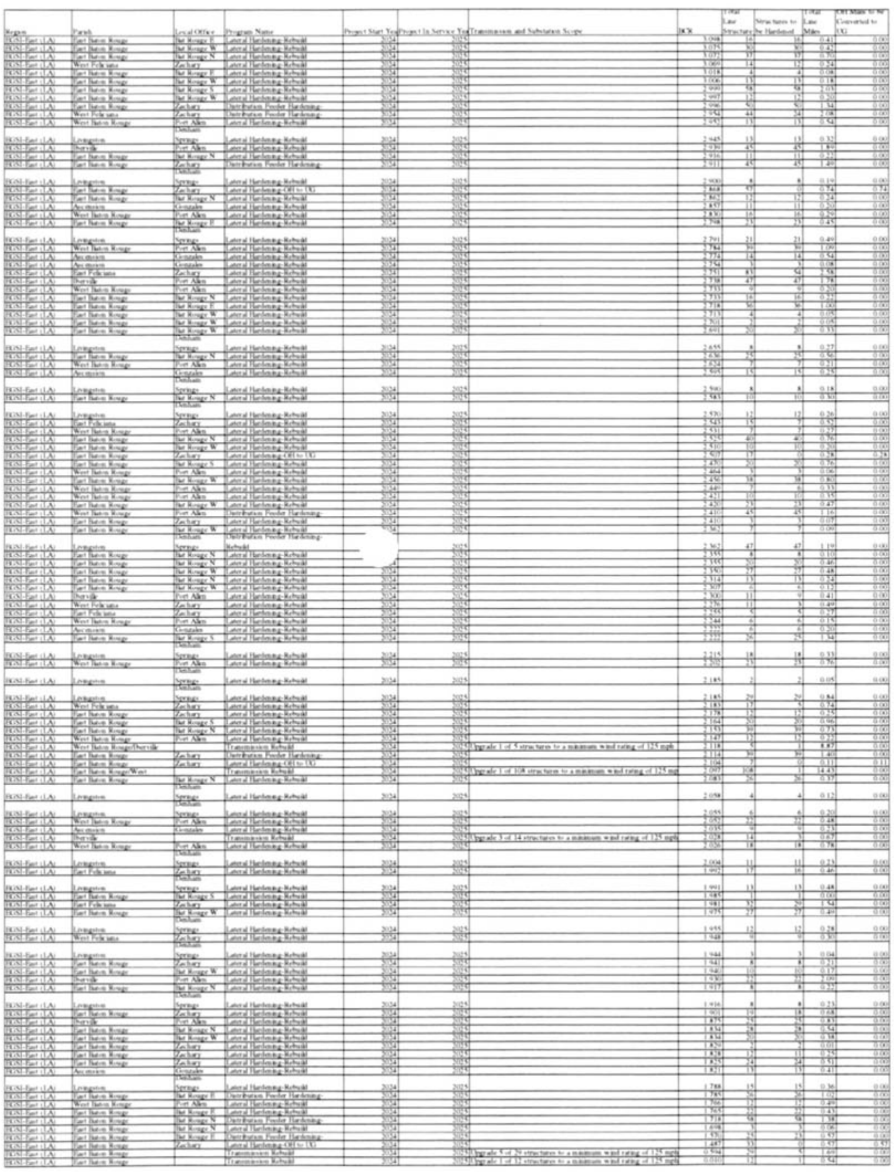
## Public Criticism

Multiple advocacy groups spoke at the meeting to express disappointment at the hasty nature of the request and asked the commission to delay acting on the application.

Lake Charles resident James Hyatt said commissioners are "supposed to be looking out for ratepayers and not for shareholder value." He pointed out that ratepayers still are paying for past storm damage while Entergy's profits increase.

Erin Hansen, representing citizen nonprofit *Together Louisiana*, said decisions that are made "rushed, under the cover of darkness, tend to represent special interests."

"We're here, and we feel a little taken — put upon, if you will — because it looks like there's a giant check that's been written and the PSC is about to sign it, but that check is linked to our bank account," Hansen said.



An illegible list of projects contained in Entergy Louisiana's grid-hardening plan | *Entergy Louisiana*

She said Louisianans want reliability improvements, but Entergy needs to allow time for public understanding. She added that a clear schedule, public input, transparency and examination are not "irritating delays to be pushed through."

"They are an essential part of your responsibility to your ratepayers," she said.

Logan Burke, executive director of the Alliance for Affordable Energy, said that while her organization supports more investments in reliability, "we expected more process."

"Louisianans expect this body, which makes decisions worth billions of dollars, to make them clear-eyed based on facts and in a way that is accessible to the ratepayers who will be impacted. The public's trust depends on that," Burke said.

Burke expressed concern that the plan's intent is not resilience but a "single-minded investment in Entergy's preferred solutions."

## Entergy Defends

Larry Hand, Entergy Louisiana's acting vice president of regulatory and public affairs, said the utility already engaged extensively with parties to the docket to craft the grid-hardening plan. He said Louisiana PSC staff "reigned in" Entergy's original plan.

"I wouldn't characterize this as, 'no one has supported this; no one agrees to it,'" Hand said. He added that the plan "is not something that fell out of the sky and should surprise intervenors."

Hand also stressed that the plan needed expedited treatment before hurricane season but said "he couldn't say" whether construction on any projects would begin prior to the impending storm season. He said the first projects likely would be of assistance during the 2025 hurricane season.

Hand said the average resident will see a peak $7.19/month increase by 2029, which gradually would decrease with depreciation.

Energy Louisiana CEO Phillip May said the plan would facilitate new growth and economic progress in the state.

"While we can't say with certainty that any project will be started before June 1, what we can say is: The state has an enormous opportunity of economic development, and those folks who are deciding whether or not to invest in the state of Louisiana … want to see a sign that their concerns are taken seriously [that] we're going to build a grid that gives them confidence to make those investments," May said. ■

## MISO News

# OMS Taps Minnesota PUC Veteran as Next Executive Director

*By Amanda Durish Cook*

The Organization of MISO States has named Tricia DeBleeckere, current MISO director of state policy and strategy, as its next executive director.

Before her two years at MISO, DeBleeckere spent nearly 14 years at the Minnesota Public Utilities Commission, serving as a commission adviser and analyst and planning director focused on transmission and distributed energy resources integration. While with the commission, she was active in OMS.

Tricia DeBleeckere | *NARUC*

"We are very excited to have Tricia return to the OMS team; she brings a wealth of industry expertise to OMS' work and is already a known asset for many MISO states. Her previous experience working for a state commission, existing relationships with OMS, and her most recent experience at MISO will be an incredible resource for our members," OMS President and Iowa Utilities Board Member Joshua Byrnes said in an April 19 news release. "Tricia brings a deep understanding of how to navigate complex regulatory and stakeholder processes, and her experience, knowledge and thoughtfulness will serve OMS and state commissions well."

