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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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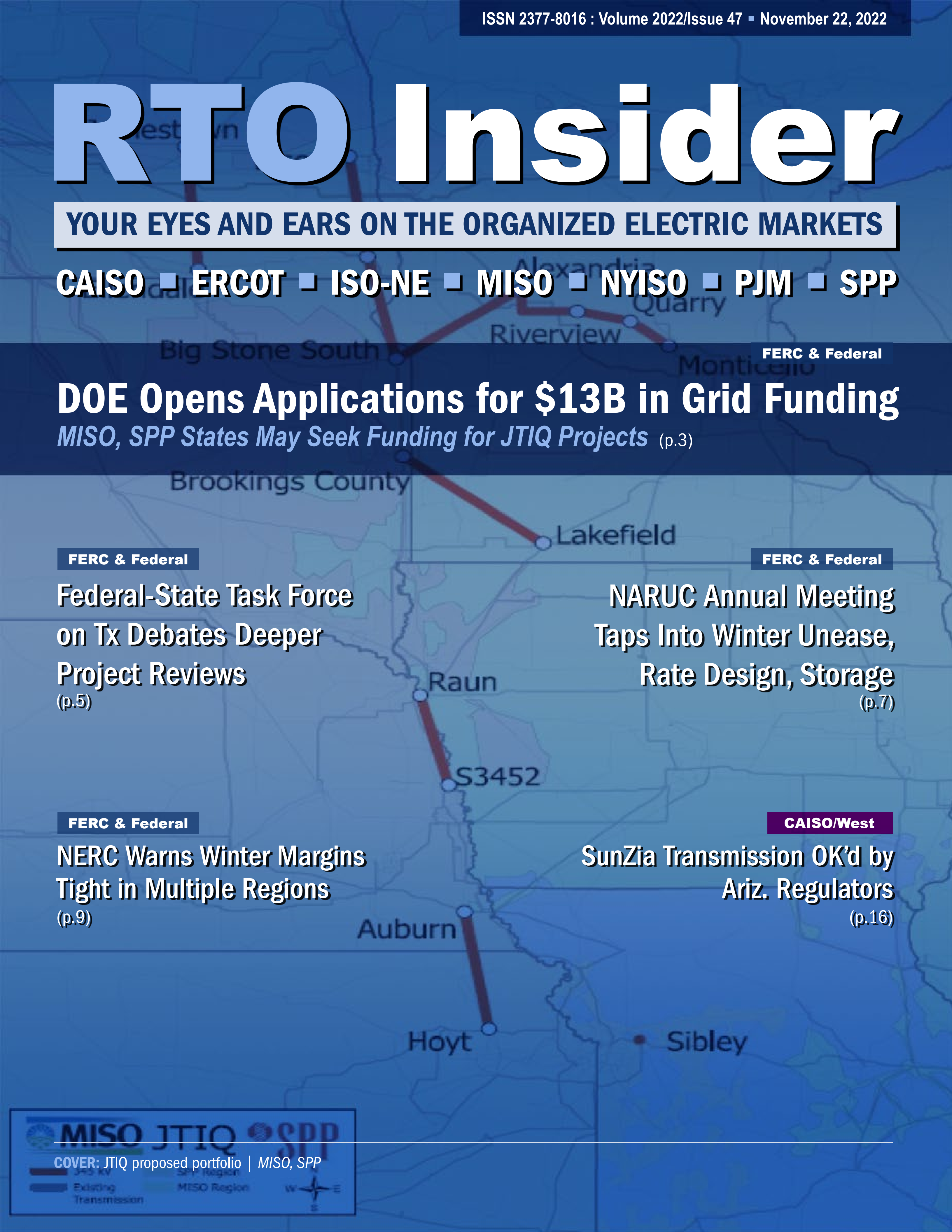

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DOE Opens Applications for $6B in Grid Funding

MISO, SPP States May Seek Funding for JTIQ Projects

By Rich Heidorn Jr.

The Organization of MISO States and the SPP Regional State Committee are discussing seeking federal funding for some of the Joint Targeted Interconnection Queue (JTIQ) projects. | *MISO, SPP*

The Biden administration last week *invited* applications for more than $6 billion in funding to expand and modernize the U.S. electric grid, opening the first round of transmission loans and grants under the Infrastructure Investment and Jobs Act (IIJA).

The Grid Resilience Innovative Partnership (GRIP) and Transmission Facilitation Program represent the largest single direct federal investment in transmission and distribution, according to the Department of Energy.

All told, the administration plans to invest more than $20 billion under its *Building a Better Grid Initiative*, which seeks to identify national transmission needs to reach President Biden's goal of 100% clean electricity by 2035 and a zero-emissions economy by 2050. DOE cited estimates that the U.S. needs to expand the grid by 60% by 2030 and may need to triple capacity by 2050 to decarbonize the economy. (See *Industry Welcomes DOE's Better Grid Initiative*.)

GRIP

Under GRIP, DOE opened applications for $3.8 billion for fiscal years 2022 and 2023 to improve grid flexibility and resilience against extreme weather and climate change. The IIJA allocated $10.5 billion in total for:

- **Grid Resilience Utility and Industry Grants** ($2.5 billion), to fund transmission and distribution technology solutions against wildfires, floods, hurricanes, extreme heat, extreme cold, storms and other hazards to the power system. Among those eligible to apply are "electric grid operators, storage operators, generators, transmission owners or operators, distribution providers and fuel suppliers."
- **Smart Grid Grants** ($3 billion), intended to increase the "flexibility, efficiency, reliability and resilience" of the power system, with particular focus on increasing transmission capacity, preventing faults that can cause wildfires and integrating renewable energy, electric vehicles and electrified buildings. DOE will accept applications from state and local governments, tribal nations, universities, and for-profit and nonprofit entities.
- the **Grid Innovation Program** ($5 billion), which will provide financial assistance to states, tribes, local governments and public utility commissions to "collaborate with electric grid owners and operators to deploy projects that use innovative approaches to transmission, storage and distribution infrastructure" to improve resilience and reliability.

"DOE believes there are significant benefits to be realized by coordinating the implementation of the three [IIJA] programs focused on power sector infrastructure, grid reliability and resilience," it said.

Applicants must submit "concept papers" for the Grid Resilience Utility and Industry Grants and Smart Grid Grants by Dec. 16, with concept papers for the Grid Innovation Program due Jan. 13, 2023. A public *webinar* to provide more information will be held on Nov. 29.

Transmission Facilitation Program

The *Transmission Facilitation Program* is a revolving fund to help attract private investments into large-scale new transmission, upgrades of existing transmission lines and microgrids.

The IIJA authorized DOE to borrow up to $2.5 billion to prime the pump for new transmission and expansions that otherwise would not get built.

DOE will purchase up to 50% of the capacity of such projects, serving as an anchor tenant to attract other customers. "By initially offering capacity contracts to late-stage projects, DOE will increase the confidence of additional investors and customers and reduce the risk of project developers under-building or under-sizing needed transmission capacity projects," DOE said.

Applications for the *first phase* are due Feb. 1, 2023. A public *webinar* will be held on Nov. 30.

Applications will be judged based on two equally weighted criteria: that a project is "unlikely to be constructed in as timely a manner or with as much transmission capacity" without

FERC/Federal News

the capacity contract and that DOE's proceeds from capacity sales will recover the cost of its contracts.

The IIJA funding is in addition to the Inflation Reduction Act's $3 billion in transmission funding, including $2 billion that DOE said "will unlock additional billions in federal lending for projects designated by the secretary of energy to be in the national interest."

MISO, SPP Eye JTIQ Projects

Marcus Hawkins, executive director of the Organization of MISO States, said OMS is discussing with the SPP Regional State Committee seeking funding for the Joint Targeted Interconnection Queue (JTIQ) projects, a $1 billion portfolio of transmission between MISO and SPP.

"I'm sure individual PUCs will also apply for funding for other types of projects, but the JTIQ projects are the only ones I have direct knowledge of," Hawkins said in an email.

MISO spokesman Brandon D. Morris confirmed the RTO's interest in the funding, saying five projects in the JTIQ portfolio may be candidates. "These projects span seven states (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota and South Dakota) and seem to align with DOE's priorities," Morris said.

CAISO, SPP, NYISO and ISO-NE said they were reviewing the funding opportunity but otherwise declined to comment. The Organization of PJM States Inc. and the New England Power Generators Association also declined to comment. PJM and ERCOT did not respond to requests for comment. The Edison Electric Institute, the Independent Power Producers of New York and the Electric Power Supply Association also did not respond to queries.

"While each of these programs is targeted to address specific problems and solutions, I think the biggest benefit from these programs is that collectively they reduce the overall cost to consumers of getting needed transmission infrastructure built and put into service and ultimately will lower the impact on individual customer bills," said Larry Gasteiger, executive director of transmission trade group WIRES.

Beyond the federal funding, Gasteiger said, "we need a moonshot effort to build more transmission on a faster timetable than we have ever built before at all levels, including interregional, regional and local transmission."

About 70% of the grid is more than 25 years old, according to DOE. Gasteiger said much of the nation's aging transmission is at the local level. "Yet there seems to be a glaring disconnect between the White House and DOE on the one hand and FERC on the other as to the importance of addressing those local transmission needs. Too much of FERC's focus is on efforts that are likely to discourage or inhibit the development of needed local transmission." (See *Transmission Owners, RTOs Defend Planning, Cost Control Practices*.)

DOE Criteria

DOE laid out the priorities for GRIP in its 140-page *funding opportunity announcement*, citing "insufficient development of projects" to increase transfer capacity between regions, reduce increasing interconnection queue times or increase the supply of "geographically and technologically diverse" resources to improve resource adequacy and reduce correlated generation outages.

It noted that the U.S.' largest electric utilities have been investing more than twice as much in their distribution systems as in their transmission systems.

"Investments should prioritize driving innovative approaches to achieving grid infrastructure deployment at scale where significant economic benefits to mitigate threats and impacts of disruptive events to communities can be attained," it added. "DOE is looking for proposals that will leverage private sector and non-federal public capital to advance deployment goals. These efforts will be aligned with state, regional or other planning activities and goals. As state resilience plans continue to be updated annually and evaluate future risks, DOE is interested in how federal funds will leverage industry investments towards hardening their system and/or advancing innovative solutions to enhance system resilience."

Among the technologies it cited as candidates were "adaptive storage deployment, microgrid deployment, and the undergrounding of distribution and transmission lines."

It also made a plug for grid-enhancing technologies (GETs), noting real-time congestion costs in CAISO, ERCOT, ISO-NE, MISO, NYISO and PJM totaled $4.8 billion in 2016. Deploying three GETs nationally — advanced power flow control, dynamic line ratings and topology optimization — could save $5 billion in annual energy production costs, "with upfront investment paid back in just six months, and double the amount of renewables that can be integrated into the electricity grid prior to building new large-scale transmission lines," it said.

DOE also said it would welcome applications to help grid operators quickly rebalance the electrical system with autonomous controls through data analytics, software and sensors.

Funding also will be available to appliance manufacturers who spend money on giving their products the ability to engage in smart grid functions and utilities that install smart grid monitoring and communication devices.

DOE urged applicants to team up with a wide range of stakeholders, including grid operators, technology vendors, system integrators and community leaders.

And in case there was any question, DOE said it will reject applications "for proposed technologies that are not based on sound scientific principles (e.g., violates the laws of thermodynamics)." ■

The Biden administration is hoping to encourage more large-scale transmission like the 5,000-MW Greenlink West project, a 525-kV line that would run 350 miles from Las Vegas to Yerington, Nev. | *NV Energy*

FERC/Federal News

Federal-State Task Force on Tx Debates Deeper Project Reviews

By Amanda Durish Cook

NEW ORLEANS — The Joint Federal-State Task Force on Electric Transmission's fifth meeting since its inception last year featured dialogue on local project review, cost management and FERC's Notice of Proposed Rulemaking on regional transmission planning, cost allocation and cost containment (*AD22-8*). (See *States Urge More Transparency on Tx Planning, Independent Monitors*.)

FERC Chairman Richard Glick opened the task force's discussion Nov. 15 during the National Association of Regulatory Utility Commissioners' annual confab by noting there is a lot of "costly" transmission on the horizon.

"So, we need to make sure that consumers get the best bang for their buck," he said.

Jason Stanek, chair of the Maryland Public Service Commission, said that even if the task force already had managed to achieve consensus on a planning approach and cost allocation methodology, cost management and project review would still be issues.

"What I've been hearing is something is lacking; something is missing in this process," FERC Commissioner Willie Phillips said of transparency in proposing and reviewing local transmission projects.

Phillips said it's "interesting" that states seem unable to replicate the results of utility planning studies, especially since FERC requires them to do so.

Glick said the depth and breadth of regulatory gaps depend on the type of project and whether they're located in an RTO. But he said a great number of local projects don't appear to have a "sufficient level of review."

FERC Chairman Richard Glick (left) and Maryland PSC Chairman Jason Stanek | © *RTO Insider LLC*

"It's not easy to determine whether a decision is right, especially when there's a lack of transparency in the process," he said.

Pennsylvania Public Utility Commissioner Gladys Brown Dutrieuille said only projects 101 kV and above that require new siting are subject to intensive review in the state. She said over the last several years, her commission has seen big increases in smaller and rebuild transmission projects that are handled by staff and don't require a thorough review.

California Public Utilities Commissioner Darcie Houck said that most of PG&E's billions of dollars in planned projects through 2026 will fall under CAISO's category of self-approved projects that bypass review.

"We're seeing the same trends," Michigan Public Service Chairman Dan Scripps said. He admitted that he isn't yet sure who should provide project oversight and said it might be some combination of FERC, the states and grid operators. He also said should the federal agency introduce independent transmission monitors, it should take care to make sure it doesn't slow project development.

Phillips said FERC also must ensure that an independent transmission monitor doesn't create an incentive for utilities to leave RTOs.

Review Tied to Formula Rates?

FERC Commissioner Mark Christie said some projects are scrutinized at the state level while others get by without oversight. He pointed out that while FERC cannot prescribe projects, it does wield control over formula rates. The commission could condition its formula rate treatment on whether a project has undergone a credible, state-level review, he said.

"And we'll let the states tell us if it was credible," suggested Christie, adding that FERC could apply the question to multiple states for interstate lines.

Christie said the national transmission rate base has increased 9% or more for the third year in a row.

"What goes into rate base goes into customers' bills — every nickel," he said.

Stanek said he didn't think states, which are "perpetually" underfunded and understaffed, should be tasked with undertaking project prudency studies on the bulk power system. He said such analyses would be too complex and expensive.

"I think Commissioner Christie is on the money that formula rates are an incentive. They're a carrot," said Matthew Nelson, chair of the Massachusetts Department of Public Utilities. He said he supported the idea of "step-down" return on investments, where cost overruns would trigger reduced rates.


FERC Commissioner Allison Clements | © *RTO Insider LLC*

FERC Commissioner Allison Clements said the task force might consider creating a standardized data collection from transmission developers across all 50 states. She asked what happens if FERC discovers a state doesn't have a credible project review process.

Christie suggested commissions call on expert RTO witnesses to testify on the prudency of some proposed projects. He reminded regulators that utilities bear the burden of demonstrating that a project is necessary before state commissions.

Kansas Corporation Commissioner Andrew French said establishing independent transmission monitors would be most helpful for local projects. He said large projects subject to regional cost sharing already are sufficiently inspected by parties that stand to pay.

French said at present, transmission owners can easily finalize local and replacement projects that maintain a status quo system.

"There just isn't an incentive to [propose] an optimal solution," he said, adding that commission staffs need help understanding the pace of investment and whether transmission owners are engaging in optimal planning.

However, Georgia Public Service Commissioner Tricia Pridemore, who replaced former Arkansas regulator Ted Thomas on the task force, denounced a "top-down" level of review. She said Georgia has a solid planning process that invites economic development, and it has never experienced a major blackout.

Glick countered that there has been a "ballooning" of local projects and some attention on them would be worthwhile.

"It might be that non-RTO states have sufficient authority," he said.

Glick wrapped the meeting by urging the task force to keep up the collaboration if he doesn't

FERC/Federal News

return to the task force for its next meeting in February. (See *Glick's FERC Tenure in Peril as Manchin Balks at Renomination Hearing*.)

Clements Weighs in on Planning Direction

In a keynote during the NARUC meeting Nov. 14, Clements urged thoughtful, low-regret transmission planning so customers don't experience "wild jumps" in the transmission component of their bills.

Clements said FERC commissioners could issue hundreds of pages of cost-management decrees and "sit very smugly," but if states and utilities don't think the resulting cost containment rules are fair, they will be pointless.

She said the commission is laying crucial groundwork to get new infrastructure built: "To me it's not so much as an ambitious agenda as it is an imperative need."

Clements repeated the industry adage that the transmission system is on the cusp of a buildout like that of the nation's highway system in the mid-1950s. She said the key to mitigating widespread extreme weather events is to have an interconnected transmission system greater than the size of the weather patterns.

She pointed out that interconnection queues are brimming with projects waiting for grid treatment.

"Right now, we're looking at twice as much generation than exists on the transmission system today trying to get on," Clements said.

She said federal and state regulators should help utilities ensure the most efficient use of the existing system through dynamic line ratings and other grid-enhancing technologies,

"Now is the time to do it, since we're thinking about larger investments in backbone transmission," she said.

However, Clements said she understands grid operators' hesitation to introduce system stressors with new transmission technologies. She said control room operators are understandably cautious and protective of system reliability and that FERC is trying to land on "the least scary way" to introduce new technologies.

"If the speed limit is 60, and it's a nice day in April, maybe go 75," Clement said. "But if it's February and icy, go 40. Make the system better and smarter, and I think that's a great analogy."

State Rights of First Refusal and Order 1000

A NARUC panel Nov. 15 deliberated on which is worse: FERC's failed attempt at competition under Order 1000 or the ensuing wave of state rights of first refusals for incumbent utilities.

