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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: Marc Joseph, labor representative from IBEW, opposed prior legislation to transform CAISO into an RTO, but labor's stance has since shifted. | *IBEW*

RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

CPower Event Charts the Future of Virtual Power Plants

By James Downing

NATIONAL HARBOR, Md. — The demand response business has changed so much in recent years that the term has fallen out of favor for "virtual power plants" (VPPs), and the trend is only going to continue as residential customers adopt more distributed energy resources.

The only thing aggregators like LS Power subsidiary CPower used to deal with was actual customer demand, CEO Michael Smith said in an interview on the sidelines of an event his company hosted on Jan. 23.

"Now we have on-site solar and storage," Smith said. "Now we have a lot of backup generation fuel cells. We have interruptible computing loads, so we talked about data centers, or Bitcoin mining, that can change their load profile and actually change their operations. So, all of these things give us more tools in the toolbox. At the same time, the needs of the grid have become more complex."

With residential customers getting more involved in the electric grid with the adoption of electric cars, distributed solar and batteries, and smart appliances, that shift is only going to accelerate.

"I think that the overall residential market just in terms of gigawatt-hours is going to be larger than the C&I [commercial and industrial] market, if you think about water, heaters, AC, that kind of thing," Smith said. "But getting to it is a challenge; it's a data challenge. But it's also a controls challenge that has to be highly, highly automated."

Many of the large C&I customers that CPower serves trim their demand at least in part by having an employee flip a switch, but residential customers need to have that process, Smith said.

That looming change has caught the attention of the U.S. Department of Energy, which is increasingly focused on helping VPPs roll out across the country, said Loan Programs Office Senior Adviser Jennifer Downing (no relation to reporter), who wrote the department's "Pathways to Commercial Liftoff" report for the technology. (See *DOE Report Lays out Commercialization Path for VPPs*.)

"Well, a big reason why now is that we are about to experience a tsunami of DER adoption," Downing said in public remarks. "And that's true across three categories of DERs."

From left: CPower CEO Michael Smith, REV Renewables CEO Edward Sondey, EVGo CEO Badar Khan and Endurant CEO Tom Chadwick | © *RTO Insider LLC*

Generation DERs like solar; flexible loads like smart thermostats and water heaters; and distributed batteries are all rolling out over the next decade with almost 25 GWh of capacity by 2030, she said, which pales in comparison to the amount of new load from electric vehicles over the same time period that will add hundreds of megawatts of batteries to be served by the grid. Not all the EVs will be plugged in at once, and often they will be unable to shift when they charge.

"But if even a fraction of this capacity is available to virtual power plants to help balance supply and demand of the grid, that's an enormous potential," Downing said.

The ability to orchestrate when some of those cars are charged will be key to supplying them with power reliably and affordably, and VPPs can make that happen, Smith said.

All the changes going on now are transforming the grid, which has generally operated the same way it has since the days of Thomas Edison and Nikola Tesla, she said.

"But now with increased distributed generation, we're finally changing the physicality [of] the grid, which is what we're experiencing right now," she added. "So, it's a balance: We're always going to have central station generation, [but] we're going to have less of it relative to the overall kind of load demand needs of the grid. More of that demand will be satisfied via on-site generation."

Solar is the main agent of change, but storage and fuel cells and other technologies will also play a part. That change is going to impact how much transmission and distribution grids are operated, Smith said.

FERC Order 2222

FERC Order 2222 was meant to set the stage for that transition, and while it does represent a major step forward, Smith and other CPower executives at a media briefing said that its implementation has fallen short of what the VPP industry would have liked. The implementation was dogged by questions about cost and jurisdiction, said Kenneth Schisler, CPower senior vice president of regulatory and government affairs.

"But it was a very positive step in the right direction," Schisler said. "So, let's recognize that regulation gets to where it needs to be over a period of time. I think we have to acknowledge that even in the markets where we're not as happy with the result of the implementation

FERC/Federal News

of Order 2222, it's a positive step in the next direction."

FERC left a lot of discretion on the details up to the ISO/RTOs and their utilities, which has led to uneven implementation and will likely require a follow-up "Order 2223," he added.

No regulator or politician is going to be able to stop the tidal wave of DERs that Downing spoke of, and that transition would be better served by having them play well with the wholesale markets, Schisler said.

"The question is, do you want these resources operating in the underbrush?" Schisler said. "Or do you want them aggregated where you have visibility and a level of control, and you can begin to model and plan around their expected behaviors? And that's, I think, where we have a very positive contribution to make."

NYISO is the only organized market that has changed its participation model, with all the others using the old DR participation model that does not reflect the major changes the industry has seen in recent years, he added.

One common issue with ISO/RTOs is they still tend to plan around large, central-station power plants, said CPower Senior Director Aaron Breidenbaugh.

"If the only tool you have is a hammer, every problem looks like a nail, and to them every problem looks like a 500-MW power plant," he added. "So, of course, you have to have six-second telemetry. So, of course, it has to be nodally located, or it's going to completely screw up the price. Of course, it has to be individually metered."

While FERC has some work left to do on VPPs and DER integration, the bulk of the activity is going to happen at the state level, where regulators have primary jurisdiction over the distribution system, Schisler said. State laws are helping to drive increased adoption of DERs, and even once skeptical states have started to embrace the role aggregators like CPower can play in coordinating those new resources.

FERC Order 719 required ISO/RTOs to remove barriers to DR, but it also let states opt out of letting their customers participate in wholesale markets as DR. That was included in the 2008 order because some states felt that DR could be a backdoor way into federally mandated retail competition, Schisler said.

The commission could end that opt-out now after some recent court findings; it has a pending complaint before it asking it to do so (*EL21-12*), while U.S. Rep Sean Casten (D-Ill.) has introduced legislation requiring that step. But Schisler argued that the issue should not be forced onto states.

"I think the opt-out is not constructive, and I would prefer it not be there; taking it away is a different proposition," he added. "And our approach has been to work with states in the Midwest, and we've enjoyed a fair amount of success in the last year. We're seeing great progress and in states like Michigan, Missouri and Indiana."

Missouri especially was a landmark case in part because it never even considered endorsing retail competition, but now it has opened to third-party aggregators like CPower. It is also split between multiple wholesale markets.

"If a state like Missouri that has figured out a model to make it work, you know, I think other states will follow suit," Schisler said. ■

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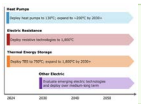

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FERC/Federal News

FERC, NRC Examine State of the Nuclear Industry

Members of FERC and the NRC meet at the commission's headquarters in D.C. | *FERC*

By James Downing

FERC and the Nuclear Regulatory Commission convened a joint meeting Jan. 25 to examine issues of common interest, including the rollout of advanced reactors and grid reliability.

FERC Commissioner Mark Christie said nuclear power has two advantages.

"No. 1, it's carbon free, and that's great," Christie said. "No. 2, it runs all the time. Not two weeks, but two months, three months, six months — it runs all the time. So that's great. So basically, any future where you want to have … reliable power and reduce carbon emissions, it's got to include nuclear."

The future of the technology seems to be centered on small modular reactors, he added. The NRC is expecting 25 applications involving SMRs in the next five years, said Andrea Kock, deputy office director for engineering for the agency's Office of Nuclear Reactor Regulation.

"Those are potential applicants that have come to us and stated that they intend to submit an application, and it spans technologies from things that look a lot like what we currently have, but smaller, to some really advanced designs," Kock said.

The regulator has resolved more than 35 technical and policy issues and issued more than 60 guidance documents to support those reviews, Kock said. NRC is also using a graded approach that will focus on the most significant safety issues.

"The NRC is doing things differently to yield timely and cost-effective reviews without compromising on safety," she added.

FERC Commissioner Allison Clements asked about the impact of the recent decision by NuScale Power and Utah Associated Municipal Power Systems to end the development of the SMR-based Carbon Free Power Project in Idaho. (See *Pioneering NuScale Small Modular Reactor Canceled*.)

Kock said the NRC is still reviewing that reactor design to allow it to be used by another project in the future if it winds up being approved.

SMRs and even smaller "microreactors," which adapt the technology used to fuel submarines and aircraft carriers to civilian uses, present new issues the NRC has encountered before, Kock said. Such reactors will be built in a central factory and transported to where they are used, presenting novel regulatory issues, she added.

The smaller reactors also bring up questions about how much staff is needed to safely operate them, with many designed to be much more passive than traditional nuclear plants, Kock said.

Another issue is how to keep existing plants running as the country transitions to a greener grid, leading FERC Chair Willie Phillips to ask about California's quest to keep the Diablo Canyon nuclear plant running and what factors policymakers should consider to keep existing plants online. (See *Diablo Canyon Secures $1.1B DOE Award to Support Operations*.)

One factor influencing the decision is how much energy a plant is producing, said David Ortiz, director of FERC's Office of Electric Reliability.

"Nuclear plants are essentially energy resources because they're on all the time," Ortiz said.

"The next [factor] is the services that those provide," he said, noting that the impact on voltage control is the transmission system support function that planners typically assess when a nuclear plant seeks to retire,

It will be important to study more than just voltage in the future because retirements can lead to other system issues, he added.

NRC is expecting to field a significant number of license renewal applications that would extend plant operations to 80 years, in part because of federal support for existing nuclear under the Inflation Reduction Act with the Civil Nuclear Credit Program, Kock said. (See *DOE Opens IIJA Nuclear Credit Program to Recently Closed Plants*.)

"We've received interest in the potential restart of the Palisades plant in Michigan, which is now looking to restart by August of 2025," she said. ■

FERC/Federal News

Biden Admin to Evaluate LNG Terminal's Impact on Climate

By Jon Lamson

The Biden administration *announced* Jan. 26 that it will delay its decision on a major LNG export terminal in order to evaluate the project's climate impacts.

The delay could extend through the elections in November and could affect 16 other proposed export terminals, according to a report in *The New York Times*.

The decision comes on the heels of an extended pressure campaign from climate activists to stop the projects, with focused opposition on the Calcasieu Pass 2 (CP2) project in Louisiana. If approved, CP2 would be the largest LNG export terminal in the country, with a capacity of about 20 million tons of natural gas per year.

CP2 needs to be first approved by FERC, which evaluates projects' direct environmental impacts, before it moves to the Department of Energy, which decides whether the export of the fuel is in the public interest, which includes the consideration of upstream and downstream GHG emissions.

But those evaluations do not include any estimate of those emissions' cumulative impact on climate change. The *Times* reported that the White House has asked DOE to analyze that, as well as the project's impact on the economy and national security.

CP2 would essentially be an expansion of an existing export terminal in Cameron Parish, La. FERC approved the first terminal in May 2019, though not without debate among the commissioners over the climate issue. Former Commissioner Richard Glick (D) insisted that FERC had been directed by the D.C. Circuit Court of Appeals to evaluate proposed gas projects' impacts on climate change, and he dissented on the approval. (See *Glick Disputes FERC 'Breakthrough' on LNG Projects*.) The commission had reached a compromise in which it quantified the upstream and downstream emissions but made no determination as to their impact on climate change.

FERC has continued to insist it cannot "determine credibly whether the reasonably foreseeable GHG emissions associated with a project are significant or not significant in terms of their impact on global climate change"; Commissioner Allison Clements (D) has continued to disagree. (See related story, *FERC Approves Pipeline to Supply New TVA Cumberland Gas Plant*.)

Climate activist and author Bill McKibben, one of the project's leading opponents, *called* the delay "the biggest thing a U.S. president has ever done to stand up to the fossil fuel industry."

A December *letter* to the Biden administration signed by 170 scientists said the current queue of LNG export terminals "could lead to 3.9 billion tons of greenhouse gas emissions annually, which is larger than the entire annual emissions of the European Union."

The letter cited *preliminary research* from climate scientist Robert Howarth of Cornell University that found lifecycle carbon emissions of LNG are between 24 and 274% higher than coal.

While scientists and climate activists have applauded the decision, it has been met with outcry from the fossil fuel industry. The American Petroleum Institute *reposted* an opinion from *The Wall Street Journal* Editorial Board arguing that the delay "won't reduce global emissions" but "would be a gift to America's adversaries and show Europe that the U.S. isn't a reliable ally."

Senate Minority Leader Mitch McConnell (R-Ky.) called the delay "a functional ban on new LNG export permits," *adding* that the administration's "deference to climate extremists continues to sell out American consumers and U.S. allies."

A report from ClearView Energy Partners noted that the climate review requirement seems likely to extend to all 17 proposed LNG export projects, although this has yet to be announced. ClearView added that the delay is unlikely to be well received by the U.S.' European allies, who have relied on LNG exports amid Russia's invasion of Ukraine.

"If a pause is in the offing, the issue would seem more a political matter than an economic or diplomatic one — that is, mobilizing young, climate-focused voters who could make a difference in closely contested 'swing' states," ClearView said.

According to the *Times*' report, the White House is unconcerned about CP2's contribution specifically, as the U.S. is already exporting so much gas.

A new *report* from Friends of the Earth, Public Citizen and BailoutWatch pushed back on the narrative that increased LNG exports are needed to support European allies.

"Contracts with European customers represent the smallest share (18%) from pending LNG facilities," the report found. "Contracts with Asia Pacific customers account for 30% of total volume, with the remaining 52% going to commodity firms and other portfolio buyers."

The report also said Europe is on track to reduce gas consumption in half by 2030 compared to 2019 levels and concluded that "long-term infrastructure is a poor solution to short-term supply needs."

Ultimately, the outcome of the pending projects may hinge on the results of the 2024 election. The two remaining Republican contenders, former President Donald Trump and former Ambassador to the U.N. Nikki Haley, have both expressed *strong support* for increasing domestic fossil fuel production.

"We will export as much liquefied natural gas as we can," Haley told a New Hampshire crowd in the days leading up to the state's primary Jan. 23. Shortly after, she was interrupted by several climate activists who criticized her for taking money from the fossil fuel industry. ■

Calcasieu Pass LNG Facility | *Venture Global LNG*

FERC/Federal News

FERC Approves Pipeline to Supply New TVA Cumberland Gas Plant

By Amanda Durish Cook

FERC put the Tennessee Valley Authority one step closer to replacing its Cumberland coal plant with a new natural gas plant when it permitted a new pipeline Jan. 18 (*CP22-493*).

Environmental groups have expressed displeasure with FERC's issuance of a certificate of public convenience and necessity for Tennessee Gas Pipeline's (TGP) 32-mile pipeline to feed the planned 1,450-MW Cumberland gas plant. TVA has said it could retire the first of two coal units at its 2,470-MW Cumberland Fossil Plant as early as 2026 with the new gas capacity online.

In its approval, FERC denied Sierra Club and Appalachian Voices' request for a hearing over the need for the pipeline and associated gas plant.

"Commenters assert that additional natural gas infrastructure is unnecessary. Many of these commenters argue that alternative sources of energy should be used to combat climate change and that TVA's plans conflict with the climate policy of the federal government," FERC noted. However, the commission said the Tennessee Valley Authority Act bestows the utility's board of directors with the "exclusive authority" to evaluate the need for generation facilities within the service territory.

FERC asserted that it did its due diligence under the National Environmental Policy Act (NEPA) to approve the pipeline. It said it found no evidence of self-dealing when TGP entered into a binding precedent agreement with the unaffiliated TVA for the project's full capacity.

The Sierra Club, Appalachian Voices and the Center for Biological Diversity, represented by the Southern Environmental Law Center, filed a lawsuit in mid-June in the U.S. District Court for Middle Tennessee, centered around what they claim were NEPA violations with the pipeline's planning. The lawsuit claims TVA disobeyed NEPA by committing to a new natural gas plant too early in the process, failing to seriously consider carbon-free alternatives, and ignoring the climate harms and volatile fuel costs the community will bear.

In their FERC protest, the groups repeated claims that TVA signed contracts for final design work on the pipeline before the NEPA process was completed.

Cumberland Fossil Plant | *Tennessee Valley Authority*

SELC, on behalf of Sierra Club and Appalachian Voices, is also challenging a state permit from the Tennessee Department of Environment and Conservation, saying the agency ignored the harm the pipeline will inflict on local waterways. (See *TVA's Cumberland Coal-to-gas Plans Press on over Resistance*.)

FERC estimated that TVA exchanging coal for gas at the Cumberland site would cut greenhouse gas emissions by about 7 million metric tons annually.

The commission said that because the pipeline will feed a project that ultimately lowers emissions, it cannot be considered harmful for NEPA purposes.

"A net reduction in the emissions of a pollutant logically cannot cause a significant adverse impact under NEPA," FERC said.

