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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Manchin and Phillips Discuss Expanding the Grid at NARUC

By James Downing

WASHINGTON, D.C. — FERC Chairman Willie Phillips and Sen. Joe Manchin (D-W.Va.) want to pass policies this year that speed up the rollout of transmission, they said at the *NARUC conference* on Feb. 27.

FERC already has released *Order 2023*, which Phillips said he hoped would speed interconnection queues. Taking a project from entering the line to putting shovels in the ground now takes an average of five years.

"We're looking forward to doing long-term and regional planning as well," Phillips said. "And we're going to do it in a way that absolutely works with the state, collaborates with our state regulator colleagues, because you do understand the system better than anybody else."

When it comes to long-term planning, FERC is not looking to favor one group of state policies over any others, but rather wants to reflect the reality of what is happening on the ground, he added.

"We know the policies across the country change," Phillips said. "And we know we have more and different resources coming on all the time. It makes no sense to pretend otherwise."

Another transmission issue Phillips is committed to tackling is interregional transfer capability, which is beneficial in the increasingly common winter reliability events that have affected the grid over the past decade.

"We can say that there are unplanned load sheds, but when something happens every other year, for the past 11 years, it's difficult to say that it's unplanned. I think it is stunningly predictable what can happen on the system. So, it's our responsibility, I believe, to make sure that we have interregional capability to handle this."

NERC is working on a study on just how much interregional capacity would make sense, and Phillips said once that was complete, FERC would hit the ground running with a proposal to get that built.

Manchin, who is retiring at the end of this year, hopes to get a "permitting reform" bill out of what he said was one of the least productive Congresses in history, having passed just 39 bills through its first year-plus compared to an average of more than 250.

"The politics that we're dealing with today has been weaponized," Manchin said. "Whether you're Democrat or Republican, independent, whatever you might be, God bless you, you're not the enemy. And the person on the other side is not your enemy."

While people certainly have opposing views, they should be viewed as opponents who help strengthen arguments and are people you can work with, not enemies who need to be destroyed as many in Washington view them, he added.

Manchin hopes to get an exception to that brand of politics by working with his fellow Energy & Natural Resources Committee leader, Sen. John Barrasso (R-Wyo.), on a bill to get energy infrastructure built quicker.

It's important to get some significant votes from both parties for their proposal to pass because in recent years, both Republicans and Democrats have made purely partisan pushes on the issue that have gone nowhere, Manchin said.

"This is our last chance, and I am not walking out of here until I give every ounce of effort that I have to get a permitting bill done that gets you from the start to the finish within two to three years," he added.

Manchin said they're still working out specifics on how to give states a first pass on dealing with major transmission projects that cross multiple states. He floated the idea of giving states and utilities a year to negotiate on siting and cost allocation before the federal government would step in.

Another issue a bill would tackle is judicial reform, specifically by proposing to limit to six months the time parties have to sue once a project has been approved. They can wait up to six years now, he said.

All these new policies are against the backdrop of an industry expected to see growing demand in the coming years from data centers, new manufacturing, and increasing electrification of transportation and heating. NERC has said demand should grow 38 GW in the next five years, which Phillips said would continue into future decades, as one study has demand growing at an average of 1% per year for the next three decades.

"That means 5,000 terawatt hours of new energy on the system by 2050," Phillips said. "It's something that we think about a lot. Increasingly, when I've been meeting stakeholders, executives across the country, we're talking about rapidly increasing demand." ■

FERC Chairman Willie Phillips and NARUC President Julie Fedorchak of North Dakota at the Winter Policy Summit. | *© RTO Insider LLC*

NARUC Winter Policy Summit

NARUC Looks at How to Manage New Large Loads

By James Downing

The power industry is facing an increasingly delicate balancing act as policies drive some generators to retirement, while major new loads are popping up and making planning for the future more difficult, presenters said during National Association of Regulatory Utility Commissioners' (NARUC) Winter Policy Summit.

Historically, PJM has seen its markets drive retirement decisions. Some 90% of the 66,000 MW that have retired in the past couple of decades have come offline when they requested, and most needed no upgrades to accommodate their absence from the grid, said PJM Director of State Policy Solutions Tim Burdis.

"I look out the next 10 years. In 2035 in the PJM footprint, we have 26 GW slated to come off of the system, just based on state and federal policy requirements," Burdis said. "So that's not factoring in anything related to the market signal, or the underlying reliability aspects."

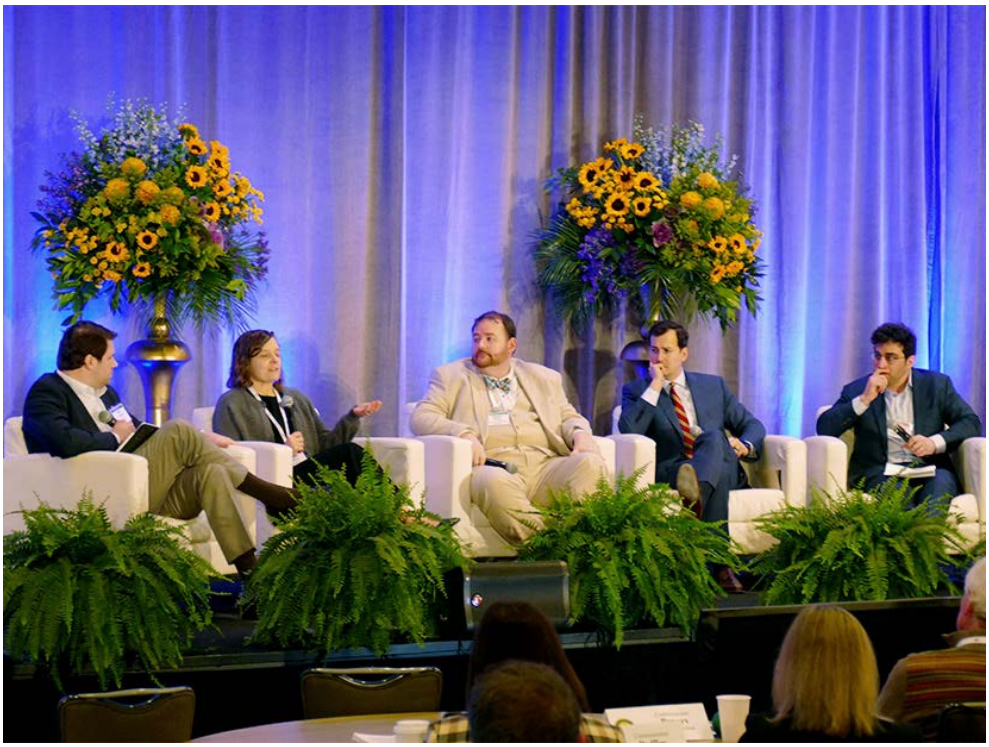
That's going to lead to more of a division between generators coming off the system and its reliability needs, which means PJM and its members will need to do more to ensure reliability, he added.

"It's also 26 GW of new load coming onto the system over that same time period in PJM's latest load forecast," Burdis said. "So that's about 52,000 MW or so that are going to have to be accounted for of new supply on the system."

While historically PJM has balanced the relatively few instances where a retirement leads to reliability issues by expanding the grid, that might not be enough going forward. Both the demand side and new generation being built at retired sites could help ensure the shift happens reliably, Burdis said.

The state of Oregon is facing many of the same issues on load, especially, which is making the PUC's job of integrated resource planning more difficult, said Chair Megan Decker.

"I'm not going to waste our time with statistics, but suffice it to say that the Pacific Northwest in general and Oregon in particular are seeing significant interest from the data centers that are needed to power, among other things, the AI revolution and, even more exciting for our state's economy, ... high-tech manufacturing," Decker said. "These can be hundreds or more megawatts at a time and collectively are pushing load growth projections for the region beyond anything we've seen or really imagined until very recently."



From left: Kentucky PSC Chair Kent Chandler runs a panel at NARUC with Oregon PUC Chair Megan Decker, Southern Renewable Energy Association Executive Director Simon Mahan, PJM Director of State Policy Solutions Tim Burdis and University of Chicago Law School Assistant Professor Joshua Macey. | *© RTO Insider LLC*

Integrated resource plans (IRP) are not accustomed to the uncertainty around big new loads, with data center demand showing up more quickly than load traditionally has, and sometimes in the middle of an IRP process, making them hard to plan for.

"Because of the customer's competitive sensitivities, they can't be as transparently scrutinized," Decker said.

Oregon is the rare state outside of an RTO with *retail competition*, and to the extent those new loads are served by competitors, Decker questioned how much retailers would contribute to the overall resource adequacy of the system.

One way of handling the situation would be to move away from IRPs and have the PUC look at procurement after the fact, but that would have negative implications for meeting state policies and affordability, she added.

Southern Renewable Energy Association Executive Director Simon Mahan is no stranger to IRPs, representing independent power producers interested in building clean energy around the Southeast. He has intervened on their behalf in many cases.

"The process is not necessarily geared towards ensuring that intervening parties like myself, like our organization, have all the information available," Mahan said. "The information asymmetry is astronomically high as an intervening party."

That makes it important for state regulators and their staff to prepare well ahead of time with data collection and ask the right questions, rather than waiting for the contested process to launch that starts a "sprint towards the finish line," he added.