Former FERC Commissioner Tony Clark, now an adviser with Wilkinson Barker Knauer, said some prefer continued transmission development under monopolies rather than a "complex bidding process that doesn't work" under Order 1000.

"The state ROFRs are the symptom, but Order 1000 is the disease," Clark said. "I think we ought to admit that this is an industry that naturally trends toward a natural monopoly."

Devin Hartman, R Street Institute's director of energy and environment, said consumers could potentially save several billion dollars with competitive solicitations. He said consumer groups and grassroots movements are organizing to fight state ROFR laws.

Hartman said there's "no economic reason" to reinstall a federal ROFR.

Ten states have enacted ROFRs: Indiana, Iowa, Michigan, Minnesota, Montana, Nebraska, North Dakota, Oklahoma, South Dakota and Texas.

Four other states have considered such laws: Colorado, Kansas, New Mexico and Wisconsin.

A consumer collective has filed a joint complaint at FERC against MISO's practice of respecting state ROFR laws in its regional transmission planning and cost allocation (EL22-78). (See *Consumer Groups File FERC Complaint Against MISO*.)

Wisconsin Public Service Commissioner Ellen Nowak, whose state discussed a bill that ultimately didn't pass, said viewing the issue as a debate between competition and full regulation is a "false choice."

"It hasn't played out as we have expected," Nowak said of competitive processes in practice. "The sticker price looked good, but then there's a lot of little exemptions that have to play out."

"States want control over who is building critical infrastructure in their state. … It's not putting up another Dunkin' Donuts; it's critical infrastructure," Nowak said, explaining that states need trusted utilities. She said incumbent utilities are still beholden to a transparent process, and they can be subjected to cost caps.

However, Nowak predicted that the bill will again be introduced during Wisconsin's next legislative session.

"ROFRs are anticompetition laws," said Ari Peskoe, director of Harvard Law School's Electricity Law Initiative. "This is benefiting the largest incumbents. I'm not sure who else benefits from this." ■

The Joint Federal-State Task Force on Electric Transmission meeting underway | *© RTO Insider LLC*

FERC/Federal News

NARUC Taps into Winter Unease, Rate Design, Storage

By Amanda Durish Cook

NEW ORLEANS — The 2022 annual meeting of the National Association of Regulatory Utility Commissioners covered ground on rate design, energy storage and reliability as the energy portfolio undergoes renovation.

The meeting, which was held Nov. 13 to 16, continued NARUC's multiyear theme of innovative and disruptive technology and regulation.

NERC's Fritz Hirst | © RTO Insider LLC

"The energy transition poses the greatest threat to reliability," NERC Director of Legislative and Regulatory Affairs Fritz Hirst said on the first day during a briefing on the reliability organization's 2022 Winter Reliability Assessment.

Hirst called NERC's summer assessment a "sobering report."

"And the winter assessment is no exception," he said, adding that a large portion of the country will confront reliability risks should severe winter weather strike.

Hirst said Texas, MISO, SERC and New England are particularly exposed to winter risk, due to generation retirements, fuel supply and generator vulnerability to the elements.

He added that the Pacific Northwest's hydropower conditions have improved since last year and SPP has added enough natural gas and wind generation to manage winter resource adequacy, likely keeping them off the season's hot seat.

Hirst said it's "cold comfort" that the National Oceanic and Atmospheric Administration is predicting a mild winter for much of the country.

"It matters not what the predictions are because all it takes is a cold snap lasting several days in a region," he said.

Hirst also said an ongoing nationwide shortage of transformers might mean longer restoration times. He said that though NERC cannot mandate resource adequacy, the "energy sufficiency challenge" is top of mind for staff. The agency's consideration of a standard for forward-looking energy reliability assessments seeks to tackle the burgeoning issue, he said.

The NARUC annual meeting's opening session on Nov. 14 | © RTO Insider LLC

"The system needs flexible, dispatchable resources, whether that's coal or natural gas," Hirst said. "Natural gas is probably your best bet … and that will be the case until we have some breakthrough in storage at scale or in hydrogen."

Michelle Bloodworth, CEO of coal lobbying group America's Power, said she's alarmed by the pace at which dispatchable resources are exiting the grid. She said operators are "vastly underestimating" the amount of coal resources poised to exit the system.

Utilities have announced the retirement of more than half of the nation's 200 GW coal fleet by 2030, Bloodworth said. She said the industry should "do a better job of publicly recognizing" that coal resources have reliability attributes that are essential for the foreseeable future. America's Power has filed a letter with FERC, asking the commission to acknowledge those attributes.

"Every coal plant that leaves puts more and more pressure on the natural gas system," said Bloodworth.

She added that she hoped carbon capture and sequestration investments on the nation's existing coal plants are given an assist by the Inflation Reduction Act.

"It takes time and sustained investment. We've seen more subsidies on the intermittent generation to date," she said.

State regulators also wrung their hands over natural gas price increases.

During a Nov. 14 roundtable, Colorado Public Utilities Commission Chairman Eric Blank said customers will see increases north of 60% on the natural gas portions of their bills.

"It's just enormous, enormous," Blank said. "I would say the regulatory options are very limited. We're just struggling."

He said "it's a lot more fun" to regulate when fuel prices are stable. He asked other regulators for ideas on limiting bill increases.

Regulators suggested prohibiting utilities from earning a return on natural gas power purchases, customer charge suspensions, and more robust energy efficiency programs that hedge high commodity prices.

Some regulators said while surging natural gas prices will strengthen some commissions' commitment to electrification, renewable energy and hydrogen substitution, others will concentrate on how to blunt the price hikes.

"It's going to be an ugly time for ratepayers

FERC/Federal News

in Georgia in the next few months," Georgia Public Service Commissioner Tim Echols predicted.

"Is the final word from this session, 'This job sucks?'" Blank joked. "Is that the takeaway?"

Rate Design Considerations

ESIG's Debbie Lew | © RTO Insider LLC

Debbie Lew, associate director of the Energy Systems Integration Group (ESIG), said zero marginal cost renewable resources and looming, immense electrification loads mean that regulators will have to introduce more dynamic pricing that incentivizes demand when supply is plentiful.

"New electrification loads are a double-edged sword — they can help or stress both the distribution and bulk power system," Lew said during a Nov. 13 panel. "We know we're going to need more than time of use rates."

But Lew said time-of-use rates are beneficial today. She said Sacramento Municipal Utility District's TOU rate created on a $5 million investment averted the need for a new, more expensive 150-MW resource to meet peak demand.

Lew said if regulators want demand flexibility, they will need to expose some customers or load-serving entities to price signals that "reflect cost causation and grid needs."

"If all demand were price-sensitive, we might not need ... reserve margins. Obviously, we're a long way away from that," she said.

The Brother Martin boys' college preparatory marching band of New Orleans serenaded NARUC attendees on Nov. 14 | © RTO Insider LLC

Brattle Group principal Sanem Sergici focused on electrifying heating with heat pumps. She called their adoption "a key component of state and city climate action plans" but said adoption hinges on their installation and operating affordability compared to natural gas.

Sergici said regulators must design new rate structures that balance customers' payback periods, fixed charges and incentives under the IRA. She said it's possible to use cost-based rates and avoid subsidies to foster heating electrification.

"With the right rate design, adoption is possible. It's time to stop discouraging electrification of heating," she said, adding that rate design can be "a constant evolution" if the bulk electric system becomes winter peaking.

From left, Enel's Greg Geller, Interstate Renewable Energy Council's Radina Valova, PJM's Danielle Croop and American Clean Power Association's Jason Burwen | © RTO Insider LLC

Storage Makes an Entrance

Jason Burwen, American Clean Power Association's vice president of energy storage, told regulators to expect 10 GW of new storage annually nationwide for the foreseeable future if transmission system planning is updated, regulatory and permitting processes are revamped, and supply chain issues stabilize.

He predicted the IRA will counteract some of the recent inflation-based price increases of storage facilities.

PJM Manager of Market Design Danielle Croop said PJM has 40 GW of hybrid generation projects and 54 GW of standalone energy storage in its interconnection queue. She said the amount of storage projects likely means that storage is becoming cost effective.

Greg Geller, Enel North America's head of U.S. and Canada regulatory affairs, said storage is a key component of decarbonization plans. He said regulators can take three steps to stimulate storage additions: collaborate with utilities and grid operators, allow storage to compete to solve grid issues, and give consumers as much cost-causation transparency as possible so they can fire up distributed resources when they stand to save the most.

Geller said Texas, in particular, has an alluring regulatory environment. Enel's storage projects in the state usually make it through the interconnection queue in one or two years, he said. Elsewhere, the wait is upward of three years. Geller said that storage solutions might help avoid decades-long stranded costs on more permanent assets. ■

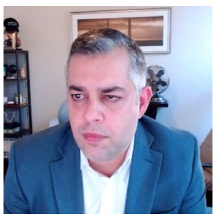
FERC/Federal News

NERC Warns Winter Margins Tight in Multiple Regions

Texas Leads Shortfall Risk

By Holden Mann

NERC staff called the organization's *2022-2023 Winter Reliability Assessment*, issued on Thursday, a "serious warning" that highlighted the possibility of "bigger problems" compared to last winter in several regions, with extreme weather once again posing a major risk to grid reliability.



John Moura, NERC | *NERC*

"When we look at events over the last several years, it's really clear that the bulk power system is impacted by extreme weather more than it's ever been," said John Moura, NERC's director of reliability assessment and system analysis, in a media call on Thursday. "And so, as we transition our system rapidly, it's vitally important that we're planning and operating a bulk power system that is resilient to … the extreme weather we're seeing, which includes both generation and transmission solutions."

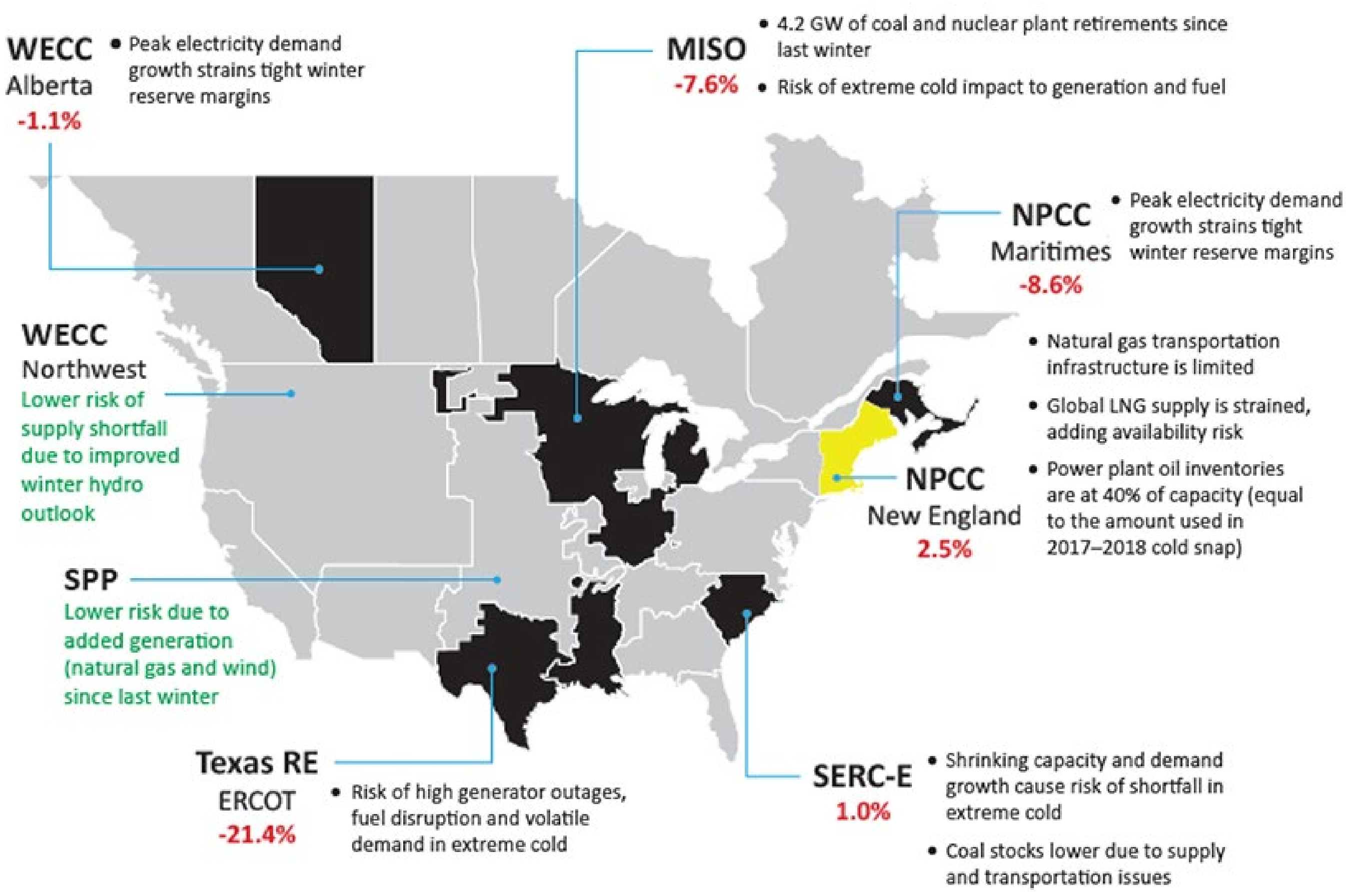
The regions where NERC identified potential for insufficient electricity supplies during peak winter conditions are MISO; ERCOT; Alberta; the Maritimes region, which contain parts of Canada and the U.S.; and SERC-East, which includes North and South Carolina. In addition, the assessment marked New England as at risk of constraints to the natural gas transportation infrastructure during cold weather, which could lead to outages of gas-fueled generation sources.

Demand Rising as Capacity Falls

NERC's winter assessments are released each year and cover the months of December through February, based on demand and generation availability forecasts provided by regional entities, utilities and other stakeholders. In Thursday's call Mark Olson, NERC's manager for reliability assessments, emphasized that "almost all areas are well prepared for … average winter years" and observed that some regions do, in fact, appear to be in a better position than they were last year.

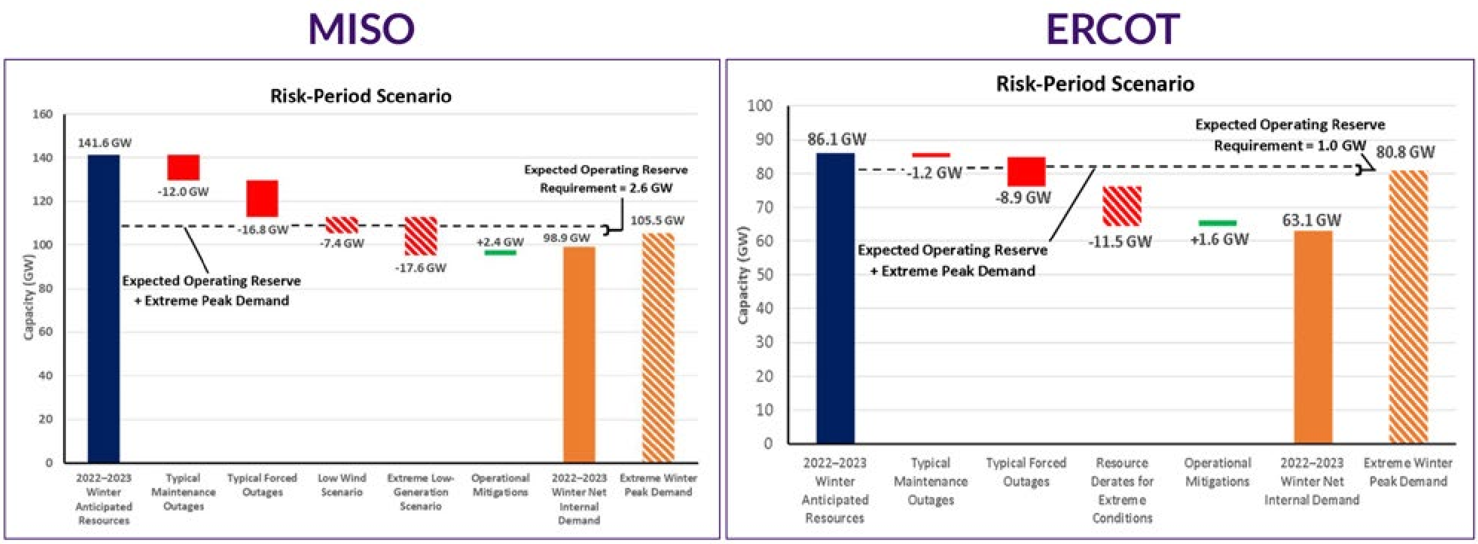
For example, the WECC-Western Power Pool assessment area had a lower risk of supply shortfall based on its improved hydropower outlook from last year, while SPP was assessed at lower risk because of added natural gas and wind generation since last winter.

However, for a significant fraction of the North American electric grid, questions exist about the ability to maintain needed levels of service in the face of extreme conditions that might affect the functioning of generators while driving up demand for electricity for heating. ERCOT faces the biggest potential shortfall,



NERC's winter reliability risk area summary. Areas highlighted in black are those at risk of insufficient electricity supplies during peak winter conditions; those highlighted in yellow face risks from limited natural gas infrastructure. | *NERC*

FERC/Federal News



Left: NERC's risk-period scenario for MISO, showing a potential for load shedding under extreme conditions; Right: the same projection for ERCOT. | *NERC*

with NERC calculating that under the region's projected reserve margin could fall as much as 21% below demand in the most severe scenario.

No other region approaches ERCOT's assessed risk: The closest is the Maritimes — comprising the Canadian provinces of New Brunswick, Nova Scotia and Prince Edward Island; and Northern Maine, which is not part of ISO-NE — which has a potential 8.6% shortfall. MISO could come short by as much as 7.6%, while Alberta, which is in WECC's footprint, has a potential 1.1% deficit.

One reason the possible shortfall in Texas is so high, Olson said, is that unlike other regions, ERCOT has "very little transfers that can come help in the event that they do [have] energy emergencies." Demand in Texas is also very sensitive to cold weather because of electric heating demand, which "significantly uses more electricity" as the temperature drops.