FERC estimated that the social cost of greenhouse gas emissions from the project could range from nearly -$1.9 billion to -$21 billion, reflectively a net decrease in overall downstream emissions, but it said it was including the figures for informational purposes only. It said its calculations don't conclusively determine whether the project will have a significant effect on climate change. FERC also said NEPA doesn't outline criteria on how to come up with monetized values to establish the magnitude of future pollutants.

"The D.C. Circuit [Court of Appeals] has repeatedly upheld the commission's decisions not to use the social cost of carbon, including to assess significance," FERC said.

Commissioner Allison Clements dissented from parts of the order in which FERC claimed it was impossible to assess the significance of greenhouse gas emissions. Clements has long argued that FERC hasn't tried to evaluate methods.

"This is the same language I have criticized many times. It does not improve with age," she said.

The SELC said FERC's decision to greenlight the pipeline "ignores the significant and long-lasting damage it will do to the climate, utility customers and Tennessee communities." The group also blasted TVA's "massive, multibillion-dollar fossil fuel spending spree."

"FERC commissioners moved to recklessly rubber-stamp this project without fully evaluating the harm this unnecessary pipeline would do to families throughout the Tennessee Valley," SELC senior attorney Amanda Garcia said in a press release. Garcia added that "clean energy technology is already more cost effective than building new gas plants and pipelines."

SELC repeated that TVA's investment in natural gas "works against" the Biden administration's goal for a carbon-free grid by 2035.

"It is irresponsible and regressive to permit new fossil-fueled power plants and pipelines that will worsen the climate crisis, create more energy vulnerabilities and increase electric bills," Sierra Club field organizing strategist Amy Kelly said. ■

FERC/Federal News

Clean Energy Advocates Call on States to Step up Support for Storage

By Jon Lamson

While the deployment of utility-scale battery storage has accelerated in recent years, additional regulatory and policy support is needed to scale up the industry and fully realize its potential benefit to the grid, a *panel of experts* convened by the Clean Energy States Alliance said Jan. 29.

The panel's discussion focused on the lack of revenue available to battery storage resources in restructured wholesale markets, despite studies showing overall cost savings associated with deploying large-scale solar on the grid.

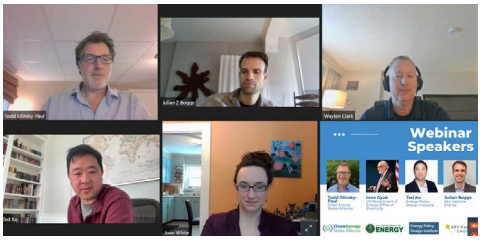
"The revenue does not equal the costs, so we need state support, and we need policy," said Julian Boggs, director of state policy for Key Capture Energy.

Boggs pointed to the large risks investors assume when developing battery storage projects that rely on wholesale market revenues. For the industry to reach the scale needed to support the clean energy transition, "it's going to take a lot more certainty in those revenues," Boggs said.

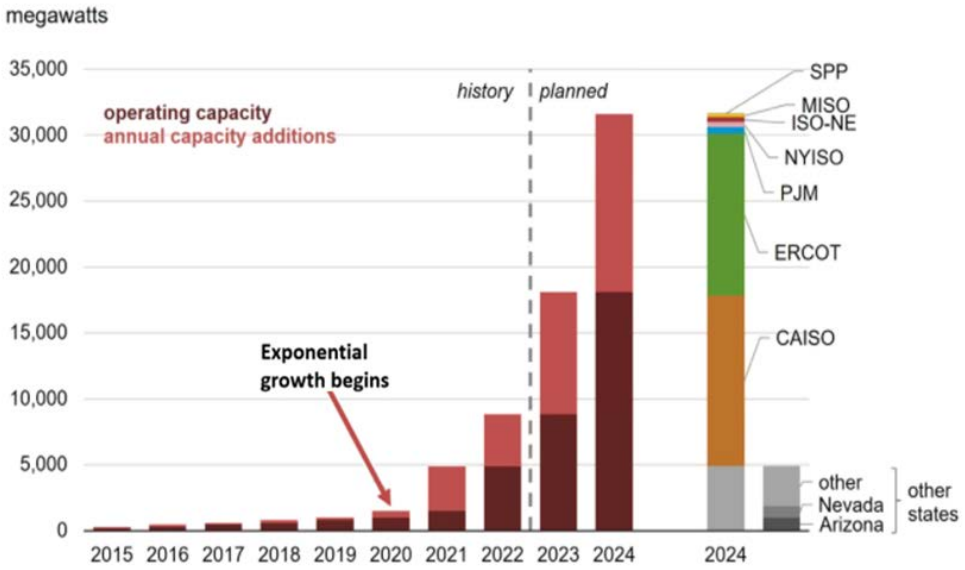
States should step up to help provide this stability, Boggs added. "You need long-term contracts at scale; that's the name of the game. I think policy makers are increasingly getting that."

Joan White, director of storage and interconnection for the Solar Energy Industries Association, said California and Texas have led the country in storage deployment because "the market fundamentals really are there."

"When the value of storage truly is captured in a market design, you can see a market take off in this exponential curve," White said. "We've seen that in California and Texas — they've got really big deltas between their off-peak energy and their on-peak energy costs."



Panel clockwise from top right: Todd Olinsky-Paul, Clean Energy States Alliance; Julian Boggs, Key Capture Energy; Waylon Clark, Sandia National Labs; Ted Ko, Energy Policy Design Institute; Joan White, Solar Energy Industries Association (SEIA) | *Clean Energy States Alliance*



U.S. battery storage growth | *EIA*

White added that the lack of carbon pricing in wholesale markets distorts the true value of battery storage.

"When we look at wholesale markets, there's no reflection of the cost of climate change or the cost of carbon," White said. "I think the biggest thing we can do in terms of market design is incorporate the cost of carbon into market prices."

Ted Ko, executive director of the Energy Policy Design Institute, also advocated for a carbon price, while highlighting *Massachusetts' Clean Peak Energy Standard* as an "interim solution."

The Clean Peak Energy Standard mandates that electricity suppliers buy an increasing number of certificates from qualifying clean resources, including energy storage and demand response.

"You eventually want to get to carbon pricing in the wholesale markets," Ko added.

Regarding ongoing issues with interconnection, White said FERC Order 2023 contains "a couple small wins for storage," including improvements to how system operators and transmission owners model storage resources in interconnection studies.

At the same time, White stressed that structural changes at a federal level are needed to "clean up the dumpster fire that is interconnection at the RTO level."

"In order to reach our decarbonization goals, we need a grid that is two to three times our current size, and FERC Order 2023 does not plan or finance that grid in any way," White added.

White also expressed concern that FERC Order 2222, which requires ISOs and RTOs to allow distributed energy resource aggregations to participate in wholesale markets, will not address the underlying revenue deficiencies that serve as barriers to entry.

"If the underlying market fundamentals aren't there … the resources aren't going to show up," White said. "The timeline is long, and the revenue isn't there in most markets."

Looking at the long-term outlook of the battery storage industry, the panelists also emphasized the need for strong regulations and standards around fire safety.

"Getting fire safety right is a must, must, must for the industry," said Boggs, who expressed support for requirements for storage systems to follow the National Fire Protection Association's 855 *standard*, submit emergency response plans, and provide emergency training for first responders.

"This is coming whether we ask for it or not," Boggs said. ■

FERC/Federal News

Transmission Coalition to Fight for Expanded Grid

New Paper Puts Dollar Amounts on how Transmission Expansion Impacts Incumbent Generators

By James Downing

A new coalition called *Transmission Possible* launched Jan. 25 to support local, state and federal efforts to expand transmission, while a recent paper from the National Bureau of Economic Research (NBER) put some numbers on an issue that has often complicated those efforts.

The new group is led by Advanced Energy United, and it includes the American Council on Renewable Energy, Americans for a Clean Energy Grid, the National Wildlife Federation, the Environmental League of Massachusetts and the Northeast Energy Council.

"Much of America's transmission infrastructure was built in the 1950s and '60s, and even though the technology has come a long way since then, we really haven't made any significant improvements to the grid in 70 years," said Verna Mandez, a director at Advanced Energy United who is overseeing Transmission Possible. "America and its energy needs are growing, and building interregional transmission lines is the way we ensure we have a reliable power grid that cost-effectively delivers energy from where it's generated to where it's needed."

Transmission Possible's campaign will encourage regional collaboration among states to plan lines across their transmission lines. It will endorse state policies that encourage the buildout of transmission lines.

The campaign will support deployment of immediate solutions to grid congestion, such as high-performance conductors and grid-enhancing technologies (GETs). It will also host a resource hub for decision-makers, stakeholders and the public about the role of transmission in ensuring grid reliability and accelerating the transition to clean energy.

Reaching the goal of 100% clean electricity by 2035 will require as many as 91,000 miles of new transmission lines over the next decade, while in the interim, the deployment of GETs could unlock as much as 40% more capacity from existing lines.

National Bureau of Economic Research Paper

A recent paper from the NBER put some firm numbers on a commonly cited barrier to transmission expansion: When lines open up isolated patches of the grid to greater competition, it cuts the prices for local generators.

"*Power Flows: Transmission Lines and Corporate Profits*" by Catherine Hausman, an associate professor at the University of Michigan's Gerald R. Ford School of Public Policy, examined the issue using publicly available data on generators in MISO and SPP. While other papers have mentioned the issue of utilities trying to protect their generators' income, Hausman estimated how fully expanding the two regions' grids to fully tap their rich wind resources would impact generators' profits.

The cost of transmission constraints has been on the rise, averaging $300 million to $400 million from 2016 to 2020, while spiking up to $2 billion in 2022 because of rising curtailments and higher natural gas prices.

"The transmission network until recently basically did what it needed to: connecting thermal power plants to load in population centers," the paper said. "But in a world with increasing quantities of renewable generation, the existing network doesn't match the spatial distribution of generation."

Lower natural gas prices in the 2010s also flattened the marketwide marginal cost for electricity, which minimized the impact of constraints.

"But with natural gas prices surging up, the marginal cost curve has rotated, and dispatching the 'wrong' unit — because of something like a regional transmission constraint — has gotten much more expensive," the paper said.

The $2 billion from 2022 could be justified if the cost of building new transmission is very high, but the paper noted that many grid observers have argued that the planning process does not lead to socially optimal investments, especially when it comes to long-distance lines crossing regions.

"The rise in wind energy in recent years has decreased profits for fossil incumbents — but crucially, by less than it would have had the market been fully integrated," the paper said. "That is, fossil incumbents have been partially protected from new competitors by a lack of transmission."

The overall impact masks important differences, with the paper finding that firms in MISO South (Entergy's territory) would lose the most because it has poorer transmission connections to the rest of the market.

| © RTO Insider LLC

If the grid were fully expanded, just four firms would stand to lose $1.6 billion, or three-quarters of the total inefficiencies seen in 2022. In other years, the number would have been smaller, but those firms' share would have been similar.

The firms that would have benefited the most are in Iowa, Illinois and Missouri, and they would have brought in about $1 billion in 2022, while wind farms would have earned an additional $800 million. The wind farms' extra profit would have been spread wide across many facilities, though the paper noted that NextEra Energy owns many of them in the region.

Entergy Arkansas and Entergy Louisiana would lose the most from the expanded grid, at a combined $930 million in 2022. Renewable energy advocates and others have alleged that the firm has tried to delay or cancel transmission improvements, the paper said.

"The results in this section suggest that the current planning process is problematic given the fact that market integration is expected to bring very large losses to some incumbents," the paper said. ■

CAISO/West News

Former Opponents Shift Position on CAISO Regionalization

IBEW, CMUA Strongly Support West-Wide Governance Pathways Initiative

By Ayla Burnett

Some of the staunchest in-state opponents of California's past efforts to "regionalize" CAISO have shifted their views on the issue.

The change of heart comes as participants in the West-Wide Governance Pathways Initiative work to build the framework for an independent Western RTO expressly designed to include — and use the capabilities of — the ISO.

Previous attempts to expand CAISO into a broader regional organized electricity market have been met with strong opposition both inside and outside California.

For electricity sector stakeholders in the rest of the West, the ISO's lack of independent governance — its board is appointed by the governor of California — has long been a nonstarter for deeper integration.

To address the governance problem, California supporters of CAISO regionalization attempted three times to advance state legislation for an independent ISO board. Three times they failed in the face of in-state opposition.

In 2016, then-Gov. Jerry Brown (D), a key supporter of an expanded and independently governed CAISO, halted the first such effort before a final bill could be crafted, citing the need to give state agencies more time to put together a politically acceptable proposal. (See *Governor Delays CAISO Regionalization Effort*.) But that pause yielded little progress, and AB 813, a bill to convert CAISO into a multistate entity, died in committee at the end of both the 2017 and *2018* legislative sessions in the face of opposition from a handful of key constituencies.

The reasons for resisting that bill varied.

For the International Brotherhood of Electrical Workers (IBEW) labor union, the change would expand the boundaries of the CAISO balancing authority area in a way that could mean that the portion of projects that California's renewable portfolio standard required to be interconnected directly to the ISO's BAA could be built outside the state, reducing job opportunities for members.

The California chapter of the Sierra Club worried that an RTO binding CAISO with PacifiCorp, a six-state utility with a large coal generation portfolio, would water down the impact of California's environmental policies pushing for renewable generation.

Marc Joseph, labor representative from IBEW, opposed prior legislation to transform CAISO into an RTO, but labor's stance has since shifted. | *IBEW*

Groups such as the California Municipal Utilities Association (CMUA) and consumer advocacy group The Utility Reform Network (TURN) warned about the potential effect on consumer rates and the ISO's mission to serve the interests of Californians.

But sentiments among previous opponents appear to be shifting as the Pathways Initiative, launched last summer by a group of utility commissioners from five states, works to build an independently governed RTO on the foundation of CAISO's real-time Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). *RTO Insider* reached out to representatives of those groups to learn more about how and why their views have changed.

'Fair and Balanced'

Marc Joseph, an IBEW representative who sits on the Pathways Initiative's Launch Committee, spoke about labor's opposition to AB 813 during a Dec. 15 update from the committee.

"We opposed the prior legislation because it would have resulted in exporting thousands of jobs building new generation and transmission created by California's RPS [Renewables Portfolio Standard] law from California to other states," Joseph said.

But the initiative's approach to the governance issue has led the union to reconsider its position.

"The key substantive difference between the prior legislation and the current options is under all the current options the CAISO's balancing authority function would remain intact," Joseph said. "We're supporting the Pathways Initiative because, like everyone else here, we're acting in our own rational self-interest."

In an interview with *RTO Insider*, Joseph again emphasized that regionalizing without expanding the physical boundaries of CAISO's BA would keep jobs in California and benefit ratepayers.

"We do see potential benefits in optimizing dispatch of plants over a wider footprint, and that will produce cost savings to consumers and therefore free up money to do the other things we need to do, such as building out the distribution grid," he said. "The question now is, how do we get more entities to participate in EDAM? That's why the Pathways Initiative exists."

Like IBEW, CMUA also opposed prior legislation, largely due to iterations of the bill that it said could have had adverse impacts on con-

CAISO/West News

sumers. But CMUA Executive Director Barry Moline said the agency was never against regionalization.

"Our concern with it was the way governance was established (who gets to serve on and advise the board)," Moline told *RTO Insider* in an email. "There was very little direction, and we worked hard to — and this is important — make sure consumers were not harmed in the process. By harm, we mean that we are concerned about affordability, and without any controls or accountability on governance, our imperative to address affordability would not be of concern."

Like other industry stakeholders, CMUA was also concerned over what it thought was a rushed timeline to transform CAISO into an RTO. (See *Governance Plan Critics Urge Slowdown of Western RTO Development*.)

But the Pathways Initiative takes an incremental approach, providing participants the opportunity to ease into an integrated market that could turn into an RTO with time.

"With the experience and trust built through the WEIM, we are working through the Pathways Initiative to build the EDAM governance model and the process to make it work," Moline said. "We believe that done correctly, with significant and continuous stakeholder input, we will continue to build trust and provide consumer and environmental benefits. It is this stepwise process that is creating trust among participants, and we are eager to continue to develop it with maximum stakeholder engagement."

Environmental concerns also played role in the failure of AB 813, despite getting support from prominent conservation groups such as the Natural Resources Defense Council, Environmental Defense Fund and Western Resource Advocates, who all viewed regionalization as a way to share renewable resources across a wider geography in order to reduce electricity-based emissions across the West.

But California's chapter of the Sierra Club had voiced concern that an expanded CAISO would reduce the effectiveness of the state rules to eliminate the import of coal-fired generation, especially given that PacifiCorp was one of first utilities to signal its intent to join an expanded ISO. Additionally, the group was concerned that AB 813 eliminated emissions tracking as a core principle, which could lead to carbon leakage.