Typically, the processes might take a year, but utilities work on the filings starting well before that, which means they can be out of date by the time they are filed.

"They will vigorously defend the report, even though there may be news articles or press releases, even from their own corporate headquarters, saying: 'oh, by the way, we plan to do

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NARUC Winter Policy Summit

Utility CEOs See Ongoing Role for Gas, Nuclear in Decarbonization

NARUC Gets Update on the Energy Transition from Companies and EPA

By James Downing

WASHINGTON, D.C. — Three senior utility executives told state regulators Feb. 27 that natural gas and nuclear power will be essential to the electric generation mix for decades as the industry decarbonizes.

Speaking at the National Association of Regulatory Utility Commissioners' (NARUC) Winter Policy Summit, the executives said the industry already has cut carbon pollution in recent decades, while acknowledging the job is far from over.

"Since 1984, carbon emissions have stayed the same out of our sector, but electricity use has grown 73%," said Edison International CEO Pedro Pizarro. "If the Obama Clean Power Plan had been implemented, the industry would have not only met it and surpassed it, [but done] so earlier than the plan would have called for. We have more than 40% of U.S. generation today coming from clean carbon-free resources like nuclear, wind and solar."

Pizarro, chair of the Edison Electric Institute, said about 50 of EEI's members have announced long-term carbon cutting goals and most of them call for net zero by mid-century.

"We're doing that now in a backdrop where electricity demand is really moving," he added.

Southern California Edison had seen 15 years of essentially no load growth, but now it is expecting load to grow by 2% each of the next several years, Pizarro said.

Tennessee Valley Authority CEO Jeffrey Lyash said emissions in the agency's footprint have fallen 60% from 2005. Now electricity is responsible for only 27% of the emissions in the TVA region.

"I think we can get the 80% [reduction from 2005 levels] and keep balanced with that energy security objective," Lyash said. "The challenge is: And then what? How do you decarbonize the rest of the electricity sector? But more importantly, how do you use electricity, which will be one of the prime ways we decarbonize the rest of the economy?"

Lyash, chair of the Nuclear Energy Institute, said nuclear power will be part of the mix, along with renewables, energy storage, carbon capture and clean hydrogen.

"It's just such a 24/7, system-stabilizing resource, I'm not sure how you get there without it," he added.

DTE Energy CEO Jerry Norcia, chair of the American Gas Association, said natural gas is going to have a continued role in a clean energy future.

Washington Utility and Transportation Commissioner Ann Rendahl leads a panel with TVA CEO Jeffrey Lyash, Edison International CEO Pedro Pizarro and DTE Energy CEO Jerry Norcia at NARUC's Winter Policy Summit on Feb. 27 | *© RTO Insider LLC*

NARUC Winter Policy Summit

"When I think about natural gas in our industry, it really has been an enabler of decarbonization," Norcia said. "About 40% of our power generation in the country now comes from natural gas and that's a fundamental shift from coal, which was the dominant fuel source for power generation in the past."

Direct use of natural gas also is popular, with about 189 million Americans using it and 70% supporting its use, he added.

The electric industry is heavily reliant on natural gas and its use is going to be "valuable and critical for a very long time," Pizarro said. Even in California, SCE's modeling has the fuel in continued use.

"We see California still having about 40% of the commodity that's flowing today; it will still be flowing in 2045 economywide," he said. "For the electric power sector for generation we still see between 4 and 5% of the electrons coming from natural gas-fired resources in 2045."

Those power plants occasionally burning natural gas in 2045 will have their emissions captured, or at least offset, through "other carbon-negative tools." Beyond gas, California will need other technologies such as nuclear and eventually offshore wind, which produces power when other renewables do not.

One major issue is whether EPA should complement the Inflation Reduction Act's incentives with requirements to shut down fossil-fired plants. Pizarro noted that EEI supported the agency when West Virginia and others sued it to stop the Clean Power Plan.

"But we need to make sure that those regulations are fair and reflect reality," said Pizarro.

Some rules requiring natural gas plants to implement carbon capture or burn clean hydrogen were too stringent based on the development of those technologies, he added. Pizarro was speaking days before EPA announced it would delay regulations impacting existing natural gas plants under its power plant rule, focusing it on coal and new natural gas. (See *EPA to Strengthen Emissions Regs for Gas Power Plants*.)

EPA Principal Deputy Assistant Administrator for the Office of Air and Radiation Joseph Goffman spoke at NARUC a day before the three trade group chairmen, saying that once the agency issues its final rule on power plants attention will shift to the states.

"The main driver will be the state plans, that's where the action is going to be," Goffman said.

As states issue plans to implement the power plant rules, EPA wants to stay in touch with the economic regulators represented at NARUC along with their environmental regulators, energy offices and legislators, he added.

"That's where the opportunity will really come to ensure that the rules achieve the urgently needed CO2 reductions from the power sector," Goffman said. "And at the same time continuing to meet the objectives of a reliable supply of affordable electricity."

Goffman was speaking alongside a group of state regulators and West Virginia PSC Chair Charlotte Lane. Lane, whose state still is 88% coal-powered without plans to shut anything down until at least 2040, often sparred with him.

"Carbon emissions may be a concern," Lane said. "But they are not the existential threat to life on this planet that some people would have us believe. I am concerned that the EPA has set its sights on a … target is not going to let up until it shuts down all fossil fuel power plants. However, I believe that the cost of an unreliable power supply will be huge and well in excess of any benefits achieved."

She asked whether the EPA was considering giving a longer timeline for fossil power plants needed for reliability. Goffman answered yes, saying commenters had made the case for the need to be flexible.

"We sort of see the question of time horizon as part of a larger fabric of flexibility," Goffman said. ■

NARUC Looks at How to Manage New Large Loads

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XYZ,' which is in total contradiction [to] what the Integrated Resource Plan actually says," Mahan said.

Mahan quipped that the IRP reports are so full of redactions, including sometimes even publicly available data, that utilities must have a "side hustle in" markers.

The rapid changes make forecasting more difficult, and that means regulators and other intervenors are going to have to "trust but verify" what is being filed.

"How can we verify that what we're being provided through the lens of the utility is what the customers need the best?" Mahan asked. "And one of the best ways is by letting people like me in the process, so that we can serve as another pair of eyes."

While the industry and its regulators face hurdles to ensuring reliability on a transitioning grid, University of Chicago Law School assistant professor Joshua Macey said one common misconception of utility is not among them.

"To the extent that regulators are open to trying ambitious new options, there are no legal barriers. Our constraints are political, and they are economic," Macey said.

The "regulatory compact" was overturned in 1934 by the Supreme Court in *Nebbia v. New York*, which gave Congress more power to regulate the economy. That overturned the old precedent on regulation, where utilities could be overseen because they had been granted a monopoly over the service territory.

"So, what's notable about this is we have a set of industries that are the only industries where we have constitutional authority to regulate," Macey said. "We then have a series of Supreme Court cases that say the question of proper regulation was a legislative determination. And yet we continue to hear arguments that the old model applies only in these industries."

Cases since then (many dealing with the fallout from Three Mile Island and its impact on the nuclear industry) have made it clear that utilities are entitled to their existing assets, but the next set of assets are open to whatever regulatory determination is correct.

"I think we should be open to experimentation," Macey said. "The fact that someone has done it in the past may or may not mean they're in a position to do it most effectively in the future. But it certainly means utilities can take a loss. If they don't reach their meet their contractual obligation, they can take a real loss." ■

FERC/Federal News

Biden Names 3 Nominees to Give FERC 5 Members Again

By James Downing

President Joe Biden announced three FERC nominees Feb. 29, which would bring the agency back to a full complement of five members even after Commissioner Allison Clements leaves.

Biden named to the federal regulator Judy Chang, a former Massachusetts official; FERC analyst David Rosner, who has been detailed to the Democratic staff on the Senate Energy & Natural Resources Committee; and West Virginia Solicitor General Lindsay See. Senate Minority Leader Mitch McConnell (R-Ky.) recommended See.

The last two have links to Sen. Joe Manchin (D-W.Va.), who chairs the Energy & Natural Resources Committee, which will hold hearings on the nominees and must vote them out before they can move onto consideration by the entire Senate. Rosner has worked under Manchin at the committee.

"A fully seated, bipartisan FERC provides more opportunity for advancing long-lasting, sensible energy infrastructure policy," Manchin said in a statement. "As chairman of the Senate Energy and Natural Resources Committee, I look forward to reviewing the qualifications of the three individuals nominated today to be FERC commissioners and assessing their commitment to American energy security."

As solicitor general, See argued her state's side of the case before the Supreme Court in *West Virginia v. EPA*, which limited how the agency can regulate carbon emissions from power plants. (See *Supreme Court Rejects EPA Generation Shifting*.)

Chang has more than 20 years of experience in energy economics and policy, including a stint as the undersecretary of Energy and Climate Solutions in Massachusetts where she helped implement its climate change mitigation efforts. She has presented and testified before federal and state agencies and regulatory authorities on energy resource deployment, energy contracts, transmission planning and electricity market design.

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

Chang is a senior fellow at Harvard University's Kennedy School of Government. She got her master's of public policy from the Kennedy School and her bachelor's at the University of California, Davis.