DeBleeckere holds a Bachelor of Science from the University of Minnesota and is finishing a Master of Business Administration from the University of Texas Permian Basin. Her new role becomes effective May 8.

"I am truly excited to be working with the OMS team again to ensure we are proceeding through the energy transition in the most cost-effective, reliable and efficient way possible. There are many challenges currently before OMS, state commissions and MISO — with many more to come in the years ahead," DeBleeckere said in a statement.

DeBleeckere, who is based in Minneapolis, will lead the Madison, Wis.-based OMS remotely.

At an April 11 OMS board meeting, Byrnes reported that OMS leadership interviewed four candidates in early April. Michigan Public Service Commission Chair Dan Scripps said OMS was faced with a difficult choice among excellent candidates.

Previous OMS Executive Director Marcus Hawkins left OMS this month to become a commissioner with the Wisconsin PSC. (See *MISO Members Send off OMS Leader Hawkins to Wisconsin PSC*.)

In March, MISO CEO John Bear said Hawkins was leaving a "hole" in OMS leadership but said he was cheered that MISO still can work with him as a Wisconsin Public Service commissioner.

Bear also thanked Minnesota Public Service Commissioner Joseph Sullivan and Byrnes for stepping up to share former OMS President and Wisconsin Public Service Commissioner Tyler Huebner's duties after he was abruptly fired by the state's GOP-controlled Senate. (See *Wisconsin Senate Votes to Fire Commissioner Huebner 4 Years into Job*.)

"It's a critical, critical partnership with OMS," Bear said.

Byrnes said Huebner's exit was "unfortunate" and that he was grateful to learn from him while he had the chance. ■

# MISO News

## Xcel Acknowledges Prairie Island Outage Result of Drilling Accident

*By Amanda Durish Cook*

Xcel Energy has revealed that a lengthy outage at its Prairie Island nuclear plant was caused by workers inadvertently drilling through a bundle of cables last fall.

The company admitted to inadequate supervision of an excavation and a failure to use ground radar to sweep the area at the nearly 1.2-GW Minnesota nuclear plant in an *event report* to the Nuclear Regulatory Commission last month.

Xcel chalked up the severed cables to a "human performance issue" that combined "weakness in the excavation permit approval process as well as … inadequate oversight of the non-nuclear supplemental workers."

"Site personnel reviewing and approving the permit were not adequately intrusive to ensure that all interferences had been properly identified prior to approving the permit," Xcel wrote, adding that its use of ground-penetrating radar prior to the drilling was patchy and wasn't conducted over the DC cable's location.

Xcel also blamed "procedural weaknesses and poor communication" between its departments regarding its supervision of the drilling crew.

The company eventually returned Prairie Island to service in mid-March, two months later than it initially estimated it would have the plant heated up.

According to the *Star Tribune*, Xcel wasn't immediately forthcoming about the cause of the outage, originally framing it as an "equipment issue" between the grid and its turbine.

Xcel said the mishap occurred Oct. 19, 2023, when Prairie Island's Unit 1 was operating at full capacity. Non-nuclear work crews were onsite, performing sideways, underground drilling for a project to replace one of the AC power cables between the substation and the plant when they accidentally drilled through a DC cable bundle containing control cables.

At the time, the plant's second unit already was offline, having been powered down two weeks earlier for refueling and scheduled maintenance.

The boring into the cable caused multiple substation breakers in the switchyard to automatically open, Unit 1's turbine to trip and led to a reactor trip with "a loss of all non-safety related buses," Xcel said. The company said operators responded as intended and safely brought the plant into a hot standby mode.

Xcel reported that when Unit 1 tripped, a pump to maintain spent fuel cooling went offline, but another pump was able to compensate without a rise in temperature.

Xcel said it was forced to replace the damaged control cables before Unit 2 could start up again and since has made "multiple procedure changes … to address the identified gaps and prevent recurrence of this event." It also said no radiological impacts occurred because of the trip and neither its personnel nor the public's health and safety were affected.

In an emailed statement to *RTO Insider*, Xcel spokesperson Kevin Coss said Unit 1 "safely" took itself offline as the plant is designed to do.

Prairie Island nuclear plant in Welch, Minn. | *Xcel Energy*

### Minn. Department of Commerce to Weigh in

Xcel is seeking to recoup from ratepayers the fuel and power purchase costs it was forced to make absent the plant's operation.

The Minnesota Department of Commerce has opened an investigation into Xcel's 2023 nuclear outages. In an April 15 filing in response to Xcel's 2023 fuel clause adjustment charges, the agency said it is wrapping up its probe and will provide written comments and recommendations as to Xcel's 2023 nuclear fuel clause adjustment charges within a month. The department otherwise recommended the Minnesota Public Utilities Commission approve the non-nuclear aspects of Xcel's fuel cost petition (E002/AA-22-179).

The Department of Commerce has questioned why Xcel's unforced nuclear outages were 995.9 GWh higher than forecast in 2023. Xcel attributed the spike to the cable damage that affected both Prairie Island units. However, the company has said the damaged cable bundle itself was aging and risked water damage, which eventually would have led to a Prairie Island shutdown anyway.

"This will now avoid the need for a shutdown of both units at a later date. We also used the fact that both units were offline to invest in long-term upgrades and to conduct additional maintenance activities, all of which sets the stage for the plant to operate reliably into the future," Coss said.

Prairie Island's continued operation factors into Xcel's plan to comply with Minnesota's law to achieve 100% carbon-free energy by 2040. The utility has said it will require 20-year extensions on the two units' operating licenses to keep them operating through the early 2050s. Xcel this year asked for a certificate from the Minnesota Public Utilities Commission to store more spent fuel at Prairie Island in above-ground casks.

The Minnesota Department of Commerce is *soliciting* public comment on the storage expansion at Prairie Island and has scheduled two public meetings this month.

Coss noted that Prairie Island supplies more than 1 million customers in the Upper Midwest with carbon-free energy and is poised to play an important role in achieving Minnesota's mandate. ■

## NYISO News

# NY PSC Launches Grid of the Future Proceeding

### *Maximum Efficiency, Reliability Sought for Flexible Resources amid Transition*

*By John Cropley*

New York has launched a process maximizing the use and effectiveness of flexible tools such as distributed energy resources and virtual power plants.

The Public Service Commission on April 18 initiated the Grid of the Future proceeding (Case *24-E-0165*) to control costs and maximize reliability amid the state's clean energy transition.

The order seeks to establish which capabilities will be needed, set targets for achieving those capabilities, identify the investments needed to reach those targets and identify the benefits that customers would realize when the targets are met.

The Grid of the Future proceeding is the latest step in a process underway for over a decade, beginning with Reforming the Energy Vision (REV) in 2014 (Case *14-M-0101*).