But the WEIM now has a rigorous GHG accounting in place, a program that will be extended to the EDAM. And since its launch in 2014, the WEIM has also been responsible for avoiding more than 904,000 metric tons of GHG emissions through reduced curtailment of renewables, according to CAISO estimates.

That record of reductions may account for why the Sierra Club appeared to move its attention away from the most recent efforts to regionalize CAISO just as the process begins to heat up again. When reached for comment, the group said it was unable to find a staff member who could speak to the issue.

TURN did not respond to a request for comment for this story, but Moline addressed past environmental and ratepayer concerns, saying "WEIM is providing great value to consumers and the environment."

He also voiced optimism about the Pathways Initiative.

"It's highly engaging and requires a lot of time from everyone impacted by a coordinated Western energy market. We see it as a smart, can-do group of stakeholders who are working hard on a fair and balanced path forward," he said. ■

Robert Mullin contributed to this article.

CAISO/West News

CAISO Considers Replacement of RA Incentive Program

Stakeholders Weigh Pros and Cons of RAAIM vs. Unforced Capacity Construct

By Ayla Burnett

CAISO staff and stakeholders are looking to re-evaluate the ISO's Resource Adequacy Availability Incentive Mechanism (RAAIM) and explore whether it should be replaced with a new program relying on an unforced capacity (UCAP) construct to ensure sufficient RA capacity.

Moderating a Jan. 16 meeting of the ISO's Resource Adequacy Design and Modeling Working Group, Jeff McDonald, vice president at Concentric Energy Advisors, said the potential ineffectiveness of RAAIM was a prominent topic in past RA meetings of the group and in submitted comments.

A UCAP construct, which seeks to procure the most reliable resources by factoring their historical lack of availability into their capacity value, has been offered as an alternative to RAAIM, although stakeholders questioned if the two programs were similar enough to replace one another or if they could operate in tandem.

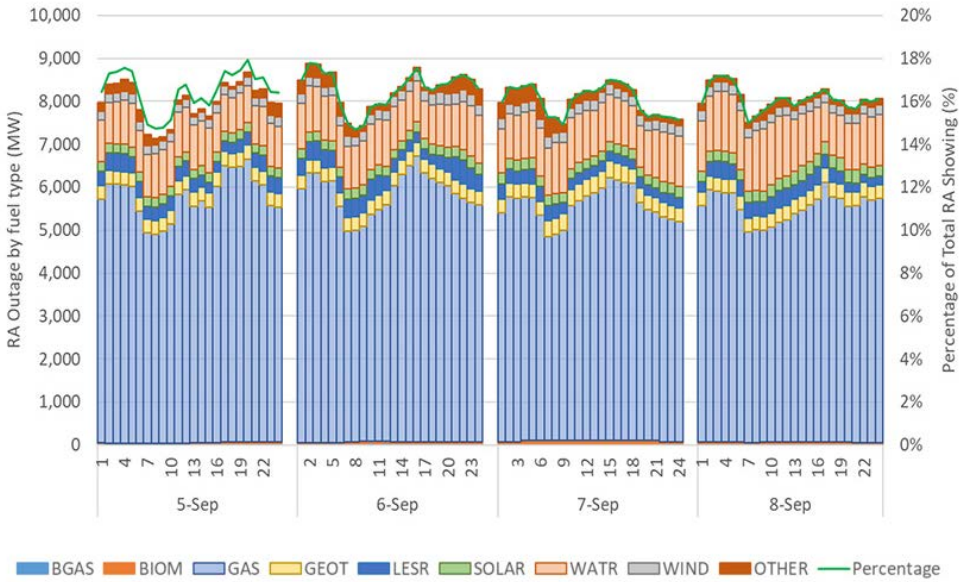
"My view is that these two issues can be conceptually separated," said Alva Svoboda, principal of market design integration at Pacific Gas and Electric. "RAAIM is an issue of how one deals with failures operationally to deliver what has been promised and UCAP can be considered simply as an improved approach to calculating what resources should be eligible to contribute in the RA plan."

Implemented in 2016, RAAIM is a bid-based mechanism designed to incentivize resources providing RA capacity to meet their must-offer obligations (MOO) and provide substitute capacity should they go on forced outage. Resources are penalized for not meeting their MOO and rewarded when they do.

Stakeholders raised concerns about RAAIM shortly after its implementation. In January 2018, CAISO submitted a *tariff amendment* to FERC requesting modification of the program after identifying a series of issues and problematic outcomes related to it. The ISO found the methodology overweighted the availability of flexible RA capacity compared with generic RA because it treated each availability assessment hour (AAH) as equal, despite differences in RA types.

The ISO also found that RAAIM was designed in such a way that resources could be led to designate a minimal flex RA megawatt amount with a maximum hourly amount to minimize penalties, reducing incentives to provide capacity at other times. As a result, staff modified the program to treat each megawatt equally within each AAH and to evaluate generic and flex RA separately, among other modifications.

While FERC approved the modifications, stakeholders still raised concerns about the effectiveness of RAAIM and whether it could be replaced with UCAP.



CAISO stakeholders question whether RAAIM is effective. | *CAISO*

RAAIM, UCAP — or Both?

At the Jan. 16 meeting, Lauren Carr, senior market policy analyst at CalCCA, disagreed with Svoboda that the two programs were conceptually distinct.

"If we have UCAP in place, it is a replacement for RAAIM, and it wouldn't make sense to have both," Carr said. "The purpose of RAAIM is to incent substitution when resources aren't available to follow their must-offer obligation, and if you're accounting for forced outages up front through UCAP, it wouldn't make sense to have substitution rules for forced outages."

Doug Boccignone, a principal at Flynn Resource Consultants, added that he thought RAAIM was redundant and feared having both programs could lead to double counting of resource contributions for both awards and penalties.

"I'm questioning whether you'd need additional incentives beyond the long-term UCAP incentive and the short-term incentive to bid your resources and get compensated for them in the market," Boccignone said. "If you are taking into account reasonable expectation for the resource … you've already taken into account forced outages. And if a unit goes on outage, it would be a double penalty to make them go get replacement capacity for that resource you were [already] counting."

Svoboda disagreed, saying that having both programs would not lead to double counting because they operate under different time frames and decision processes.

"The risk of double payment or over-penalizing is better addressed by getting the prices right and requirements right than by throwing the sticks on the table and trying to redesign from scratch," he said.

But meeting participants largely agreed that the ISO should reevaluate RAAIM before deciding about UCAP.

"I think the re-evaluation of RAAIM is one of those low-hanging fruits that will be easy for the ISO to potentially change some of the layouts of the RA construct and the incentivization to show resources," Nick Burki, senior integrated resource planner with City of Anaheim Public Utilities, said.

The RA Working Group's next meeting is set for Feb. 13. ■

CAISO/West News

CPUC Fines PG&E $45M for 2021 Dixie Fire

Split Vote as 2 Commissioners Question Whether Penalty is High Enough

By Elaine Goodman

California regulators approved a $45 million penalty against Pacific Gas and Electric on Jan. 25 for the utility's role in the 2021 Dixie Fire, the second-largest wildfire in state history.

The California Public Utilities Commission voted 3-2 to approve the penalty as part of a settlement negotiated between PG&E and the commission's Safety and Enforcement Division (SED).

The penalty includes a $2.5 million fine that will be paid to the state's general fund. PG&E will pay another $2.5 million to tribes whose land was impacted by the fire.

In addition, the utility agreed to spend $40 million to transition to electronic recordkeeping for inspections of overhead and underground distribution equipment. PG&E has agreed to not seek recovery of the $40 million through customer rates.

As part of the settlement, PG&E denied any fault in connection with the Dixie Fire, which was sparked by a tree falling on one of the utility's distribution lines in the Sierra Nevada foothills.

5-county Blaze

The Dixie Fire started July 13, 2021, when a Douglas fir tree fell onto PG&E distribution lines, a Cal Fire investigation determined. The fire spread across 963,309 acres in five Northern California counties and destroyed about 1,300 structures.

The proposed settlement went to the commission for a vote Nov. 30. But two commissioners — Darcie Houck and Genevieve Shiroma — said they needed more information, and the vote was postponed.

Following the Nov. 30 meeting, SED provided written responses to the commissioners' questions.

But during the Jan. 25 meeting, Houck and Shiroma said they weren't satisfied with the answers. They voted against approving the settlement agreement.

Houck questioned whether the relief provided by the settlement was enough given the magnitude of the fire.

"In light of the enormous impact this fire had on the state of California and the five counties impacted, the relief that is being proposed here, based on the information and reports we have today, I still believe is inadequate," Houck said.

Houck also said she was worried about the impact of the agreement in a future cost-recovery proceeding. Under terms of the agreement, PG&E retains the right to pursue recovery of costs associated with the Dixie Fire.

"There's still a concern about how the information and the fact that the settlement was there with no admission of fault would be looked at when we're looking at things like cost recovery," she said.

Role of Recordkeeping

Several of Houck's questions during the Nov. 30 meeting were related to the $40 million for electronic inspection records. She asked for more specifics on what information would be digitized and how that would improve safety.

In its written response, SED said digitization "is important for speed and efficiency at the commission and across other agencies responsible for wildfire safety."

"The continued and accelerated improvement of inspection processes by PG&E pursuant to the [agreement] will support public safety and facilitate commission oversight," SED wrote.

Commissioner John Reynolds, who voted in favor of the $45 million settlement, emphasized the importance of digitizing records during the Jan. 25 meeting.

"Modernizing records related to the condition of PG&E's assets may not sound exciting to the public," he said. "But better information about the condition of electrical assets is vital to improving inspection and preventive maintenance procedures, which are bread-and-butter wildfire safety activities."

Commissioners also noted that PG&E has taken steps to reduce wildfire risk since the Dixie Fire.

CPUC President Alice Busching Reynolds said the utility now has a system that shuts down distribution lines when it detects a fault, such as one caused by a tree falling on the line.

In a release issued after the vote, the CPUC said it has "taken many actions to hold PG&E accountable for safely serving its customers."

Those include a $150 million penalty for the 2020 Zogg Fire, a $1 million penalty for the 2019 Easy Fire and a $125 million penalty for the 2019 Kincade Fire. ■

The Dixie Fire burned 963,309 acres and destroyed about 1,300 structures in Northern California in 2021. | *U.S. Forest Service*

CAISO/West News

DOE, BOEM Kick off West Coast Offshore Wind Tx Planning

Agencies Convene Stakeholder Workshops to Address Regional Challenges

By Ayla Burnett

The U.S. Department of Energy and Bureau of Ocean Energy Management on Jan. 17 kicked off a series of stakeholder workshops to address the specific challenges to siting transmission for the first generation of West Coast offshore wind projects.

Agency representatives said the meetings aren't intended to produce siting or regulatory decisions, but to establish a set of recommendations and actions for publication as an addendum to the *Atlantic Offshore Wind Transmission Action Plan*, released in 2023. (See *Feds Release Road Map for Offshore Transmission Grid*.)

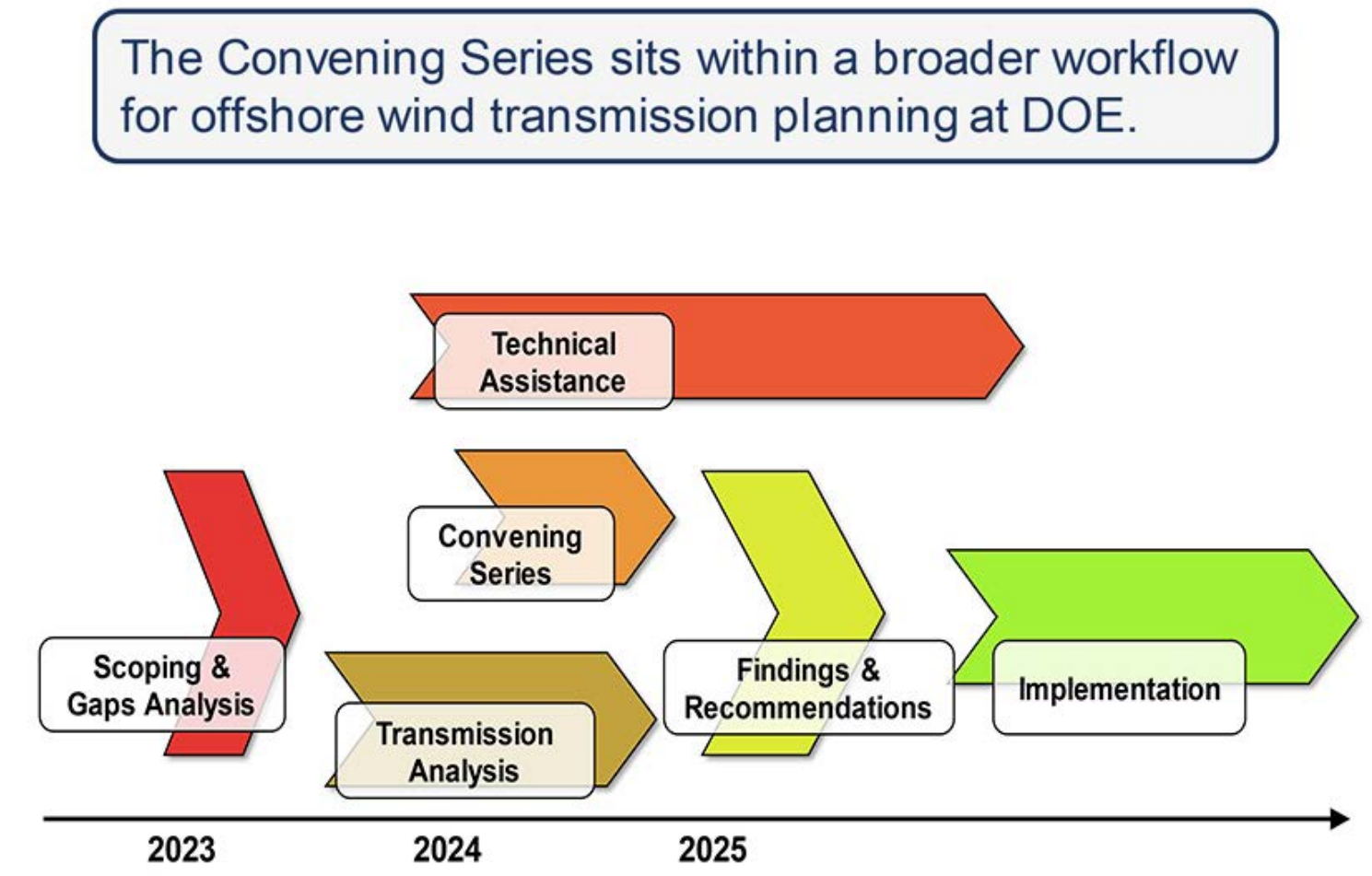
The Biden administration set a goal of deploying 30 GW of offshore wind in U.S. waters by 2030 and an additional 15 GW of floating offshore wind — the type needed in the deeper waters off the Pacific Coast — by 2035.

Speaking during the Jan. 17 virtual meeting, Jocelyn Brown-Saracino, offshore wind energy lead at DOE, highlighted that the U.S. now has a combined potential capacity of approximately 52 GW of offshore wind, up nearly 50% from three years ago. And in the last year, she noted, the global floating offshore wind pipeline grew from around 60 GW to about 103 GW.

Planners are looking to the West to accelerate that progress: California has established a goal of deploying 25 GW of offshore wind by 2045, and Oregon set a target of 3 GW by 2030.

But the West Coast currently lacks the transmission infrastructure to meet those goals. And while the Atlantic Offshore Wind action plan serves as a road map for planning in the Pacific, development along the West's more remote coastlines comes with its own unique obstacles.

"We know that bringing this energy to shore poses a host of challenges," said BOEM Director Liz Klein. "On the West Coast, the lack of off- and onshore transmission pathways to access offshore wind development and the harsh ocean energy environment [are challenges]. We need to work together to understand these challenges and to identify potential solutions."



The Department of Energy established a workflow for offshore wind transmission planning at a Jan. 17 meeting. | *DOE*

CAISO/West News

Another challenge lies in the complications of developing transmission that extends beyond a federal lease area. BOEM's authority over transmission siting starts at the outer continental shelf, allowing the agency to grant easements and rights-of-way for the production, transmission and transportation of energy sources. But BOEM does not have jurisdiction over landfall sites, so a project developer must work with regional and state entities and utilities to determine the appropriate points of interconnection.

In convening the workshops, the agencies hope that engaging states, transmission operators, tribal nations, ocean users and others will foster collaboration for the development of offshore wind. The series is part of a broader effort, and DOE is finalizing the scoping phase and beginning technical analysis.