On the other hand, Olson pointed out that ERCOT has implemented a number of improvements to cold weather performance since the winter storms of February 2021 that "also should improve the fuel availability to the natural gas-fired generators." Moura added that while NERC only assesses the readiness of the bulk electric system, he was "sure" that those responsible for regulating the natural gas supply "have made strides" in preparing their system.

For MISO, reserve margins have fallen by more than 5% since last winter, largely because of more than 4.2 GW in nuclear and coal-fired generation retirements. While 2.25 GW of demand response and wind generation with nameplate capacity of 3.2 GW have been added, Olson reminded listeners that the inherent uncertainty around the weather impacts the availability of these resources.

"If wind comes in below projections ... that can drive whether there is an energy emergency or not in MISO," Olson said. "If it's low, it's more likely to have emergencies, and if it's high, it can alleviate some of those concerns."

Coordination Recommended

NERC's assessment includes several recommendations to utilities to lower the risk of energy shortfalls this winter. The first is for balancing authorities and reliability coordinators to work with generator owners to ensure adequate fuel supplies both for normal and extreme conditions; this includes filling storage capacity, preparing fuel delivery systems, and coordinating with fuel providers to make sure additional fuel can be secured when needed. GOs should keep BAs and RCs apprised of their fuel levels and readiness as well, while RCs and BAs should actively monitor fuel adequacy and be prepared to step in with "proactive steps" to assist if needed.

The ERO also said policymakers at the state and provincial levels should be aware of energy risks for the winter season as well, and delay generation retirements if they are likely to negatively impact reliability. State regulators can also support environmental and transportation waivers requested by grid operators (GOPs) in the event of cold weather, in addition to issuing public appeals for electricity and gas conservation.

Finally, the assessment recommends that grid operators, GOs and GOPs implement the mitigations in NERC's recent *Level 2 alert* related to cold weather preparations, as well as any additional recommended winterization steps for their facilities. ■

Offshore Wind Seeks State Leadership on Transmission

By Michael Brooks

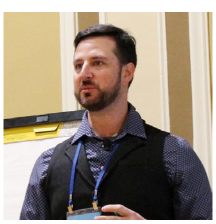
CHARLESTON, S.C. — Offshore wind and transmission developers say the states that are driving project development need to lead on the transmission side by collaborating to build an offshore grid.

That was the consensus that seemed to form at the Business Network for Offshore Wind OSW Grid & Transmission Summit on Nov. 9 as attendees brainstormed the most cost-effective way to interconnect the massive amounts of offshore wind states are procuring to meet their decarbonization goals.

The summit was held over two days at the Francis Marion Hotel to discuss strategies for offshore transmission development, mostly on the East Coast.

Rather than the typical format for an energy conference, the Business Network tried something different for the first day: a marathon series of discussions among the audience, mostly about the offshore wind industry's dream: a "backbone" transmission line along the East Coast, from Maine to Florida, connected to the onshore Eastern Interconnection and allowing offshore wind projects to "plug and play."

Such a "mesh-ready" system would save all stakeholders — states, developers, utilities and ratepayers — money on costly onshore transmission upgrades and allow projects to provide more capacity, speakers said.



Jason Gershowitz, principal at Kearns & West, led attendees of the summit in a series of free-wheeling discussions Nov. 9. | © *RTO Insider LLC*

The discussions were held under the Chatham House Rule: Attendees were free to use the information but not to reveal who provided it at the meeting. (As such, *RTO Insider* can not quote anyone who spoke.) Jason Gershowitz, principal at Kearns & West, lightly guided attendees as they traded tales of their experiences getting their projects built — the challenges, setbacks and successes. They also debated what is needed going forward and offered solutions for observed problems.

Also in attendance were state and federal officials charged with implementing their governments' goals, as well as European developers.

Attendees of the Business Network for Offshore Wind's OSW Grid & Transmission Summit packed a ballroom at the Francis Marion Hotel in Charleston, S.C., for a series of panels on Nov. 10. | © *RTO Insider LLC*

What played out was an exercise in problem solving among players in a nascent industry still struggling to find its sea legs.

Bottom-up Collaboration Needed

The problems with offshore transmission development are similar to those onshore in the U.S.: diverse state policies and goals; clogged supply chains; different standards and rules in each grid operator; and opposition by not-in-my-backyard residents.

While FERC has instituted several proceedings seeking to encourage interregional transmission development onshore and make it easier for generators to interconnect to the queue, it has not sought an active role in offshore transmission. Judging by several comments at the conference, that isn't necessarily desired. Though attendees did not come to any hard solutions, they agreed that there needs to be a bottom-up approach among stakeholders, not a top-down mandate from the federal government.

Currently, each state that is procuring offshore wind is soliciting transmission solutions on its own. There seemed to be some reluctant acceptance among attendees that the New Jersey Board of Public Utilities' recent selection of the Larrabee Tri-Collector Solution — which will only involve onshore transmission upgrades and a new substation — was the state's only real option given the costs of offshore transmission and lack of proposals for an offshore backbone. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

States are also very protective of the benefits that will come with the projects, especially the construction, manufacturing and shipping jobs, and they are competing among themselves for manufacturing and logistics hubs at their ports. Several attendees suggested pressuring states to put aside competition and collaborate on building an offshore grid that would benefit all involved. The states could form a coalition, laying out a clear goal and agreeing to share costs.

Others suggested that the three grid operators along the East Coast — ISO-NE, NYISO and PJM — come together, perhaps with a "nudge" from FERC, to independently plan an offshore grid. Still, states would need to play a key role in pushing the RTOs and FERC to work together. Here the challenge is a lack of consistency — as well as the inevitable difficulty of getting three different stakeholder bodies to reach agreement.

Still others suggested that wind developers themselves should collaborate among themselves rather than wait for the state governments to fix things for them. Developers could propose joint transmission solutions that incrementally build the backbone.

Several Europeans in attendance seemed bewildered that U.S. states with similar clean energy policies, such as those in New England, could not come together like countries in the North Sea — such as Belgium, the Netherlands, Germany, Denmark and Norway — which *recently committed* to building an offshore network in the sea by 2050.

Not Enough People

The attendees also discussed the lack of workers to fill all the open positions in the offshore wind field.

The industry began by picking off workers from the offshore oil and gas industry for their expertise in ocean construction and operating marine vessels. It then began enticing more with promises of training for industry-specific jobs.

Now that that labor pool has been exhausted, several attendees noted, developers are recruiting workers from competitors with hefty signing bonuses.

Attendees said there needs to be more engagement with students in high school and lower grades to encourage them to study electrical engineering and other related fields in college. One attendee, however, noted that it's difficult to get children excited about infrastructure. ■

Former NRG CEO Faces Tough Questions at Senate ENR Hearing

If Confirmed, David Crane Will Lead DOE Office of Clean Energy Demonstrations

By K Kaufmann

Sen. Joe Manchin (D-W.Va.) opened the Thursday confirmation hearing for three key posts at the Department of Energy by asking the nominees "a pretty simple, yes or no" question.

"Do any of you believe that the United States of America can be energy independent within the next 10 years without a robust clean fossil [fuel] energy program?"

And one after the other, David Crane, Jeffrey Marootian and Gene Rodrigues all answered "no," during the hearing of the Energy and Natural Resources Committee.

The question was particularly pointed for Crane, the controversial former CEO of independent power producer NRG Energy, who was recently named to lead DOE's new Office of Clean Energy Demonstrations (OCED), where he will oversee the development of both carbon capture and hydrogen hubs funded by the Infrastructure Investment and Jobs Act.

Marootian, who previously was head of the D.C.'s Department of Transportation, has been tapped as assistant secretary for energy efficiency and renewable energy, while Rodrigues, a former executive at Southern California Edison, will be assistant secretary for electricity delivery and energy reliability.

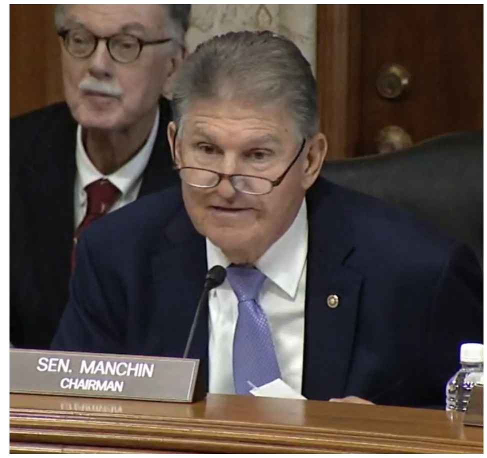
Both Manchin, the committee chair, and Sen. John Barrasso (R-Wyo.), the committee's ranking member, had tough questions for Crane, who was infamously fired from NRG in December 2015 after the company's stock fell 63% in 11 months. He has also been outspoken on the need for utilities and corporate America to move faster on decarbonization and during his tenure at NRG closed several of the company's coal plants.

Given the financial losses at NRG, Barrasso asked Crane, "Why should we believe that you're going to manage the American people's money better than you managed the NRG money?"

While dramatic, the losses at NRG were "actually consistent with [losses at] other companies in the industry" at that time, Crane said. According to a *2016 article* in Greentech Media, Dynegy, an NRG competitor, saw its stock's value tumble 50% in the same time period.

Crane also countered that his long experience "at the intersection of big capital and big energy projects" gives him the skillset needed at the OCED. He also pledged to Manchin that he would implement the carbon capture and hydrogen provisions of the IIJA "with the same vigor that I implement every other provision."

Those provisions, along with the Inflation Reduction Act's expansion of the 45Q tax credits for carbon capture "are catalyzing a response that I think is going to be very good for the industry," he said.



Sen. Joe Manchin | *Senate ENR Committee*

At Thursday's Senate confirmation hearing, (from left) David Crane, Jeffrey Marootian and Gene Rodrigues | *Senate ENR Committee*

Similarly, Crane said the response to DOE's call for initial proposals for $7 billion in hydrogen hub funding, which closed on Nov. 7, was "extremely enthusiastic," ensuring that the projects chosen will meet the IIJA's requirements that hubs be located in different regions and use different fuel stocks, including fossil fuels. (See *DOE Opens Solicitation for $7B in Hydrogen Hubs Funding*.)

Sen. Martin Heinrich (D-N.M.) also quizzed Crane on what metrics the OCED would use "to ensure that those large demonstrations are truly addressing the key risks, to be able to move those things towards adoption [and] deployment scale?"

Crane said his office would be focusing not only on the technical side of the demonstration projects but "more on the commercial offtake. These projects not only have to operate within their ring fence, but they have to be commercially sound. …

"The Department of Energy has a lot of negotiating influence in these public-private partnerships" for demonstration projects, Crane said. "But what we can't do is structure projects that the private sector would never replicate. I will tell you, in my two months at the DOE, the word 'replicability' has passed my lips more often than it has in my previous 63 years."

From Baseload to Grid-edge

Thursday's hearing was the first meeting of the ENR Committee since the midterm elections,

FERC/Federal News

which left Democrats in control of the Senate, and Manchin likely to retain leadership of the committee.

The hearing also underlined other key trends in energy policy in Congress and at DOE. First, the administration continues to promote its commitment to an all-of-the-above approach to decarbonization, which includes at least the potential for carbon capture and sequestration and green hydrogen to provide economic growth for the struggling fossil fuel communities Manchin and Barrasso represent.

DOE is also focused on making the projects it funds with IIJA dollars commercially viable, which has resulted in the agency recruiting industry leaders like Crane and Rodrigues.

By contrast, Marootian, whose most recent position was as a special adviser to the Office of Energy Efficiency and Renewable Energy, clearly does not have the depth or breadth of experience of Crane or Rodrigues. For example, when Heinrich asked him if DOE would help to set standards to accelerate the deployment of advanced conductors and other grid-enhancing technologies, he said only that

Sen. John Barrasso | *Senate ENR Committee*

he would be "delighted" to work on the issue.

Rodrigues, on the other hand, smoothly navigated grid-related questions from Republicans and Democrats. Responding to a query about baseload power from Sen. John Hoeven (R-N.D.), Rodrigues said that the complexity of ensuring the reliability of the U.S. electric grid means "we need a mix of resources that can be used in different ways. Baseload energy is critically important."

A top priority for the Office of Electricity, he said, will be "ensuring that each and every state's policy decisions, policy preferences and decisions made around the resource mix that they want to serve their constituents — that the grid is enabled to take those resources and affordably get them to the American people."

At the same time, Rodrigues also stressed the importance of developing grid-edge resources, like vehicle-to-grid technologies, to increase reliability.

While technological barriers still need to be overcome, Rodrigues said, "if and to the extent the grid is able to accept [grid-edge] resources, to integrate them, then we will have ways to increase reliability, increase affordability."

The Office of Electricity will work to advance these technologies, Rodrigues said, "to ensure that the visibility of these resources, the controllability of these resources and … [the] policies are in place to ensure that consumers recognize the value of being a beneficial part of how we control our grid." ■

FERC/Federal News

FERC Enforcement Continues to Ramp up Activity

By Michael Brooks

FERC approved 11 settlements last fiscal year that resulted in market participants paying a total of about $57.52 million in penalties and disgorgements for alleged violations, Office of Enforcement staff told commissioners at their open meeting Thursday.

The amount represented more than a sevenfold increase over the previous fiscal year's $7.9 million, though the bulk of the money came from a massive settlement with Salem Harbor Power Development, which in June agreed to pay nearly $43.8 million in penalties and disgorgement (IN18-8). Enforcement had alleged that the company behind the Salem Harbor gas plant in Massachusetts misled ISO-NE about the construction timeline of the project and took more than $100 million in capacity payments before it was in operation. (See *Developer in ISO-NE Hit with FERC Fine for Capacity Market Fraud*.) The case also cost ISO-NE $500,000 for mishandling the project's delays. (See *FERC Investigation Faults ISO-NE in Capacity Market Fraud*.)

The details of the case were included in Enforcement's annual *report* for fiscal year 2022 (Oct. 1, 2021, to Sept. 30). Even without the Salem Harbor settlement, Enforcement still collected about $5.8 million more than it did in FY21, when FERC Chair Richard Glick lauded the office for its aggressiveness. (See *FERC Enforcement Rebounds from COVID Slowdown*.)

"I think the office is back in terms of being active [and] making sure it fulfills its responsibilities that the commission gives it," Glick said Thursday, using similar rhetoric as he did last year. "It's important to have the cop on the street so that people ... think twice before they engage in market manipulation, before they try to evade a commission rule."

Glick highlighted the fact that, of the total amount, about $34 million were returned to customers through disgorgement. But Enforcement's Division of Audits and Accounting, he noted, also directed about $158 million to be refunded or prevented from being collected as a result of 51 findings of noncompliance. This amount was also up significantly over FY21, when it directed $18.5 million.

New investigations were also up, with the office's Division of Investigations opening 21, compared to 12 in FY21. According to the report, "12 involved potential market manipulation, nine involved potential tariff violations and seven involved potential misrepresentations prohibited by the commission's Duty of Candor rule. The 21 investigations involved a wide range of additional issues, including NERC's Rules of Procedure, ISO/RTO must-offer requirements and Section 205 of the" Federal Power Act.

While it does not disclose the specifics of these investigations, the report provides some examples of those that were closed without enforcement action. Five of these were based on 10 referrals from RTO market monitors, and often the office could not find sufficient evidence any rules were broken, or it found minor, unintentional rule violations that it determined did not cause any substantial harm to the markets. The other five referrals that resulted in new investigations remain open.

"Ensuring that our energy markets are free from manipulation so that they can continue to serve consumers is a top priority at FERC, and it requires vigorous oversight and enforcement efforts," Glick said. ■

FERC Office of Enforcement staff present the office's annual report to commissioners at their open meeting Nov. 17. | *FERC*

FERC/Federal News

Public Citizen: Natural Gas Exports Driving up US Gas, Power Prices

Blue Hydrogen Hubs Could Exacerbate Problem

By John Funk

A surge this year in U.S. LNG exports — some with long-term contracts to Asia — is driving up domestic natural gas prices and contributing to uncertainty about the reliability of the electric grid as winter begins, according to consumer watchdog Public Citizen.

LNG exporting companies must seek approval from the Department of Energy as well as from FERC. But DOE is not scrutinizing the impact of the growing exports on domestic markets, Public Citizen's Tyson Slocum said in a news conference Thursday.

Public Citizen and seven other consumer groups less than a month ago appealed to DOE to use its statutory authority and order a "substantive analysis" as required by the Natural Gas Act to determine the impact of additional U.S. export terminals on domestic markets.

In a *letter* to Energy Secretary Jennifer Granholm, the consortium said that the exports are "binding American household energy bills to global calamities, resulting in a domestic energy pricing crisis." They argued that DOE must develop a better analytical tool to measure the impact of unbridled LNG exports. The letter also noted that LNG exporters are charging European customers whatever the market will bear.

"To protect our European allies from price-gouging, DOE must condition any export authorization utilizing a global energy security justification to be subject to a cost-of-service standard tied to the landed delivery price," the groups reasoned.

Slocum argued that DOE's reliance on an economic study rather than a detailed analysis of every LNG export application is at the heart of the problem.

"The Department of Energy relies almost exclusively on a 2018 macroeconomic study," he said. The study "concludes that exports at roughly the same levels that are being exported today will provide net economic benefits. They projected no increase in costs in natural gas prices domestically.

Tyson Slocum, of Public Citizen | *© RTO Insider LLC*

"And the report that the Biden administration relies upon from 2018 states that even if domestic energy prices were to increase, the income that families would receive from their stock ownership in LNG export terminals would exceed any increase in their monthly energy bills, which is a preposterous and wholly unsupported assertion," he said.

In response to a question, Slocum said the consumer groups have been talking to congressional members about the issue.

John C. Allaire, a veteran environmental manager for the oil and gas industry who is now opposing a proposed LNG terminal in Texas, said China was the second largest importer of U.S. LNG last year. "But they're not our friends," he said. "It's not in the interest of the U.S., but we don't have a long-term plan. Our plan is to get it out of the ground and sell it to the highest bidder."