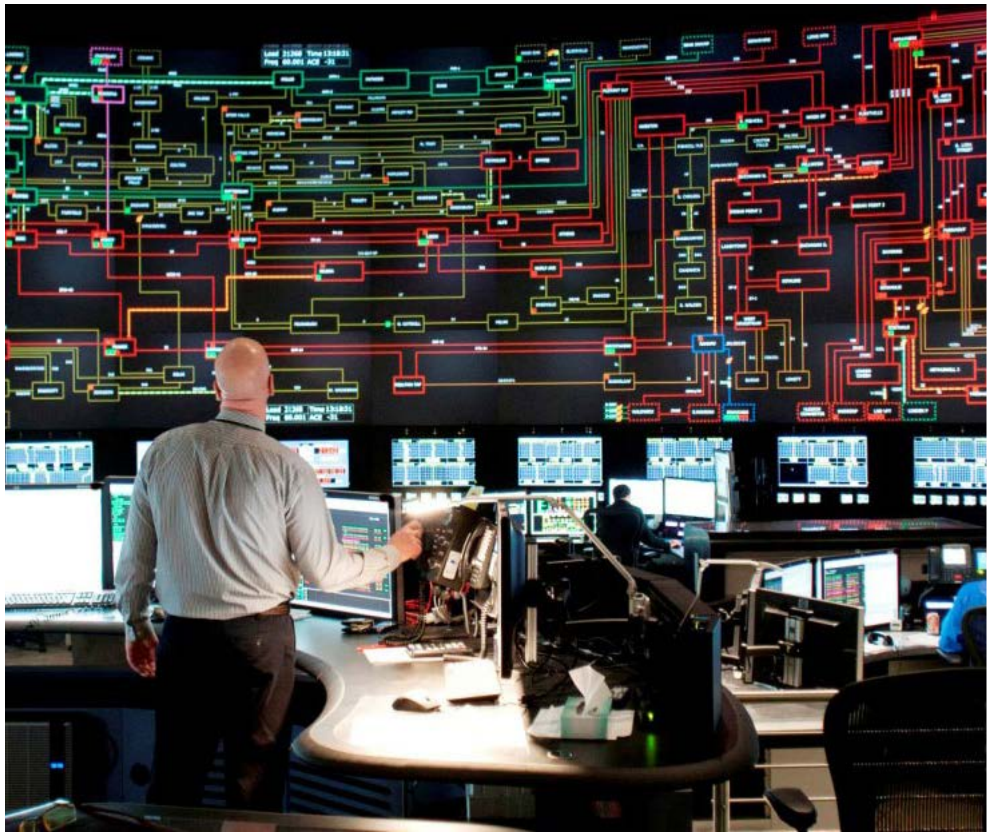
PSC Chair Rory Christian said the process began before any current members joined the commission, and the challenges it was intended to address have come to pass.

"They're the type of challenges to be expected from any 100-plus-year-old system, built under a set of paradigms that are quickly being made obsolete through the progress of technology and evolving societal needs," he said. "Challenges that are further amplified by severe weather events that are increasingly more severe."

The state's landmark Climate Leadership and Community Protection Act of 2019 created a statutory requirement for 70% renewable energy by 2030 and 100% zero-emissions energy by 2040.

The 70-by-30 goal seems increasingly out of reach amid slow regulatory processes and rising costs, but not for lack of effort — state regulators are simultaneously trying to change longstanding power generation and consumption patterns while ensuring the power grid can meet much higher demand with a much more intermittent generation portfolio.

DERs and VPPs are expected to be an important part of a suite of dispatchable emissions-free resources to keep the lights on, and the Grid of the Future proceeding is designed to help move the state to a place where that is possible.



The NYISO control room is shown. The New York Public Service Commission has initiated to develop a Grid of the Future planning process. | *NYISO*

Department of Public Service staff will convene at least one stakeholder conference to inform the process in the second half of this year.

The order directs staff to conduct a Grid Flexibility Study on flexible resources' status and potential by Nov. 15, 2024.

The first iteration of the Grid of the Future Plan is due by Dec. 31, 2024; the second, a year later.

The structure of the plan will evolve with stakeholder input, but initial required elements are:

- An inventory must be prepared of the resources expected to be needed, including how much of each is needed, how they will be obtained and what opportunities or barriers exist to securing them.
- Key elements of distributed system platforms must be identified; new or revised utility distributed system implementation plan requirements must be recommended.
- New or modified compensation plans for flexible resources must be considered, to encourage their best use by customers.
- Customer savings and benefits must be identified through better price signals on utility bills.
- The needs of market participants such as NYISO and utilities must be identified; the opportunity for changing roles and responsibilities for these participants also must be identified, along with improved interoperability among them.
- Changes in technology and information infrastructure must be accounted for.
- Rigid physical and cybersecurity protocols must be included.
- The plan must address variability and flexibility in the need for deployment and use.
- Allocation of costs and benefits among customers must be equitable. ■

## NYISO News

# FERC Approves NYISO's 10-kW Minimum for DERs in Aggregations

*By Michael Brooks*

FERC on April 15 approved NYISO's proposed tariff revisions that set rules for distributed energy resources seeking to participate in its markets, including a 10-kW minimum for individual resources to be included in an aggregation (*ER23-2040*).

The commission sent two deficiency letters in response to the proposal, submitted by NYISO last year, over the 10-kW rule, directing it to provide more explanation for how it decided on that figure and why it would not be unduly discriminatory. (See *NYISO Defends 10-kW Minimum for DER Aggregation Participation*.)

FERC ended up accepting the entirety of the proposal without directing any compliance filings, finding that the ISO had "demonstrated that, at this time and based on the record herein, the 10-kW minimum capability requirement reasonably balances the benefit of enabling NYISO to implement its DER and aggregation participation model immediately against the drawback of maintaining a limited barrier to certain DERs so that NYISO may feasibly enroll and monitor individual DERs in an aggregation and efficiently administer the wholesale markets."

The commission rejected complaints that the rule was contrary to Order 2222, which directed RTOs and ISOs to open their markets to DER aggregations. Although the order did not institute a minimum requirement, it also did not preclude grid operators from instituting one, FERC said.

It also noted that NYISO said the rule was not

| Shutterstock

necessarily permanent and subject to reevaluation. To that end, FERC did order the ISO to submit an informational filing in two years describing its experience administering the new rules and "the estimated effect that the 10-kW minimum capability requirement has had on potential participation, including on the total number of DERs under 10 kW in" New York.

FERC Chair Willie Phillips and Commissioner Allison Clements said in a joint concurrence that although they approved the minimum rule, they did not "arrive at this finding lightly."

They cited the New York Public Service Commission's arguments in its protest that DERs are expected to increase significantly in the next few years based on state policies. "Despite commenters' valid concerns about the potential limiting effect of the 10-kW minimum capability requirement in the future," Phillips and Clements said they based their decision "on the record before us."