Scoping in early 2023 identified gaps in planning, including the need for more interregional coordination and collaboration with tribal governments. DOE is working with the National Renewable Energy Laboratory (NREL) to engage tribes through the *Tribal Nation Offshore Wind Transmission Technical Assistance Program*, which will offer educational resources, training, technical assistance and funding for participation.

Technical Progress

The effort will also get significant technical support from U.S. national laboratories. Last May, the Pacific Northwest National Laboratory (PNNL) and NREL launched the *West Coast Offshore Wind Transmission Study*, which over the span of 20 months will explore transmission options to support offshore wind development through 2050. The labs reviewed 13 technical studies on offshore wind development, identified key themes in the region and determined that coastal interconnection points lack existing capacity for integrating offshore wind.

Mark Severy, a PNNL adviser to DOE, also identified gaps in the body of work reviewed, finding that most studies were focused on a single region or state and lacked consensus on the optimal technology or topology for offshore grid infrastructure.

According to Travis Douville, wind systems integration portfolio manager at PNNL, the study is the first of its kind to assess the entire West Coast. It considers a variety of guiding questions, including how much offshore wind should be developed through 2050 and where, and lays out nine tasks designed to help answer those questions.

To determine where transmission is needed, task two identified a series of zonal capacity expansion targets that span the Western Interconnection and provide information on how much offshore wind could be brought online. The targets will then be used to build nodal representations to simulate information on the economic dispatch of individual generators and model various sensitivities such as weather.

Tasks three and four involve the consideration of various siting conflicts, such as ocean co-use and topology. Douville said Pacific coastline is particularly challenging due to the depth of the water and the contour of the sea floor and canyons.

The team is constructing four topology sets to help consider where projects should be built. With those in place, the researchers will conduct weather-synchronized simulations of historical and future load, wind and solar patterns to provide insights into the types and location of needed generation.

After the modeling is complete, the labs will quantify the changes to capital and production cost, emissions, resource adequacy and resilience characteristics to the system, as well as the socioeconomic impacts and benefits to coastal and ocean co-use communities.

Lessons Learned

Alissa Baker, senior technical adviser for offshore transmission with DOE's Grid Deployment Office, discussed lessons learned from developing the Atlantic action plan.

"We're not inventing the wheel from scratch here," Baker said. "We're starting with a plan and hopefully refining and learning from the things that went well and the things that could go even better here."

Key among the insights, Baker emphasized the importance of partnerships, particularly among state and regional entities and with tribes. She also highlighted the need for greater interregional offshore topology planning that spans ISO, RTO and state boundaries.

Baker's presentation noted that FERC Order 1000 "sets forth the current generic federal requirements for considering potential interregional transmission" but requires only "coordination" between regions. "Fully integrated interregional planning is allowed but not required and, to date, has not been successfully implemented for any large-scale infrastructure," it said.

Baker also suggested updating NERC standards for offshore wind generation to ensure they're applicable to ocean transmission infrastructure and offshore wind generation tie-lines.

Another key recommendation was the support of local communities through community benefit agreements between project developers and those impacted.

"We want to make sure that the communities that are impacted by infrastructure are benefiting from that infrastructure and that the benefit is something that is greater than the impact they're perceiving," she said.

The Jan. 17 meeting closed with a lighthearted prerecorded discussion between DOE Deputy Secretary David Turk and Laura Daniel-Davis, acting deputy secretary at the Department of the Interior, which oversees BOEM.

"The Biden-Harris administration has an ambitious goal of deploying 30 GW of offshore wind by 2030," Daniel-Davis said. "When we get there, that's enough to power 10 million homes and we're going to cut 78 million metric tons of carbon pollution … all while we build a domestic supply chain, creating these good-paying union jobs, and we're lowering consumers' energy prices."

Turk reflected on the Atlantic convening series workshops and their benefit to transmission planning in the West.

"It was an incredibly good forum, and I think the West Coast can do an even better job of these kinds of discussions going forward," he said. ■

West news from our other channels

Draft Plan Outlines California Vision for Offshore Wind

NetZero Insider

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

CAISO/West News

Petition Seeks PURPA Protections for Rooftop Solar

By Elaine Goodman

Solar advocates have petitioned FERC to take enforcement action against Arizona's Salt River Project for setting rates that allegedly discriminate against customers with rooftop solar.

The rooftop solar rates are in violation of the Public Utilities Regulatory Policies Act (PURPA), according to the petition. It was filed Jan. 12 by the nonprofit advocacy group Vote Solar and two SRP residential customers with rooftop solar.

"SRP's current policies for residential customer solar violate the commission's rules and have decimated what was previously a robust market for solar," the petition said.

The petition asks FERC to compel SRP to offer nondiscriminatory electric rates for rooftop solar customers as well as fair rates for buying electricity from those customers.

As an alternative to an enforcement action, the petition asks the commission to make a finding that SRP's rates for rooftop solar customers violate PURPA.

PURPA is intended to encourage development of small power producers and co-generators and to reduce fossil fuel demand.

SRP said in a statement that it is reviewing the FERC filing.

"Based on an initial review, we believe the claims are without support and the background provided regarding SRP's programs and support of its solar customers is inaccurate," the utility said.

SRP said it has a number of rate options for rooftop solar customers and, as of September, had more than 54,000 residential customers with rooftop solar systems.

Solar Rate Plans

Rate disputes are often resolved by a state's public utility commission, according to David Bender, an Earthjustice attorney who's working on the case on behalf of Vote Solar.

But because SRP is not regulated by the Arizona Corporation Commission, the petitioners took their issue to FERC, Bender told *RTO Insider*.

If FERC doesn't initiate an enforcement action within 60 days, the petitioners may bring an action in federal court.

| *Sun Valley Solar Systems*

According to the petition, SRP has separate rate plans for rooftop solar customers and nonsolar customers.

The solar customers pay a fixed monthly charge that is up to $25.44 higher than that paid by nonsolar customers, the petition said, while the kilowatt-hour charge and demand charge are the same for both types of customers.

In addition, the petition said, only non-solar customers are offered the EZ-3 time-of-use plan, which includes a "more advantageous" three-hour peak period: 3 to 6 p.m. or 4 to 7 p.m.

In contrast, the time-of-use plan offered to solar customers has a longer peak period that varies by season — 2 to 8 p.m. in the summer and 5 to 9 a.m. plus 5 to 9 p.m. during the winter, according to the petition.

"All of the solar-customer tariffs impose higher fixed charges and preclude solar customers from benefits available under tariffs for nonsolar customers," the petition alleged.

SRP's rates to buy electricity from solar customers also violate PURPA, according to the petition, which said that the 2.8 cents/kWh reimbursement under several of SRP's tariffs is lower than the utility's full avoided costs.

New Mexico Case

Bender worked on a similar case involving solar rates charged by the Farmington Electric Utility System, owned by the city of Farmington, N.M.

In that case, FERC declined to act on a petition filed in April 2019 by Vote Solar and several Farmington residential electric customers who had rooftop solar. The parties contested a "monthly standby charge" that the Farmington utility charged its solar customers.

They took their case to federal court. The case was dismissed in U.S. District Court, but a Court of Appeals reversed the decision. Farmington rescinded its additional charges for solar customers and, under the terms of a settlement, agreed to credit or refund customers who had paid the standby charge. ■

ERCOT News

Texas PUC Sends ESR Change back to ERCOT

By Tom Kleckner

Texas regulators have remanded back to *ERCOT* a controversial protocol change attempting to regulate energy storage resources, but not before stripping out language related to state of charge (SOC) and enforcement processes.

The unanimous decision during the *Public Utility Commission*'s Jan. 18 open meeting is a victory, albeit temporary, for the energy storage sector, which has been battling the proposed change since last summer. As written, nodal protocol revision request (*NPRR1186*) sets a one-hour SOC for energy storage resources participating in two ancillary services (ERCOT contingency reserve service and non-spinning reserve). It also includes penalties of up to $25,000 per violation. (See "PUC Delays Approval of Rule Change that Penalizes Storage Resources," *Texas Public Utility Commission Briefs: Nov. 30, 2023*.)

Storage developers say the new rules hold energy storage resources (ESRs) to higher standards than conventional thermal resources and could result in fines if batteries fall below SOC thresholds and still deliver the power promised.

ERCOT staff filed a *report* before the meeting trying to address questions raised by the PUC in November. It said with ESR capacity projected to grow from 4.4 GW to more than 20 GW by 2026, the rules are necessary to preserve reliability. The data presented showed similar failure rates for ESRs and for thermal resources involved in the ancillary service markets (*54445*).

Commissioner Jimmy Glotfelty, who has declared the rule change to be "discriminatory" to energy storage, was not swayed.

"They all fail. Singling out ancillary services providers of battery storage is discriminatory. Gas plants fail. Nuclear plants fail. Coal plants fail," he said. "That's why we over-procure ancillary services. I just cannot pass something that puts a compliance penalty on a type of service when the data from ERCOT shows that dispatchable resources fail in the same types of services."

Commissioner Jimmy Glotfelty shares his opinion on controversial energy storage rule change. | *Admin Monitor*

"It really is a big deal from a liability perspective to make sure that those ancillary services can provide the products that we need for the duration that we need them to," Dan Woodfin, ERCOT's vice president of system operations, told the PUC.

Commissioner Lori Cobos said ERCOT should withdraw or table *NPRR1209*, a directive from the Board of Directors as NPRR1186 ran into trouble. ERCOT staff said Jan. 24 the rule change was tabled in November within the stakeholder process to allow the commission to work out its issues with 1186, which also was a board priority item.

Both measures are seen as stopgaps until ERCOT deploys real-time co-optimization, currently targeted for the latter half of 2026.

The ERCOT board now will take up 1186 and the PUC's changes for approval before they get sent back to the commission for a final review and vote.

The open meeting took place the day before Thomas Gleeson was appointed as the PUC's chair. Gleeson was formally sworn in Jan. 23. (See *Abbott Names PUC Executive Director as Chair*.)

VoLL Study to Begin

The Brattle Group will open a value-of-lost load (VoLL) survey of ERCOT retail customers in March. The results will be reported back to the PUC in August as part of the grid operator's effort to quantify VoLL (*55837*).

ERCOT is analyzing the frequency of load shed, but also its magnitude and duration, with an expected unserved energy metric. According to a staff *filing*, every 1% improvement in a plant's weatherization reduces the needed for 175 MW of capacity.

The commission also *requested comment* on DC ties, such as the Southern Spirit line. Glotfelty asked PUC and ERCOT staffs to model the effect of that line had it existed Sept. 6, the last time ERCOT was in emergency operations (*55984*). (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

The PUC will discuss the issue in February. ■

ERCOT News

ERCOT Expands Leadership Team with Promotions

ERCOT said Jan. 23 it has increased its executive leadership team with four promotions.

The grid operator said the changes expand on the executive team's "deep experience and knowledge ... to proactively manage the complexities of a rapidly transforming electric grid." They were effective Jan. 1.

"ERCOT requires focused, value-driven, timely, transformational changes to its tools, technology and processes," CEO Pablo Vegas said in a statement. "Transformation necessitates innovation, and these organizational changes will continue to position ERCOT as a leader in the electric industry."

Those promoted are:

Jayapal "J.P." Parakkuth, senior vice president and CIO, leading the IT group and supporting the development, delivery and operations of technology.

Venkat Tirupati, vice president of dev-ops and grid transformation, will manage technology innovation capabilities to address the complexities of a rapidly transforming grid.

Sean Taylor, senior vice president, CFO and chief risk officer, overseeing ERCOT's financial health.

Adam Martinez, vice president of enterprise risk and strategy, with responsibility for the ISO's Enterprise Risk Management program and ensuring strategic objectives are achieved.

ERCOT has bolstered its leadership team with several promotions. | © RTO Insider LLC

The promotions boost ERCOT's executive team to 14 members, with Vegas, five senior vice presidents and eight vice presidents. ■

—Tom Kleckner

ERCOT News

GCPA Elects R Street's Garza as President

By Tom Kleckner

HOUSTON — The Gulf Coast Power Association's membership has elected Beth Garza, a senior adviser for R Street Institute and long-time presence in the ERCOT market, to a two-year term as president.

Garza joined R Street after 11 years with Potomac Economics. She served as the ERCOT Independent Market Monitor's deputy director or director for Potomac until 2019.

Her 35 years in the electric industry also have included leadership roles at ERCOT, NextEra Energy and Austin Energy, where she gained expertise in generation and transmission planning, system operations, regulatory affairs and market design. She has an engineering degree from the University of Missouri and is a registered professional engineer in Texas.

GCPA's Board of Directors filled out its officers by selecting Brian Lloyd, vice president with Oncor, as vice president; Mark Egan, Energy Evolution Advisors' founder, as treasurer; and Donna Benefield, senior vice president with NRG Energy, as secretary.

Outgoing President Mark Dreyfus made the announcement during the GCPA's annual meeting Jan. 18. He said 2023 was a "fantastic" year with corporate memberships up from 137 to 153, its largest corporate membership on record. Individual memberships increased from 301 to 337. Registrations for meetings and conferences were up 28% over 2022 as the organization set attendance records for its annual spring and fall conferences and its MISO-SPP forum.

The attendance numbers resulted in strong financials for the organization. Total revenues exceeded $1.9 million, an increase of just over $400,000 from the prior year "because of the economic recovery and strong attendance memberships revenues," and added $651,000 to the GCPA's coffers.

The profits will be used to fund the organization's scholarship program, which was resumed after the COVID-19 pandemic. Under the revamped program, GCPA will award ERCOT, MISO and SPP $20,000 each to go to outstanding students in their summer internship programs.

Dreyfus said the hunt continues for a new executive director with the experience and contacts "to really keep the organization moving forward." Kim Casey announced her retirement last year; she was the fourth ED in GCPA's history. ■

New GCPA President Beth Garza chats with member Beth Emery following the group's annual meeting. | © RTO Insider LLC

ISO-NE News

NEPOOL Nears a Vote on Order 2023 Compliance

By Jon Lamson

ISO-NE reviewed changes to its Order 2023 compliance redlines with stakeholders at the NEPOOL Transmission Committee (TC) on Jan. 23 as the committee prepares for a vote on compliance in February. Multiple clean energy organizations, meanwhile, proposed compliance amendments.

Al McBride, director of transmission services and resource qualification at ISO-NE, first summarized the tariff redlines at the December meeting of the TC. (See *ISO-NE Details Order 2023 Tariff Changes*.) At the January meeting, McBride detailed *redline changes* largely intended to clarify and clean up aspects of ISO-NE's compliance proposal.

McBride also provided an *update* on the status of the interconnection queue, which consists of 203 active projects totaling 39,563 MW. Of those projects, 68 accounting for 11,423 MW have completed their system impact studies, which means they will not need to enter initial transitional cluster study.

System impact studies for 5,573 MW worth of late-stage interconnection requests are expected to be completed before the current cutoff point for these projects to avoid needing to enter the transitional cluster.

Representatives from Advanced Energy United, RENEW Northeast, New Leaf Energy, Cypress Creek Renewables and Glenvale Solar provided updates on their compliance amendments and outlined the proposals they will offer for a TC vote in February.

New Leaf's first *proposal*, supported by Advanced Energy United, would have the RTO extend the cutoff date for system impact studies that are expected to be completed prior to the start of the transitional cluster study but are not completed by the currently proposed cutoff point.

McBride told the TC that nine projects amounting to 1,485 MW are on track to complete their system impact studies after the current cutoff point but prior to the first cluster study.

New Leaf also proposed to calculate withdrawal penalties for the transitional cluster study strictly based on study costs incurred within this cluster, excluding any study costs from before the cluster from the penalties, to "fairly calculate withdrawal penalties for all projects in the transitional cluster."

The company's third proposal would require ISO-NE to determine during the customer engagement window whether interconnection customers will be included in a cluster subgroup. The RTO said it "does not intend to use subgroups in the clustering process," but would have the option to create subgroups.

Cypress Creek, a solar and storage company, said three of its four previously proposed amendments have been adequately addressed by ISO-NE, and has withdrawn the fourth amendment related to site control because the issue is subject to an ongoing rehearing request with *FERC*.

Advanced Energy United, which previously expressed concern about the extended length of the cluster timeline compared to the process proposed by FERC, is proposing to create an "Interconnection Reforms Working Group" aimed at reducing cluster study timelines.

"At the heart of *Order 2023* was a resolve to accelerate interconnection study and processing timeframes, and we must strive to meet the order's requirements even if we cannot commit right now," said Alex Lawton of United.

The clean energy industry association also proposed to increase guidance and transparency around the selection of alternative transmission technologies as upgrade solutions, including the explicit consideration of dynamic line ratings.