DOE's efforts to jumpstart the production and use of hydrogen in the U.S. through $8 billion in matching grants to assist industry and local governments create hydrogen hubs is likely to further complicate matters. At least two of the hubs DOE wants to fund will produce hydrogen from natural gas.

Because blue hydrogen producers will be dealing "with increasingly expensive feedstock costs to acquire that natural gas, and they're going to be in direct competition with LNG exporters, I just don't see that LNG exports are consistent with these efforts to try and build a domestic hydrogen production economy in any sort of meaningful way," said Slocum. ■

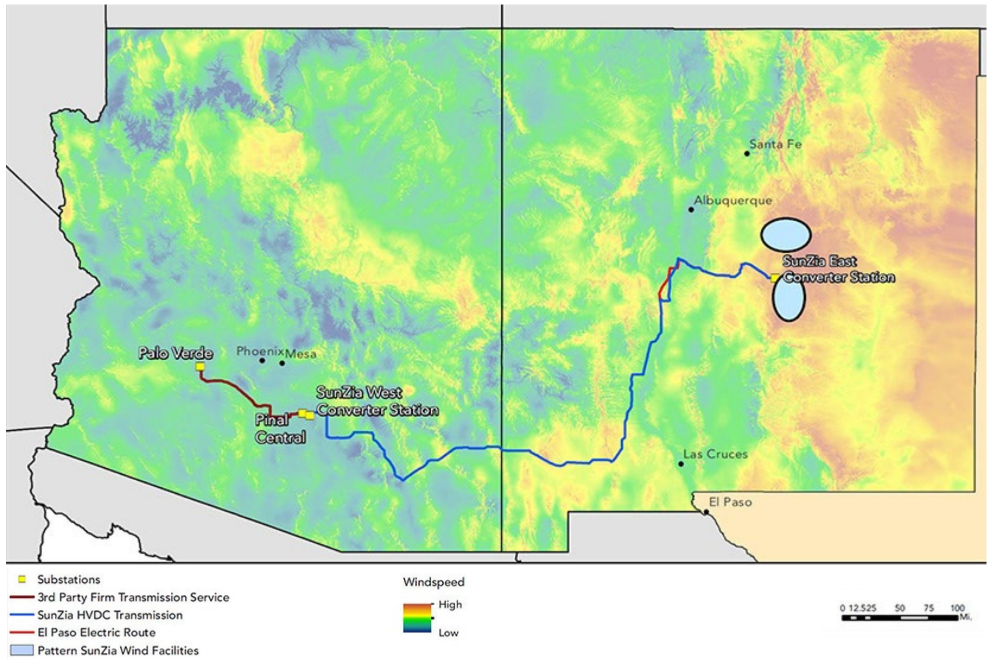
Freeport LNG on Quintana Island, Texas, has been shut down since June following an explosion and fire. Its reopening, possibly in December or early 2023, is expected to drive U.S. natural gas prices — and possibly power prices — higher over the winter as more gas is exported. | *Freeport LNG Development*

CAISO/West News

SunZia Transmission OK'd by Ariz. Regulators

Project Still Needs Approval from Federal Agencies

By Elaine Goodman



Arizona regulators have approved the portion of the SunZia transmission project that runs through that state. | *Pattern Energy*

Arizona regulators have granted a key approval to the SunZia Transmission project, Pattern Energy's proposal for delivering wind energy from central New Mexico into Arizona.

The Arizona Corporation Commission (ACC) this month approved a certificate of environmental compatibility for the project, which will consist of two 525-kV transmission lines across a 550-mile corridor.

The lines are intended to send energy from the 3,500-MW SunZia Wind project, which Pattern is looking to develop in central New Mexico, to population centers in Arizona. SunZia Wind will be the largest wind project in the Western Hemisphere, the company said in a *release* Nov. 14.

"SunZia is proof that New Mexico is leading the charge in the clean energy transition," U.S. Sen. Martin Heinrich (D-N.M.) said in a statement.

The ACC approval completes the Arizona state permitting process for the transmission project. In addition, the New Mexico Public Regulation Commission granted two separate approvals — in May and in October — related to SunZia Wind, Pattern said.

The company said it's awaiting approval from federal agencies, including the Bureau of Land Management, as well as local jurisdictions. Construction is expected to start in mid-2023.

Amendments Requested

The ACC originally approved an environmental certificate for SunZia Transmission in 2016. In May, SunZia Transmission LLC asked the commission to amend the approval. SunZia asked the commission to split its decision into two separate environmental certificates to allow separate ownership of each line. The move will facilitate financing.

SunZia also asked the commission to approve additional structure types and updated structure design for the project. In addition, the company asked to extend the time to complete the project, from February 2026 to February 2028.

Pattern called the commission's unanimous decision to approve the requests a "major milestone."

Critics of the project said it would harm wildlife and questioned the benefit to Arizona, because New Mexico power would be sold to California, according to a draft order to approve the certificate.

A Pattern spokesman said agreements are still being negotiated, so it's too early to say how much of SunZia's wind energy would go to California.

Regarding wildlife, Pattern said previously that SunZia Transmission worked closely with wildlife conservation groups to analyze environmental impacts and find the best route for the transmission project.

Supporters of the transmission project pointed to the need for more renewable energy to combat climate change and the economic benefits the project would bring to rural Arizona.

"Our window to combat [climate change] by reducing greenhouse gas emissions is closing quickly," Adam Stafford, Western Resource Advocates' managing senior staff attorney in Arizona, said in a statement. "We need to take action now, and building the SunZia lines helps us move in the right direction."

Kevin Wetzel, Pattern's senior director of business development, said the SunZia projects would "greatly benefit" Arizona. SunZia wind will complement solar energy produced in the state, he said, helping utilities and commercial customers reach their renewable energy goals.

In addition, "new transmission and diversified generation resources will improve overall WECC reliability and resiliency, which benefits all Western states, including Arizona," Wetzel said in a statement provided to *RTO Insider*.

Project Acquisition

In July, Pattern *announced* it had acquired SunZia Transmission from SouthWestern Power Group. Pattern had previously been awarded the full 3,000 MW of capacity of the transmission line.

SouthWestern is retaining ownership of a second 500-kV transmission line, El Rio Sol Transmission.

Combined, the SunZia transmission and wind projects form the largest renewable energy infrastructure project in U.S. history, with a total investment of more than $8 billion. Both projects are privately funded.

After initial approval of SunZia Transmission, the route was adjusted in consultation with the Department of Defense and White Sands Missile Range. The modified route partially parallels the existing Western Spirit Transmission line for 35 miles, which reduces environmental impacts, Pattern said. ■

CAISO/West News

Klamath Dams Set for Removal After FERC OKs Delicensing

Action Will Represent Largest Decommissioning in US History

By Robert Mullin

FERC last week approved the surrender of the license for the 163-MW Lower Klamath hydroelectric project straddling the California-Oregon border, setting the stage for the largest dam removal and salmon restoration effort in U.S. history.

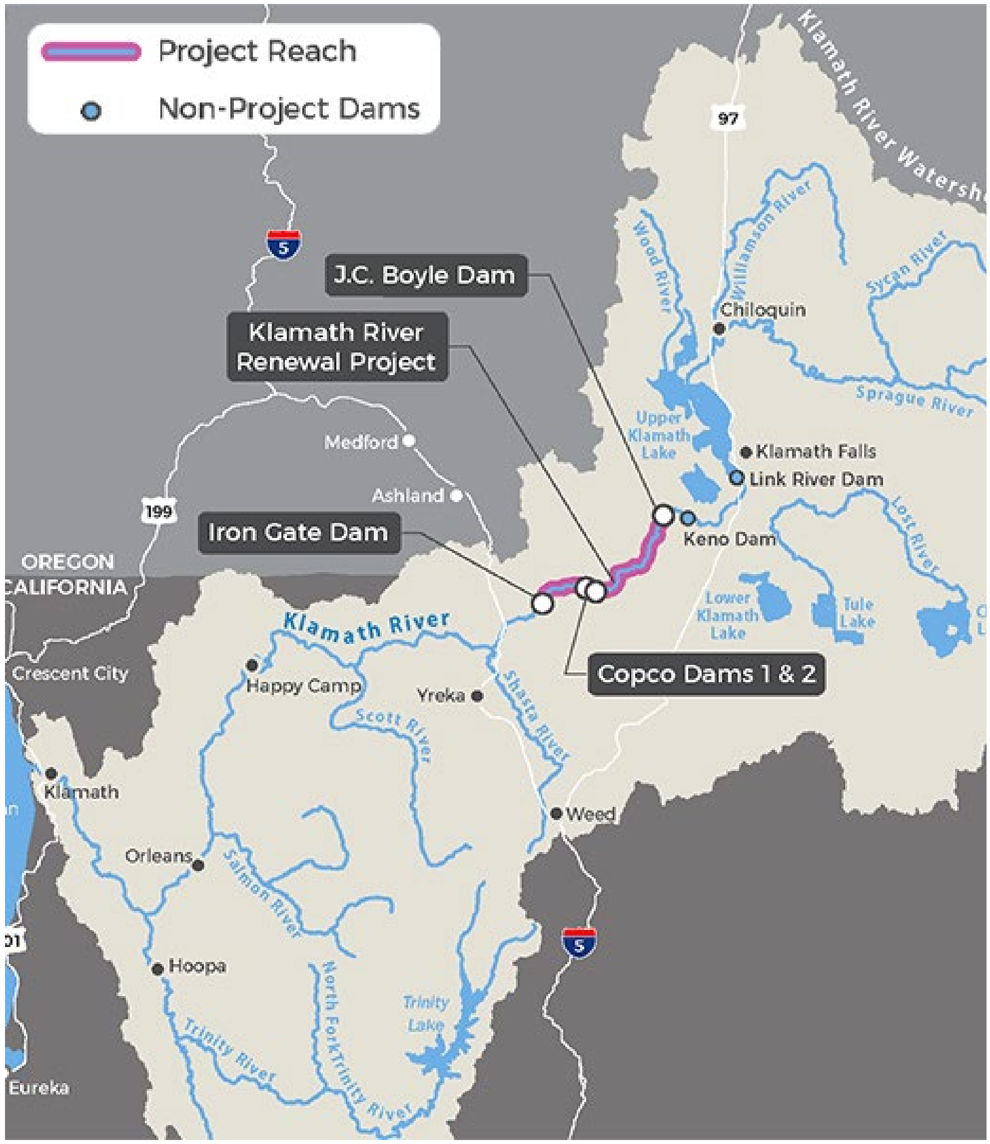
The commission's decision marks a major victory for local tribes and environmental groups in the region, who for years have sought the breaching of the dams to restore salmon runs to an area of the Klamath River that saw fish populations decline dramatically with the completion of the first dam in 1918. For Northwest tribes, salmon represent a traditional source of food and a vital component of cultural identity.

During the commission's open meeting on Thursday, Chair Richard Glick said some people might wonder why a hydro plant licensee would agree to remove dams "in this time for great need for zero-emissions energy."

"First of all, we have to understand that this doesn't happen every day. The last time there was approval for decommissioning dams was about 10 years ago," Glick said.

The FERC chair pointed out that the dams were built during a time "when there wasn't as much focus on environmental issues."

"Some of these projects have a significant impact on the environment and a significant impact on fish and other wildlife, so when companies are contemplating going through the relicensing process, people recognize that now we have new information and different laws, and so on, and sometimes these relicensing processes can be rather expensive," he said.



The Lower Klamath Project consists of four dams slated for removal. | *Klamath River Renewal Corporation*

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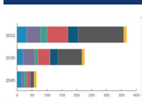

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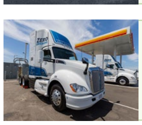


California PUC OKs $1B EV Charging Program — NetZero Insider

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

CAISO/West News

Glick added that, while the Klamath dam removals "make sense" from the perspective of wildlife protection, tribal concerns weighed heavily as well.

"I think it's a very important issue," Glick said. "A number of years back, I don't think the commission necessarily spent a lot of time in thinking about the impact of our decisions on tribes, and I think that's an important element that I think is in today's order and a number of orders recently. And I think for [the] good we're making progress on that front. Still a ways to go, but I think we're making the right progress there."

A Model for Other Removals?

Culminating a process that began more than 15 years ago, last Thursday's 174-page order authorizes Klamath River Renewal Corporation (KRRC) and PacifiCorp — the dams' previous owner — to remove four hydroelectric developments along the river, including the J.C. Boyle Dam in Oregon and the Copco No. 1, Copco No. 2 and Iron Gate dams in California (*P-2082-063*).

"Never before have so many large dams been removed from a single river at one time in the U.S.," the Congressional Research Service *said* in a report last March, noting that the project could become a "proof-of-concept for other major dam removals."

The Lower Klamath Project was originally part of the 169-MW, seven-dam Klamath Hydroelectric Project, built between 1918 and the early 1960s. In 2007, PacifiCorp decided not to seek relicensing of the four lower dams following a long-running dispute over water rights and the health of salmon runs in the Klamath Basin. The utility determined that new mitigation measures that would have been required under renewed licenses for the four aging structures would be too costly to implement.

For years the dams operated under a series of interim licenses, until FERC in June 2021 approved transfer of their licenses to the KRRC, a group comprising the Yurok and Karuk tribes, area farmers, ranchers, fishermen and environmental groups. The states of California and Oregon assumed roles of co-licensees to ensure that KRRC's decommissioning and restoration efforts had sufficient backing. (See *Klamath Hydro License Transfer Approved*.)

Under the terms of the transfer, PacifiCorp has continued to operate the dams until decommissioning. Three dams further upstream, which have been modernized with fish ladders to facilitate salmon runs, will remain in service.

Opponents of the dam's removal said the reservoirs created by the projects play an important role in irrigation, flood control and wildfire protection, as well as recreation and hydroelectric production. While acknowledging those concerns in its order, the commission noted that California, Oregon and the KRRC have committed to addressing many of them, including monitoring wells currently located near the reservoirs for declines in water levels and modifying the region's fire management plans to account for the loss of a ready water supply, including an increase in storage tanks and installation of remote, camera-monitored fire-detection systems to allow for "precise triangulation" of wildfires.

The commission acknowledged that dam removal could have mixed effects on property values, with the loss of value for formerly waterfront properties potentially offset by increased values because of improved water quality and "an enhancement of the natural riparian environment."

The commission also noted that commenters such as Siskiyou County, Calif. — home to the three of the dams — raised concerns that removal could result in a significant reduction in their tax revenue. "While it is possible that revenues related to the presence of the project will be lost, we have previously stated that the termination of any business venture reduces tax revenues to governments but is not a reason to deny a surrender application," FERC wrote.

Terms of Surrender

FERC's order requires the Lower Klamath co-licensees to submit an owner's dam safety program within 30 days, which will be effective from the termination date for each facility until removal. And, at least 60 days prior to any construction activities, the licensees must provide the secretary of the commission with final decommissioning design documents and an independent board of consultants' review of those documents.

Within 30 days of completing decommissioning, the licensees must submit to the secretary a final decommissioning report, with photographs, which documents that the dams have been decommissioned in accordance with FERC's order.

"The surrender of the license for the Lower Klamath Project shall not be effective until the commission's Division of Dam Safety and Inspections – Portland Regional Engineer has issued a letter stating that the project's facilities have been decommissioned in accordance with this surrender order and the commission's Division of Hydropower Administration and Compliance is satisfied with the required monitoring in accordance with this surrender order," the commission wrote. ■

CAISO/West News

West Could Save $1.2B a Year in CAISO EDAM

Day-ahead Market Would Generate Many Benefits of a Western RTO

By Hudson Sangree

CAISO's proposed extended day-ahead market (EDAM) for its Western Energy Imbalance Market could generate $1.2 billion a year in benefits, or 60% of the savings of a West-wide RTO, if it encompassed the entire U.S. portion of the Western Interconnection, a new study commissioned by CAISO found.

The report by Energy Strategies was similar to a study the consulting firm performed last year that found a single RTO covering the entire U.S. portion of the interconnection could save the region $2 billion a year in electricity costs in test-year 2030. The study was prepared for state energy offices in Colorado, Idaho, Montana and Utah with funding from the U.S. Department of Energy. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

The firm's EDAM *study* for CAISO built on that work. It examined operational savings obtained through more efficient dispatch and management of transmission capacity, lower operating reserve requirements, and the removal of transmission wheeling costs in the market footprint. It also looked at capacity reductions from regionally shared planning reserve requirements met through geographic diversity of generation resources and peak demand.

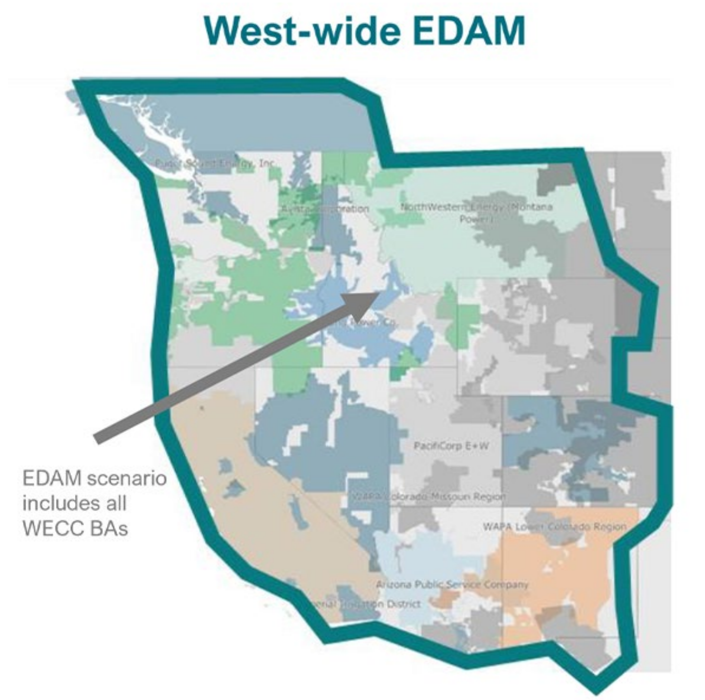
"The methodology and the underlying databases used to perform this assessment were consistent with those that my firm used to perform the state-led market study for a consortium of Western states," Energy Strategies Principal Keegan Moyer said Friday in a meeting hosted by the Committee on Regional Electric Power Cooperation (CREPC). CREPC is seeking to play a larger role in Western market formation. (See *CREPC Seeks to Become an OPSI for the West*.)