Rosner has 15 years of experience on energy technologies, market design and energy policy issues, including his stint working on assignment for Manchin's committee staff. He also was a senior policy adviser at DOE's Office of Energy Policy and Systems Analysis and associate director of the Bipartisan Policy Center's energy project and holds degrees in economics and public policy.

Before becoming solicitor general, See worked at Gibson, Dunn & Crutcher in Washington, D.C. She graduated from Harvard Law School and is from Michigan.

The nominees and the potential return to a full slate of FERC commissioners this year was welcomed by many in statements issued Feb. 29.

"A full complement of commissioners is critical to ensure robust debate and efficient progress on the important issues that FERC will be asked to weigh in on in the coming months and years, from interconnection reform to transmission planning to market rule changes in light of the energy transition," Advanced Energy United Managing Director Caitlin Marquis said in a statement. "We encourage the Senate to move forward quickly with the review process and look forward to working with a fully staffed commission under the leadership of Chair Willie Phillips."

Sierra Club Executive Director Ben Jealous put out a statement saying while FERC may not be well known to the public, it is critical to bring more renewable energy online quickly.

"A fully staffed FERC has the opportunity to tackle the climate crisis while making our transmission grids more resilient and reliable," Jealous said. "But FERC must turn around its track record of acting as a rubber stamp for the fossil fuel industry. As these nominees move through the Senate confirmation process, we will be watching for these candidates to commit to weighing climate, environmental justice, health and consumer cost impacts heavily in any decision they make. The courts have repeatedly said FERC must factor in these considerations, and the Sierra Club is committed to ensuring the makeup of the commission is in step with this mandate."

The Natural Resources Defense Council also welcomed the new nominees, with Sustainable FERC Project senior attorney Christy Walsh saying a fully staffed commission is important.

"We hope for a swift and robust confirmation process that will give the nominees a chance to offer their perspectives and plans on key issues like transmission, interconnection, markets, gas regulation and environmental justice," she said.

The Electricity Transmission Competition Coalition also said it wants to see a full complement of five commissioners.

"I urge the nominees to put consumers first and support electricity transmission competition, which is the key to fulfilling FERC's mandate of providing affordable and reliable electricity," ETCC Chair Paul Cicio said in a statement. "FERC's role is more important than ever with spending on transmission set to grow; pro-competition commissioners will be key to ensuring that upgrades to the grid come at the lowest cost to consumers." ■

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FERC/Federal News

EPA to Strengthen Emissions Regs for Gas Power Plants

Proposal for Existing Facilities, Criticized as Lenient, will be Delayed for Reworking

By John Cropley

EPA is holding off on new emissions restrictions for existing natural gas-fired power plants.

The agency in May 2023 *proposed* stronger greenhouse gas pollution standards for new and existing fossil-burning generation facilities and received more than 1.3 million comments in response. (See *EPA Proposes New Emissions Standards for Power Plants*.)

The process had been nearing its conclusion but will now continue.

EPA will soon send a finalized version of its proposal to the Office of Management and Budget, but the rules will not cover existing gas facilities — EPA said Feb. 29 it wants to strengthen provisions that pertain to existing gas.

EPA Administrator Michael Regan said in a news release:

"As EPA works towards final standards to cut climate pollution from existing coal and new gas-fired power plants later this spring, the agency is taking a new, comprehensive approach to cover the entire fleet of natural gas-fired turbines, as well as cover more pollutants including climate, toxic and criteria air pollution."

Gas-burning plants are cleaner than coal-burners, but they do produce emissions and are more numerous. The *Energy Information Administration* tallied 2,073 gas-burning plants rated at least 1 MW nationwide in 2022 and only 242 coal-burning plants.

Some Republicans and industry groups criticized the original emissions proposal as strict and potentially damaging to grid reliability, which EPA denied. (See *Regan: New EPA Standards Designed to not Jeopardize Grid Reliability*.)

In contrast, some environmental advocates criticized the original emissions proposal as too lenient, saying it would have applied to only a small percentage of existing gas-fired plants.

The EPA is delaying release of new emissions regulations for existing natural gas-burning power plants. | *Shutterstock*

This sentiment was captured in a celebratory quote EPA provided Feb. 29 from Washington Gov. Jay Inslee (D):

"This is excellent news from Administrator Regan, and I commend him for his continued leadership. We cannot mitigate emissions and pollution from power plants by ignoring our country's largest source of electricity generation: existing gas plants. Washington state is eager to support EPA in undertaking this rulemaking as quickly as possible."

Some environmental advocates offered messages that were more wait-and-see than celebratory.

NRDC President Manish Bapna said in a prepared statement:

"We can't tackle climate change and clean up air pollution without slashing emissions from the existing gas-fired power plants already pumping huge amounts of carbon and other dangerous pollutants into the air. EPA needs to finish the job without delay."

Peggy Shepard, executive director of WE ACT for Environmental Justice, said:

"We are wholly appreciative of EPA's leadership in demonstrating the need for further review, and at the same time request a clear and transparent process as we look forward to collaborating for its improved realization. Only when this rule is finalized can we truly know we are on a path to resilience and justice."

Regan touched on these concerns in EPA's news release:

"This stronger, more durable approach will achieve greater emissions reductions than the current proposal. EPA proposals on criteria pollutants and air toxics also will help address local air quality impacts to better protect vulnerable frontline communities.

"This comprehensive approach to reducing climate and air pollution will also consider flexibilities to support grid operators and will recognize that ongoing technological innovation offers a wide range of decarbonization options. EPA will immediately begin a robust stakeholder engagement process, working with workers, communities with environmental justice concerns and all interested parties to help create a more durable, flexible and affordable proposal that protects public health and the environment." ■

FERC/Federal News

Utility Regulators Repeat Concerns About Tx Siting Oversight

Task Force Meets with NIETC and FERC Backstop Processes Pending

By John Cropley

State utility regulators reiterated their concerns about FERC's efforts to promote transmission development at the Feb. 28 meeting of the task force established for that purpose.

The issue of federal authority usurping state and local control has been raised repeatedly since plans were announced to create National Interest Electric Transmission Corridors (NIETCs) and to give backstop authority to FERC. (See *What are National Interest Electric Transmission Corridors and Why Do We Need Them?*)

Grid constraints are a potentially fatal obstacle to the electrification goals set by the federal government and many states. Siting new transmission to address those constraints can be slow and difficult, particularly for lines that cross regional boundaries. NIETCs and backstop authority are two ways to potentially address this.

The Feb. 28 meeting was the eighth for the Joint Federal-State Task Force on Electric Transmission, formed under a June 2021 FERC order (Docket AD21-15-000). FERC Chair Willie Phillips and Kimberly Duffley of the North Carolina Utility Commission co-chair the task force.

Phillips said Feb. 28 that FERC has already heard the concerns of states and stakeholders during the comment process, "but there is something to be said for sitting around this table and hearing from you directly, and face-to-face."

Moderator Jonathan Raab opened the discussion by asking task force members to identify the transmission siting challenges that exist in their regions.

Kansas Corporation Commission Chair Andrew French said the growth of renewable generation on the Plains has created difficult optics.

"More and more," he said, "as energy becomes exported, there's at least a perception that Kansas land is increasingly being used to benefit faraway customers in other states to satisfy their policy goals."

Riley Allen of the Vermont Public Utility Commission had good things to say about the transmission siting process in his state and in the ISO-NE region. But he noted it typically takes 13 to 20 months in Vermont, which exceeds the 12-month threshold that is one of the triggers proposed for FERC backstop action.

"But I think there's room for improvement," he said. "I think backstop authority will certainly add some life to the timeliness of these things going forward."

Darcie Houck of the California Public Utilities Commission said complications frequently arise when working with federal land management agencies, particularly when coordinating joint environmental processes. Also, federal technical studies supporting permitting often are delayed. And the PUC must coordinate with tribal nations and local governments, creating a complex process with many stakeholders.

"Another challenge to timely siting of transmission comes from substantial community opposition," Houck added, which often includes legal challenges demanding PUC response.

Tricia Pridemore of the Georgia Public Service Commission listed several complicating factors nationwide, including regulations on federal land, local opposition, disagreements over environmental reviews and cost allocation, interconnection queue delays, supply chain constraints and multilayered planning processes with multiple responsible entities.

These usually are not an issue in the Southeast, she said, due to its market structure, but major transmission projects there still take years to build, due to their complexity — seven years or longer for a 50-mile, 500-kV line.

"The intensely local and regional differences are of course what makes one-size-fits-all transmission policies very challenging," Pridemore said.

She welcomed changes to federal policies that would remove barriers to transmission development but added: "From the vantage point of the Southeast, we must also ensure that those changes do not upend processes that are working so well."

The task force retained a collegial tone, but Pridemore was not alone with concerns; others cited other potential sticking points.

Wyoming Public Service Commission Chair Mary Throne said whatever new federal process emerges should allow state and local review to play out before initiating a parallel federal process.

"Concurrent proceedings are probably not ideal," she said. "Certainly, in Wyoming's case and most places in the interior West, I don't think it's the state and local proceedings that are slowing down the processes — not that we are incapable of our own bureaucratic delays and duplication. But understanding the local lay of the land before you start is essential."