United and RENEW jointly proposed to provide an opportunity for interconnection customers to reduce project size if ISO-NE determines a restudy is needed. This opportunity would extend only to modifications that do not affect the cost or timing of another project.

"Order 2023 provides a clear and firm basis for allowing reductions that are not material," United said.

RENEW also *proposed* that ISO-NE separately calculate costs for Capacity Network Resource (CNR) Interconnection Service and Network Resource (NR) Interconnection Service. The clean energy nonprofit also *proposed* to "allow CNR Interconnection Requests to downgrade their requested service to NRIS" in response to the results of a cluster study, restudy or facilities study, with some limitations.

The organization also proposed *changes* to let new resources with completed SIS and a commercial operation date prior to June 1, 2028, to participate in reconfiguration auctions in 2024.

Glenvale Solar proposed a series of *amendments* that would incentivize cash deposits over letters of credit for commercial readiness deposits (CRDs), reduce the first posting of CRDs and reduce CRDs for modifications of existing generation that do not add capacity.

The TC will vote on the ISO-NE compliance proposal and stakeholder amendments on Feb. 15.

Longer-term Transmission Planning

Brent Oberlin of ISO-NE provided *additional information* on the RTO's efforts to create a new process for transmission projects that address needs identified in its longer-term transmission studies. (See *ISO-NE Details Order 2023 Tariff Changes*.)

The new process is being developed in coordination with the New England States Committee on Electricity (*NESCOE*), which represents the interests of all six New England states. The process is intended to establish "the rules that enable the states to achieve their policies through the development of transmission to address anticipated system concerns and the associated cost allocation method," Oberlin said.

For project bids to be eligible for selection, a quantitative comparison of benefits and costs must show net benefits. Oberlin told the TC that this analysis will include production cost and congestion savings, avoided transmission and local resources needed to meet demand, and reductions in losses.

The factors considered do not explicitly include climate or public health benefits, which several stakeholders expressed an interest in including as considerations.

NEPOOL also proposed the creation of a supplemental process that would enable it to select projects that do not meet the cost-benefit threshold.

"This supplemental process would allow one or more states to fund costs if the [benefit-cost ratio, BCR] threshold was not met in order to move the project forward," said Sheila Keane of NESCOE, who noted this process would be used only if no project proposals meet the threshold.

"Costs commensurate with the BCR tariff criteria will be regionalized with one or more states agreeing to cover the remaining costs," Keane added. "If the NESCOE selected project has BCR = .95, the region pays for 95% of project costs on a load-share basis and one or more states fund the remaining 5% of costs." ■

MISO News

Crypto Load on MISO-SPP M2M Constraint Draws FERC Complaint from Montana-Dakota Utilities

By Amanda Durish Cook

Montana-Dakota Utilities Co. has filed a complaint against *MISO* and *SPP* over a market-to-market flowgate chronically congested by a new cryptocurrency mining operation in SPP.

The utility said the RTOs are violating their joint operating agreement by conducting "unwarranted" and "unjust" M2M congestion coordination on the Western Area Power Administration 230-kV Charlie Creek-Watford line in North Dakota (*EL 24-61*).

Montana-Dakota Utilities — a MISO member — said its customers have been overcharged about $18 million for congestion on Charlie Creek-Watford. It said FERC should order a stop to MISO and SPP's M2M coordination on the line, direct SPP to refund payments MISO made to it for M2M coordination and order refunds for "duplicative payments made by Montana-Dakota for M2M coordination."

The company also said FERC should pronounce MISO and SPP's interregional coordination process unreasonable because it allows MISO or SPP to "insist on continued coordination of a flowgate" even when the coordination is not shown to reduce congestion. MISO and SPP should be conducting M2M coordination only when it's effective at cutting congestion, Montana-Dakota argued.

Montana-Dakota maintained the RTOs' interregional coordination process never should have been enacted in the case of Charlie Creek-Watford because the constraint "was of local, not regional, concern."

"SPP's decision to enact and maintain M2M coordination for the local issue of congestion on the Charlie Creek-to-Watford City line violated and continues to violate [the JOA] and constitutes an unjust and unreasonable practice," the utility told FERC. If SPP "continues to insist on use of M2M coordination for the Charlie Creek-to-Watford City line congestion issues, then Montana-Dakota and its customers will continue to be unfairly and unjustly assessed overlapping congestion charges."

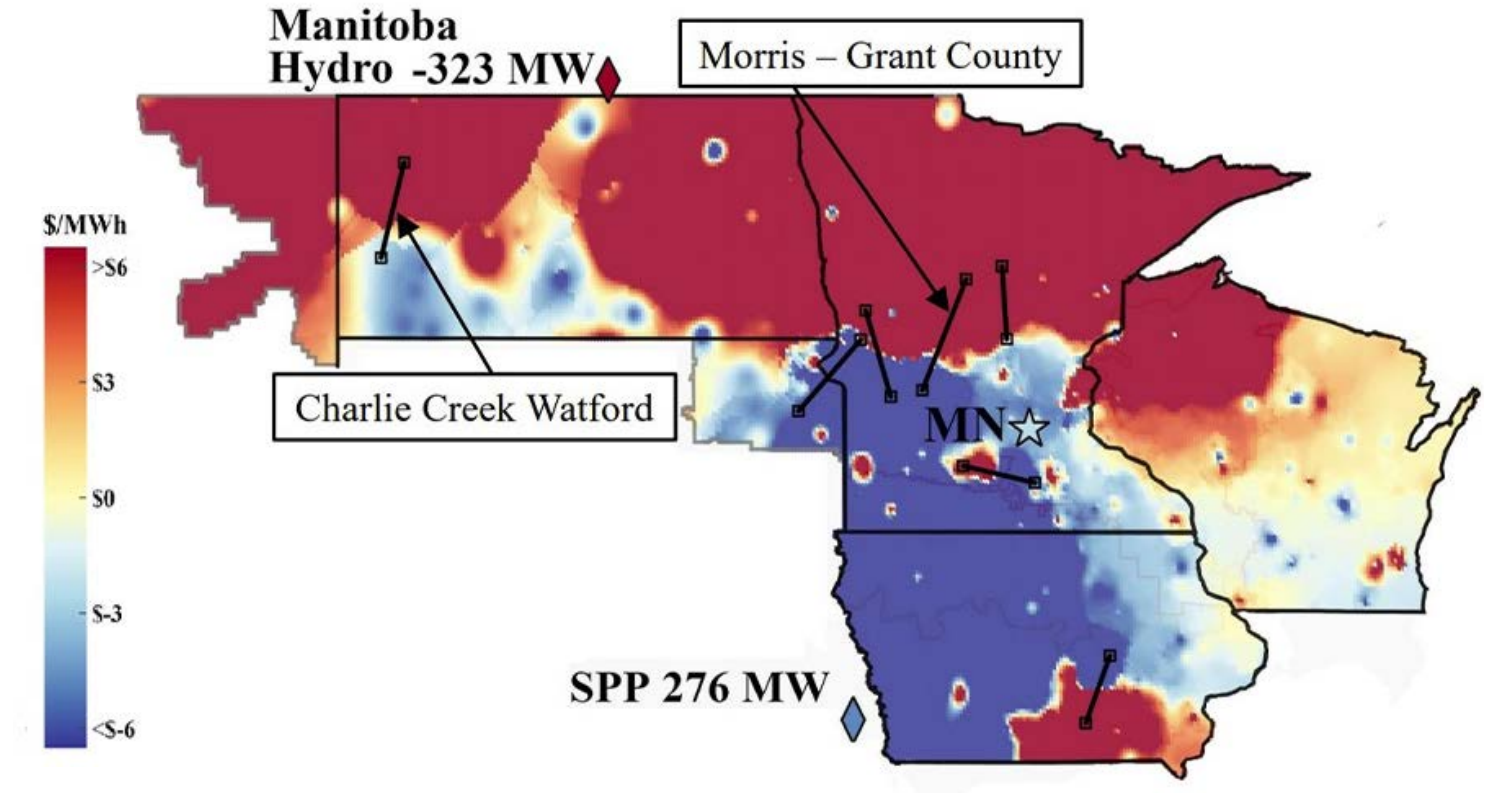
MISO's Independent Market Monitor late last year called attention to the flowgate as a major source of congestion since the line began delivering power to 220 MW in new load from a cryptocurrency mining operation. (See *MISO and IMM: M2M Flowgate Issue with SPP not Sustainable, May Require Litigation*.)

MISO IMM David Patton said MISO and SPP should revoke Charlie Creek-Watford's status as an M2M constraint because MISO can offer little congestion relief for the line and it's costing MISO millions in payments.

MISO staff said new load was allowed to be activated in an already-constrained SPP load pocket with planned transmission upgrades for the area not in service yet.

MISO itself hasn't ruled out litigation with SPP over the overworked flowgate.

In mid-January, MISO deputy general counsel Kristina Tridico confirmed that MISO pursued alternative dispute resolution with SPP over the constraint and is at the "beginning stages" of negotiations. ■



The MISO IMM's heat map of congestion problem areas over fall 2023, including the Charlie Creek-Watford flowgate | *Potomac Economics*

MISO News

MISO to Re-examine Schedule for Reviewing Expedited Tx Projects

By Amanda Durish Cook

CARMEL, Ind. — MISO's Planning Subcommittee this year will tackle possible modifications to the RTO's expedited project review process, which allows transmission developers to begin construction earlier than MISO's annual approval process usually allows.

The RTO's Planning Advisory Committee on Wednesday voted to allow the subcommittee to begin deliberations in March on a new schedule for the study process to better manage the increasing number of requests.

At a Jan. 24 PAC meeting, expansion planning engineer Amanda Schiro said expedited requests until recently have been few enough not to burden MISO resources.

"However, in the past three years, we have seen large load additions that increase the volume and complexity of expedited requests," Schiro said, adding that requests often are driven by "spot load growth," such as data centers.

MISO late last year said it's become inundated with expedited review requests and that it likely needs to overhaul how it handles transmission projects that can't wait until the usual December board approval to begin construction. (See *MISO Board Approves $9B MTEP 23; Members Deliberate on New Expedited Review Rules*.)

Schiro said the expedited requests and their "isolated processes" are causing a "strain" on MISO's planning staff to study all expedited requests alongside the RTO's annual Transmission Expansion Plan (MTEP).

Schiro said MISO held 17 meetings over 2023 to review individual projects and the RTO needs to reduce the frequency of meetings. She said MISO might contain project submission times and introduce a timeline to accomplish a more streamlined process.

"We'd like to reduce that number both for us and our stakeholders," she said.

Schiro said when conducting outreach on the issue, stakeholders urged MISO to keep the "valuable" expedited process. She said MISO has no plans to discontinue expedited reviews.

However, the Union of Concerned Scientists' Sam Gomberg said he thought MISO's plan to focus only on the expedited review timeline "misses an opportunity" for the RTO to plan for load additions more proactively.

Under the existing process, MISO conducts individual studies on expedited requests to confirm the projects won't result in reliability violations before allowing them to proceed ahead of the usual MTEP cycle.

Stakeholders have suggested MISO enact voltage or cost thresholds so small projects don't have to go through an expedited project review.

Generally, projects must rate at least 100 kV or cost at least $1 million to be considered candidates under MTEP and compelled to apply for expedited treatment when necessary.

This month, MISO analyzed an expedited need from Jonesboro City Water and Light, which proposed an $874,000 rebuild of a 69-kV line in northeastern Arkansas due to state Department of Transportation work. Some

| Great River Energy

stakeholders at a Jan. 16 South Technical Study Task Force questioned whether MISO should have devoted time to examining such a small project. ■

MISO News

FERC Approves Settlement in MISO Reliability Payments to Wisconsin Coal Plant

By Amanda Durish Cook

A Wisconsin coal plant kept online for the sake of reliability will receive smaller monthly payments from MISO, *FERC* ruled in a settlement approval last week.

Under the settlement, Manitowoc Public Utilities will collect $880,000 per month, totaling about $10.5 million annually, for the term of its System Support Resource (SSR) agreement on its 63-MW Lakefront 9 unit (*ER23-977*). FERC said the amount was more appropriate than the $1.03 million in monthly compensation to keep the plant running the utility originally proposed. (See *FERC Approves SSR Agreement for Wisconsin Coal Plant*.)

Manitowoc Public Utilities will receive about $1.8 million less per year than it requested.

The company's Lakefront 9 began operating as an SSR in February 2023 after MISO found that thermal overloading and voltage issues could occur on several nearby constraints if the plant was permitted to suspend operations as scheduled. The utility wanted to idle Lakefront 9 until 2026 to convert it to a renewable fuel source.

MISO has one other active SSR designation in its Midwest region. The RTO may keep Ameren Missouri's 1.2-GW Rush Island coal plant online until sometime in 2025 for reliability reasons. (See *MISO Poised to Extend Missouri Coal Plant's Life*.)

Manitowoc Public Utilities' Lakefront power plant | *Manitowoc Public Utilities*

MISO enacts its SSRs agreements in one-year increments and evaluates the need for them annually until it finds the system is stable enough to lift them. ■

NYISO News

New York PSC Seeks Rehearing of RTO Adder for Offshore Tx Project

By John Norris

The New York Public Service Commission on Jan. 25 requested a rehearing of FERC's December order granting a 50-basis-point RTO participation adder for the *Propel NY Energy* transmission project (*ER24-232*).

Propel — a $2.7 billion, 345-kV joint venture between New York Transco and the New York Power Authority — was selected from NYISO's public policy transmission needs (PPTN) assessment to deliver at least 3,000 MW from offshore wind farms near the Long Island coast.

NY Transco *petitioned* FERC for transmission incentives, including a cost-containment mechanism, a base return on equity of 10.7% with a 150-basis-point risk adder, 100% coverage for abandoned plant and construction work in progress, and a 50-basis-point RTO participation adder. The commission approved these requests, but it reduced the risk incentive to 75 basis points and suspended the proposed base ROE pending hearing and settlement judge procedures. (See *FERC Approves Incentives for NY OSW Transmission*.)

However, the PSC said in its protest that the RTO adder is "neither necessary nor warranted" and "harms New York consumers" who will be "required to overpay to encourage a voluntary conduct on the part of the developer where the conduct sought to be incentivized is already required."

FERC granted the adder with the condition that the developer continue its "membership in NYISO and transfer ... operational control of the project to NYISO once it has been placed in service."

But the PSC argued that the adder, typically used to incentivize voluntary participation, is redundant for Propel NY, as NY Transco's involvement with NYISO is a regulatory requirement, not a discretionary choice. The adder "gives the developer an unjustified windfall while unnecessarily increasing costs to New Yorkers," it said.

To support its position, the PSC cited FERC's ruling last month that Pacific Gas and Electric was not eligible for an RTO adder in CAISO (*ER24-96*). (See *Citing California Law, FERC Rejects PG&E Request for RTO Adder*.) It said the two cases "are analogous."

The PSC, along with New York City and Multiple Intervenors, had *opposed* NY Transco's requested ROE and incentives. They complained that the 10.7% ROE was inflated and argued that NY Transco failed to demonstrate any special project risks.

The first settlement conference over the ROE is *scheduled* for Jan. 31. ■

Workers prepare to begin construction on the Propel NY Energy project. | *Propel NY Energy*

NYISO News

FERC Approves NYISO Waiver on Interconnection Study Requirements

Commission Still Considering ISO's Order 2023 Compliance Filing

By John Norris

FERC on Jan. 25 granted NYISO a waiver allowing a temporary suspension of tariff rules for its interconnection study processes to assist developers and facilitate a smoother transition to the procedures prescribed by Order 2023 (*ER24-342*).

NYISO has been working to implement the commission's order, which seeks to unclog the nation's interconnection queues. It submitted a partial compliance filing in November and was granted an extension to April 3 to submit its full proposal. (See *NYISO Stakeholders Question Proposed Interconnection Timelines, Deposit Rules*.) In the meantime, developers under the ISO's current tariff rules face mandatory feasibility and system impact studies for their queued projects at their own expense.

To address this, NYISO proposed in its waiver *request* to establish a set of limited interim rules for its large facility interconnection procedures (LFIP) that would allow developers to choose between completing ongoing studies, opting for limited studies, withdrawing without penalty or not starting studies at all. The ISO argued that these proposed rules would "minimize the expense, time and resources" needed to advance studies in the interconnection queue.