The EDAM study differs from the state-led study because it dealt with a specific market proposal instead of a generic RTO framework, Moyer said.

"The framework that we assume here is really just based off of a sharing of resources, assuming planning reserve margins stay consistent, and we just begin to plan for a consolidated peak relative to individual peaks," he said. "It's really quite simple. It's just a regional arbitrage of non-coincident peaks.

"There are, of course, other energy benefits that were not captured in this analysis," he said. "So, for example, an EDAM could produce price signals that improve the efficiencies of transmission planning. That would be helpful to see a day-ahead price process to plan the transmission grid better, but that benefit isn't captured here.

"Markets also tend to increase access to public-policy renewable resources," Moyer said. "The reason for that is that you don't have to wheel them across the system and/or you have different settlement points or different transaction options that are typically seen in SPP and MISO and help to increase that offtake optionality for those resources. So, it just provides better access to those low-cost wind regimes and solar regimes."



Energy Strategies estimated benefits based on the WEIM extended day-ahead market including all U.S. states in the Western Interconnection. | *Energy Strategies/CAISO*

The Western Energy Imbalance Market (WEIM) operates in real-time to share lower-cost and renewable resources among its *participants*, which now number 19. It has generated nearly $3 billion in benefits since it launched operations eight years ago. (See *WEIM Benefits Top $500M, Near $3B Total*.)

The fast-growing WEIM produced $739 million in savings for its 15 participants last year and $325 million in 2020 for its then-11 members. Energy Strategies said the EDAM would more than double the average of $525 in annual benefits from the past two years.

California would be the single largest beneficiary, with about $309 million in benefits in 2030, it said. All other Western states combined would save $886 million in 2030, including operational and capacity savings.

"An EDAM footprint across WECC causes California operational costs to decline by 6.2% from the status quo," the firms said.

The operational-only benefits of the EDAM would equal 78% of the operational savings from a single all-encompassing Western RTO, as modeled in the state-led study, it said. Including capacity savings, the EDAM would achieve 60% of the benefits of a Western RTO.

The report bolstered CAISO's sales pitch to Western entities to join the EDAM once it is approved.

CAISO fast-tracked the EDAM stakeholder initiative this year amid competition for Western market share by SPP, which is pursuing its own day-ahead Markets+ program and a Western RTO.

In a Nov. 14 meeting, CAISO presented its draft final proposal for EDAM with hopes of finalizing it next month and seeking approval from its Board of Governors and the WEIM Governing Body in February. (See *CAISO Finalizing Plan for WEIM EDAM*.)

"Some of the design is still in flux, but we're kind of at the tail end of the design phase," CAISO COO Mark Rothleder said at the start of Friday's CREPC meeting. "Hopefully these additional data points, in terms of the value proposition of EDAM, help in the final stages of the process and really understanding its total value proposition." ■

CAISO/West News

DOE Grants PG&E $1B for Diablo Canyon Extension

State's Last Nuclear Plant Deemed Essential for Reliability

By Hudson Sangree

The U.S. Department of Energy said Monday it will award Pacific Gas and Electric's Diablo Canyon nuclear power plant $1.1 billion in first-round funding from the Civil Nuclear Credit Program, established last year to support the continued operation of nuclear plants at risk of closing for economic reasons.

Diablo Canyon, the last nuclear plant in California, had been scheduled to close in stages in 2024 and 2025, but this year the state deemed its 2.2 GW of baseline power essential for reliability as CAISO faces continuing summer shortfalls.

"This investment creates a path forward for a limited-term extension of the Diablo Canyon Power Plant to support reliability statewide and provide an onramp for more clean energy projects to come online," Gov. Gavin Newsom said in a news release. "I thank the Biden-Harris Administration for this critical support."

Newsom's office had asked DOE in May to change the eligibility criteria for the Civil Nuclear Credit Program, or CNC, which was created last year as part of the $1.2 trillion Infrastructure Investment and Jobs Act.

The department said in April that CNC funding was only for nuclear plants that do not recover more than half their costs from ratepayers. PG&E recovers nearly all its Diablo Canyon costs from customers under rate cases approved by the California Public Utilities Commission.

Newsom's office asked DOE to exclude the cost-of-service requirement to allow Diablo Canyon to qualify for the federal funds. The plant provides 8.5% of in-state generation, which will be needed as the state tries to switch to 100% clean energy by 2045, the governor's office said.

The transition to renewables has exacerbated strained grid conditions in California. CAISO declared energy emergencies during heatwaves the past three summers, as solar power ramped down in the evenings, but air conditioning demand remained high. It said it could face similar shortfalls this summer and beyond.

On June 30, DOE announced it was making the changes requested by Newsom's office "given the request's potential applicability to reactors nationwide."

"This change affects the eligibility of reactors who may apply in the first round of awards," the department's Office of Nuclear Energy said in a *statement*.

DOE also extended the application deadline for the first round of CNC funding to Sept. 6. (See *DOE Changes Funding Rules to Help Diablo Canyon Stay Open*.)

Newsom signed a budget trailer bill in June that allocated $75 million toward keeping the plant open, and in September he signed a bill *granting* PG&E a $1.4 billion forgivable loan to keep Diablo Canyon operating five years beyond its scheduled retirement. The measure, Senate Bill 846, told PG&E to seek federal funds to offset the loan and lower customer costs if Diablo Canyon's license was renewed.

PG&E filed its application for federal funding on Sept. 2. On Oct. 31, the utility said it had formally applied to the Nuclear Regulatory Commission to renew the plant's license and postpone its decommissioning.

The moves reversed courses for the state and PG&E.

The utility had been planning to shut down Diablo Canyon since 2016, when it signed an agreement with environmental, labor and anti-nuclear groups to close the plant on the state's Central Coast rather than invest billions of dollars in environmental and safety upgrades.

On Monday, PG&E CEO Patti Poppe called DOE's funding decision "another very positive step forward to extend the operating life of Diablo Canyon Power Plant to ensure electrical reliability for all Californians."

"While there are key federal and state approvals remaining before us in this multiyear process, we remain focused on continuing to provide reliable, low-cost, carbon-free energy to the people of California, while safely operating one of the top performing plants in the country," Poppe said in a news release.

The $1.1 billion in funding is conditional, PG&E said.

"Final award amounts will be determined following completion of each year of the award period, and amounts awarded will be based on actual costs," it said in the news release.

Energy Secretary Jennifer Granholm said in a statement Monday that DOE's Diablo Canyon funding decision was "a critical step toward ensuring that our domestic nuclear fleet will continue providing reliable and affordable power to Americans as the nation's largest source of clean electricity. Nuclear energy will help us meet President Biden's climate goals, and with these historic investments in clean energy, we can protect these facilities and the communities they serve." ■

Diablo Canyon, California's last nuclear plant, had been scheduled to retire by 2025. | *PG&E*

After Banner Year, BPA Proposes Steady Rates for 2024/25

By Robert Mullin

The Bonneville Power Administration last week proposed to hold key power and transmission rates mostly flat over its next two-year rate cycle — and said it might cut rates this year — in light of a "strong" financial performance over the past 12 months.

The federal power marketing agency said steady rates will provide a "buffer against market volatility" for its customers, which largely consist of publicly owned utilities across the Pacific Northwest. Those utilities serve residents with some of the cheapest power in the U.S., most of which is generated by the region's extensive network of hydroelectric dams.

"This is one of those bountiful years where all the elements and timing came together in such a manner that we can consider staving off inflation for another two years by keeping rates flat for our power and transmission customers," BPA Administrator John Hairston said in an *announcement* Friday.

The agency said it earned $964 million in net revenues during fiscal year 2022, far outdistancing its target of $172 million.

"Each quarter, we have signaled our expectations that Power and Transmission were expected to have a solid year, and I'm happy to report that was in fact the case, with both business lines significantly beating net revenue targets," Marcus Harris, BPA's acting CFO said in a press *release* Thursday.

During its *quarterly business review* on Wednesday, the agency said it would consider using its financial reserves to reduce rates in FY 2023, which began Oct. 1.

Friday's announcement kicked off the formal process for BPA's power rate case (BP-24) and transmission rate proceeding (TC-24) for fiscal years 2024/25 (Oct. 1, 2023 to Sept. 30, 2025). Agency staff will officially publish initial proposals for the new power and transmission rates on Dec. 2, the same day as a pre-hearing conference to discuss the plans, but both plans are already available *online*. The proposed rates were the subject of a series of stakeholder meetings held this summer.

BPA's power rate schedule consists of four categories of primary rates for federal energy sales, including the:

- Priority Firm Power Rate (PF-24), or "Tier 1," which applies to firm power sales to BPA's public body, cooperative and federal agency customers;
- New Resource Firm Power Rate (NR-24), which applies to firm sales to investor-owned utilities and public customers serving new large, single loads. (BPA is forecasting no sales at this rate during the BP-24 period);
- Industrial Firm Power Rate (IF-24), which is applicable to firm power sales to Direct Service Industrial customers; and
- Firm Power and Surplus Products and Services Rate (FPS-24), applicable to "sales of various surplus power products and surplus transmission capacity for use inside and outside the Pacific Northwest."

Spillway structure at BPA's Bonneville Dam | *© RTO Insider LLC*

Tier 1 "non-slice" contracts represent the majority of BPA's power sales. "Non-slice" refers to a type of contract in which the customer is guaranteed a specified volume of energy regardless of conditions on the hydro system; in contrast, total volumes delivered to "slice" customers can vary based on availability.

In a *notice* filed in the Federal Register on Friday, BPA said non-slice rates will remain flat at an average rate of just under $35/MWh. But when slice rates are considered, average Tier 1 prices should actually decline slightly, according to the notice.

"The individual experience — slight increase/decrease/flat — of customer utilities will vary based on what products they use and the ways in which they use them," BPA spokesperson Kevin Wingert told *RTO Insider* in an email.

In the notice filed Friday, BPA said it expects to sell power to only one industrial customer at the industrial rate over 2024/25, but that customer can expect to see significantly higher costs during the most energy-constrained months, with December prices rising from $51.99/MWh to $63.40/MWh, and August rising from $49.10/MWh to $73.29/MWh. That is in part a reflection of changing expectations for river flow patterns in the Northwest — as well as summer cooling needs — caused by climate change.

BPA's proposal would extend current transmission rates unchanged into FY 2024/25, with "main grid" and "secondary system" — or lower-voltage — charges remaining at $0.0774/mile and $0.76/mile, respectively.

The agency operates about 15,000 miles of transmission, about 75% of the system in the Northwest. ■

ERCOT News

Legislators, Stakeholders Pan Proposed ERCOT Market Design

By Tom Kleckner

Texas lawmakers and ERCOT stakeholders did not hold back last week as they took their first shots at the Public Utility Commission's proposed redesign of the grid operator's market.

"The end loser is the end user," Sen. Donna Campbell (R) said during a Thursday hearing of the Senate Business and Commerce Committee. "This plan is so convoluted, [and] a long timeline to be put into place, that it's a setup for failure for everybody."

Campbell was one of several senators who cast doubt on the PUC's proposals, chief among them the performance credit mechanism (PCM). The design would require load-serving entities to buy performance-based credits from generation resources that meet reliability standards. It has been widely portrayed as throwing extra money at dispatchable generators and ignoring cheaper renewable resources.

The PCM is one of six market designs the commission has asked ERCOT stakeholders and the general public to provide feedback on by Dec. 15. The commission only rolled out the designs earlier in November after months of analysis and modeling by two consulting firms. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

The performance credits must be produced during the highest reliability risk hours to meet the reliability standard. LSEs can purchase the credits, awarded to resources through a retrospective settlement process based on availability during the riskiest hours, according to their load-ratio shares during those same periods. This allows generators and LSEs to trade credits in a voluntary forward market, the consultants said. Generators must participate in the forward market to qualify for the settlement process.

San Francisco-based Energy and Environmental Economics (E3), which was paid $614,000 for its *work*, recommended a forward reliability market that has been called a "straight-up forward capacity market." Other designs it analyzed included an LSE reliability obligation and a backstop reliability service that the PUC first proposed last December.

"To be quite frank, I don't see … a requirement for new generation," B&C Committee Chair Charles Schwertner (R) said. "That's what I think we need to be focusing on: … ensuring we get what we need as a state. The bottom line is we need more dispatchable thermal generation because of the changing characteristics of the world and the federal pieces of law that allow for non-dispatchable to be really incented. Texas has to respond."

PUC Chair Peter Lake (left) and ERCOT CEO Pablo Vegas listen as IMM Carrie Bivens shares her view on market redesign. | *Business & Commerce Committee*

Texas Sen. Charles Schwertner | *Business & Commerce Committee*

The state's politicians have focused on new dispatchable thermal resources since the February 2021 storm, despite the fact that they, like all resources, failed to perform during the event. PUC Chairman Peter Lake said E3's analysis recommended that the PCM's reliability payments only go to "truly reliable sources" that can commit in advance. He said that by reserving revenues for those resources, the PCM's expected costs are $200 million cheaper than ERCOT would be expected to pay in 2026 "in the absence of any reform."

Schwertner asked Lake how fast Texas would see the 5.6 GW of gas-fired capacity that E3 said would be on the system by 2026.

"As always, it depends on a number of variables, [the] first of which the generators would tell you is regulatory certainty," Lake said, noting E3 expected it would take three or four years to build out the ERCOT system. "Some generators have expressed to us that once they have regulatory certainty, they'll start building generators concurrently."

"Are they prepared to come before us today and promise they'll do that?" Schwertner asked.

"I'll leave that to them," Lake responded.

"Yeah, they're not going to be here today," Schwertner said.

The lawmakers zeroed in on the costs of the proposed designs and whether they will incent the dispatchable generation. E3 said the recommended designs would improve ERCOT's loss-of-load expectation (LOLE) to 0.1 day/year by 2026 at an incremental cost of $460 million over the current energy-only construct's total customer costs of $22.3 billion. A hybrid design combining the backstop reliability service and dispatchable energy credits would be most expensive at an incremental increase of $920 million a year.

Carrie Bivens, ERCOT's Independent Market Monitor, said the E3 report doesn't accurately model the operating reserve demand curve, the market mechanism that values the market's operating reserves based on their scarcity and reflects that value in energy prices.

"This will understate the future revenues of the energy-only market and therefore alter the build and retention signals for resources," Bivens said. She said E3 also overstates generator retirements by 2026 at 11 GW, resulting in an LOLE that is higher than it should be.

"We don't see 11,000 MW of retirement. ... That affects many of the conclusions throughout the report," Bivens said.

She allowed that the PCM could be designed to send appropriate price signals "consistent with competitive market principles," but the backstop reliability service would be costly because it would immediately sideline about 5 GW from the energy-only market and withhold it at the price cap, she said.

"That's economic withholding and that will serve to increase energy revenues in the short run," Bivens said.

The IMM has recommended that ERCOT develop a two- to four-hour day-ahead capacity product to account for the increased uncertainty associated with intermittent generation, load and other factors. It says the product could be deployed to bring online longer lead-time units when the grid operator detects operating conditions are "departing from expected conditions."

Speaking for Texas Industrial Energy Consumers' commercial customers, Katie Coleman said she shared Bivens' concerns. She said the E3 report's newest recommendations are "new spins on old concepts ... essentially, the Northeastern-style forward capacity market."

The PCM "is still fundamentally creating an electricity tax where customers are being mandated to pay a certain amount to generators. All the complexity in this report is just figuring out what's the size of that tax," Coleman said.

"None of these proposals guarantee any new investment. None. The PUC does not have the authority to command capital. You can create incentives based on reports from a consultant, and you can hope that the capital markets respond, but there is no guarantee that they will. ... If they don't, what happens is customers pay a penalty price."

"It seems like the loser is always the end user, and this is getting really, really expensive," Sen. Lois Kolkhorst (R) said. "We can come out with all these proposals, but nobody's willing to really say, 'I'm going to do that.' So, there's market uncertainty."

Lake responded to the repeated comments and questions about increasing costs to ratepayers with the same message, saying, "We can deliver 10 times improvement in reliability for roughly the same or even lower cost to our consumers in the absence of action."

Once it receives stakeholder input next month, the PUC plans to issue its final market design, which will then be vetted by lawmakers early next year.

"I'm looking forward to see what the marketplace and the public tell us," Lake said. ■

NYISO News

NY TOs Seek Clarification on ROFR for Upgrades

NYISO Previews Winter for Stakeholders; Committees Elect Vice Chairs

By John Norris

New York transmission owners have proposed tariff amendments that would clarify their ability to exercise a right of first refusal (ROFR) for public policy transmission (PPT) network upgrade facility (NUF) upgrades identified in the interconnection study process.

FERC in March approved tariff changes that confirmed TOs could exercise a ROFR for upgrades that are proposed by other developers, but they lacked provisions on whether this applied to upgrades identified later by NYISO as necessary to reliably interconnect a project (EL22-2-001). (See *FERC Approves ROFR for NY Transmission Upgrades*.)

The Operating Committee on Thursday recommended that the Management Committee and Board of Directors authorize NYISO to file the proposed revisions, *presented* at the meeting by Stu Caplan, partner at Troutman Pepper, which represents the eight TOs.

In a statement to *RTO Insider*, Caplan said the proposed revisions would "merely apply a similar mechanism to upgrades that are identified in the interconnection process for the public policy transmission projects that are selected by the NYISO board."