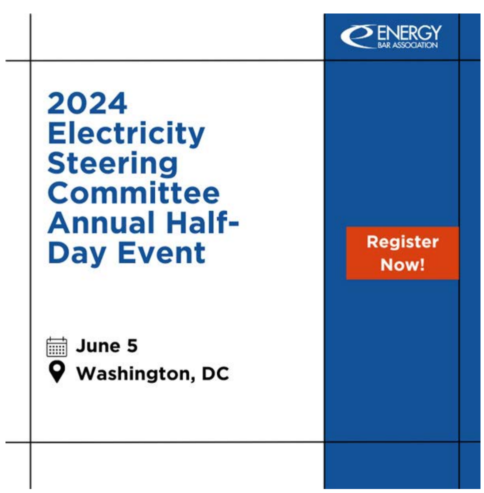
"We find persuasive NYISO's explanation that the 10-kW minimum capability requirement is necessary for NYISO to implement its DER participation model immediately and that the lack of such a requirement would substantially delay rollout of the participation model," they said. "Rejecting NYISO's filing would therefore have significantly delayed DERs' eligibility to participate in NYISO's markets — thereby depriving NYISO and market participants an opportunity to gain valuable experience that can improve the participation model going forward. ...

"We are only now leaving the starting gates in unlocking the potential of DERs to provide reliability value to our grid, but that value will be essential to ensuring we meet new and emerging reliability challenges in the future in an efficient manner that protects customers."

Commissioner Mark Christie issued his own concurrence, a brief and somewhat terse statement that "NYISO — in what can only be described as a 'Groundhog Day' experience — was required to repeatedly explain" its reasoning for the 10-kW minimum. In a footnote, he noted that he "was not consulted nor asked my opinion on the issuance of" the two deficiency letters.

Christie also complimented the ISO for "airing its suspicions that ... '[FERC] may have preferred the NYISO to develop one or more alternatives to its proposal'" and "reminding this commission of its obligations under [Federal Power Act] Section 205 to limit its review to" whether the proposal before it was just and reasonable, and not whether there was a better alternative. ■



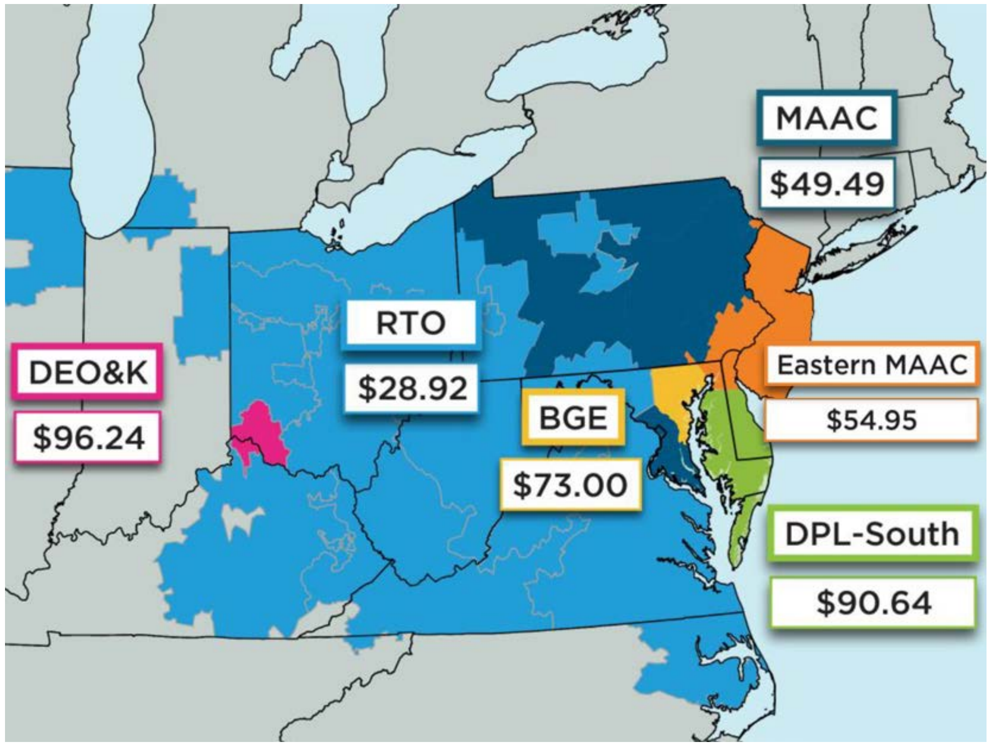



# PJM News

## Stakeholders Spar over PJM Request to Recalculate Capacity Auction Results

*By Devin Leith-Yessian*

Stakeholders filed comments April 11 debating PJM's request that FERC direct it to recalculate the results of the 2024/25 Base Residual Auction and rerun the third Incremental Auction (IA) based on those results, with general support from generators and opposition from state regulators and consumer advocates (*ER23-729*).




PJM capacity prices for delivery year 2024/25 | *PJM Interconnection*

The 3rd U.S. Circuit Court of Appeals in March vacated FERC's order allowing PJM to revise the locational deliverability area reliability requirement for the DPL South zone after the BRA had been conducted but before the publication of its results, finding that it constituted a violation of the filed-rate doctrine.

PJM on March 29 petitioned FERC to order it to use the results that would have been the outcome in December 2022 had it not revised the reliability requirement. It also requested to rerun the capacity period's third IA, completed March 11, arguing that matching the "new" BRA results with those of the IA would be too complicated. (See *PJM Awaiting FERC Response to Court Rejection of 2024/25 Capacity Auction Parameters*.)

The issue stems from PJM identifying a substantial increase in capacity prices because of the interaction between a "misalignment" in resources that offered into the auction and the expected resource pool based on the reliability requirement. The RTO asked FERC to allow it to revise the calculation of the requirement after bids had been received to exclude generators expected to offer that ultimately did not. (See *Capacity Auction 'Mismatch' Roils PJM Stakeholders*.)

PJM requested FERC to act by May 6. It argued that rerunning the third IA would prevent generators that did not clear under the original auction from being assigned a capacity commitment with less than a month to make any preparations necessary to meet their obligations before the start of the delivery year (June 1). Some generators that did not originally clear may also have sold their uncommitted capacity through bilateral transactions, raising the risk that capacity may be double-counted if those resources are picked up should the BRA be rerun with different parameters.

Should the commission decline to rerun the auction or not reach an order by then, PJM presented a "less optimal" alternative of allowing it to relieve market sellers of capacity commitments that both increased through rerunning the BRA and exceed what they reasonably believe they could provide. Market sellers would have seven days to request that PJM relieve them of their capacity obligations, which the RTO expects to be such a small amount that finding replacement capacity would not be necessary. PJM said that option would remain viable until May 22.