Federal officials continue their efforts to expedite power transmission siting and permitting. | *Shutterstock*

FERC/Federal News

Pennsylvania Public Utility Commission Vice Chair Kimberly Barrow made a similar point: "A simultaneous prefiling process that's going on while the state process is ongoing will be problematic."

States appreciate the need for speed and efficiency, but parallel proceedings would be confusing for stakeholders, she added, and it would be a conflict of interest for PUC staff to participate in both at once.

Allen said the idea of simultaneous state and federal reviews is his one significant issue with the backstop proposal. "I would much rather see the processes sequenced," he said, adding that stakeholders should be directed toward the state review because state processes have been groomed over the course of decades and inherently are local in character.

That said, Allen does support the idea of backstop authority. "I just worry that if we push too hard in parallel it's going to create some complications that are going to undermine the longer-term objectives," he added.

French urged that FERC not make some existing problems worse as it addresses others. "While I think that our planning does need to get more anticipatory, more holistic, solving multiple needs," he said, "I think as you do those things, it becomes much more difficult to communicate to the public and to landowners why your state needs to build this project that is maybe serving lots of different stakeholders."

Connecticut Public Utilities Regulatory Authority Chair Marissa Paslick Gillett said many utility regulatory agencies are having trouble recruiting engineers and other staff to do the work needed, and many of those hired are early in their careers, so technical assistance from federal agencies is helpful.

"I will say however, sometimes it's difficult to even take advantage of free assistance." That might sound like an oxymoron, she acknowledged, but if a state requires a contract and a fixed timeline for anyone involved in the process, it is not.

New York Public Service Commission Commissioner John Howard urged greater federal control over a specific area of concern for his state: getting the mandated 9 GW of electricity from offshore wind turbines to land, and someday more than 20 GW. New York has finite opportunities for radial transmission lines from each wind farm to land because of its geography, he said. A meshed offshore grid that spans RTO boundaries from New England to the Mid-Atlantic is a better solution.

"Now is the time to begin planning for this multi-ISO meshed network," he said. "I would pose the question to this group and to FERC: Is it time to acknowledge that the Atlantic Ocean may be a national interest corridor in and of itself? That is something we should come to grips with very quickly."

Howard added: "I don't believe that the states alone will be able to find the individual leadership necessary to move this process forward."

Houck said California supports the goals of NIETC and backstop, but she picked apart some of the details of those proposals. Twelve months may not be enough time for a state to approve a complex project, she said, but at the end of those 12 months, the state might be able to conclude the process more quickly than FERC would if it started a backstop proceeding.

She called for a more nuanced approach than a one-size-fits-all solution.

Michigan Public Service Commission Chair Dan Scripps said if a proposed transmission line is entirely within a state and will serve only that state, great deference should be given to the local siting authority. "It's unclear to me why FERC would substitute its judgment for the local siting authority — for a single-state project."

If a multistate RTO project benefiting multiple states is being blocked by one state, there could be a role for backstop authority, Scripps added, but FERC should limit itself to siting, and leave cost allocation and planning to the RTO.

French made a similar point: "If a state is, in FERC's opinion, acting too parochially in looking at the need for the line, not considering regional and interregional benefits," he could understand FERC stepping in.

But if FERC finds it needs to override a state decision, he said, it should do so as narrowly as possible, and defer as much as possible to the state's underlying proceeding, particularly on the routing of a proposed line — review of which is a large part of the state regulator's workload.

French also urged clarification on what exactly a FERC siting permit would entail — just routing, or also things such as interconnection and cost recovery mechanisms. "I think there is a lot of angst from folks about what approval of a line through the backstop siting process really means."

Duffley said she thought that with the Feb. 28 meeting, the task force had covered the ground it set out to cover. "FERC's final rule on transmission issues, we're all anticipating that it will be issued soon," she said. ■

FERC/Federal News

Grain Belt Express Gets Partial Approval for Negotiated Rate Authority from FERC

By Amanda Durish Cook

After a fresh FERC review, Invenergy has walked away with half the authorizations necessary to charge negotiated rates for transmission service on its $7 billion, 5-GW Grain Belt Express transmission project.

Late last year, Invenergy sought FERC permission to amend its negotiated rate authority for Grain Belt Express because the merchant transmission project's design had changed substantially since FERC originally granted authority in 2014 (*ER24-59*).

FERC scrutinized the project using its four-factor test. The commission said while Grain Belt satisfied its requirements for just and reasonable rates and regional reliability, it lacked information on whether Grain Belt would parcel out capacity on its line fairly.

"We reserve judgment on whether Grain Belt's capacity allocation process satisfies the commission requirements for undue discrimination and undue preference (factors two and three). We will make a determination regarding those factors at such time as Grain Belt submits a filing providing sufficient detail to evaluate whether its capacity allocation process satisfies the commission's requirements, either in advance of its open solicitation or post-open solicitation," FERC wrote in a Feb. 29 order.

FERC said while Invenergy requested "flexibility" for its upcoming capacity allocation process, it provided only "limited detail on the selection process or selection criteria for the commission to evaluate." The commission said it couldn't be confident Invenergy would not bestow undue preference on generation affiliates when selling the line's capacity.

Invenergy said last year it intends to launch an open solicitation for takers of capacity on the first, 2.5-GW phase of the line, which runs from Kansas to Missouri. In its filing, it said it has hired the Brattle Group to serve as an independent consultant and oversee the open solicitation for a "portion of capacity for Phase 1." Invenergy said the Brattle Group will develop selection criteria and ensure the solicitation is conducted in a transparent and non-discriminatory manner. Invenergy also promised a post-solicitation compliance filing to FERC.

The Missouri Joint Municipal Electric Utility Commission already has agreed to buy up to 225 MW of capacity on Grain Belt.

The Missouri Landowners Alliance protested Invenergy's request to amend its negotiated rate authority and said the commission should require Invenergy to reapply for permission to offer capacity on Grain Belt at negotiated rates. The landowners argued that project ownership, capacity and interconnection points have changed too drastically since FERC originally granted Grain Belt's negotiated rate authority.

Invenergy acquired development assets for Grain Belt from Clean Line Energy Partners in 2018. The Missouri Landowners Association argued Invenergy didn't notify FERC of the handover and the expansion of the project. (See *Invenergy Announces Grain Belt Express Expansion*.)

The association also voiced concern that Invenergy "controls a large inventory of energy facilities," including generation, and suggested it could give its affiliate customers preferential treatment or have an incentive to withhold capacity. It cautioned FERC that Grain Belt's "use of an independent evaluator should not take the place of regulatory scrutiny and guidance."

Invenergy rebutted that FERC rules don't allow it to unduly discriminate or show undue preference in the open solicitation process.

The association also accused Invenergy of beginning negotiating capacity sales ahead of its future open solicitation. Invenergy said the Missouri landowners' allegation was incorrect and based on the association conflating sales of transmission service with a sale or lease of an undivided interest in Grain Belt.

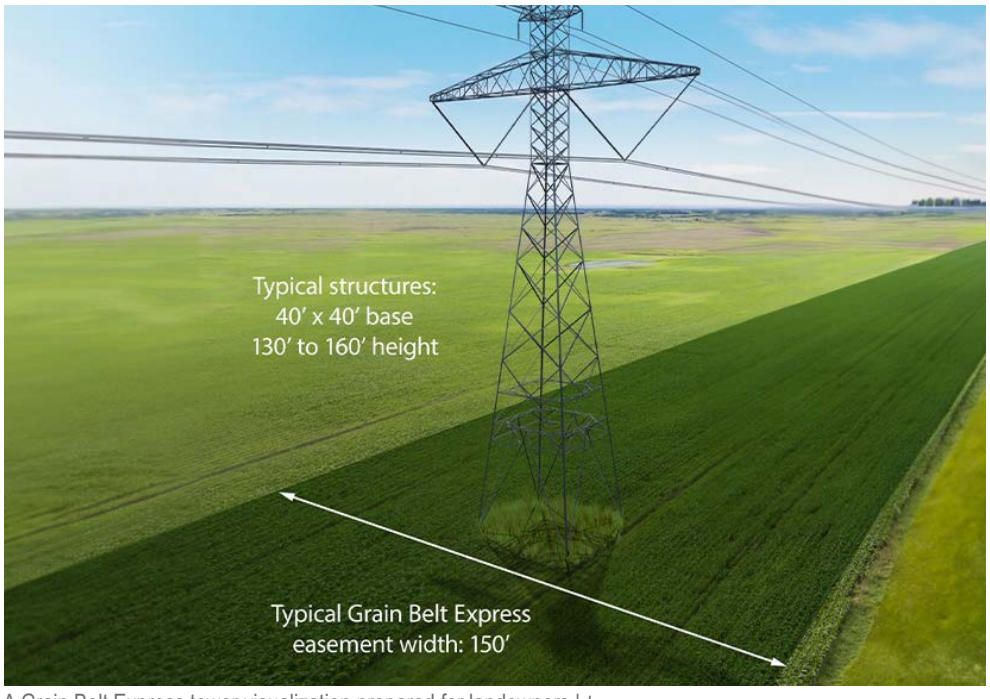
FERC didn't address the debate because it left those sections of the four-factor test undecided.