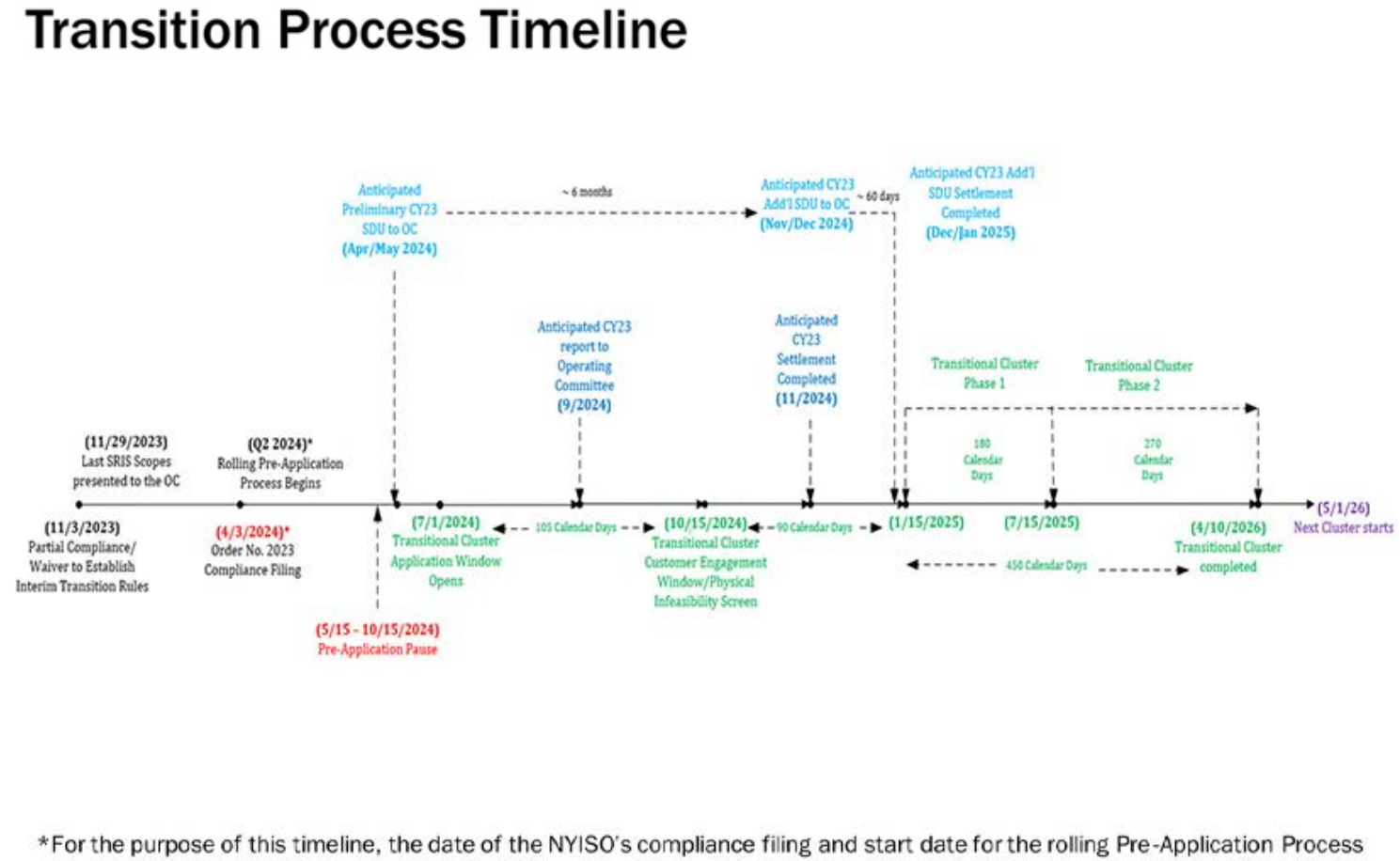
NYISO's current LFIP require developers to undergo three successive studies: an optional feasibility study that evaluates a project's configuration and local system impacts; a system impact study that evaluates a project's impact on transfer capability and system reliability; and a class year facilities study that evaluates the cumulative impact of a group of projects.

Now developers can either remain in the interconnection queue or withdraw their requests, thereby avoiding unnecessary costs until the new procedures take effect. However, they must make their decision within 30 calendar days following FERC's order.

The commission said the waiver was "limited in scope," remedies a "concrete problem" and would not "have undesirable consequences."

NYISO has nearly 530 projects in its interconnection *queue*, and nearly all of them are renewable projects, according to an S&P Global *analysis*.

The waiver is effective beginning retroactively from Nov. 30 until FERC rules on the ISO's partial compliance filing. The commission noted that it made "no findings as to the merits of NYISO's partial compliance filing at this time." ■



NYISO's proposed interconnection transition process timeline as of Jan. 11 | *NYISO*

PJM News

PJM Initiates Transitional Interconnection Queue

By Devin Leith-Yessian

PJM has begun studying 308 generation interconnection requests sorted into its Transitionary Cycle 1 (TC1), marking a milestone in the RTO's shift in how it conducts studies of the grid upgrades necessary for resources in its clogged queue, the RTO told FERC on Jan. 16 (*ER22-2110*).

The cycle is the first to use the cluster-based approach FERC approved in November 2022. The process groups projects to study what upgrades will be necessary and to allocate costs. In an *announcement* of the start of TC1 studies, PJM said projects sorted into the cycle are expected to be complete in mid-2025, clearing 46 GW of new generation to move to construction. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

The first step of the transition, the sorting process, resulted in 616 eligible projects being evenly split between TC1 and an expedited "fast lane" process for studying projects with estimated upgrades below $5 million. The fast lane queue is intended to allow projects PJM believes can be studied quickly to progress under the former serialized study and cost allocation process as it shifts studies expected to take longer to complete over to the cluster approach. Study cases for expedited projects are expected to be posted by Jan. 26, and final documentation is anticipated to be complete by the end this year. Projects that have been placed in the fast lane can be moved to TC1 if the short circuit, stability or feasibility analysis determine that more than $5 million is required.

Projects submitted in the AG1 and AH1 queue windows will be required to resubmit their projects to match the transitional rules before being included in Transitionary Cycle 2. Submissions in queue window AH2, which was open between October 2021 through March 2022, will form the first full cycle under the new rules after the completion of the transition.

The FERC-approved interconnection study regime also includes that deposits be made throughout the process to ensure that developers are covering the cost of the studies and to weed out speculative proposals that have been blamed for congesting the queue with requests that may never lead to actual construction. To that end, PJM launched its *Queue Scope* tool, which allows developers to get a sense of potential upgrades necessary to interconnect a generator at a given location.

In a social media *post* responding to PJM's announcement, White Pine Energy Consulting said the RTO has been staying on track with implementing the changes.

"I am looking forward to seeing how well the new interconnection process works, but first we need to get through the transition. PJM has been doing a good job staying on schedule as they implement the first transition cycle," it said. ■

PJM News

PJM: Grid Performed Well During Jan. Winter Storm

By Devin Leith-Yessian

PJM last week said the grid maintained reliability through nearly a week of harsh winter conditions during the winter storm that blanketed much of the nation during mid-January.

Dave Souder, PJM executive director of system operations, told the Jan. 24 meeting of the Markets and Reliability Committee that the grid was at its most strained Jan. 17, which saw a peak load of 134,777 MW and some emergency procedures implemented to mitigate transmission constraints. Cold weather alerts were in place from Jan. 14-17 and Jan. 19-22.

Comparisons to December 2022's Winter Storm Elliott dominated the discussion, with PJM making the case that several market and operational improvements bolstered performance. Souder said the RTO drew on its experience with generation performance during cold weather to take more action before the storm arrived. Dispatchers manually committed thousands of additional megawatts through the day-ahead market to give long-lead units time to come online and combustion turbines that have had trouble procuring gas in the past additional notice to firm up their fuel.

Conservative operations were in place between Jan. 13 and 17 to provide dispatchers with greater flexibility to keep long-lead resources online when they'd otherwise be released on economics.

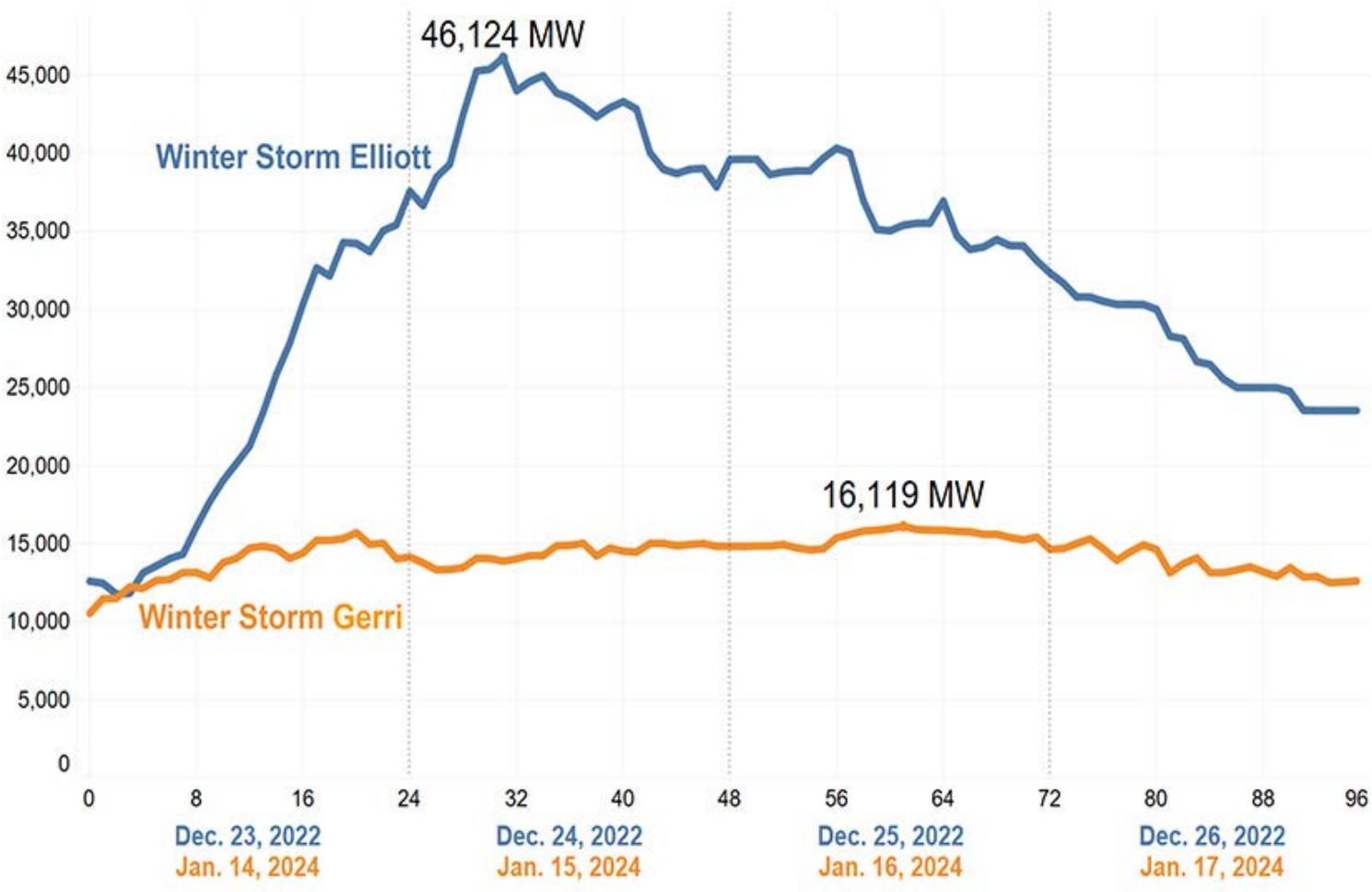
"We took a risk-based unit commitment approach," Souder said.

PJM's Brian Chmielewski said transmission congestion also peaked on Jan. 17, with 19 constraints reaching the $2,000/MWh transmission constraint penalty factor (TCPF). Heavy load interchange and congestion drove system marginal prices to the $500/MWh range Jan. 17 and 18.

Vitol Vice President of Regulatory Affairs Jason Barker questioned if price spikes on the mornings of Jan. 16, 17 and 18 were driven by PJM load or exports to neighboring regions, saying that the timing appears to align with the MISO morning peak. PJM representatives were unable to confirm the observation but agreed to examine event data.

Souder said additional information will be presented at next month's Market Implementation and Operating committee meetings, scheduled for Feb. 7 and 8, respectively.

The rate of generation outages was around a



A comparison of the rate of generator outages during the January 2024 winter storm, known as Gerri, to December 2022's Winter Storm Elliott | *PJM*

PJM News

third of the peak during Elliott at 16,119 MW offline Jan. 16 versus 46,124 MW on forced outage Dec. 24, 2022. Souder said the gas fleet's performance in particular was much stronger this month; though pipeline capacity restrictions were in place throughout the storm, there were few compressor station or gas well failures, and pipeline operators coordinated with PJM to improve forecasting.

Generators that did experience disruptions impacting their output also made use of PJM's newly implemented temporary exception process to report their diminished output. One of the challenges PJM highlighted following Elliott was a significant number of generators not reporting issues to the RTO until dispatchers attempted to bring them online.

Independent Market Monitor Joe Bowring told *RTO Insider* that PJM took a "very conservative" approach to the storm and relied on a forecast that turned out to be much more accurate than that for Elliott. While he applauded the performance of PJM operators in keeping the grid online through their actions, he said that a stronger market design would commit generators based on economics.

"The operators made the system work, and we're happy they did, but when we think of the bigger picture, markets were not relied on," he said.

He argued that the need to manually commit resources during the storm highlighted the need for ongoing stakeholder discussions over the reserve market design to focus on how to include market parameters that reflect a need for short-term reserves. He contrasted the need for reserves that can operate through a storm lasting a few days to the decision to increase the synchronized reserve requirement by 30% last May. (See "Stakeholders Reject PJM Synch Reserve Manual Change; RTO Overrides," *PJM MRC/MC Briefs: May 31, 2023*.)

"You don't need more reserves year-round; you needed them for a couple days last week," he said.

Several stakeholders questioned the cost of $28 million in uplift payments to generators committed under conservative operations, arguing that costs should be built into the market, while others said the current market structure provides dispatchers with flexibility to commit units as they may be needed in real time.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said that both uplift payments and exports during strained conditions are worrying, but in this instance PJM's actions appear to be warranted because of the concern that generators wouldn't be able to perform during a holiday weekend winter storm — the same scenario PJM found itself in during Elliott. In this case, the holiday was Martin Luther King Jr. Day, instead of Christmas in 2022.

The storm brought a new record-high peak load of 34,524 MW in the Tennessee Valley Authority region Jan. 17, and other PJM neighbors also saw high loads, leading the RTO to export 12,131 MW, the equivalent of nearly 10% of its own load.

Gregory Carmean, executive director of the Organization of PJM States Inc. (OPSI), questioned whether the large amount of exports signal that other regions are leaning on the RTO for reliability at the same time that it has been recommending reducing projected reliability benefit of imports reflected in the capacity benefit of ties (CBOT) value. The package of market changes PJM proposed in the Critical Issue Fast Path process last year would have set the CBOT to zero, but the Board of Managers did not include that component in its proposal now pending before FERC. (See *PJM Board Releases Outline of Capacity Market Changes*.)

Noting that the drop in temperatures was most severe in the ComEd zone, AEP Energy Director of RTO Operations Brock Ondayko said more detailed analysis on generation outages by zone could provide more information about any incremental improvements made in generator performance in subzero temperatures. ■

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PJM News

Virginia State Corporation Commission Finally Gets All Seats Filled

By James Downing

The Virginia State Corporation Commission (SCC) has a full complement of commissioners after the Virginia General Assembly approved two new members last week.

The legislature picked Kelsey Bagot, a former staffer of FERC Commissioner Mark Christie who was working at NextEra Energy, and Sam Towell, who is associate general counsel for Smithfield Foods and previously worked for the state attorney general.

"Kelsey is an excellent choice by the Virginia General Assembly for the State Corporation Commission," Christie said in an interview Jan. 26. "As a former commissioner on the State Corporation Commission, I know that Kelsey brings exactly the qualities and the dedication to serving the public that the Virginia Commission needs and that the people of Virginia deserve."

The two new members join Jehmal Hudson, who has been the only member of the state regulator since former Chair Judith Jagdmann stepped down in 2022.

The issues with staffing the SCC go back to when Jimmy Dimitri stepped down in 2018 and the legislature failed to find a long-term replacement for him. Dimitri has, however, been able to come back and help move needed business with Hudson in recent months because the body requires two votes for a quorum. The general assembly, which has seen its chambers flip between Republicans and Democrats multiple times in recent years, likewise had been unable to find a long-term replacement for Christie, who served on the SCC for nearly 17 years before joining FERC in 2020.