"In other words, only a capacity resource that is committed in the recalculated Base Residual Auction to provide more megawatts than it is now capable of providing (due to either bilateral transactions or commitments from the February 2024 third Incremental Auction of capacity not committed under the prior Base Residual Auction results) would be eligible to be relieved of such excess megawatts," PJM explained.

### Consumer Interests Urge Rejection

In a joint protest, several state commissions, consumer advocates and industrial groups *urged* the commission to reject PJM's petition, arguing that rerunning the BRA with the original reliability requirement would increase DPL South consumers' capacity bill by $178 million with little reliability benefit.

They cited informational auction results PJM *posted* April 4, which showed what the December auction results would have been if the requirement had not been modified. Those figures, which PJM's petition proposed using as the new auction results, show an increase in the DPL South clearing price from $90.64/MW-day to $426.17/MW-day, for a regional capacity cost of $288.4 million.

Rerunning the IA would exacerbate the issues that have made commission reluctant to order auctions be reconducted by substantially increasing load-serving entities' and consumers' capacity costs with little time to find ways to lower them, argued the organizations, which included American Municipal Power, the Delaware Division of the Public Advocate, Delaware Energy Users Group, Delaware Municipal Electric Corp., Delaware Public Service Commission, Maryland Office of People's Counsel and Old Dominion Electric Cooperative.

"Rather than proposing to maintain the posted BRA results in light of these problems, PJM doubles down and proposes to rerun the third Incremental Auction. But that will not solve problems; it will instead create even greater disruption," they told FERC. "PJM ... ignores that doing so could adversely impact market participants who have relied in one way or another on the already completed third Incremental Auction."

# PJM News

Instead, they argued FERC should reaffirm that the BRA results PJM posted in February will stand because the commission's obligation to protect consumers outweighs the general presumption that resolving a legal error should revert parties to their standing prior to the error.

"The equities especially disfavor rerunning the auctions in this case, where PJM and one commissioner have acknowledged — and no one has meaningfully disputed — that the new prices reflect an unjust and unreasonable result of using an inflated reliability requirement, at odds with actual reliability needs, that increases capacity charges by more than $177 million, or 160%, with no consumer benefit," the organizations said, referencing Commissioner Mark Christie's concurrence with the commission's order accepting PJM's changes to the auction parameters.

"Indeed, the commission here already balanced the equities when it weighed customers' interest in paying only a just-and-reasonable rate against the generators' allegedly settled expectation of exorbitant rates driven by use of an inflated reliability requirement, and concluded that the former outweighed the latter."

"PJM's proposal would have profound adverse impacts on consumers in the Delmarva peninsula. Granting PJM's proposal would serve only to provide power plant owners an unjustified windfall through massive price increases. It should be rejected," Maryland People's Counsel David Lapp said in a *statement*.

In a *statement* regarding the Maryland Public Service Commission's own *protest*, Chair Frederick Hoover said PJM's proposal would result in "excessive capacity costs" for consumers and replace auction parameters the commission found just and reasonable last year with a flawed market design.

"Allowing PJM to apply the same flawed market design that it has once correctly characterized as being unjust and unreasonable would be unconscionable," Hoover said. "With FERC's acknowledgement of the consequences of a flawed market, PJM already set the fair price for electric capacity well over a year ago. We are asking FERC to require PJM to retain those rates in order to ensure that customers on the Delmarva Peninsula will not be harmed by having to pay for reliability at inflated prices with no economic or reliability justification."

## Generators Supportive of New BRA Results, Divided on IA

The Electric Power Supply Association and PJM Power Providers, which appealed FERC's order to the 3rd Circuit, jointly *supported* PJM's petition, saying that resolving the case before the delivery year begins is imperative.

While they said both routes PJM proposed were acceptable, they preferred leaving the third IA results in place and instead allowing market sellers to ask the RTO to relieve any increased capacity obligations they could not serve. Rerunning the IA could result in unintended consequences by allowing all market participants to adjust their positions after the results of the original IA had been posted, which they said is unnecessary because a smaller number of participants are expected to be affected by the issues PJM is seeking to resolve.

Constellation Energy *supported* PJM's entire proposal, stating that the IA was based on the same parameters the court found invalid and that rerunning it would allow market sellers to adjust their offers to account for changes in the BRA parameters.

"If the BRA results are recalculated but the third Incremental Auction is not rerun, there will be a disconnect between the quantity of capacity procured in the BRA and the quantity needed in the third Incremental Auction" Constellation said. "Additionally, market participants should have a meaningful opportunity to adjust their participation in the third Incremental Auction in light of the recalculated BRA outcome." ■

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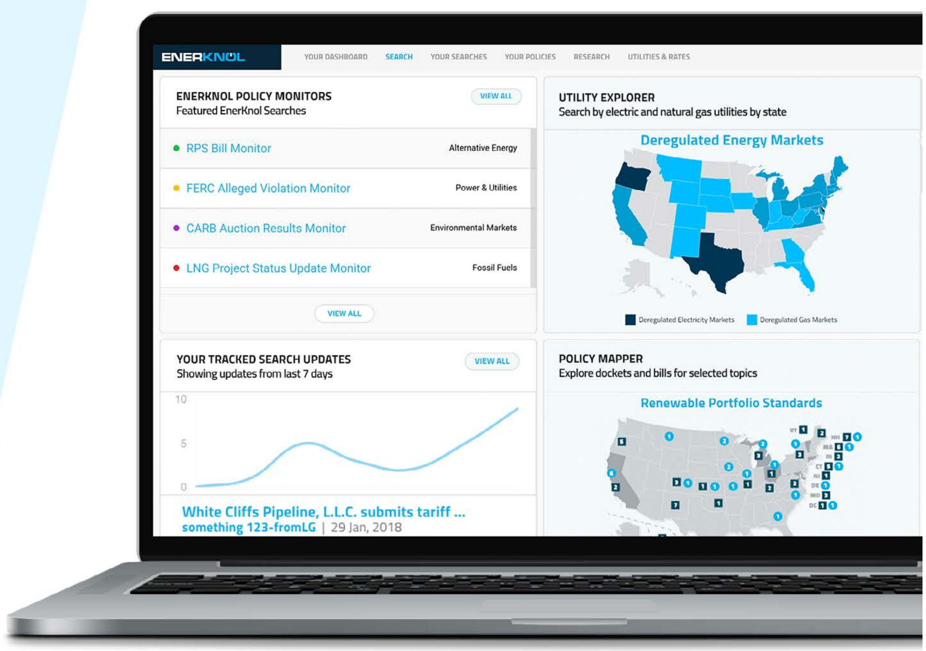


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# PJM News

## PJM Stakeholders Considering Changes to Generation Deactivation Compensation and Timelines

*By Devin Leith-Yessian*

PJM and the Independent Market Monitor presented the Deactivation Enhancement Senior Task Force (DESTF) with two proposals increasing the notification generators seeking deactivation must provide PJM and standardizing compensation for those that agree to continue operating beyond their desired retirement date.