The Sierra Club in late October wrote to support negotiated rate authority for Invenergy.

"The Grain Belt Express Project will lower electricity costs for consumers, markedly improve the economic operation of these regional electric grids, offer significant resilience value — especially during storms and other high-demand events — and improve resource adequacy for customers and utilities," the environmental group said.

Invenergy plans to begin construction on Grain Belt in early 2025 and has said it already secured 95% of the land necessary for Phase 1 of the project. The Kansas-to-Illinois line will connect SPP, Associated Electric Cooperative, MISO and PJM. Invenergy has selected Siemens Energy to provide the HVDC technology for the first phase of the 800-mile line.

Invenergy said it expects to put separate filings for approval before FERC to transfer Phase 1 capacity to buyers and/or lessees via sales and/or leases of undivided interests in the transmission line. Those require individual approvals. ■



A Grain Belt Express tower visualization prepared for landowners | *Invenergy*

FERC/Federal News

FERC Rejects Bridgepoint-ECP Deal for Failing to Disclose Common Owner

By James Downing

FERC denied a merger proposal in which Bridgepoint tried to buy a 19.9% stake in Energy Capital Partners, saying it did so without prejudice because the first firm failed to disclose its relationship with a third company — Blue Owl (*EC24-2*).

ECP is a private equity firm that owns interests in Calpine Corp., Terra-Gen Power Holdings, Convergent Energy and Power, and Pivot Energy, while Bridgepoint has a similar business model, but with more assets outside of FERC's purview.

Blue Owl owned stock in both firms but told FERC only about its shares in Bridgepoint, saying part of the deal would involve executing an irrevocable deed under United Kingdom law to restrict its actual voting shares below 10%, which is the commission's threshold that triggers affiliate regulations.

Public Citizen intervened in the FERC case to note that in requesting approval for the deal from U.K. regulators, the firms said that Blue Owl also owns 19.3% of ECP's share. That information was never filed at FERC.

"We find that, based on the record in this proceeding, applicants have not shown the voting restriction is sufficient to eliminate a potential affiliation between Blue Owl and Bridgepoint and that applicants did not provide information as to the holdings of Blue Owl for the purposes of the commission's competition analysis," FERC said.

FERC staff would have normally reached out to the applicants and asked them to file information related to Blue Owl's overlapping holdings, but the rejection (without prejudice) shows the commission is running out of patience when sophisticated players do not reveal required information, said Public Citizen's Energy Program Director Tyson Slocum.

Bridgepoint Group's London headquarters | *Bridgepoint Group*

"FERC is a regulator that relies almost exclusively on self-reporting," Slocum said. "They heavily rely on companies to just come to the table and put all of their cards on the table. And FERC apparently perceived that they didn't do that here."

Because the deal was rejected without prejudice, Bridgepoint said March 4 that it would shortly refile the application with the previously missing information and hoped to close the deal for nearly a fifth of ECP by the second quarter of this year.

"I think FERC is trying to navigate this space of dealing with increasingly complicated financial structures that are getting into the utility business," Slocum said.

ECP is a dominant player in FERC-jurisdictional markets while Bridgepoint owns a great deal of energy infrastructure in Europe, so their combination would be huge. While the deal involves just $1 billion in cash, Slocum said the fact that two top executives at ECP are getting voting rights at Bridgepoint makes this "a merger of equals."

FERC is looking at how it regulates investments in the utility with a Notice of Inquiry (AD24-6) announced late last year, which Slocum said will see comments later this month. (See *FERC Reconsidering Blanket Authorizations for Investment Companies*.)

Part of the reason for the NOI is the growth in "passive" investors like Vanguard and Blackrock that have put money behind multiple utilities but are not supposed to be active in their governance.

"Blackrock is a little unique in that it doesn't just passively manage these funds on behalf of folks' retirement accounts," Slocum said. "They also have an actively managed fleet of private equity vehicles that go in and buy up majority stakes in infrastructure assets." ■

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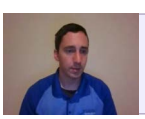

SERC: Details Crucial for Physical Security Plan — ERO Insider

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CAISO/West News

NW Cold Snap Dispute Reflects Divisions over Western Markets

Debate Around January Freeze is Proxy for Contest Between EDAM, Markets+

By Robert Mullin

A dispute around the January cold snap that forced Northwest utilities to sharply increase electricity imports to meet surging demand has become a proxy for the broader contest between CAISO and SPP over their competing Western day-ahead markets.

The debate over exactly what played out on the Western grid during the Jan. 12-16 winter freeze comes amid growing tension in the Western electricity sector as stakeholders await word from the Bonneville Power Administration in April about whether it favors joining CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+. It centers on whether CAISO and its Western Energy Imbalance Market (WEIM) played a key role in supporting the Northwest during the storm or other factors were more important.

The weather event that drove Northwest temperatures close to historic lows while pushing loads to nearly record highs coincided with a confluence of other developments that stressed the region's grid. Those included: derates on the Pacific AC and DC interties; an 800-MW forced outage at Montana's coal-fired Colstrip plant (until Jan. 13); and a fault that caused Washington's Jackson Prairie natural gas storage facility to sharply reduce its sendout on Jan. 13, prompting pipeline operator Williams to declare a force majeure that cut deliveries to interruptible customers, including some power generators.

Those developments unfolded within the context of unusually low water levels in the region's hydroelectric system, which has required BPA to operate the Columbia River system at minimum flows to ensure sufficient capacity behind the Grand Coulee Dam for spring fish operations.

A Feb. 8 *assessment* of the weather event by the Western Power Pool (WPP) showed how dire conditions became on the region's grid. Reliability coordinator RC West placed four Northwest balancing authority areas into varying levels of energy emergency alerts (EEAs), including one EEA 3, a critical threat level that requires preparations for rolling blackouts to maintain system stability. (See *WPP: Cold Snap Showed 'Tipping Point' for Northwest Reliability*.)

Relying on interchange data reported to the Energy Information Administration (EIA), WPP's report showed the Northwest was a net importer of 4,900 MW of energy per hour during the five-day freeze.

The Northwest grid was heavily supported by imports during an extreme cold snap in January. | © *RTO Insider LLC*

And while the report showed that CAISO and other California BAs exported an average of 2,833 MW to the Northwest during the event, it also noted that the data indicated the California BAs themselves were net importers, suggesting most of the imports rescuing the Northwest originated from the Rockies and Desert Southwest — not California.

"The same interchange data shows the Desert Southwest/Rockies BAs were net exporters of approximately 5,334 MW on average," WPP wrote. "Those exports from the Desert Southwest/Rockies region supported CAISO and other California BAs, as well as 2,833 MW of imports to the Northwest on the Pacific AC Intertie."

Congestion Conflict

The Portland, Ore.-based Public Power Council (PPC) amplified that theme in a Feb. 23 letter to BPA Administrator John Hairston urging the agency to choose Markets+ when it issues its day-ahead market "leaning" in April. (See *Northwest Public Power Group Endorses Markets+ over EDAM*.)

The PPC told *RTO Insider* it conducted its own analysis "using data from a variety of sources including ... EIA, CAISO OASIS and other publicly available sources." It also reviewed data from WPP and *Energy GPS*.

While the letter's case against CAISO's EDAM (and in favor of Markets+) focused largely on

CAISO/West News

governance issues, the PPC highlighted the January cold snap, conveying concerns about how congestion revenue is allocated in the ISO's WEIM.

"During the recent winter event in the Northwest, Northwest load imported resources largely coming from the Southwest and wheeling through CAISO," the PPC wrote. It then spotlighted a complaint among some Northwest entities about how the ISO allocated transmission congestion fees generated during the event.

"CAISO's congestion policies resulted in over $100M of congestion revenues being collected by the CAISO BAA, despite most of the generation serving the Northwest coming from outside California. The policy creating this result is explicitly maintained in the CAISO EDAM," the PPC said.

CAISO responded to that contention in a Feb. 27 email to *RTO Insider*, saying the $100 million in congestion rent stemmed from the need for the ISO to hold back some energy flows to avoid damaging the Northwest grid because of the transmission outages in Oregon.

"Despite the assertions in the PPC letter, the ISO does not collect congestion rent for itself," the ISO said. "It distributes it to holders of congestion revenue rights (CRRs). CRRs are mechanisms that guard against high congestion prices. They are available to a variety of market participants, including load-serving entities in the Pacific Northwest."

CAISO noted that it is unique among Western grid operators in its technical capability for managing congestion in the day-ahead time frame.

"As a result, CAISO cannot ignore transmission constraints; it must avoid sending energy to areas where it cannot be received," it wrote.

In a March 1 message to *RTO Insider*, Lauren Tenney Denison, PPC director of market policy and grid strategy, said her organization recognizes that CAISO distributes the congestion rents it collects to CRR holders within the ISO.

"While entities outside of the CAISO BAA can hold CRRs, it is our understanding that to the extent that Northwest load-serving entities were able to meaningfully hedge against the congestion charged over the California-Northwest Interties during the cold snap, they would need to have purchased CRRs from the CAISO via auction for the portion of the path within CAISO's BAA," Tenney Denison said.