New State Corporation Commissioner Kelsey Bagot with her former boss, FERC Commissioner and former SCC Commissioner Mark Christie. | *Mark Christie via X*

"I'm very, very happy that finally, after three years, all three seats are filled with permanent appointments, permanent elections, and they're all three quality people," Christie said. "The State Corporation Commission of Virginia is the most important state agency in Virginia that most people have never heard of."

The SCC oversees energy, as well as large swaths of the state economy, including all insurance (it helps set up the state marketplace for health insurance under Obamacare), banking, securities, retail franchises and railroads. It also is the state's central filing office for corporations, limited partnerships and LLCs.

"I think it's the outstanding regulatory agency in America at the state level, based on the history and based on the broad jurisdiction," Christie said. ■

SPP News

SPP Markets+ Participants Executive Committee Briefs

Members Acknowledge Likelihood of 2 Western RTOs

WESTMINSTER, Colo. — The competing efforts by SPP and CAISO to build and deploy an RTO in the Western Interconnection have sometimes been painted as a race in which the winner will be first grid operator to reach the finish line.

Hold your horses, now (pun intended).

Some in the West have come to the conclusion there are likely to be two day-ahead markets in the West: CAISO's Extended Day-Ahead Market, and SPP's Markets+ and/or RTO West. They're also saying it is now time for CAISO and SPP to begin talking about seams issues.

Vijay Satyal, Western Resource Advocates | © RTO Insider LLC

"We are accepting the possibility of two day-ahead markets," Vijay Satyal, deputy director of regional markets for Western Resource Advocates (WRA), said last week during SPP's first Markets+ Participants Executive Committee (MPEC) meeting of the year. "For now, we will seek to ensure there's little seams impact from possible bifurcated day-ahead markets in the West."

MPEC Chair Laura Trolese (right), of The Energy Authority, and Vice Chair Brian Cole, of Arizona Public Service, lead the committee meeting. | © RTO Insider LLC

Satyal raised the possibility of two markets several times during the meeting. WRA, a nonprofit environmental law and policy organization, has maintained for five years that the region's economic, reliability and environmental benefits are maximized with one large Western RTO.

Now, Satyal says, "the sooner, the better" that CAISO and SPP start talking with each other.

SPP said its Markets+ staff and CAISO began regular informal monthly meetings in July to discuss the design and status of both markets. The RTO has much more regular communication over reliability issues with CAISO as a neighboring reliability coordinator in the West.

Carrie Simpson, SPP's senior director of seams and Western services, said the conversations include "making our seams as seamless as possible" and present an opportunity for SPP to work with CAISO and stakeholders to find a better way to mitigate the risks on both sides.

"This could be one of those areas that we've worked for improvement. This [design item] is a good way to just recognize that [participants] might have to carry more [flexibility reserve] because this type of product is coming in," she said, noting tariff language brought forward by the Markets+ Seams Working Group (MSWG). "The seams group felt it was appropriate to allocate the uncertainty costs to these types of transactions. It allocates the cost to those who are buying from CAISO to sell into SPP because of the uncertainties around those types of transactions."

Chelan County Public Utility District's Tuuli Hakala chairs the MSWG. She suspects most members of her team joined to work on those very issues.

"My expectation is that as we're working through protocols, we're identifying elements where this is an area where this policy could be improved through formal coordination," she said.

Satyal said he didn't think the discussions between the grid operators go far enough or give enough transparency to stakeholders that might be affected by both market footprints.

"It is going to be extremely important to build interoperability agreements (i.e., seams management) so that we have better coordination between the two markets," he told *RTO Insider*. He called for agreement on issues "involving either reliability management or the economic impacts, transmission and greenhouse gas management that come with two adjoining markets at work together."

"This is a proactive request that WRA feels is important and in the interest of the public, ratepayers and customers," Satyal said. "The next year and a half are critical for both markets to come to the table and agree on a principle statement around the seams, to agree on what are the operational areas and then what are the specific practices that require coordination. [CAISO and SPP] have had initial discussions, but if there's going to be a true transparent stakeholder process ... the utilities and market participants that are going to sign

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participation agreements should be aware and be part of this.

"Doing so now would make future seams agreement work more flexible to update and propose to FERC for approval," he added, calling for a seams evaluation or study scenarios that look at three different levels of power flows as the ideal next step. "It's important that all parties come to the table and support the two market operators in the minimum elements of a seams framework."

MMU, MSC to Collaborate

SPP's Market Monitoring Unit and the Markets+ State Committee (MSC) agreed to collaborate on clearly defining an observed participant obligation gap in the tariff that was identified by state regulators.

At issue is a 2022 FERC Notice of Proposed Rulemaking related to "duty of candor." It would require all entities communicating with the commission or other organizations — e.g., the MMU — about FERC matters to provide "accurate and factual information" (*RM22-20*). (See *FERC NOPRs Would Require 'Candor,' Improved Accounting for Renewables*.)

Oregon Public Utility Commissioner Letha Tawney called into the meeting and said the MMU's "continued concern" of a weakness in the existing Markets+ tariff "concerns the MSC." She said the committee is seeking rules that "explicitly apply" to all entities, with everyone held to the same expectations.

"We all know when there is trust, and that is built on transparency, and the rules apply to everyone who participates ... and you are seeking those customer benefits that an efficient, well-functioning market can deliver. From that perspective, we are all very aligned," Tawney said. "We all know from our shared experience in the West that there is a fragile trust that the West has begun to build in the concept of security-constrained economic dispatch."

The MMU argued before the MPEC in November that "duty of candor" language was missing from the tariff. Asked for examples of duty-of-candor violations, Monitor Keith Collins said he could offer hypothetical examples, but he would be breaking FERC rules by giving specific examples of what counts as privileged information.

"There are times when we asked for more information, and we would expect that information to be accurate and factual," Collins said. "Unfortunately, that has not always been the case, and that can create some problems for us."

"It remains unclear to MSC members that all market participants will have the same obligations in how they respond to requests for information from the MMU outside of a specific market-manipulation situation," Tawney said. "There have been challenges [in the Eastern Interconnection] to holding everybody to that obligation to respond."

The Markets+ legal subgroup will assist the MMU and MSC in determining any changes that need to be made in addressing the issue and bring recommendations to MPEC's Feb. 20 virtual meeting. If consensus is not reached, the MPEC will move forward with the existing tariff language.

The MPEC also asked the MSC to update the Interim Markets+ Independent Panel (IMIP) that is overseeing the first phase of the market's development.

Independents Sector Changes

MPEC members unanimously endorsed a recommendation from the Independents sector to create a Markets+ Interim Governance Task Force that would review and process governance issues before they go to the committee.

The group's makeup is subject to MPEC's determination.

Those issues include the weighting of votes within the sector, a sticking point since last year, and potential improvements of Markets+ sector definitions. (See *IMIP Approves SPP Markets+ Governance Tariff Language*.)

The Independents sector has also proposed that its votes be calculated on a single-vote-per-member basis, with at least half of the sector reserved for Markets+ participants, stakeholders with at least 1 MW in the market's footprint or stakeholder organizations with at least five members, a majority of whom must be involved in wholesale markets.

The sector is a catch-all comprising public information groups, independent power producers, markets and other participants that aren't investor-owned or public power utilities.

"It's a very broad sector," said Kylah McNabb, speaking for the National Resources Defense Council. "This helps the Independent sector manage itself, given our diversity."

Draft Tariff Posted

Stakeholders endorsed several more pieces of tariff language during the meeting, with SPP *posting* the draft's 592 pages Jan. 26. MPEC members have until Feb. 9 to submit their comments on the tariff and its 14 attachments detailing the market's services, terms and conditions.

The IMIP will take up the tariff for approval in late February. The SPP Board of Directors will then consider it during a special meeting in late March, after which it will be filed at FERC.

SPP is hoping for the commission's approval in about nine months, allowing it to begin Phase II of Markets+'s development. ■

— Tom Kleckner

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SPP Markets and Operations Policy Committee Briefs

Stakeholders Endorse Congestion-hedging Policies' Implementation

SPP stakeholders approved congestion-hedging implementation policies last week, six years after first taking up the issue.

"This may be a little more like Groundhog Day because we're coming back once again with congestion-hedging improvements," Evergy's Jim Flucke said during the Markets and Operations Policy Committee's virtual meeting. "The [Market Working Group] has been working on these improvements for probably about six years now. The Holistic Integrated Tariff Team [HITT] took it over for a while, but it came back to us.

"We've worked very hard to find some compromise positions that satisfy the needs of those entities that aren't getting congestion-hedging rights from their transmission that they've purchased. It is not everything that those entities had requested at the beginning, but after six years of work, it is a compromise between the two positions of not wanting anything and the desire to have more balance between market participants," Flucke added.

The revision request (RR591) would implement congestion-hedging policies already approved by the Board of Directors and Regional State Committee (RSC).

MOPC Chair Alan Myers, with ITC Holdings, reminded stakeholders that the policies already have been decided to head off further discussion.

"What we'll be talking about today is implementation," Myers said.

The board and RSC approved a package of eight proposals, designed to increase equity, fairness and financial transmission rights awards among market participants, in July. (See *SPP Board/Members Committee Briefs: July 24-25, 2023*.)

Since then, the MWG has added language for the annual long-term congestion rights (LTCRs) analysis performed during each round of the auction revenue right (ARR) nomination process to ensure nominated candidate ARRs do not violate any normal transmission-line thermal ratings under normal system conditions.

The group also added language to distribute ARR surplus. This includes an iterative approach to the ARR allocation's first round and the distribution of excess auction revenues.

SPP says 6.8 GW of imports saved the day during the recent winter storm. | *Entergy*

Once approved by FERC, SPP would allocate 50% of the excess revenue in one year under the old method and 50% under the new method. After that, the new process will take over.

Terry Wolf, whose Missouri River Energy Services has filed a Section 206 complaint at FERC over the issue, said it still does not go far enough.

"Given our situation of having long-term firm service that predated joining SPP and receiving zero LTCRs, we continue to believe it is unreasonable and not consistent with what the precedent is," he said. "It's taken too darn long, and it's not turning quickly enough to provide equity to folks with long-term firm service. I continue to be frustrated by the lack of movement here."

MOPC Passes Plethora of RRs

MOPC approved 23 RRs and several other documents during the meeting. Myers told the Strategic Planning Committee on Jan. 18 that the agenda's "volume of approval stuff" required members to "pound through pretty hard."

"Hopefully, better days are ahead as the rest of our meetings this year will be face-to-face," he said.

The endorsed revisions included:

- The Project Cost Working Group's RR574, a response to concerns raised by stakeholders that SPP-issued upgrades were delayed past their need date and/or first reported in-service date. The PCWG and staff developed an in-service date delay report and a phased approach to improve transparency and situational awareness. A modified version of the RR that would have extended the original 90-day trigger for PCWG review to 180 days failed. "Extending this time to half a year is not going in the right direction," the Advanced Power Alliance's Steve Gaw said. "We should be adding some teeth to some of these cases." The measure passed with 83% approval.
- The Transmission Working Group's RR577, which clarifies the SPP flowgates that will be automatically included in the RTO's initial constraint list; establish criteria for classifying facilities as economic needs because of congestion from planned or forced historical outages; and establish criteria for classifying facilities as reliability needs due to pre-contingency or post-contingent facility rating or voltage limit exceedances.
- RR578 passed unanimously with two abstentions. It creates a new and "appropriate"

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uninstructed resource deviation (URD). With an average cost to resources in 2022 of $3.65/MW of deviation proving not to be a sufficient deterrent for dispatch noncompliance, the MWG proposes the URD charge be equal to the real-time deviation above or below the resource operating tolerance multiplied by the absolute value of the real-time LMP.

- *RR600.3*, setting up rates for point-to-point and network service because of Western Area Power Authority's Rocky Mountain Region and Upper Missouri region having facilities in both interconnections. The associated revenue distribution will be based on the amount of annual transmission revenue requirement specific to the facilities in an interconnection. The revision passed unanimously.

Imports Help Weather the Storm

C.J. Brown, SPP's director of system operations, told stakeholders that were it not for a record 6.8 GW of energy imports during the Jan. 14-17 winter storm, the RTO would have been in an energy emergency alert.

"We almost got to [7,000 MW] ... but 7,000 MW of imports during the storm, which is really impressive indeed, kept us out of an emergency," he said, delivering an initial report on the event. "If you take away those imports, we would have 100% been in an EEA the entire time Sunday through Tuesday, no doubt about it. If you took away half those imports, we're probably in an EAA, but we're definitely on Sunday and Monday, maybe even Tuesday."

Some of the imports came from ERCOT on Jan. 14, attracted by higher prices in SPP. Power flows went in the opposite direction Jan. 15.

The imports drew the attention of FERC Chair Willie Phillips during the commission's open meeting Thursday. He *said* the storm underscored the importance of interregional transmission ties.

SPP wound up setting a peak load record for January at 46.7 GW on Jan. 17, bettering the previous mark of 43.2 GW set in 2018.

Brown said SPP experienced up to 20 GW of conventional resource outages during the event becuase of frozen coal piles and plant issues along the Missouri River. With wind "screaming" at times and producing 20 GW of energy at its high point, the grid operator was able to meet demand.

"Things just do not operate well in -20 temperatures. They just don't," Brown said.

McAdams to Consult with REAL Team

The leadership may have changed within the Resource and Energy Adequacy Leadership (REAL) Team, but it still is focused on addressing SPP's resource adequacy corporate risk and goals, staff told MOPC.

"It continues to be one of our corporate goals to mitigate this risk and move forward in a valuable and measurable manner for all of the various policies and initiatives we have going on," SPP's Casey Cathey said.

Kristie Fiegen, chair of the South Dakota Public Utilities Commission, has replaced former Texas commissioner Will McAdams as the REAL Team's chair. McAdams resigned from his posts in December. (See *McAdams Honored During Last Texas PUC Meeting*.)

McAdams will remain involved with the team's work. He has formed his own consulting firm, McAdams Energy Group, with a focus on energy and infrastructure development. The RSC already has contracted with McAdams' firm to consult on mitigating the resource adequacy risk within the RSC and the REAL Team, SPP's Kim O'Guinn said.

Kansas Corporation Commissioner Andrew French has filled McAdams' RSC seat on the REAL Team. To preserve the team's regional balance, Texas Public Utility Commission senior economist Shawnee Claiborn-Pinto has replaced KCC staffer Shari Albrecht.

Staff credited McAdams with the team's success last year, which included developing and approving revision requests related to a winter season resource adequacy requirement (RAR) (*RR549*), performance based accreditation (*RR554*), and effective load-carrying capability (*RR568*), and demand response accreditation and fuel assurance policies; beginning an expected unserved energy (EUE) study and the load evaluation portion of the Future Energy and Resource Needs Study (FERNS); and completed the 2023 loss-of-load expectation study.

This year, the team has set its sights on an "appropriate" accreditation of resources, winter season requirements, planning reserve margin (PRM) methodology changes, load forecasting and a future resource mix/EUE study.

The workload includes addressing FERC's November rejection of SPP's proposed winter resource adequacy requirement. The commission said the RTO can address FERC's concerns and resubmit the proposal (*ER23-2781*). (See "FERC Rejects Winter Requirement," *'Therapy Session': SPP REAL Team Reviews Draft LOLE Study*.)

The commission said the proposal did not contain any requirement that a load-

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responsible entity's (LRE) resources are expected to be available. It said SPP has not demonstrated it is reasonable to permit LREs to rely on resources that are not expected to be available in the winter season to satisfy their resource adequacy requirements.

"They gave us very tangible feedback," Cathey said. "From a staff perspective, we have not lost effective dates such that we can still move the ball forward with the winter PRM."

SPP plans to refile the winter RAR at FERC in April. If approved, it will be nonbinding until the 2026-27 winter.

The REAL Team begins its slate of meetings with a *virtual meeting Friday*.

2 Items Pulled off Consent Agenda

Members pulled two revision requests off the consent agenda for individual votes but ended up approving both.

Renewable energy interests asked for more transparency into the calculations of *RR603*, which increase study deposits for new generator interconnection requests using FERC *Order 2023*'s mandated schedule and adds a nonrefundable application fee. The change also increases deposits for surplus, modification and replacement studies.

Staff said a survey of the last seven study clusters indicated costs generally are 10 to 30% more than the current maximum study deposit of $90,000. Under the Order 2023 schedule, most deposits will range from $100,000 to $150,000 and would have covered the average costs for the clusters, they said.

"I've asked for the documentation," Gaw said. He acknowledged SPP has said the study costs are correct but said, "There's been some degree of concern about how these things have been handled, on the amount of the consultants that have been used and how contracts are done."