Speaking at the April 15 task force meeting, Monitor Joseph Bowring said that when requesting payment for reliability-must-run (RMR) contracts, generators include a combination of sunk costs and estimated costs in an artificial regulated utility rate case framework that results in significant overcompensation. RMR contracts are needed for generators that want to retire but which the RTO has determined must remain online to maintain reliability for a period that can extend to five years or longer.

Bowring argued the current practice is inefficient and creates uncertainty for all parties as settlement discussions last for years. He said the Monitor's first principle is that compensation rules should be clear and unambiguous. Under the Monitor's proposal, generators would be paid the actual costs the generation owner would incur in keeping the unit online, net of any revenues the unit received through PJM's markets, plus an incentive. There would be a verification process for all such costs.

The proposal would allow generators to include in their RMR compensation: actual maintenance costs; short-run marginal costs, such as fuel and consumables; and new investments needed for the generator to remain available, along with an incentive payment calculated as a percent of incurred costs. Costs related to general overhead, artificial utility rate case elements, and previously incurred capital and inventory costs would not be included.

Generators seeking retirement would be required to notify PJM of their intent six to 12 months in advance of the capacity auction for the delivery year in which the unit would go offline, with the aim of giving other market participants time to offer resources that could resolve reliability needs prompted by the deactivation.

Resources operating on an RMR contract would be dispatched only when required for reliability and would not be included when calculating the capacity emergency transfer objective and capacity emergency transfer limit values, which are inputs used to determine the amount of capacity PJM aims to procure through Base Residual Auctions (BRAs). Market sellers operating on an RMR contract would not receive capacity performance (CP) bonus payments, nor would they be subject to underperformance penalties during emergency conditions. Bowring has argued that including RMR units in the capacity market and resource stack suppresses prices that could incentivize new generation.

Bowring also argued PJM should use the same reliability criteria in defining the demand in the capacity market as it uses to define the need for an RMR contract. Currently, a unit could fail to clear in the capacity market but be deemed necessary for reliability and thus eligible for an RMR contract.

Christian McDewell, of the Pennsylvania Public Utilities Commission, said FERC rejected limiting bonus payments to capacity resources and excluding energy-only resources when it rejected changes to the CP design PJM proposed following the critical issue fast path process (*ER24-98*). (See *FERC Rejects Changes to PJM Capacity Performance Penalties*.)

Bowring said consumers shouldn't have to pick up all the costs of keeping a fuel production facility operational in addition to the marginal costs to keep the generator online. He added that potential interactions between RMR compensation and fuel procurement warrant further stakeholder consideration.

Responding to stakeholder questions of whether PJM should be granted the ability to mandate RMR contracts, Bowring said he believes that would be unnecessary if the RMR design ensures contracts provide appropriate revenues for generators contemplating deactivation. Bowring stated that compensation should be the same in both cases and cover all actual costs of being an RMR unit plus an incentive.

### PJM Proposal Centers on Notification Deadlines

The PJM package focuses more heavily on the notification requirements for deactivation and leaves compensation changes for further stakeholder deliberation. The proposal groups deactivation requests into three classifications based on the energy that would be brought offline: Requests larger than 300 MW would be required to provide notification three years in advance of their desired deactivation date; units between 100 MW and 300 MW would require one year's notice; and those under 100 MW would follow the status quo 90-day period.

The notification period could be curtailed under PJM's proposal if the capacity auction for the delivery year in which the resource would go offline is after the notification deadline. In such cases, generators could submit a deactivation request before the deadline for them to offer into the BRA.

Generators also would be permitted to retire earlier if PJM finds no reliability violations from by taking the unit out of service ■.

Monitoring Analytics President Joe Bowring | *© RTO Insider LLC*

# PJM News

## PJM and Monitor Seek to Revise Reserve Requirements and Dispatching

*By Devin Leith-Yessian*

The Reserve Certainty Senior Task Force (RCSTF) is considering two proposals from PJM and the Independent Market Monitor aimed at improving the performance of reserve resources.

Stakeholders have been tackling reserve performance since the response rate for committed resources has fallen after a market redesign consolidated the Tier 1 and 2 synchronized reserve products and lowered the offer cap from $7.50/MWh to 2 cents. (See "Stakeholders Reject PJM Synch Reserve Manual Change; RTO Overrides," *PJM MRC/MC Briefs: May 31, 2023*.)

The PJM *package* would allow operators to modify the procurement targets for 30-minute reserves without having to do so for synchronized and primary reserves and create a formula for dynamically changing the 30-minute reliability requirement, PJM's Emily Barrett told the RCSTF during its April 17 meeting. The calculation would use the larger of the primary reserve requirement, the largest active gas contingency and the average load forecast error, plus the average forced outage rate. The requirement is set at 3,000 MW, which was double the largest contingency when the requirement was established.

The changes would align the 30-minute reserve requirement with the breadth of operational risks dispatchers face and would grant flexibility to increase those reserves during periods of increased risks, such as harsh weather conditions, Barrett said.

PJM's Lisa Morelli said staff will draft manual language and more details to present to stakeholders for a potential first read during the May 15 RCSTF meeting, with the intention of holding a vote June 12.

### Monitor Focuses on Communications

The Monitor's *proposal* would focus on getting reserve dispatch signals to generators in a manner that they can act on as quickly as possible. Joel Luna, of Monitoring Analytics, said the Monitor and PJM have been speaking with generation owners about the root causes of poor reserve performance since last spring and found that lags in communication can lead to generators not initiating their response until minutes after PJM has begun a reserve deployment.

Pointing to a synchronized reserve event Feb. 24, 2024, Luna said about 61% of the 1,882 MW resources deployed did not meet their assignment, of which he said 1,041 MW underperformed due to communication issues. Some units were waiting for a phone call from PJM to confirm their deployment. Others experienced lag between when the all-call signal was initiated by PJM and when it was received on their end due to how those generation owners relay signals between their control centers. And some experienced lag from the required switch to manual ramp from automatic dispatch signal.

The Monitor's proposal would replace all phone communications used to convey deployment orders with automatic electronic signals and would include the deployment MW generators are being assigned through the existing security constrained economic dispatch (SCED) signals.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said many generators are being asked to run at a loss when providing reserves and compensation needs to be addressed alongside the communication issues.

"Prices need to reflect the system conditions, and clearly that's not the case here," he said.

Tom Hyzinski of the GT Power Group said adopting the Monitor's recommendations could resolve some of the issues in the reserve market and clear the air to simplify addressing any remaining design issues. So long as all other options remain on the table should the proposal be endorsed, he argued there are no downsides to advancing the Monitor's changes. ■


Lisa Morelli, PJM | © *RTO Insider LLC*


## Mid-Atlantic news from our other channels

*New Jersey BPU Picks 8 Grid-scale Solar Projects Totaling 310 MW*

NetZero Insider

*NJ Creates Green Bank to Support Clean Energy Goals*

NetZero Insider

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

## SPP News

# FERC Conditionally Accepts OG&E Rate Filing

FERC on April 19 conditionally accepted Oklahoma Gas and Electric's (OG&E) proposed formula rate template revisions effective Jan. 1, 2024, as requested. The commission also directed OG&E to submit a compliance filing within 30 days of the order (*ER24-722*).