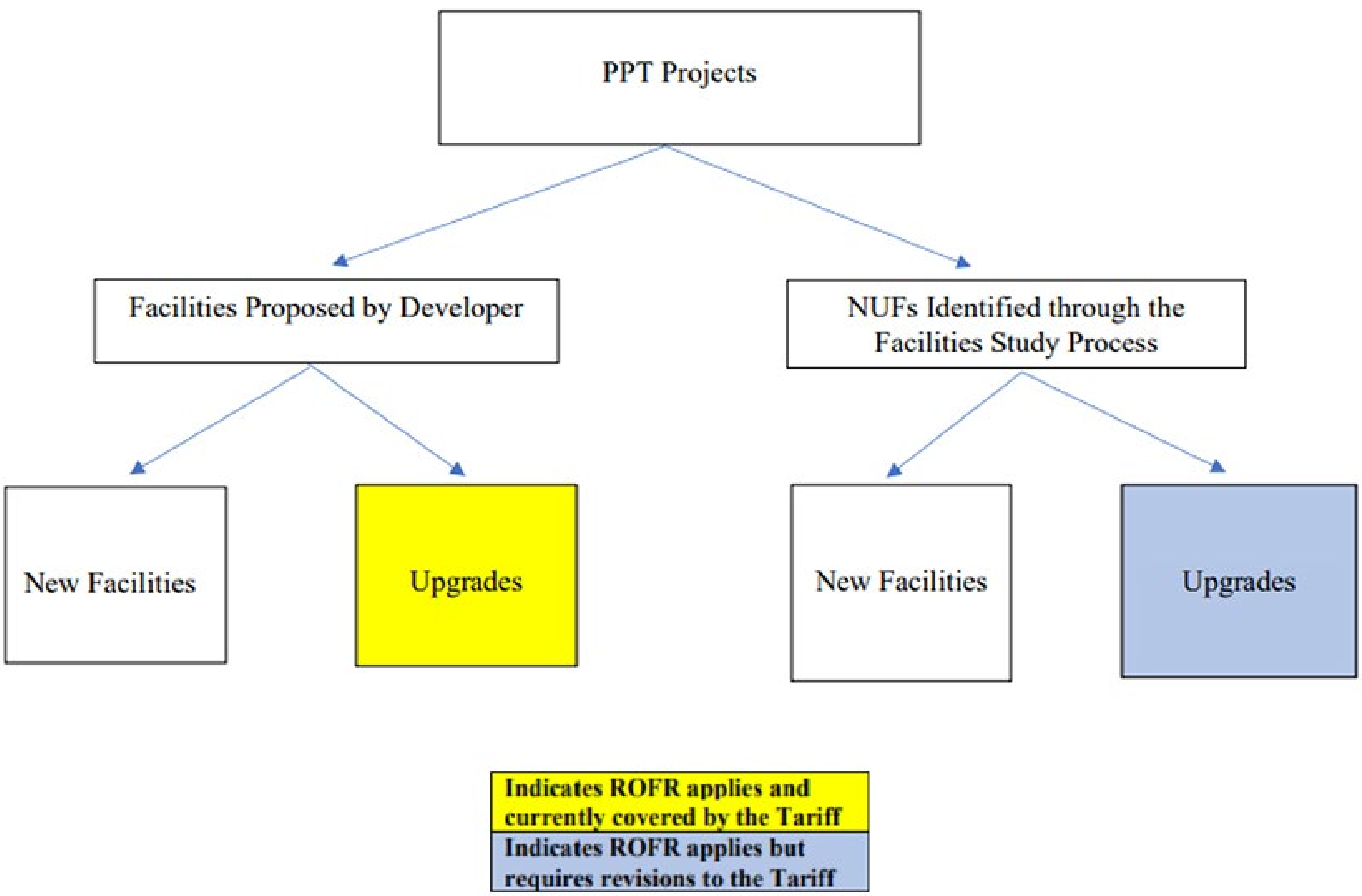
The revisions are the "logical extension of the process FERC approved in March of this year for upgrades identified at the project proposal stage," he said.

Caplan told stakeholders that the proposal would replace a bilateral process that lacks certainty and timelines, provide for a transparent process that closely replicates approved standards, and define the ISO's role in identifying which of the NUF components might qualify as an "upgrade" subject to a ROFR.

The TOs also want to make sure the rules are clear amid NYISO's ongoing PPT project solicitation for interconnecting offshore wind. (See "Offshore Wind," *NYISO Stakeholders Propose Three Areas for Public Policy Transmission*.)

"It is the only current solicitation for a public policy transmission projects, and the first project that may result in the identification of upgrades in the interconnection process for a public policy transmission project," Caplan said.

During Wednesday's Business Issues Committee meeting — where the proposal was also



Proposed ROFR tariff revision to "upgrades" identified in NUFs processes | *Troutman Pepper*

NYISO News

presented — Howard Fromer, who represents the Bayonne Energy Center, asked whether NYISO had expressed support for the changes.

Caplan answered that the ISO has said the TOs are "free to carry this forward as a TO-led effort."

This response was followed up by a NYISO representative, Brian Hurysz, who said that "nothing has jumped out as an immediate concern" to the ISO.

The proposed amendments now move to the Nov. 30 MC meeting for approval.

Winter Capacity Assessment

NYISO expects sufficient capacity margins for this winter but anticipates continued year-to-year declines as more fossil fuel generators retire.

The ISO told stakeholders that that they expect a total of 477 MW worth of generation to be deactivated and a total of 672 MW of new generation to be added during the upcoming seasonal assessment period.

SRIS Scopes Amended

The OC unanimously approved revisions to the system reliability impact study (SRIS) scopes for 35 generation projects, which the ISO identified as possessing evaluations that could either be removed, were redundant or could be conducted later.

NYISO had recommended that these previously OC-approved SRIS scopes be narrowed to expedite interconnection processes and streamline transmission studies (See *NYISO Identifies 35 Projects for Narrowed SRIS Scope*.)

Intermittent Resources Update

For the first time, NYISO shared the total nameplate value of installed intermittent power resources in the New York Control Area:

- Land-based wind: 2,191 MW
- Behind-the-meter solar: 4,123 MW
- Front-of-the-meter solar: 74 MW

NYISO promised to expand this list to more intermittent resources, such as OSW, as they are installed in greater amounts, and promised to consider including battery storage in the future.

BIC & OC Elections

NYISO stakeholders unanimously elected Scott Leuthauser of Hydro Quebec Energy Services and Greg Yozzo of Central Hudson Gas & Electric as the new vice chairs of the BIC and OC, respectively. ■

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NY Stakeholders Balk at NJ OSW Cost Allocation

'Border Rate' Settlement at Issue

By Devin Leith-Yessian

Linden VFT delivers power from its only customer, PSEG Energy Resources & Trade, to its facilities near the PJM border. | *DCO Energy*

Stakeholders in New York are challenging a proposed revision to PJM's tariff that they say could saddle them with some of the $1.07 billion New Jersey regulators have agreed to pay for transmission upgrades to accommodate the Garden State's offshore wind projects.

The PJM Transmission Owners filed a proposal Aug. 19 to assign the costs of the transmission upgrades to New Jersey ratepayers on a load-share ratio basis, and provided additional information, in response to a FERC deficiency letter, on Oct. 5 (*ER22-2690*).

The TOs' filings prompted a protest Oct. 31 by Long Island Power Authority, New York Power Authority and three merchant transmission facilities, Neptune Regional Transmission System, Linden VFT, and Hudson Transmission Partners (filing as the "MTF Parties"), who said the tariff change could lead to cost assessments on parties outside of New Jersey, in violation of PJM's State Agreement Approach. The SAA allows states to sponsor transmission to support their public policy needs while requiring them to pay 100% of the costs. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

The MTF Parties said they were alarmed by the TOs' response to the deficiency letter, which suggested they could face costs if FERC rejects an uncontested settlement in a separate dispute over revisions to PJM's border rate, which has not been increased since 2004 (*ER19-2105*). (See *Settlement Hearing Set for PJM Border Rate Dispute*.)

Linden said the proposed changes would increase its border rate charges from $6.1 million to about $16 million annually, leaving it insolvent or forcing it to change its business model. Under the settlement, the border rates would more than double over seven years but with discounts for customers using transmission paths from PJM to the three MTFs. The settlement, which was certified as uncontested in December 2021, awaits commission action.

In their response to FERC's deficiency letter in the SAA docket, the PJM TOs stated that "even if the commission declines to approve the border rate settlement and at some point in the future the revenue requirement of projects constructed under Rate Schedule FERC No. 49 is included in the border yearly charge, it would constitute only a very small fraction of the border yearly charge applicable to point-to-point transmission service with a point of delivery to an MTF."

The MTF Parties asked FERC to revise the SAA cost allocation provisions to require that cost responsibility apply only to firm point-to-point transmission service within New Jersey "for the delivery of energy to, and consumption of such energy by, native load customers within the state of New Jersey." It also requests that language be added that precludes border of PJM service customers from being assigned any cost responsibility

"The commission must further make clear that border rate service is excluded from cost responsibility for the NJ-SAA projects — and that principle and commitment by the NJ BPU cannot be undermined by indirect means," they said.

The New Jersey Board of Public Utilities and the TOs responded to the MTF protest Nov. 10, saying the issues they raised are speculative and out of scope.

The BPU said "that if the MTFs believe that the current border rate tariff provisions may inappropriately allocate a small portion of public policy project costs to them, they should address those concerns in a separate proceeding rather than delay approval of the proposed methodology for allocating the direct costs of SAA projects."

The TOs said that when SAA projects are complete, they become a part of the PJM's integrated transmission system and border rate service does not reflect the cost of individual Regional Transmission Expansion Plan projects.

"When voluntarily requesting border rate service, the MTF Parties are paying, through the border yearly charge, for the support provided by the entire PJM transmission system to enable their export transactions — they are not paying for the costs of specific RTEP projects' construction for which cost responsibility has been assigned to responsible customers," the PJM TOs said.

The 660-MW *Hudson Transmission* project connects PJM and New York City, providing power for customers of the NYPA. *Neptune* operates a 660-MW 65-mile undersea and underground HVDC line from Sayreville, N.J. to Nassau County, Long Island under a long-term agreement with LIPA. *Linden VFT* delivers power from

PJM News

its only customer, PSEG Energy Resources & Trade, to its facilities near the PJM border.

$400M Reduction in Capacity Costs?

During a Nov. 4 PJM Transmission Expansion Advisory Committee special session, Committee Chair Suzanne Glatz said the RTO anticipated a resolution of the SAA revisions in October but that the deficiency letter and subsequent filings have extended that timeline to December.

PJM's TEAC presentation estimated the installation of 7,500 megawatts of offshore wind, with a 2,370-MW unforced capacity rating, could reduce the cost of capacity sold in the 2028/29 Base Residual Auction by as much as $400 million. The estimate relies on a set of *assumptions* including the 2023/24 BRA market offers and associated price mitigation rules, planning parameters remaining similar, and a 2028/29 load forecast from the RTEP study.

With those assumptions, *the estimate found* an expected $1,007,908,145 in capacity sold with no addition of offshore wind and $612,091,604 sold with the addition of the project and corresponding transmission upgrades. Each of the three alternative scenarios considered for the upgrades had approximately the same estimated impact.

The 660-MW Hudson Transmission project connects PJM and New York City, providing power for customers of the NYPA. | *Hudson Transmission Partners*

PJM cautioned that the figures it presented are not projections of future market prices and were produced to compare the impact of the transmission studies.

"The market analysis simulations were performed as a potential factor in differentiating between the transmission solutions proposed and not for the purpose of projecting or forecasting future market performance. Our intent was to compare transmission solutions; the key takeaway is that the difference in market performance between the transmission solutions studied was negligible," PJM wrote in an email.

Glen Thomas, president of PJM Power Providers, said in an interview that the PJM markets have demonstrated the ability to "absorb significant amounts of new generation," however he's concerned about the possibility for the OSW to bid into the BRA for the 2025/26 delivery year, the earliest the project is expected to come online, and construction delays resulting in that capacity not being available when the year comes. In his opinion, the project should not be permitted to participate in BRAs until there's a "reasonable assurance" that they'll be available on time.

"These projects tend to come in behind schedule and when you have a three year forward capacity market that's hard, because they have to know in [2022] if they're going to be available in [2025/26]," he said. ■

Neptune operates a 660-MW 65-mile undersea and underground HVDC line from Sayreville, N.J. to Nassau County, Long Island under a long-term agreement with LIPA. | *Neptune Regional Transmission System*

PJM Defends Quadrennial Review Parameters from Generator Protests

By Devin Leith-Yessian

PJM this month defended the proposed capacity auction parameters in its quadrennial review before FERC against two protests from the generation sector (*ER22-2984*).

The major changes proposed in the *quadrennial review filing* include shifting the reference resource from a combustion turbine to a combined cycle generator, updating the calculation of the gross cost of new entry (CONE), revising the adjustment of CONE in the years between reviews, steeping the variable resource requirement (VRR) demand curve, and shifting from a historical energy and ancillary service (EAS) offset calculation to a forward-looking approach.

The changes detailed in the Sept. 30 filing would be effective for the 2026/27 Base Residual Auction, scheduled for November 2023. The PJM proposal was endorsed by the Markets and Reliability Committee with limited support at its Aug. 24 meeting over stakeholder and Independent Market Monitor proposals. (See *No Consensus on PJM Capacity Parameters*.)

P3 Protests Transparency, VRR Curve and Forward-looking EAS

The PJM Power Providers Group (P3) *argued* that the proposed changes in PJM's filings are not just and reasonable because of insufficient transparency in the data and models used to derive the market parameters. It also said the adoption of a steeper VRR curve will disincentivize construction of new generation needed for reliability.

In the shift to a future-looking EAS, PJM would rely on "paywalled" data from private exchanges and proprietary algorithms, which P3 argued obscures the mechanisms of the market, while historical prices are a "reasonable proxy for future prices" and are easily calculated and understood.

"As currently structured, this information will not be available, and therefore, it will be challenging, if not impossible, for stakeholders (whether supply or load) to fully understand how future revenues are being calculated. The 'black box' approach to such a critical component of future capacity market performance will inject needless uncertainty into decisions related to future investments in PJM," P3 said.

It also argued that shifting the reference resource to a combined cycle generator will

Glen Thomas, P3 | © *RTO Insider LLC*

increase volatility in the capacity market by further exposing it to the fluctuations in fuel prices.

P3 President Glen Thomas said in an interview that together, the changes would increase capacity market volatility, curbing investment in generation.

"When you go to [combined cycle], you're going to expose your reference technology to those vagaries, which is going to expose net CONE to significant shifts, which will lead to significant swings in capacity prices. Yes, our organization represents suppliers, but ultimately they're going to be more motivated by stability and predictability; it's tough to sell investors on boom-bust markets, which is exactly what this capacity market is heading towards," he said.

Thomas noted that PJM President Manu Asthana made remarks at the Organization of PJM States Inc. Annual Meeting and the RTO's own Annual Meeting that laid out reliability concerns over the next decade should the introduction of renewables lag behind growing load. Thomas said those concerns clash with the RTO's proposed changes in the capacity market.

J-Power Critiques Amortization Period

The central argument of the second *protest*, from J-Power USA, is that PJM's calculation of the gross CONE could create a scenario where the combined cycle reference unit cannot be constructed in some regions without having a lifespan shorter than the 20-year amortization period because of climate legislation. It referenced the Illinois Climate and Equitable Jobs Act (CEJA), which requires that all generating units reduce carbon emissions to zero by 2045.

J-Power posits that PJM should create adjusted CONE values for the Commonwealth Edison locational deliverability area (LDA) that reflect the possibility for shortened unit lifespans in that region.

"Reliability requires the CONE values for any modeled LDA to reflect the realities faced by developers of the new resources or owners of existing resources," J-Power wrote. It added that PJM therefore "has an obligation to reflect the reduced asset life due to CEJA in ComEd when applying the CONE values to modeled LDAs."

PJM Defends Proposed Changes

PJM argued that the forward-looking EAS offset and the methodologies used in both its derivation and the calculation of CONE are commonplace in the practices of market participants and have precedent in past FERC orders.

Shifting to a forward-looking offset can better "reflect the expected range of possible supply, demand and export conditions prevailing in future delivery periods," PJM said, while a historical lookback can create "disequilibrium" under certain circumstances. The response gives the example of a lookback at a period of scarce supply, which would create a high EAS offset, reducing net CONE and scaling down the VRR curve, ultimately leading to less capacity being purchased when more is needed.

Because the market data and algorithms PJM is seeking to use under the proposal can be purchased for use by anyone, and they are already in widespread use, the RTO argued they are sufficiently transparent.

PJM also defended the proposed shift to a combined cycle reference unit by noting that no combustion turbines are currently under construction and none have been built since 2018.

"The proposal to move to a CC reference resource is consistent with current generation development trends, offers flexibility in operational parameters and produces net CONE reflecting the most economic technology. These results depart significantly from the findings underlying the 2018 quadrennial review," PJM said.

In regard to J-Power's concern about a 20-year asset life, PJM argued that it would be inappropriate to make "one-off" adjustments to an LDA through the quadrennial review. ■

PJM News

PJM Opens Poll on Co-located Load Proposals

By Devin Leith-Yessian

PJM opened a poll on Friday to gauge support for dueling proposals to revise the rules for load behind-the-meter (BTM) of a co-located generator.

The *two packages*, the first jointly drafted by Constellation Energy and Brookfield Renewable Partners and the second from the Independent Market Monitor, largely differ in how they would account for the power being consumed by the load when determining how much capacity the generator can offer into the PJM markets. Under Constellation's proposal, the facility's capacity offer would not be reduced because the energy would remain available for PJM to call upon when needed, with the BTM load curtailed.

The IMM, however, argues that the power consumed by behind-the-meter load should not be counted toward the generator's capacity offer. Its *package* would subtract the net peak load from the unit's installed capacity.

Speaking during a Nov. 17 Market Implementation Committee special session to discuss the packages prior to the opening of the poll, Constellation's Jason Barker said his *company's language* would expand customer choice by providing options for companies whose loads are curtailable and don't require the full services of the transmission grid.