Although the revision passed the Regional Tariff and Transmission Working Groups with just one abstention, staff said they have responded to stakeholder concerns by implementing a request-for-proposal process for special studies; reached out to SPP-approved consultants for pricing and availability; added consultants to the study pool to increase diversity and competitive costs; and performed special studies in-house when resources are available.

MOPC endorsed RR603 with 85.1% approval.

The committee also separately approved a remedial action scheme (RAS) in western North Dakota with a near-unanimous vote. The RAS will provide temporary relief in the Williston load pocket until the Roundup-Kummer Ridge 345-kV line is completed early next year.

Flucke expressed concern over the proposal, saying it is causing TCR underfunding.

SPP's Micha Bailey said the RAS will help TCR underfunding because it loosens as the impact of that congestion constraint decreases. "That's going to lessen the amount of congestion on that [region], which then was the amount of money owed to those TCR holders."

MOPC's consent agenda included 15 RRs, five of which (RR600.1-RR600.6) are related to western entities integrated into SPP's RTO. It also included approval to retire the Thunderhead RAS in Nebraska in November; a lessons-learned report on the third Regional Cost Allocation Review; the 2024 Transmission Expansion plan; the 2023 Integrated Transmission Plan's (ITP) short-term reliability project report; and a 2024 ITP market powerflow models waiver.

The RRs would:

- *RR560*: Move operating criteria language to the system operating limits (SOLs) methodology.
- *RR583*: Allow SPP to nominate LTCRs for federal service exemption and grandfathered agreements carveouts to further mitigate load's exposure to the day-ahead market's (DAMKT) congestion costs.
- *RR587*: Correct the virtual energy offer curve from 0 to 100 MW to accurately reflect current pricing.
- *RR588*: Modify the regulation-selection process to include qualified resources that cleared regulation in the DAMKT for the operating hour, reducing their financial risk to competitively offer ancillary services in both the day-ahead and real-time markets.
- *RR593*: Clarify the cost allocation for two Basin Electric substations so that both can correctly be allocated according to the base plan.
- *RR594*: Incorporate improvements mandated by *FERC Order 2023* to ensure the generator interconnection process is just, reasonable, and not unduly discriminatory or preferential.
- *RR595* Close a market design gap related to *FERC Order 831*'s implementation by using make-whole payments to compensate resources being unable to recover their cost of incremental dispatch in some scenarios.
- *RR597*: Document the DAMKT high-level process used for effective limit application.
- *RR598*: Remove planning criteria portions outlining the methodology to develop SOLs and interconnection reliability operating limits (IROLs) in the planning horizon. This aligns with NERC's retirement of *Mandatory Reliability Standard FAC-010-3*.
- *RR600.1*: Clarify for western parties integrating into SPP's RTO terms and conditions that Attachment AU, which describes the distribution to transmission owners of revenue received from MISO under a settlement agreement, applies to TOs in the Eastern Interconnection.
- *RR600.2*: Include existing non-radial lines, substations and associated facilities operating at 100 kV or above, and radial lines and associated facilities operated at or above 100 kV that serve two or more eligible customers that are not affiliates of each other as transmission facilities in the West under Attachment AI.
- *RR600.4*: Remove Attachment AT and its definition of a contract services agreement between Basin Electric Power Cooperative and SPP, which no longer will be needed with Basin's integration into SPP's western RTO.
- *RR6005*: Modify the tariff to refer to a WAPA division where it currently refers to WAPA-Upper Great Plains.
- *RR600.6*: Revise Attachment S, under which transmission providers determine megawatt-mile impacts separately for the SPP East Region and SPP West Region, to also include SPP Region, if needed. Because WAPA's Upper Missouri and Rocky Mountain Region zones having facilities in both interconnections, some rates for point-to-point and network service and their associated revenue distribution will be based on the amount of annual transmission revenue requirement specific to those facilities in an interconnection.
- *RR601*: Ensure multiday minimum runtime RRs and clean-up RRs (*RR382*, *RR540* and *RR569*) are accurately implemented and functioning as designed. The revision creates new determinants to represent the effective start-up amount of a resource that will only be used in the evaluation of the day-ahead and real-time multiday minimum run time make whole payment. ■

— Tom Kleckner

Company News

NextEra: Disruption Only Strengthens the Company

By Tom Kleckner

Noting "disruption often presents opportunity at NextEra Energy," CEO John Ketchum said Jan. 25 the company relied on 25 years of experience with renewable energy to navigate "clear headwinds for renewables" over the past two years.

Ketchum told financial analysts during NextEra's quarterly earnings call that its competitive, clean energy business, NextEra Resources, had its best year yet by adding about 9 GW of new renewable and storage origination to a backlog that now exceeds 20 GW. About 5.6 GW of renewables and storage were commissioned during the year, NextEra said.

"We successfully managed through the disruption," Ketchum said. "We believe that the disruption over the last two years has made NextEra Energy an even stronger company. Our business model is more resilient. Our development platform is even more advanced, and our supply chain is more diversified than it has ever been."

Ketchum noted inflation and inflation rates have declined from their peaks, solar suppliers have been provided with more certainty around rules for imports and new solar supply chains have led to lower panel costs that have declined by about 25% from their peak over the past 24 months.

"Ultimately, all these tailwinds are great for customers, and we believe that should drive greater renewables demand in 2024 and beyond," he said.

NextEra *reported* year-end earnings of $7.31 billion ($3.60/share), up from $4.15 billion ($2.10/share) the year before. Fourth-quarter earnings were $1.21 billion ($0.59/share), compared to $1.52 billion ($0.76/share) for the same quarter in 2022.

Ketchum expressed frustration with NextEra's stock performance this year. The company's share price closed at $57.98 Jan. 25, down $4.94 from a Jan. 8 peak of $62.92.

"We recognize and are disappointed by the underperformance in the share price, and as we start 2024, we remain steadfast in our continued focus on execution and creating long term value," Ketchum said. "Bottom line, we believe NextEra Energy is well positioned headed in the 2024."

Xcel: Coal Closures to Continue

Xcel Energy also *reported* year-end and fourth-quarter earnings Jan. 25. Annual earnings were $1.77 billion ($3.21/share), compared with $1.74 billion ($3.17/share) for the same period a year ago.

For the quarter, earnings were $409 million ($0.74/share), compared with $379 million ($0.69/share) during the same quarter in 2022. Xcel reaffirmed its 2024 EPS guidance of $3.50-$3.60.

CEO Bob Franzel told financial analysts that the retirement in December of the first of three coal-fired units at the Sherburne County Generating Station (Sherco) sets the stage to retire all of its coal plants by 2030. Sherco's other two units are targeted for closure in 2026 and 2030. (See *Xcel Says Coal Retirements on Track Despite South Dakota PUC's Plea for Extensions*.)

"This is a milestone as we work to exit coal by 2030 and another sign that we're leading the nation's clean energy transition," Franzel told financial analysts.

Xcel plans to replace the units with 2.1 GW of wind and 2.5 GW of solar with what it says will be the largest solar facility in the Midwest.

The company's share price closed at $58.89, up 67 cents on the day. Xcel opened the year at $63.47. ■

NextEra says dropping solar and storage prices have it well positioned for the future. | *NextEra Energy Resources*

Company Briefs

BP, Equinor Trade Ownership of OSW Projects

Equinor and BP on Jan. 26 reached an agreement to restructure the ownership of their joint U.S. offshore wind projects, which will result in BP taking ownership of Equinor's 50% stake in the Beacon Wind 1 and 2 projects and Equinor taking ownership of BP's 50% stake in the Empire Wind 1 and 2 projects.

Under the agreement, Equinor will also take 100% ownership of Empire Wind Holdings and BP's 50% share of the South Brooklyn Marine Terminal lease. At the same time, BP will get Beacon Wind Holdings and the associated project company that holds the Astoria Gateway for Renewable Energy site.

Subject to regulatory approvals, the transaction is anticipated to close around mid-2024.

More: *offshoreWIND.biz*

BP Faces Activist Investor Pressure to Ditch Clean Energy Pledges

Activist investor Bluebell Capital Partners on Jan. 29 called on BP to ditch its commitment to cut oil and gas output as well as other keys parts of its strategy to transform the company into a clean energy provider.

Bluebell, a London-based hedge fund, wrote to BP Chair Helge Lund in October shortly after acquiring a small stake in the energy major. In the letter, Bluebell said BP's pledge to reduce oil and gas production by 25% by 2030 compared with 2019 levels meant it was destroying shareholder value by moving away from hydrocarbons faster than society. The hedge fund also challenged the pace and extent of investment in BP's transition businesses — biofuels, convenience, charging, renewables and hydrogen.

CEO Murray Auchincloss has said he is committed to the company's plan.

More: *Financial Times*

Chipmakers Among 15 US Firms Eyeing $8B Vietnam Investment

Fifteen U.S. companies, including semiconductors firms, have expressed interest in investing $8 billion in Vietnam in clean energy infrastructure, contingent on the country's progress on renewable energy rules, U.S. Undersecretary for Economic Growth, Energy and the Environment Jose Fernandez said Jan. 26.

Fernandez underlined that those firms had obligations to shareholders so the investment would be conditional on regulatory progress on renewable energy in Vietnam. He declined to name the companies.

More: *Reuters*

Federal Briefs

Republican Governors Urge EPA to Roll Back Proposed EV Standards

In an open letter released Jan. 22, 16 Republican governors called on EPA to walk back its EV standards that two-thirds of new cars sold in 2032 must be electric.

The group of governors outlined the need for stronger infrastructure supporting domestic EV battery production, grid capacity and charging stations.

The draft rule is currently in the interagency review process after receiving more than 250,000 public comments, according to EPA.

More: *USA Today*

Biden Vetoes Measure to Block Policy on Foreign Content in EV Chargers

President Joe Biden on Jan. 24 vetoed a Republican measure that would have blocked a White House waiver that allows some foreign-made content in federally funded chargers for EVs.

If enacted, the GOP resolution would revert U.S. policy to a 1983 rule that waives domestic requirements for many manufactured products. The Reagan-era waiver allows federal money to be spent on a range of products made outside the U.S., including in "competitor nations like the People's Republic of China," the White House said. Supporters said the measure would keep China out of the supply chain for EV chargers.

Both the Senate and House passed the measure in November and January, respectively.

More: *The Associated Press*

New Lawsuit Filed Against Utilities on Behalf of Holiday Farm Fire Survivors

A small coalition of law firms in Oregon and California collectively filed suit against three utilities for their alleged lack of safeguards and mishandling of electrical transmissions right before the Holiday Farm Fire broke out on Sept. 7, 2020.

In a complaint filed with Oregon's U.S. District Court on Jan. 16, the attorneys alleged that Bonneville Power Administration failed to properly inspect and monitor its power line where the fire occurred, as well as not properly ensuring that trees wouldn't fall against or contact the line during high winds and a "red flag" event. Other allegations include failing to remove trees from where lines stood and not de-energizing BPA lines that provided power to The Eugene Water & Electric Board's and Lane Electric's lines that day.

The suit was filed on behalf of 188 individuals, eight minors, 18 companies and 24 family or investment trusts. Attorneys seek a jury trial and $232 million in damages.

More: *Oregon Public Broadcasting*

State Briefs

ALABAMA

Alabama Power Announces Plan to Remove, Recycle Coal Ash in Mobile

Alabama Power on Jan. 25 announced a deal with Eco Material Technologies to remove and recycle "almost all" of the 22 million cubic yards of toxic coal ash sitting in an unlined lagoon on the banks of the Mobile River.

The partners will build a new coal ash recycling facility in Bucks, Ala., which would treat and dry the coal ash slurry from the James M. Barry Electric Generating Plan. The recycled material will be used in making concrete.

More: *Alabama.com*

CALIFORNIA

Humboldt County OSW Development Awarded $426M

Humboldt County on Jan. 24 was awarded a $426 million grant meant to fund the construction of a terminal in Samoa that would allow turbine construction off the coast.

The grant, awarded to the Humboldt County Harbor, Recreation and Conservation District, aims to create a terminal for the transportation, assembly, construction and maintenance of floating offshore wind turbines.

More: *Times-Standard*

ILLINOIS

Chicago Could be 1st Major Midwest City to Ban Gas in New Construction

The Clean and Affordable Buildings Ordinance, introduced by Chicago Mayor Brandon Johnson (D), would effectively phase out fossil fuel-based appliances and heating systems in new construction and substantially improved buildings. The ordinance would make Chicago the first major Midwestern city with an indoor emissions standard.

The push for building electrification is part of a broader project to not just wean the city off fossil fuels but also address utility bills and the health impacts of indoor air pollution. The effort was a key recommendation of the city's Building Decarbonization Policy Working Group in 2022, which determined that buildings are Chicago's largest source of greenhouse gas emissions (70%).

The new rule would take effect within a year of approval.

More: *Grist*

LOUISIANA

PSC Approves Entergy Request for Additional Renewable Facilities

The Public Service Commission on Jan. 24 approved Entergy's request for the construction of facilities that would add 225 MW of solar power to its generation portfolio.

Along with the 225 MW, the company also has 475 MW of solar power previously approved by the PSC, with an additional 3,000 MW pending approval. Currently, Entergy has approximately 230 MW of renewable resources.

More: *Entergy*

MAINE

Climate Council Holds Emergency Meeting to Discuss Winter Storms

The Maine Climate Council on Jan. 23 gathered for an emergency meeting to discuss the impacts from the recent storms and share ideas on how communities could better prepare.

State officials acknowledged that their to-do list to clean up from the recent storms and prepare for future weather extremes is daunting. Members also said the public needs more education about how to read flood maps and understand warnings from the National Weather Service.

The council said it will incorporate the research and recommendations into the next statewide climate plan, which is due at the end of the year.

More: *Maine Public Radio*

DEP Proposes Fine for Erosion Violations at Embden Solar Farm

The Department of Environmental Protection on Jan. 25 proposed a $148,836 fine for solar company Tower Solar Partners after concluding the company failed to control erosion on a project along the Kennebec River.

The DEP outlined a string of violations, including inadequately installed and maintained erosion controls that allowed sediment to flow into the nearby Kennebec River and Alder Brook. Documents also noted that at one point, 30 acres of the 35-acre site were disturbed and unstable — three times the amount allowed under department rule.

More: *The Maine Monitor*

Legislation Tries to Limit Utility Disconnections

Senate President Troy Jackson (D) on Jan. 25 urged lawmakers to pass legislation that would limit service disconnections by creating more stringent rules for when utilities can cut customers off.

The legislation would stipulate that the Public Utilities Commission must issue rules that a utility cannot disconnect service unless a customer doesn't pay or make a payment arrangement on a bill that is more than $225. It also calls for banning disconnections during extreme weather conditions.

The measure comes as Maine's for-profit utility companies, Central Maine Power and Versant, collectively sent tens of thousands of disconnection notices to customers last year.

More: *News From The States*

OREGON

Jury Awards $85M to 9 Victims of 2020 Wildfires

An Oregon jury Jan. 23 awarded $85 million to nine victims of wildfires that ravaged the state in 2020.

The fires were among the worst natural disasters in the state's history, killing nine people, burning more than 1,875 square miles and destroying upward of 5,000 homes. In June a jury found PacifiCorp liable for damages for negligently failing to cut power despite warnings from top fire officials, saying its power lines were responsible for multiple blazes. PacifiCorp has appealed.

PacifiCorp expects post-verdict rulings and insurance payments to bring its share of the verdict to just under $80 million, the company said in a statement.

More: *The Associated Press*

VIRGINIA

Judge Dismisses Lawsuits Opposing Botetourt County Wind Farm

Circuit Judge Edward Stein on Jan. 25 dismissed a lawsuit filed by opponents of a proposed Rocky Forge Wind farm in Botetourt County that threatened further delays of the project.

Stein ruled that the opponents lacked proper standing to challenge the county's approval of a temporary concrete plant planned by developers that would supply the foundations for 13 turbines on top of North Mountain. A second lawsuit, which took issue with an extension granted to the farm during the COVID-19 pandemic, was dismissed by Stein in December.

Although it has been postponed for nearly a decade, the farm remains on track to become the state's first onshore wind farm. Construction is scheduled to begin this summer.

More: *The Roanoke Times*

WASHINGTON

Puget Sound Energy Cancels LNG Plant Expansion in Tacoma

Puget Sound Energy on Jan. 24 announced it has canceled an expansion of its liquefied natural gas plant in Tacoma.

The Puyallup Tribe of Indians and a coalition of community groups appealed project permits to the state Shoreline Hearings Board. The case had been scheduled for an April hearing, but rather than defend the project, PSE backed down.

The proposed expansion would have allowed vessels and barges to load LNG to power their ships, but also to transfer fuel to other ships, making them floating fuel suppliers.

More: *The Seattle Times*