The commission found several errors and inconsistencies in OG&E's proposed worksheets and formulas. It said the inclusion of populated plant balances, depreciation expense and revenue requirement for SPP allocation were not shown to be just and reasonable and ordered the company to remove the data in the compliance filing.

OG&E filed the revisions in December. It requested a waiver of the commission's 60-day prior notice requirement so an effective date of Jan. 1, 2024, could be set. The company said allowing the proposed changes to take effect at the beginning of the rate year would avoid a midyear formula rate change and simplify the future calculation of the true-up adjustment.

Western Farmers Electric Cooperative, Arkansas Electric Cooperative Corp. and Oklahoma Municipal Power Authority, all OG&E customers, protested the filing. They argued the company did not provide sufficient information to back up its claim that the formula rate changes were "exclusively ministerial."

FERC disagreed, finding the revisions are just and reasonable, pending OG&E's compliance filing.

FERC has conditionally accepted OG&E's latest rate revisions. | *OG&E*

"We find that the revisions ... are ministerial in nature and do not change the methodology by which the rate is calculated and will have no effect on rates," the commission said. It noted the revisions will make the formula rate template easier for interested parties to review during the annual update process. ■

*— Tom Kleckner*



# Company Briefs

### Tesla to Lay off 10% of Workforce After Dismal Quarterly Sales

According to multiple reports, Tesla plans to lay off about a tenth of its workforce as it tries to cut costs following dismal first-quarter sales.

CEO Elon Musk detailed the plans in a memo sent to employees. The layoffs could affect about 14,000 workers.

More: *The Associated Press*

### NYISO Appoints Michael Crowe to Board of Directors

NYISO on April 16 announced its selection of Michael Crowe to its board of directors, effective the same day.

Crowe has 39 years of experience in software development, IT infrastructure and cybersecurity with several private-sector entities. From 2014 through 2022, he served as the chief information officer for Colgate-Palmolive.

More: *NYISO*

### Copenhagen Infrastructure Partners Acquires NY Onshore Wind Portfolio

Copenhagen Infrastructure Partners (CIP) on April 15 announced it has acquired Liberty Renewables, a 1.3-GW portfolio of onshore wind projects in New York.

Liberty's inaugural project, Hoffman Falls Wind, is scheduled to begin construction in 2026. The remaining projects are expected to start construction between 2027 and 2030.

More: *North American Windpower*

### Nova Clean Energy Acquires 1 GW Wind, Solar Portfolio in Texas

Nova Clean Energy on April 17 announced it has acquired a 1-GW wind and solar development portfolio from BNB Renewable Energy.

The portfolio on the Texas Gulf Coast, known as HyFuels, also includes an early-stage green ammonia project. Financials of the transaction were not disclosed.

More: *Power Technology*

# Federal Briefs

### SCOTUS: Companies' Disclosure Omissions Aren't Securities Fraud

The U.S. Supreme Court on April 12 ruled that shareholders can't sue companies under federal fraud law for not disclosing information about future risks unless the omission makes another statement misleading.

The court sided with Macquarie Infrastructure in a lawsuit filed by Moab Partners back in 2018. Moab sued Macquarie for not disclosing that its revenue was vulnerable to a phaseout of high-sulfur freighter fuel between 2016 and 2018.

A ruling the other way could have raised company executives' concerns about the SEC's paused climate disclosure rules, which leave it to companies to determine what information is material and thus should be disclosed.

More: *Axios*

### BLM Approves Dry Lake East Energy Center Solar Project in Nevada

The Bureau of Land Management on April 19 approved the 200-MW Dry Lake East Energy Center Solar Project in Clark County, Nev.

The project, which will sit on 1,635 acres of public land, will provide up to 600 MW of storage.

More: *BLM*

### Climate Task Force to Address Trade, Manufacturing Emissions

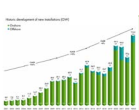
The U.S. will create a trade task force aimed at reducing carbon emissions from global commerce and manufacturing, White House senior adviser **John Podesta** said April 16.

The task force will focus on addressing carbon leakage, carbon dumping and emissions associated with upstream manufacturing and production. It will also ensure carbon emissions data is available for implementing national climate and trade policies.

More: *Reuters*

## National/Federal news from our other channels

*BNEF Summit Focuses on Financing Energy Transition, Fast and Slow* — NetZero Insider



*Wind Energy Development Set Records Worldwide in 2023* — NetZero Insider

*Industry Approves NERC's Cyber Monitoring Standards* — ERO Insider

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

# State Briefs

## REGIONAL

### NARUC Executive Director Greg White Announces Retirement

NARUC Executive Director Greg R. White on April 15 announced plans to retire at the end of 2024.

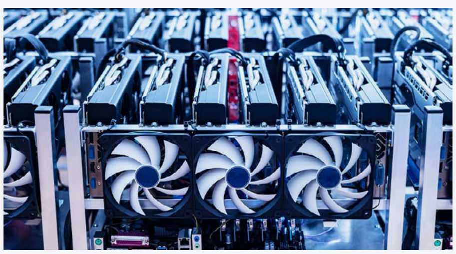
"It's been my greatest privilege to work alongside the incredibly talented and dedicated staff at NARUC, both past and present, including the team at NRRI. They are simply the best and I thank them all," White said.

White assumed his position with NARUC in December 2015.

More: *NARUC*

## ARKANSAS

### Lawmakers Advance Crypto Mining Resolutions



The House Select Committee on Rules on April 16 authorized the House of Representatives to consider allowing the introduction of bills to regulate cryptocurrency mining during the fiscal session.

The committee approved eight resolutions amending the Arkansas Data Centers Act of 2023, which limited the state's and local governments' ability to regulate crypto mining operations.

The Senate cleared the way for lawmakers to take up crypto-related legislation when it approved resolutions last week.

More: *Arkansas Advocate*

## FLORIDA

### Hillsborough Greenlights Carbon Capture Proposal

Hillsborough County commissioners on April 17 voted 5-2 to approve a carbon capture pilot program.

The decision authorizes LowCarbon to build a facility that will capture 1 ton of carbon dioxide daily from the county's waste-to-energy plant in Brandon.

At the end of the trial period, commissioners may choose to move forward with a larger, permanent facility and will open bids to the company and others like it.

More: *Tampa Bay Times*

### JEA Board Hires Vickie Cavey as Interim CEO

The JEA Board of Directors on April 15 voted to name former administrator Vickie Cavey as the utility's interim CEO.