"What we have seen is we have new large commercial customers that are choosing to locate highly interruptible loads behind-the-meter of generation resources, both to reduce their costs and ensure physical supply of carbon-free power," he said.

Since the amount of power produced and consumed would remain the same regardless of whether the load is placed behind or in front of the generator's meter, Barker argued that there would be no impact on prices. The arrangement would also allow for the behind-the-meter to rapidly be curtailed and that power shifted to PJM when LMPs exceed the facility's market offer, or when called upon by the RTO.

"The response time is the same as a [synchronized] reserve product. And I highlight for all of the folks on the call that we have many, many, many capacity resources that provide capacity commitments today for which their energy is callable not in minutes, but in hours or in some cases even days. So this is a superior product

Jason Barker, Constellation Energy | *© RTO Insider LLC*

to most of the capacity commitments you're getting in that respect," he said.

PJM's Independent Market Monitor Joe Bowring told the MIC that even if capacity prices remain unchanged, allowing generators to sell a portion of their energy to behind-the-meter customers while keeping that output in the capacity market would effectively reduce the amount available to PJM and send incorrect incentives to the markets about the amount of additional capacity needed to maintain reliability.

"The Constellation proposal is to sell the capacity twice, once to the behind-the-generator load and once to PJM customers," he said

"What this is really doing when you think about it is taking a resource which is providing low-cost energy, 8760 [hours a year], and providing energy for a small number of hours a year. … That will create potentially very significant issues, depending on the level of the megawatt hours taken off the system," he said. "Removal of this level of energy inputs at key points in the transmission system that was designed around these units would have extremely significant impacts on the grid. PJM should provide analysis of the impacts. PJM's analyses to date do not address the real issues, including the combined impact of multiple such requests."

Bowring said the rules need to be finalized before investments in the behind-the-meter load configurations under discussion start coming in, calling Constellation's proposal a "sea change."

To date, PJM has received requests to add 4,469 MW of co-located load behind-the-meter of 18 existing generation units, with a combined installed capacity of 15,800 MW. Of the new load requests, 3,906 MW is proposed to be configured to receive power from the generator without being interconnected to the PJM grid.

"The IMM's approximate calculations show that removal of 20,000 MW of low-cost energy could raise energy costs for other customers by billions. There is no indication that the referenced loads would join PJM in the absence of the proposal. If the loads did join PJM, they should follow the same rules as all other load," Bowring said. "There are current provisions for interruptible load that would address the stated goals."

Studies have been completed for 864 MW of the co-located load requests, which are being treated as amendments to the generators' existing interconnection service agreements under the existing rules, said Augustine Caven, PJM's manager of infrastructure coordination.

Jurisdiction Over Co-located Load Disputed

The MIC also debated the issue of whether co-located load falls under federal or state regulation at the Nov. 17 meeting. Several stakeholders argued that such loads receive the benefit of synchronized reserve, regulation and ancillary services through the generator's interconnection to the PJM grid, even if the load is not directly interconnected itself.

PJM Senior Counsel Chen Lu, who *presented* the RTO's perspective that co-located load is state regulated, said during the Oct. 13 MIC special meeting that the issue is similar to the question of power consumed by generators.

"To me this really isn't that different from the station power cases that FERC has decided. And in those cases when a generator is receiving station power, they may still be benefitting from the grid. But FERC has explained since those are not sales for resale, they weren't FERC jurisdictional and those are ultimately state jurisdictional retail sales. And so just by virtue of the fact that they may have some benefit from the grid, doesn't necessarily make it FERC jurisdictional," he said.

PJM Director of Market Settlements Initiatives Lisa Morelli said a logical extension of requiring co-located load to pay for services such as synchronized reserve would be that generators could also then be required to pay that as well.

"I think if you continue pulling that thread, that is where you would land," she said. ■

PJM MRC Briefs

MRC Approves VOM Package

The PJM Markets and Reliability Committee endorsed an RTO-sponsored package to standardize variable operations and maintenance costs, with nearly 90% sector-weighted support.

An alternative measure from Constellation Energy — which would have removed nuclear unit refueling as VOM — did not receive a vote during Wednesday's meeting. (See "Two Proposals Remain on Variable Operations and Maintenance Costs," *PJM MRC Briefs: Oct. 24, 2022*.)

If accepted by the Members Committee, the language would create default adders for minor maintenance and operating costs as an alternative to generators submitting unit-specific information, and provide definitions of major maintenance and minor maintenance for more clarity on which costs fall into each.

The default adders would be calculated based on historical maintenance values provided to PJM and would be adjusted annually using the Handy-Whitman Index.

PJM accepted a friendly amendment suggested by Adrien Ford of Old Dominion Electric Cooperative to maintain the status quo for the submission deadline, rather than moving it to March as was originally written in the proposal when it was believed the RTO and the Independent Market Monitor would be reviewing submissions in succession rather than parallel.

Constellation's Jason Barker said the company is in agreement with PJM on the key points of the VOM measure, with the exception of maintenance unique to nuclear units during planned outages, which he said can be scheduled up to three years in advance and does not vary with run time or number of starts.

Monitor Joseph Bowring said the costs of major maintenance shouldn't be included in energy offers, and called the determination from PJM and FERC to do so a mistake, but he disagreed with the notion that nuclear generation should be treated differently from other resources.

Paul Sotkiewicz of E-Cubed Policy Associates said many resource types have the sort of time-based expenses Barker outlined and asked if he would accept a friendly amendment to expand the nuclear carveout to all time-dependent maintenance. Barker responded that the amendment was too large of a change to make on the fly.

The topic isn't a "make-or-break issue for the nuclear industry," said Alex Stern of Public Service Electric and Gas, but it does make the economics of operating a carbon-free resource harder.

"The country and the region have been spending a lot of time trying to figure out how to preserve zero-emissions generation like nuclear exactly because we need baseload generation as we move toward this changing generation mix, Stern said. "So there's been a lot of customer expense being thrown at — properly so — trying to preserve reliable generation from nuclear. And I think that the concern here that Constellation is raising is that we're throwing money at trying to make nuclear economic, but we're going to take a step here that's incorrectly putting costs on nuclear."

Alex Stern, PSE&G | *© RTO Insider LLC*

Bowring responded that the PJM proposal does not impose any costs on nuclear or make any changes to the economics or margins for resource owners. Rather, it changes the markets to which the costs are assigned, not what they are. "For example, the Constellation proposal does not change the capacity market offer caps for nuclear units in any way. There is no good reason to exempt nuclear units from the rules that apply to all other units."

Stakeholders Approve Quick Fix for Capacity Replacement Transactions

The committee voted to approve an *issue charge and solution* under PJM's quick-fix rules to allow generators to replace capacity sold in a Base Residual Auction in years where there is only one Incremental Auction. The new language was approved by acclamation with two objections.

Michael Borgatti of Gabel Associates, representing Eagle Point Power Generation, said the current compressed timeline, in which there is one instead of three IAs each year, limits the opportunities for generators to engage in replacement resource transactions.

The revisions allow for capacity to be replaced if a "financially and physically firm commitment to an external sale of its capacity for the entire delivery year [has been] demonstrated with supporting evidence." The changes are limited to currently scheduled delivery years during which there is only one IA scheduled.

Stakeholders expressed some reticence about the use of quick-fix rules to make the change, noting the possibility of those with objections not having adequate time to make their voices heard, but Borgotti said there is limited time to make manual revisions in time for the next auction date.

Bowring pointed out that for any resource facing the referenced issue of wanting to sell capacity outside PJM, there are defined steps in the tariff and in the manuals.

"This proposal provides an incentive to ignore the tariff rules about how to qualify for a must-offer exemption in the capacity market, to offer and clear and then to later withdraw the commitment to sell the capacity. That affects the market prices received by all other market participants," Bowring said. "Approval of this proposal as a quick fix is effectively saying that any market participant that does not like the rules can come to the MRC at the last second and get the rules changed in their favor."

Coal Resource Permitted to Enter Maximum Emergency for Fuel Shortages

Stakeholders also approved a manual change to allow coal generators to elect to enter into maximum emergency should their fuel stores fall below 10 days, effectively exempting them from the must-offer requirement while they rebuild their inventories. Facility owners can only make the voluntary determination to seek maximum emergency status from PJM should the fuel shortage be outside of their control and not the result of economic decisions.

PJM's Chris Pilong said examples of legitimate issues beyond a facility operator's control are mine fires, floods and tight supply chains. So long as those events are reported to PJM, it can examine whether permitting maximum

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emergency is warranted. The revisions passed by acclamation with no objections and one abstention. (See *PJM Considers Changes to Max Emergency Status for Coal Plants*.)

A facility cannot be granted maximum emergency status if PJM has issued a hot or cold weather alert or conservative operations, and the RTO can deny a request for any reason. A generator can remain under maximum emergency until it has reached 21 days worth of fuel inventory, if the owner elects to terminate the condition or if PJM issues one of the aforementioned conditions.

Bowring said there are legitimate reliability concerns related to coal inventories, but the responsibility of taking on and mitigating that risk should fall on the facility owners, not PJM.

"PJM is proposing a short-term fix that is unnecessary and is inconsistent with PJM's stated objective of providing incentives for flexibility," he said.

Susan Bruce, PJM Industrial Customer Coalition | © *RTO Insider LLC*

Susan Bruce, representing the PJM Industrial Customer Coalition, questioned if the markets are realizing the full benefits of coal resources if their inventories can't be guaranteed and said there should be an oversight role to ensure owners are not managing inventories to be economically or physically withholding.

Because the changes were limited to manual revisions, only MRC approval was required, and the changes go into effect immediately.

TCPF Adjustments Permitted for Issues with Ongoing Solution

Stakeholders approved allowing PJM to modify the transmission constraint penalty factor (TCPF) in situations where the issues causing congestion are being addressed by in-progress Regional Transmission Expansion Plan projects. The revisions to the manual, tariff and Operating Agreement were passed by acclamation with one objection.

PJM's Susan Kenney said the purpose of the penalty factor is to incentivize supply or load to address constraints through short-term solutions and develop long-term investments. When such investments are already underway and there are not feasible short-term solutions, applying the penalty factor may not make sense, she said.

Kenney noted the spark for taking a look at the functioning of the penalty factor came after one of three transmission lines into Virginia's Northern Neck peninsula was put on outage for a planned upgrade in 2020.

The outage caused congestion into the peninsula, which pushed the TCPF to its default of $2,000/MWh in the real-time energy market. Because the completion of the upgrades would resolve the issue and it wouldn't be possible for new generation to be added prior to the work being finished, PJM successfully argued to FERC that the design of the penalty factor created "unjust and unreasonable energy market rates" for consumers. (See *FERC Approves Pause of PJM Tx Constraint Penalty Factor in Va.*)

A second proposal from the IMM would have broadened the criteria for adjusting the TCPF and used a different methodology to determine when to do so, but it received limited support and did not advance from the Energy Price Formation Senior Task Force. Bowring argued during the MRC's first read of the PJM package that the proposal would allow the RTO to subjectively determine penalty factors and does not address why penalty factors are triggered so often. (See "MRC Discusses Transmission Constraint Penalty Factor Revisions," *PJM MRC Briefs: Oct. 24, 2022*.)

1st Read on Proposal to Allow Flexibility for Market Participation During Defaults

PJM presented a first read of a proposal to grant flexibility for parties to continue participating in markets after a default under certain circumstances. The OA currently uses conflicting language regarding market participant involvement during a default, with some sections using "shall" and others saying "PJM may limit," though Associate General Counsel Colleen Hicks said the OA generally uses mandatory language.

The factors that could warrant allowing continued market involvement are: grid reliability, the ability to generate revenues in the future and the ability to post collateral. A fourth consideration recognizes that certain transmission customers cannot have their service terminated without FERC approval and acts more as a clarification in the package under consideration, Hicks said. The proposal would also modify the tariff with reciprocal provisions.

Other Committee Actions

The MRC also passed with no objections:

- proposed governing document changes to prohibit critical natural gas infrastructure from participating in demand response or price-responsive demand programs. The language was the same as the first read during the Oct. 24 MRC meeting. (See "Reworked Language on Critical Gas Infrastructure Participation in Demand Response Presented," *PJM MRC Briefs: Oct. 24, 2022*.)
- proposed tariff revisions that would require that financial transmission rights bilateral agreements to be reported to PJM with certain data within 48 hours of their execution. The primary economic term data that must be reported alongside the agreement includes the FTR start/end, quantity, source and price.

An anticipated vote on packages to create a "circuit breaker" that would limit extended price increases was deferred until the next MRC meeting to give sponsors time to work on the possibility of a compromise package. (See "Support for Circuit Breaker Remains Mixed," *PJM MRC Briefs: Oct. 24, 2022*.) ■

— Devin Leith-Yessian

SPP News

Governance, Resource Adequacy Key to SPP's Markets+

SPP Gathering Final Comments on Western Service Offering

By Tom Kleckner

Snow greeted attendees on the first day of SPP's Markets+ development session. | © *RTO Insider LLC*

WESTMINSTER, Colo. — Steve Wright, a newly minted member of SPP's Board of Directors who has promised to "strengthen the bridge" to the grid operator's potential members in the Western Interconnection, put his words into action last week during a two-day development session for its RTO-light Markets+ service offering.

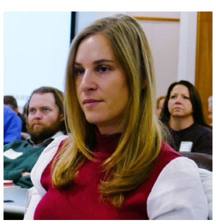
Stepping to the podium Wednesday to help open the meeting's second day, Wright fondly recalled his time in the Pacific Northwest, where he served as the Bonneville Power Administration's CEO before retiring last year as general manager of Washington's Chelan Public Utility District.

"I was always very proud of the collaboration work we did at Bonneville. We did a lot of really important stuff," Wright told stakeholders.

But that experience did little to prepare him for SPP's bottom-up, stakeholder-driven governance structure.

"Just in my short time at SPP, I see collaboration on steroids. In fact, it's almost collaboration to the point of deference to stakeholders and what they want," said Wright, who joined the board in October. (See "Membership Elects 2 New Directors," *SPP Board/Members Committee Briefs: Oct. 25, 2022*.)

Collaboration is also important to Arizona Public Service (APS), said Aly Koslow, the utility's director of federal regulatory affairs and compliance.



Aly Koslow, Arizona Public Service | © *RTO Insider LLC*

"We are really keenly focused on some of the collaboration benefits that we see [in Markets+]," she told *RTO Insider*. "The fact that we haven't had a more organized day-ahead market to join for a long time has made reaching our individual clean-energy goals a little bit less clear."

APS has a target of delivering 100% carbon-free energy by 2050. Koslow said the utility has a "good idea" about how it will reach 80% of that goal but said, "That last 20% is much more difficult to achieve. It's going to be new technology, and it's going to be collaboration."

"That is a big part of why we are looking to potentially join a market," she added.

Koslow was joined by dozens of other representatives from Western utilities at Tri-State Generation and Transmission's headquarters outside of Denver. Like APS, the potential RTO stakeholders are comparing SPP's Markets+ offering with CAISO's Western Energy Imbalance Market (EIM) and its extended day-ahead market (EDAM).

CAISO has a head start, but SPP is attempting to close the gap with a transitional real-time balancing market similar to its Western Energy Imbalance Service (WEIS). (See *SPP Briefs: Week of Nov. 7, 2022*.)

"That is a part of the dynamic out here," Garrison Marr, senior manager of power supply for Washington's Snohomish Public Utility District, said Friday of the ongoing RTO evaluation. "The value proposition is really relative to our counterfactual today of an unorganized bilateral market that can be pretty inefficient as we move through the trading trajectory."

If SPP has a leg up in the competition with CAISO, it's the RTO's governance model that gives stakeholders an enormous say over policies and processes. The grid operator says it gets that Western utilities place "high value" on having a voice in shaping the "ever-changing energy landscape" and that the "Western utility landscape represents many diverse interests that must be balanced in every decision."

"These objectives are at the heart of who SPP is and how we do what we do," SPP says in its *draft Markets+ service offering*. "Our customer-driven approach will ensure Western customers get the products and services they need at affordable rates they help control."

"This whole voting system is designed to give you power, and the board sees itself as primarily managing process to make sure we get the process that leads to the decisions that lead to as much consensus as possible," Wright said.

Mark Holman, Powerex | © *RTO Insider LLC*

SPP's potential market participants have responded positively. Mark Holman, managing director of Canadian power marketer Powerex and a vocal supporter of Markets+, said governance is one of two pillars of a successful market, along

SPP News

with resource adequacy.

"What we want to see happen in any governance framework is that we never end up with a situation where a minority of participants that are very large can drive decisions, but also that we end up with a situation where a majority of participants, but a very small share of the footprint, can drive decisions," Holman said.

SPP has proposed a five-member Markets+ Independent Panel (MIP), unaffiliated from market participants and stakeholders, that reports to the RTO's Board of Directors and oversees a Markets+ Participants Executive Committee (MPEC). The MPEC would direct the market's working groups — likely focused on operations reliability, seams and market design — and task forces; an *ad hoc* settlements group has already been proposed.

The grid operator's staff have recommended a two-tiered voting structure, with the first tier requiring a 67% approval threshold from three sectors (investor-owned utilities, public power, and public interest organizations and independents). The second tier would be a regional vote with a 51% approval threshold.

Staff hope to have the structure in place when Markets+'s first development phase begins in April. If the Phase 1 participants are unable to agree on the MIP's representation, SPP has proposed that a subcommittee of its board be used in the interim, with one of the directors staying on the MIP to smooth the transition.

Paul Suskie, the RTO's general counsel, conducted a straw poll on governance preferences by asking for a show of hands. By a 17-13 margin, stakeholders indicated they would like to stand up an MIP before Phase 1 but were not opposed to the board subcommittee structure.

SPP plans to add a Markets+ State Committee (MSC), like the Regional State Committee in the Eastern Interconnection. The Western states will determine their level of involvement and the MSC's composition during Phase 1.