The issue, she said, is that Northwest LSEs with ownership or capacity rights on the northern half of the interties will not receive any of the congestion revenue.

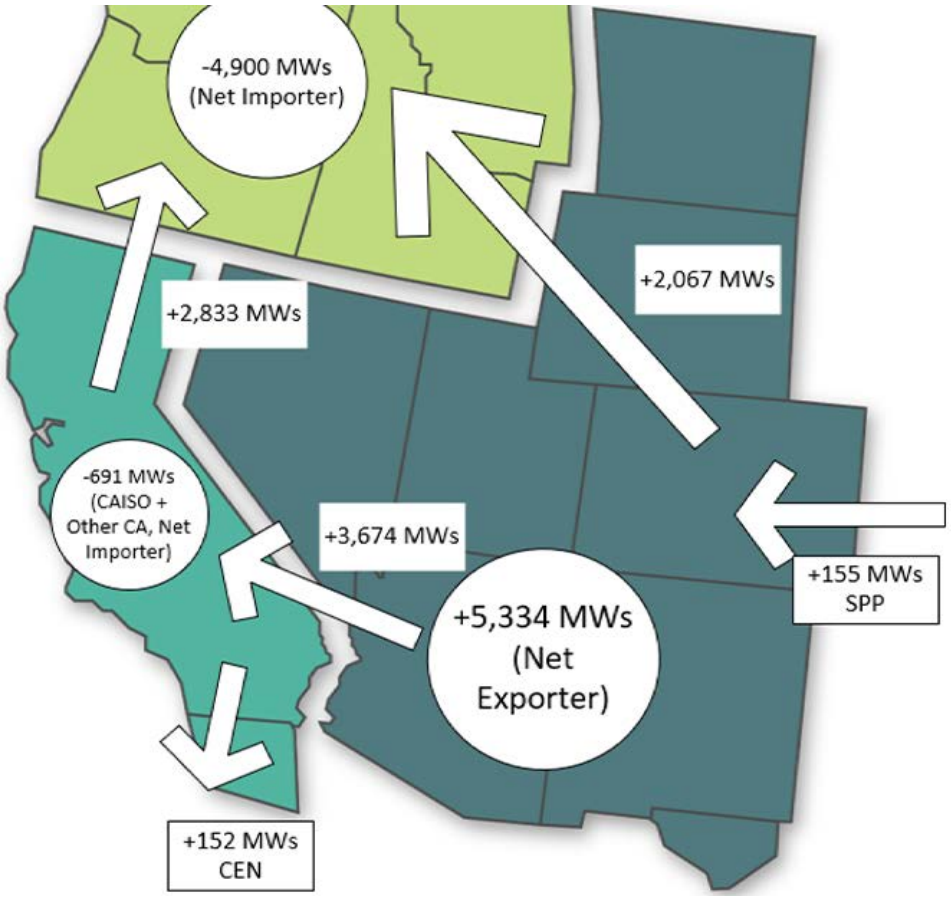
"We would like to emphasize that these assets were built based on regional coordination and with the historical mission to create benefits for both the Northwest and Southwest," Tenney Denison said.

The PPC is asking that the value created by AC and DC interties between California and the Northwest — "as manifested here by congestion rent allocation" — be "shared equitably" by those who have invested in the lines, she said.

Tenney Denison said the PPC also understands CAISO reasons for re-dispatching around system constraints during the event.

"We look forward to additional discussion on where those constraints were observed and whether those constraints were the result of physical flows or CAISO modeling assumptions," she said.

She added that "it is unclear when CAISO took actions to re-dispatch around these constraints whether those actions were taken as a balancing authority area, or the market operator based on CAISO's comments."



Analysis by the Western Power Pool and Public Power Council indicates that most of the power supporting the Northwest during the cold snap originated in the Rockies and Southwest regions. | *Western Power Pool*

'It Came from Everywhere'

Fred Heutte is a senior policy associate with the Northwest Energy Coalition (NWEC), which has been a vocal advocate for Northwest participation in a single Western market based on EDAM. In an interview, Heutte emphasized caution about reading too much into the EIA interchange data cited by the PPC and WPP, contending the numbers don't provide sufficient insight into how power actually flowed across the system during the cold snap.

"Because all the interchange data just really does is say, 'How much generation did you have inside your balancing authority? How much demand did you have? And, therefore, what's the net difference?' It doesn't tell you that much," Heutte said. "And especially in the Northwest, where things are very complicated. We have lots of different balancing areas."

Heutte said the WEIM collects a "tremendous amount" of data that will take time to examine to identify exactly how power flowed during the event. But he also downplayed the importance of where the energy originated.

CAISO/West News

"I think a couple of things are really clear: that the AC intertie brought us a lot of power when we desperately needed it, and the Energy Imbalance Market was really crucial to that," he said. "Because the market doesn't just provide power from Point A to Point B, it optimizes the dispatch over a very wide area."

"To me, personally, the notion of 'where does the energy come from' is it came from everywhere," Heutte said.

Heutte additionally pointed to the "load and resource diversity" benefit of a market as broad as the WEIM is now.

"Because when it's super cold up here, it's not as cold in Southern California and Phoenix [and] Las Vegas," he said. "If it's really hot there, it might not be so hot here. So, load diversity helps provide some of the additional resources that the transmission in the market can then move around."

But the PPC has drawn a different conclusion about the role of the WEIM during the freeze.

"Over the week of the cold event, CAISO's public data shows they were a net importer during the evening peak when electricity demand is the highest," Tenney Denison said in the March 1 email. "Other public analysis performed by the Western Power Pool and Energy GPS reaches the same conclusion. CAISO also publishes EIM transfer data that shows while the EIM did facilitate transfers to the [Pacific Northwest], comparing to the level of transmission flows published by BPA demonstrates most of the energy flowed outside of the EIM market."

CAISO told *RTO Insider* it is close to issuing a "comprehensive" report on the winter event, which should be out as early as this week.

"The report will cover the dynamics of the WEIM and will provide a detailed analysis hour-by-hour of how the WEIM was able to economically re-dispatch resources to find the least-cost solution considering all the physical constraints on the system to move power across the West," ISO spokesperson Anne Gonzales said. "That will include analysis of power flowing through California from the Desert Southwest to serve the high demand in the Northwest. The report will provide detailed information showing the actual transfers through the WEIM across the region."

For its part, BPA has only obliquely weighed in publicly on the issues around the cold snap. In a Jan. 31 *news release*, the agency described how it helped keep the region powered through sophisticated maneuvers that managed to maintain targeted water levels while meeting a level of demand not seen since the time when energy-hungry aluminum smelters dominated the economy of the Columbia River region.

When asked to comment on the ongoing dispute about the winter event, including CAISO's response, BPA spokesperson Nick Quinata said, "We're aware of the situation and have no comment."

Delayed Decision Urged

BPA's reluctance to weigh in on the debate is understandable, given that its day-ahead market decision is at the heart of the larger conflict around whether the West will end up with one or two organized electricity markets.

Multiple industry sources not authorized to speak for attribution on behalf of their organizations have told *RTO Insider* that BPA has been favoring Markets+ throughout its public exploration of day-ahead markets, launched last July. During day-ahead market workshops hosted by BPA, agency officials themselves have expressed a preference for SPP's approach to market governance.

And while BPA has emphasized that it has not yet identified a preferred day-ahead market — or whether it will join one at all — it has been a key participant in the process for developing Markets+. It has also been conspicuously absent as an active contributor to the West-Wide Governance Pathways Initiative, an effort kicked off by state regulators last year to create the framework for a single Western market that builds on the WEIM and EDAM.

Sources also say Northwest utilities Idaho Power, Portland General Electric (PGE) and Seattle City Light — the PPC's largest member by customer base — are leaning toward commitments to EDAM.

Asked to comment, Idaho Power spokesperson Brad Bowlin said, "We don't have a schedule for a public announcement. No recommendation has been made to our board of directors yet. Once that happens, depending on the outcome, we will have some work to do communicating with our regulators prior to any formal announcement."

PGE spokesperson Andrea Platt responded that the utility "recognizes the potential value in a day-ahead market, as well as the barriers to achieving a full RTO for the West."

"While PGE continues to evaluate participation in both the Extended Day-Ahead Market (EDAM) and Markets+, we are also actively engaged and support the West-Wide Governance Pathway[s] Initiative, which continues to explore ways to build on the benefits of the Western Energy Imbalance Market and realize the potential for a broader footprint in EDAM and enable a path forward for a potential West-wide market," Platt said. PGE Director of Transmission and Market Services Pam Sporborg is co-chair of the Pathways Initiative's Launch Committee.

Regarding City Light, utility Regional Affairs Manager Josh Walter also is a member of the Launch Committee. The utility, which manages its own BAA, told *RTO Insider* Feb. 28 that it backs BPA's exploration of day-ahead market participation but "does not support endorsing Markets+ at this time" due to "the lack of essential information and the number of unknown variables."

"City Light urges BPA to give careful consideration prior to making any market leaning. Doing so now would be premature, given undetermined and unresolved critical foundational issues including market footprint, transmission connectivity and governance," spokesperson Jenn Strang said in an email. "City Light remains committed to creating a pathway to independent governance for the West and urges BPA to include the work of the West-Wide Governance Pathways Initiative in their market determination."