Cavey left retirement in March when the board hired her as its adviser and staff liaison to JEA administrators.

Cavey will replace Jay Stowe, who agreed to part ways following discussions about how the utility will move forward .

More: *Jacksonville Florida Times-Union*

## GEORGIA

### PSC Approves Georgia Power to Use Fossil Fuels to Power Data Centers

The Public Service Commission on April 16 approved Georgia Power's updated plans to significantly expand its generation capacity by investing in fossil fuels and adding more renewable energy over the next several years.

The plans include building natural gas or oil-burning generators and solar battery energy facilities to meet increasing demands from data centers and other large industrial users in the next decade. It will also allow Georgia Power to bypass the normal construction bidding process at Plant Yates to quickly construct units designed to produce electricity for another 40 years.

Georgia Power projects the updated plans will save the typical residential customer about $2.89 on their monthly bills from 2026 to 2028.

More: *Georgia Recorder*

## KANSAS

### Douglas County Approves Solar Farm Permit

The Douglas County Commission on April 13 unanimously voted to approve a permit for the Kansas Sky Energy Center, a massive solar farm to be built north of Lawrence.

The 159-MW solar farm will be built, owned and operated by Evergy.

Commissioners noted that a lot of community concerns discussed were not factors required in considering approval of the permit.

More: *The Lawrence Times*

## LOUISIANA

### Top Employees at DEQ Resign in Clash with Leader

Four officials named to prominent positions at the Department of Environmental Quality have left after clashing with Republican Gov. Jeff Landry's appointee to the agency's top job, Aurelia Giacometto, according to documents and interviews with senior aides.

Chandra Pidgeon, undersecretary at the Office of Management and Finance, along with Communications Director Megan Molter, Chief of Staff Justin Crossie and Director of External Communications Myles Brumfield have all resigned since Giacometto began in November. A redacted version of Pidgeon's resignation letter was later released.

Senior officials who remain at the DEQ and spoke on condition of anonymity said the agency is also in turmoil over Giacometto's insistence on pre-approving contact made by employees with individuals in other state agencies, federal agencies, businesses and industries, and nongovernmental organizations.

More: *The Advocate*

## MAINE

### Lawmakers Reverse Course, Pass Sand Dune Plan for OSW Port

The House of Representatives on April 17 voted 77-65 to approve a proposal from Gov. Janet Mills (D) exeppmting the Sears Island offshore wind terminal from coastal sand dune protections.

The decision to agree with the Senate in supporting the governor's bill was a dramatic change following the House's initial 80-65 vote to oppose it.

State officials have noted various environmental impact studies and permits are still needed before construction begins on the port.

More: *Bangor Daily News*

## MASSACHUSETTS

### Boston Appoints Chief Climate Officer

Boston Mayor **Michelle Wu** on April 17 appointed city hall veteran Brian Swett as the city's first chief climate officer. He will begin in June.

Swett served as Boston's chief of environment, energy and open space from 2012 to 2015 and is a principal at Arup, a global engineering, design and consulting firm focused on sustainable development.

Swett will lead the Environment, Energy and Open Space cabinet, which includes the Environment Department, the Parks and Recreation Department, the Office of Historic Preservation and the Office of Food Justice.

More: *WBUR*

## MINNESOTA

### Xcel Drops Rate Fight with PUC

Xcel Energy is no longer appealing the Public Utility Commission's decision to limit a crucial profit measure after dropping part of its lawsuit against the regulator.

Xcel dropped a central part of its lawsuit against the PUC, which in June granted a 9.6% rate increase through three years that fell short of Xcel's 10.2%. Xcel had fiercely contested the ruling and its limit on return on equity, saying it would hamper the company's transition away from fossil fuels.

Xcel did not withdraw its lawsuit entirely. The utility is still challenging aspects of the PUC ruling, including a limit on how much it can make customers pay for top executives' salaries.

More: *Star Tribune*

## PENNSYLVANIA

### Judge Orders PUC to Turn over Reports Regarding West Reading Explosion

A federal judge on April 16 ordered the Public Utilities Commission to turn over unredacted inspection reports to the National Transportation Safety Board regarding UGI Utilities.

UGI Utilities operates the natural gas pipeline involved in a fatal explosion at a West Reading chocolate factory in March 2023. Initial findings have shown the blast was caused by a natural gas leak.

The PUC refused to provide the documents, saying in September it cannot share the material because it is considered confidential security information. The NTSB issued a subpoena for the records and asked a federal judge to order the PUC to comply with it.

More: *Reading Eagle*

## TEXAS

### CEQ Fines Freeport LNG for Environmental Breaches

The Commission on Environmental Quality on April 16 fined liquefied natural gas exporter Freeport LNG $152,173 for violating state air pollution emissions rules between 2019 and 2021.

The CEQ said Freeport LNG had released more carbon monoxide, hydrogen sulfide, nitrogen oxides, sulfur dioxide and volatile organic compounds than allowed over several years from flaring at its Quintana, Texas, plant.

More: *Reuters*

## VIRGINIA

### Dominion Energy Launches RFP for Solar, Storage Projects

Dominion Energy on April 15 announced it is seeking proposals for solar, wind and energy storage projects in the state.

Dominion will accept five types of proposals, including new solar PV projects and new PV solar generation co-located with energy storage. It will also look at new onshore wind, onshore wind co-located with energy storage and standalone energy storage.

The projects will help the utility reach its goal of net zero greenhouse emissions by 2050, part of which is deploying 3.1 GW of energy storage by 2035.

More: *Energy Storage News*

## VERMONT

### Supreme Court: PUC Failed to Follow Rules in VGS Pipeline Case

The state Supreme Court on April 17 said the Public Utility Commission didn't follow its own rules when enforcing penalties against Vermont Gas during the construction of the Addison County pipeline.

Despite making "substantial changes" not approved under the project's original Certificate of Public Good, the PUC allowed the company to amend the permit. In its ruling, the Supreme Court sided with opponents of the project, finding the PUC failed to conduct the proper public input process.

More: *WCAX*

## WISCONSIN

### We Energies, WPS Apply for Rate Hikes

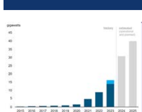
We Energies and Wisconsin Public Service — both owned by WEC Energy Group — filed applications April 12 with the Public Service Commission to increase electric and gas rates in 2025 and 2026.

We Energies hopes to increase electric rates 6.9% in 2025 and 4.6% in 2026, according to the application. It also requested increases for both its gas utilities. Wisconsin Public Service requested an 8.5% electric rate increase in 2025 and a 4.9% increase in 2026. WPS also requested gas rate increases of 6.8% next year and 3.9% in 2026.

The PSC will hold public hearings on the cases later this year and could decide by November.

More: *Wisconsin Public Radio*

## National/Federal news from our other channels



*DOE Urges Utilities to Embrace 'Holistic' Reliability Solutions*

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