Suskie told his audience that while in New Orleans earlier in the week for the National Association of Regulatory Utility Commissioners' annual meeting, a FERC commissioner told him, "You have the fewest protests at FERC because you work it out with the stakeholder process."

Staff said they have received a *large set of comments* supporting the proposal that a common resource adequacy program be a prerequisite for Market+ participation. The Western Power Pool is several steps ahead there, having begun a *Western Resource Adequacy Program* (WRAP), the West's first regional reliability planning and compliance program, at the request of regional utilities. The WPP has filed a tariff at FERC and has asked for a response by mid-December.

SPP's two-day Markets+ development session draws another large crowd. | *© RTO Insider LLC*

"We plan to respond to whatever may come, and I'm very confident that we will resolve the process in a positive manner. We're very confident that we will be operating under the tariffs shortly," WPP CEO Sarah Edmonds said, asking that those in the region "come forward" with contractual and financial commitments.

Fortunately for SPP, its staff have been working closely with WPP since 2019 in helping set up and manage the WRAP. A joint task force will be established early in Phase 1 to determine how the program will interact with Markets+.

Unlike CAISO's *EDAM* , the WRAP will not have a separate, binding resource-sufficiency test.

"A lot of us are at this table for that reason," Koslow said during the meeting. "If resource adequacy was great in CAISO, this conversation would not be happening. I'm really worried about what that might look like in EDAM."

Referring to the "challenges we've had with resource adequacy in the EIM," Russ Mantifel, Bonneville's EIM program manager, said, "It would be great … if the best landing spot for everybody was as a member of WRAP."

SPP plans to release the final service offering in late November after it addresses the comments received in Westminster and *on the draft offering*. It will engage through March with the entities who have committed to funding Phase 1; staff have projected that will cost $9.7 million and take about 21 months.

Those entities that commit to the funding will be eligible to vote on design decisions and ensure Markets+ keeps moving forward, staff said. During the phase, staff and stakeholders will work on the protocols and tariff language that will be filed at FERC. At the same time, staff will explore an opportunity to add Markets+'s energy imbalance market, with a target implementation date of June 2024.

SPP has assumed that by Phase 2, when the day-ahead market is designed, Markets+ will be about a 50-GW system with up to 30 balancing authorities and 90 market participants. The phase is estimated to take three years and cost about $130 million, staff said, based on their experience with the day-ahead *Integrated Marketplace* they launched in 2014.

Staff said they will look for ways to minimize costs for entities who choose to transition from Markets+ to SPP's RTO West. They said seven parties are expected to decide whether to become RTO members by March. ■

SPP News

FERC Partially Grants Z2 Protests Against SPP

Commission Declines to Grant Developers Financial Relief

By Tom Kleckner

Xcel lineman works on upgrades to a transmission line. | *Xcel Energy*

FERC last week partially granted three complaints by SPP members alleging the grid operator violated its tariff's terms and generator interconnection agreements (GIAs) and engaged in unduly discriminatory and preferential practices related to its revenue crediting process under Attachment Z2 (*EL19-75*, *EL19-96*, *EL19-93*).

The commission, however, rejected a similar complaint from Oklahoma Gas & Electric (*EL19-77*).

EDF Renewables, Enel Green Power North America, NextEra Energy Resources and Southern Power filed a joint complaint in May 2019 under three sections of the Federal Power Act. They argued that they are entitled to revenue credits associated with transmission service that could not have been provided but for the use of network upgrades for which they paid.

Under Attachment Z2, SPP transmission customers that fund network upgrades can be reimbursed through transmission service requests, generator interconnections or upgrades that could not have been honored "but for" the upgrades. FERC in 2020 approved the RTO's request to replace revenue credits with incremental long-term congestion rights. (See *FERC Approves SPP's 2nd Go at Dropping Z2 Credits*.)

The developers argued their companies had together funded, through their respective GIAs, almost $95 million in network upgrades owned by SPP transmission owners on the RTO's system. The first of the upgrades became operational in 2010, they said, but SPP took until 2016 to add the software required for Z2, collecting charges for service that relied on network upgrades.

In their complaint, the developers pointed out that FERC said in a 2016 response to an SPP waiver request that the grid operator had already determined that they are eligible for revenue credits associated with their funded creditable upgrades.

FERC agreed with the complainants that SPP had violated the tariff, GIAs and the filed-rate doctrine, but it denied the remaining allegations. It also declined to set the proceeding for hearing and settlement judge procedures and to grant the developers' requested relief, that being the full revenue credits and interest for transmission service SPP provided over the creditable upgrades since 2010. The commission said the underlying facts were "materially the same" as a D.C. Circuit Court of Appeals ruling in an OG&E complaint against SPP.

"We believe that exercising our authority under [Section 309 of the Federal Power Act] under these circumstances would be inappropriate for the same reasons," FERC said.

FERC Commissioner James Danly agreed in a concurring statement to all four orders, writing that "FPA Section 309 cannot be invoked to provide equitable exceptions or retroactive modifications to the filed rate. … It is not a matter of discretion."

The commission used the same arguments and reached the same decisions in complaints filed in September 2019 by Cimarron Windpower II.

It relied on some of those arguments in accepting and rejecting parts of Western Farmers Electric Cooperative's August 2019 request that it be able to recover and retain revenue credits that it said it was entitled to under its network integration transmission service agreement and Attachment Z2. FERC found the attachment does not guarantee full cost recovery for network upgrades "but merely provides the opportunity to recover such costs."

FERC rejected OG&E's complaint, filed in May 2019, that being required to refund revenue credits related to the use of OG&E's transmission facilities would violate Attachment Z2, the filed-rate doctrine, and the sponsored upgrade agreement between OG&E and SPP. The utility had also argued SPP must pay restitution if it required the revenue credits be refunded.

The commission responded by saying the upgrade agreement does not supersede the tariff, as OG&E suggested, because the agreement expressly incorporates the tariff. SPP does not have the revenue credits to provide as restitution to OG&E; those funds are with the transmission customers, who cannot be invoiced for credit payment obligations because of the tariff's one-year billing adjustment limitation, FERC said.

SPP had been trying to replace Z2 credits since 2016, when controversy arose after the grid operator identified eight years of retroactive credits and obligations that had to be resettled after staff failed to apply credits. (See *SPP Invoices Lead to Confusion on Z2 Payments*.)

The commission granted the grid operator a retroactive waiver of its tariff so that it could invoice transmission service customers for Z2 credit payment obligations dating back to 2008. However, it reversed course in March 2019, saying its original decision was prohibited by the filed-rate doctrine and the rule against retroactive ratemaking.

FERC in March 2019 issued a voluntary remand of the waiver following a D.C. Circuit ruling in a separate waiver case involving PJM. The court ruled in 2021 that the commission acted correctly in reversing the retroactive waiver. (See *DC Circuit Upholds FERC Ruling on SPP Z2 Saga*.) ■

Company Briefs

GM to Expand EV Parts Plant in Indiana

General Motors last week said it plans to invest $45 million to expand electric vehicle parts production at its casting operations in Bedford, Ind.

The investment will be used to support additional production of EV drive unit castings ahead of what the company anticipates will be a strong demand for the Chevrolet Silverado EV and GMC Sierra EV full-size pickup trucks.

GM said the expansion will begin immediately.

More: *Indianapolis Business Journal*

First Solar to Build Solar Panel Plant in Alabama

First Solar last week announced it plans to build a $1.1 billion solar panel manufacturing facility in Alabama.

The plant will be the company's fourth U.S. manufacturing facility to produce 3.5 GW of solar modules annually by 2025.

First Solar aims to produce more than 10 GW of solar modules within the next three years. The company is spending more than $4 billion to build U.S. facilities — three in Ohio, including one slated to come online during the first half of 2023.

More: *Chattanooga Times Free Press*

Envirotech Shows First Profits

EV manufacturer Envirotech Vehicles last week reported third-quarter profits of $126,749, the first profits in company history.

The company showed a loss of $850,475 in the same period last year.

Sales were $3.9 million, an increase from $709,092 last year, boosted by the sale of 37 vehicles in the quarter compared to eight the prior year.

More: *Arkansas Democrat Gazette*

Federal Briefs

FERC Unanimously Approves Commonwealth LNG Terminal

FERC last week unanimously approved the Commonwealth LNG terminal on the Louisiana coast.

The LNG project, which is expected to export 8.4 million tons of LNG a year from Cameron, La., was the first to be approved by FERC in more than two years and is expected to begin shipping in 2027.

Despite their approval, Democratic commissioners cited concerns about the project's impact on greenhouse gas emissions and communities frequently exposed to pollution.

More: *Reuters*

BOEM Identifies Draft Wind Energy Areas in Central Atlantic

The Bureau of Ocean Energy Management (BOEM) last week announced eight draft wind energy areas off the central Atlantic coast for public review and comment as part of the Biden administration's goal of deploying 30 GW of offshore wind energy by 2030.

The draft areas cover about 1.7 million acres off North Carolina, Virginia, Maryland and Delaware, with their closest points ranging from 19 to 77 nautical miles off the central Atlantic coast.

BOEM said it used a process to identify potential locations that appear most suitable for renewable energy development, taking into consideration impacts to local resources and ocean users. BOEM collaborated with the National Oceanic and Atmospheric Administration's National Centers for Coastal Ocean Science to use an ocean planning model that seeks to minimize conflicts.

More: *Department of the Interior*

Forest Service to Study Mountain Valley Pipeline Through Jefferson Forest

The U.S. Forest Service last week said it will study the environmental impact of the Mountain Valley Pipeline burrowing through a 3.5-mile stretch of the Jefferson National Forest.

The latest evaluation comes after a federal appeals court rejected two earlier approvals for the pipeline. Both times, in 2018 and again earlier this year, the 4th U.S. Circuit Court of Appeals ruled that the Forest Service did not adequately address the erosion

and sedimentation to be caused by clearing land and digging a trench for a buried pipe that will traverse steep slopes through federal woodlands.

The service said a draft environmental impact statement will be completed by January and will be followed by a 45-day public comment period.

More: *The Roanoke Times*

EPA Fines Evergy for Hazardous Chemicals at Coal Plant

The EPA last week fined Evergy $120,000 after chemicals, including arsenic, were found during groundwater monitoring near the Tecumseh Energy Center.

The company operated the center before it closed in October 2018. The plant included a four-acre area for coal ash — located less than a half mile from the Kansas River — and a 56-acre landfill. In the year before it closed, elevated levels of boron, fluoride, calcium and other chemicals were discovered at the coal ash and landfill sites. An analysis completed in January 2019 also found levels of arsenic and cobalt that violated groundwater standards at two of the coal ash disposal's monitoring wells, the EPA said.

According to the agreement, Evergy must pay $120,000, install additional monitoring wells, start sampling and take several other water monitoring steps.

More: *The Kansas City Star*

EV Registrations Rose 57% so far in 2022

EV registrations rose 57% through the first nine months of 2022 compared to the same period last year, according to Experian Automotive, as more than 530,000 new battery-EVs were registered in the U.S.

through September.

While Tesla dominated with nearly 350,000 registrations (up 50%), traditional automakers and startups accounted for 183,750 registrations — a 71% increase for non-Tesla vehicles.

More: *Automotive News*

Solar Farms Cited for Environmental Violations

The Justice Department and the EPA last week cited four companies that developed

solar facilities in Alabama, Idaho and Illinois, and had them pay a total of $1.3 million for violating construction permits and rules for handling groundwater.

The cases involved AL Solar A, American Falls Solar, Prairie State Solar and Big River Solar. The solar farm owners are all subsidiaries of large international companies, the government said.

The agencies said the companies used a common construction contractor and failed to take steps to control runoff water.

More: *The Associated Press*

State Briefs

ARKANSAS

Entergy Agrees to Carbon-free Energy for Federal Customers

Entergy Arkansas last week agreed to provide more electricity from carbon-free sources to federal facilities in the state.

The agreement was struck to help federal agencies in the state meet President Biden's Executive Order 14057, issued last December to reduce emissions across federal agencies and invest in clean energy industries and manufacturing. The goal of the agreement is to ensure at least 50% carbon-free electricity eventually would be provided continually.

The utility's federal customers include Little Rock Air Force Base, the Clinton Presidential Center, the Pine Bluff Arsenal, federal prisons and the U.S. Food and Drug Administration's National Center for Toxicological Research laboratories.

More: *Northwest Arkansas Democrat Gazette*

CALIFORNIA

Alameda County Approves Grant Line Solar 1 Project

The Alameda County Board of Supervisors on Nov. 10 voted 3-0 to approve construction of the 12-acre Grant Line Solar 1 Project.

The board approved the 2-MW project, rejecting a Friends of Livermore appeal that contended the project violated provisions to protect open land.

More: *The Independent*

Marin County Mandates All-electric New Construction

Marin County supervisors last week voted unanimously to approve an ordinance mandating that all new residential and commercial construction must be all electric, effective Jan. 1.

The ordinance also includes provisions designed to cut greenhouse gas emissions by reducing natural gas use. Natural gas accounted for 26% of Marin's countywide greenhouse emissions in 2020.

The county is not contemplating all-electric requirements for renovations or remodels of existing buildings, nor does it intend to require appliance swaps at the time of replacement.

More: *Marin Independent Journal*

FLORIDA

PSC Approves Plans to Harden Grid

The Public Service Commission last week approved four plans submitted by utilities allowing roughly $22 billion for efforts to "harden" the state's grid over the next 10 years.

Florida Power & Light, Duke Energy Florida, the Florida Public Utilities Company, and Tampa Electric each submitted petitions, asking for approval to stormproof their systems in the event of extreme weather events.

The PSC will vote on the cost recovery plans in a set of hearings beginning this month

More: *WFLA*

ILLINOIS

Logan County Board Approves Wind Farm

The Logan County Board last week voted 5-4 to approve plans for the Top Hat Wind Farm project despite opposition from residents.

Several members cited the need for the revenue the project is expected to generate while another member said officials should reevaluate spending priorities instead. Opposing residents expressed concerns about the farm's potential effect on doppler radar data.

The project is slated to include 60 turbines.

More: *The Pantagraph*

MICHIGAN

Groveland Mine Site Being Developed into Solar Farm

The Groveland Mine site, which sat vacant for 42 years, is being developed into a solar farm by Circle Power Renewables.

The next step is for Circle Power to obtain permits from three townships. Once the solar farm is constructed, Circle Power says it will provide power to the region for at least 30 years.

The project is expected to cost $100 million and should take a year to construct.

More: *WLUC*

PSC Approves DTE Rate Hike

The Public Service Commission last week voted to approve a DTE Energy rate increase totaling $30.56 million annually. The amount is less than 10% of the $388 million DTE originally requested.

DTE said it needs the extra revenue to fund infrastructure improvements that would prevent outages and improve worker safety. It has not had a rate increase since before the COVID-19 pandemic.

The increase will raise average residential bills by less than 1%.

More: *ProPublica*

MINNESOTA

Clean Energy Poised to Take Priority in New Dem-controlled Legislature

Legislators and clean-energy advocates are planning to pass an ambitious climate agenda now that Democrats have won control of the legislature and the governor's office. The Democratic caucus in the House has several climate initiatives it hopes to update, pass in the Senate, and send to Gov. Tim Walz next year. Walz and Democrats ran on getting to 100% clean energy by 2040. The version of a bill that passed the House last session would commit all state utilities to reach 100% carbon-free energy by 2040, with benchmarks every five years. A 100% clean energy bill would align Minnesota with 15 other states, Puerto Rico, and Washington, D.C., which have 100% clean or renewable energy goals enshrined by law or executive order.

More: *Sahan Journal*

NEW MEXICO

Commission Votes Against Solar Farms

The Roswell-Chaves County Extraterritorial Commission last week voted against three proposed solar projects after hearing objections from residents.

Residents' concerns included decreased property values, rising temperatures, and possible radiation. Some residents also expressed concerns that the panels contain hazardous substances, even though the developers said that is not the case with their products.

The decision will be final unless appealed to the Extraterritorial Zoning Authority.

More: *Roswell Daily Record*

NORTH CAROLINA

Scientists Oppose Duke Energy's Plans for More Gas-fired Plants

A group of 45 scientists are urging state officials not to approve Duke Energy's plan to build more gas-fired power plants, as Duke looks to expand its natural gas use as part of a plan to reduce and eliminate carbon emissions by 2050.

In a letter to Gov. Roy Cooper and Duke CEO Lynn Good, the scientists said Duke should "begin winding down" its use of natural gas. The scientists want to see more solar and wind power and battery storage.

The Utilities Commission has until Dec. 31 to approve a carbon plan that meets the state's climate goals. They include reducing greenhouse gas emissions from power plants by 70% from 2005 levels by 2030, and to net zero by 2050.

More: *WFAE*

OKLAHOMA

PSO Seeks Permit to Buy 1 GW Wind, Solar Portfolio

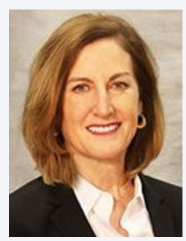
The Public Service Company of Oklahoma (PSO) last week said it is seeking Corporation Commission approval to acquire a 999.5-MW portfolio of wind and solar projects in Texas and Kansas that represent an investment of $2.47 billion.

PSO is targeting six projects that have been identified through a competitive bidding process and are expected to become operational by the end of 2025.

More: *Renewables Now*

VIRGINIA

Jagdmann Resigns from SCC



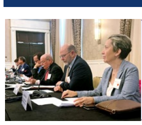
State Corporation Commissioner **Judith Jagdmann** announced last week that she will resign from her post, effective Dec. 31.

Jagdmann, a commissioner since 2006, announced her plans in a letter to General Assembly leaders. She said she will be available for recall in January to maintain a quorum and give the General Assembly a chance to elect her successor.

Her resignation will create a second vacancy on the three-member board and leave Jehmal Hudson as the only remaining member.

More: *Richmond Times-Dispatch*

National/Federal news from our other channels



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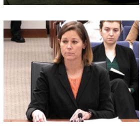

FERC Addresses IBRs in Multiple Orders

ERO Insider

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