With six-state utility PacifiCorp already committed to EDAM, a Markets+ consisting of just BPA and British Columbia's Powerex in the Northwest and possibly a few entities in the Desert Southwest risks isolation and fragmentation. Under those conditions, it would not be as effective as the WEIM is in managing stressed conditions like the January cold snap, according to Heutte, who also recommends that BPA delay its decision.

"If Markets+ succeeds in moving forward with a lot of support across the West, [there will be] a Northwest zone and a Southwest zone with no direct connection from transmission," he said. "It'll have to transfer power across the grid of other entities that are not in Markets+, and that dramatically shrinks the load and resource diversity that's actually available" in the West.

Along with BPA, Arizona Public Service has been a visible participant in developing Markets+ but, Heutte warned, "We have yet to see how enthused the Southwest utilities are really going to be about" the SPP market.

"One possibility is we'll end up with something that doesn't really come close to the performance of a much bigger market, and I think that's a pretty legitimate issue here," he said. ■

CAISO/West News

Northwest Public Power Group Endorses Markets+ over EDAM

Public Power Council Urges BPA to 'Lean' Toward SPP's Day-ahead Option in April

By Robert Mullin

A group representing the Northwest's extensive network of publicly owned utilities has asked the Bonneville Power Administration to choose SPP's Markets+ when the agency issues its day-ahead market "leaning" in April.

The Portland, Ore.-based Public Power Council (PPC) laid out its case for favoring Markets+ over CAISO's Extended Day-Ahead Market (EDAM) in a Feb. 23 *letter* addressed to BPA Administrator John Hairston.

The PPC's argument included the need to defend the right of BPA's "preference" customers to access low-cost electricity from the Federal Columbia River Power System, continued reservations about CAISO's ability to alter its state-run governance structure and concerns about the fairness of CAISO's existing market practices — with the last point eliciting a pointed response from CAISO provided to *RTO Insider*.

The letter also praised SPP's stakeholder-driven approach for developing Markets+.

"Currently, the Southwest Power Pool (SPP) Markets+ offering is PPC's preferred day-ahead market option, and we support BPA making a similar declaration in its April leaning," said the letter signed by PPC Executive Director Scott Simms and members of the group's Market Development Committee (MDC). "While information is still evolving, the majority of criteria that PPC has evaluated supports continued pursuit of BPA's participation in Markets+."

The letter was signed by all eight members of the MDC, which includes representatives from Idaho Falls Power, Tacoma Power, Fall River Rural Electric Cooperative (Idaho), Clatskanie (Ore.) Public Utility District, Pacific County (Wash.) PUD, Modern Electric Water Co. (Wash.), Grant County (Wash.) PUD and Snohomish County (Wash.) PUD.

The MDC crafted the letter at the direction of the PPC's *Executive Committee*, Lauren Tenney Denison, the organization's director of market policy and grid strategy, told *RTO Insider*.

Until recently, the MDC included Seattle City Light's (SCL) Emeka Anyanwu, who left the utility last fall to take over as CEO at Lincoln Power in Nebraska. SCL, which operates a small balancing authority area, has been a key participant in the West-Wide Governance Pathways Initiative, which is working to establish the framework for a Western RTO that expressly includes CAISO and rests on the ISO's technical capabilities. SCL did not respond to a request for comment on its position on BPA's market choice in time for publication of this article.

'Dual Roles'

The Feb. 23 letter indicates PPC members clearly doubt the Pathways Initiative will be able to settle the CAISO governance issue in a manner they think is equitable for entities outside California.

"Current California law stipulates several areas that keep CAISO's mission and operation tied with the interests of California," the PPC letter says. "First, CAISO's corporate status is tied to oversight from the state of California and thus the CAISO Board of Governors can neither irrevocably delegate authority nor allow another entity to unilaterally make decisions on market policies."

Second, the ISO's Board of Governors is appointed by California's governor and confirmed by the state Senate, the letter notes.

The letter also argues that CAISO's independence as the operator of a multistate market is "further confused" by its "dual roles."

"The CAISO functions both as a market operator and as a participant Balancing Authority Area (BAA) in the [Western Energy Imbalance Market] and EDAM markets. At times there is a lack of transparency about which role CAISO is serving when taking certain actions. This only adds to concerns about equity among market participants," the letter states.

Tenney Denison told *RTO Insider* that legal analysis conducted by the PPC and CAISO's own legal staff as part of work by the WEIM's Governance Review Committee indicates "a legislative change would be necessary to provide PPC members the assurance they need that their interests would receive equal consideration under CAISO governance.

"We are closely watching the approach that is being taken by the Pathways Initiative, including developing a legal review of multiple options, and look forward to discussing those results with other stakeholders," she said. "We are uncertain at this time whether there would be sufficient support for the types of changes that PPC is seeking and there is not a clear timeline of when such changes could be implemented if they are pursued."

The PPC's governance concerns extend to CAISO market design issues that the group contends will carry over into the EDAM from the WEIM. The letter particularly points to market outcomes stemming from a sharp January cold snap in the Northwest, when the region was forced to import large volumes of power from the Rockies and Southwest regions, with supplies from the latter wheeled through the ISO. (See *WPP: Cold Snap Showed 'Tipping Point' for Northwest Reliability*.)

Energy flows during the Jan. 12-16 weather event, which caused four entities to enter an Energy Emergency Alert (EEA) Watch, EEA 1 or EEA 3, and caused significant northbound transmission congestion out of CAISO and into Oregon, leading some Northwest entities to contend the ISO unfairly raked in the lion's

BPA's The Dalles Dam | © *RTO Insider LLC*

CAISO/West News

share of the revenue associated with that congestion, a point amplified in the PPC's letter.

"CAISO's congestion policies resulted in over $100M of congestion revenues being collected by the CAISO BAA, despite most of the generation serving the Northwest coming from outside California. The policy creating this result is explicitly maintained in the CAISO EDAM," the PPC wrote.

But CAISO contested that assertion in its Feb. 27 email to *RTO Insider*. The ISO said outages on Oregon transmission lines during the cold snap meant the ISO could not send some energy north without damaging the Northwest grid. The resulting congestion on the California-Oregon Intertie resulted in CAISO collecting about $100 million in congestion rent from Northwest entities.

"Despite the assertions in the PPC letter, the ISO does not collect congestion rent for itself," CAISO said in the email. "It distributes it to holders of congestion revenue rights (CRRs). CRRs are mechanisms that guard against high congestion prices. They are available to a variety of market participants, including load-serving entities in the Pacific Northwest."

The ISO also noted it operates the only mechanism in the West for managing congestion in the day-ahead time frame.

"Operators of transmission lines in the Pacific Northwest do not," it said. "As a result, CAISO cannot ignore transmission constraints; it must avoid sending energy to areas where it cannot be received."

"That is why the ISO had to take action, and why congestion rents were collected on the California side of the constraint of the border and not by entities in the Pacific Northwest," the ISO said.

The PPC letter also raised another, more enduring complaint among Northwest electricity sector participants — that CAISO's pricing policies don't accurately account for the value of the region's flexible hydroelectric generation.

"This means that the federal generating facilities funded by PPC members would receive lower compensation for their generation, thus increasing the costs borne by PPC members for operating those facilities. A study co-funded by the PPC showed the potential for CAISO's pricing policies to reduce revenues for Northwest generators selling into the CAISO BAA by $100M-$200M per year," the PPC wrote.

The PPC also points to a complaint shared with entities elsewhere in the West regarding CAISO's decision, after California's 2020 summer blackouts, to alter its tariff to restrict "wheel-throughs" in its territory during periods of extremely tight supplies. (See *FERC Approves CAISO Wheel-through Rule Changes*.)

"This policy, which was heavily criticized by non-California parties, demonstrates the California-centric nature of the CAISO decision making process," the PPC said.

Stakeholders, Not Staff

The PPC's critical comments about CAISO were matched by laudatory ones regarding SPP and Markets+.

"SPP Markets+ has an equitable, inclusive, representative and independent governance structure. It includes committees comprised of market participants and stakeholders, which has resulted in a high level of engagement in the market's design," the group said.

In a reference to CAISO's more staff-driven model for initiating market changes, the PPC pointed out that in Markets+, "participants and stakeholders determine what proposals advance to the decision-makers, not SPP staff."

Referring to the proposed board structure for Markets+, the letter noted that "decisions are also made by a 'panel' of independent members who have no responsibility or obligations to any group of participants over another. This decision-making process ensures all market stakeholders have a voice in what policies are explored, developed and ultimately implemented."

The letter also points out that Markets+ includes elements that "will help BPA continue to serve its historic mission and return value to Northwest ratepayers for the federal assets they have financed through BPA's rates."

Those include price formation policies that "will more adequately compensate BPA (and all suppliers) for flexible and reliable generation made available to the market — particularly in times of scarcity," as well as the ability to "attribute" generation to specific loads.

"PPC sees this as a useful tool for meeting BPA's statutory obligation to serve preference customers from the federal system," the letter said. "These and other tools included in Markets+ will also ensure that BPA customers can claim the environmental attributes of the low-carbon federal system," helping PPC members to meet policy goals to reduce carbon emissions.

"As stated in their letter to Bonneville Power Administration, the PPC believes Markets+ will allow fair pricing for generation and the ability to attribute generation to specific loads," SPP spokesperson Meghan Sever said via email. "While these are a few of the benefits most recognizable to this group of entities, there are many more benefits of participation in Markets+, and SPP is pleased to be a part of developing a market that provides financial and environmental benefits and enhances electric reliability in the Western Interconnection for years to come."

Seams vs. 'Superior Market Design'

The PPC letter played down the concerns among some industry stakeholders about potential costs and inefficiencies stemming from "seams" between two Western day-ahead markets. The issue was the subject of a recent study commissioned by the Western Power Trading Forum and Public Generating Pool. (See *Western Market Seams Issues to Differ from East, Study Finds*.)

"Seams do have the potential to reduce market efficiency, but they also exist today in multiple areas (not just market to market, but [between] different Resource Adequacy programs, different carbon regulations, etc.) and will continue to exist into the future," the PPC wrote, noting the loss of efficiency "can be outweighed by the benefits of superior market design and governance."

The group also expressed hope there will be "large incentives" for the two markets to work together to reduce seams issues "to the greatest extent possible, to facilitate continued trade."

PPC expects seams impacts could be mitigated by "significant amounts" of trading outside the day-ahead market.

"Multiple studies evaluating different market footprints have suggested that seams have the greatest potential to impact entities in California, who rely on imports of Northwest resources at a low price," the letter said, pointing to *studies* conducted by the Western Markets Exploratory Group. "This should only work to create an even greater incentive for the existing CAISO market to work together with Markets+ to ensure that trading can continue."

Asked how the PPC's letter will influence BPA's day-ahead market decision, agency spokesperson Nick Quinata said: "BPA appreciates the PPC's participation in our public process and it is a comment we will consider as we continue to do our due diligence on whether or not to join a market and which market we select if we go that way." ■

CAISO/West News

NV Energy to Reap More from EDAM than Markets+, Report Shows

Brattle Group Study Estimates Top-end Benefits of $149M in EDAM, $16M in Markets+

By Robert Mullin

NV Energy would gain significantly more economic benefits from participating in CAISO's Extended Day-Ahead Market (EDAM) than SPP's Markets+, new analysis from the Brattle Group shows.

The analysis was included in *slides* referenced — but not presented — by the utility during an RTO markets workshop hosted by the Public Utilities Commission of Nevada on March 4. An NV Energy official said the utility will review the findings with the commission at a future workshop, the date for which has not been determined. (See *Nev. Commission to Tackle Rules for RTO Membership*.)

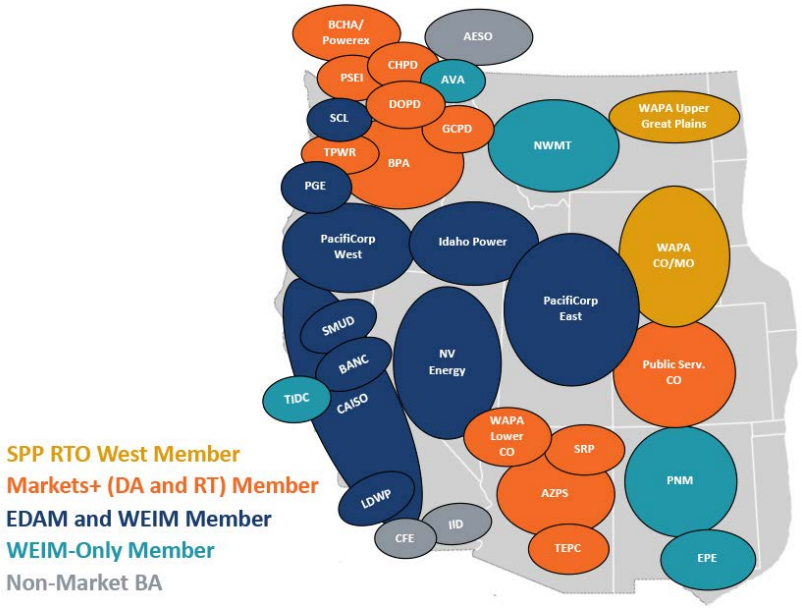
The Brattle study looks at financial outcomes for NV Energy based on five market footprints, with benefits measured against a business-as-usual scenario that assumes membership in CAISO's Western Energy Imbalance Market remains unchanged.

Brattle said it conducted the simulations underpinning the study using a nodal production cost model of the Western Interconnection "with added market functionality, such as contract-path transmission."

The study looks at performance in 2032, "which aims to reflect the first decade of markets operations, representing both an intermediate year in the near future and a year with reasonably high renewable penetration in the" Western Interconnection, Brattle said.

In the "Bookend EDAM" scenario, which assumes nearly all utilities in the Western Interconnection participate in the EDAM, NV Energy would gain about $62 million in annual benefits from higher transfer revenue and lower annual production costs (APC). In that scenario, the utility would facilitate a sharply increased amount of trade between with Southwest and California, while also helping to transfer more low-cost generation from California and the Southwest to the PacifiCorp-East and Idaho Power balancing authority areas.

NV Energy would reap the most benefits — $149 million — from the "Middle View 1" scenario, in which EDAM contains all entities that already have announced for that market, plus Seattle City Light, Portland General Electric, Idaho Power and NV Energy. In that scenario, the Bonneville Power Administration and most of the Northwest's publicly owned utilities, Puget Sound Energy, and all Arizona BAAs join Markets+. NV Energy sees fewer transfers here than in Bookend EDAM, but it also has less competition for low-cost renewable generation, reducing its purchase costs by about $50 million.



Brattle Group's analysis indicates that NV Energy would actually reap the most benefits under the "Middle View 1" scenario, in which it plays a central role in transfers within CAISO's EDAM. | *Brattle Group*

The "Bookend Markets+" scenario assumes NV Energy is participating in Markets+ along with all Northwest and Southwest (including New Mexico) entities, putting a seam between PacifiCorp-East and CAISO and PacifiCorp-West. In that scenario, NV Energy earns $16 million in benefits based on transfer revenues and lower APC but loses access to low-cost generation in the EDAM.

The "Middle View 3" scenario keeps NV Energy in Markets+ but removes the Avista, NorthWestern Energy, El Paso Electric and PNM BAAs, reducing the Nevada utility's annual benefits to $9 million based on lost revenue and increased purchase costs in the smaller footprint.

But NV Energy would incur net losses from participating in Markets+ in "Middle View 2," which assumes Idaho Power joins EDAM, "cutting off a major pathway" between the Southwest and Pacific Northwest, with flows between areas restricted to just 200 MW. In that scenario, energy flows with Idaho decline by about 3,000 GWh a year.

Takeaways

Among Brattle's suggested "key takeaways" from the study: NV Energy's estimated benefits would be highest in the EDAM, "largely due to the opportunity to sell additional generation at higher prices and buy at excess solar at lower prices."

The study also found that the scale of NV Energy's benefits is heavily influenced by the market footprint's shape "due to its large amount of transfer capability and centrality" in the Western Interconnection.

"NVE benefits tend to be higher when it is central to the market and facilitates transfers within the market (e.g., in Bookend M+ case, in which NVE facilitates transfers between the PNW and SW; or Bookend EDAM case, in which NVE facilitates transfers between CAISO and the SW)," Brattle said.

Conversely, benefits decline for the utility when it sits on the margin of Markets+, the analysis found.

Brattle noted also that NV Energy would suffer negative impacts from shifting out of the WEIM and into Markets+ "as it loses access to excess renewable supply from CAISO in real time and sees lower prices for [real-time] sales." ■

CAISO/West News

Nev. Regulators to Weigh Approaches to RTO Membership

Some Stakeholders Worry About Delaying NV Energy Day-ahead Market Participation

By Elaine Goodman

NV Energy and several stakeholder groups have weighed in on how Nevada regulators should evaluate a request from the utility to join a day-ahead market or RTO.

Several of those who filed comments with the Public Utilities Commission of Nevada noted that PUCN faced a similar issue in 2014 — when NV Energy asked for approval to join CAISO's Western Energy Imbalance Market (WEIM).

NV Energy made that request through an amendment to its energy supply plan. Some stakeholders said that process could also work well for considering a request to join a day-ahead market.

But joining an RTO raises new issues, stakeholders said, and PUCN should consider rulemaking to detail how such a request would be considered.

"NV Energy's participation in the day-ahead market is analogous to its current participation in the WEIM in that NV Energy would not transfer operational control over any assets … and current state regulatory authority would be left unchanged," Ben Fitch-Fleischmann of Interwest Energy Alliance, an association of utility-scale renewable energy developers, said in written comments.

"In contrast, joining an RTO may require a host of changes, including the development of joint transmission tariffs, consolidation of balancing area authority and operations, and changes to how transmission planning would be coordinated, and costs allocated," Fitch-Fleischmann added.

PUCN will hold a workshop March 4 to discuss a process for reviewing an RTO or day-ahead market request.

Legislative Mandate

Senate Bill 448 of the Nevada Legislature's 2021 session directs NV Energy to join an RTO by 2030, unless PUCN waives the requirement or grants a delay. A waiver or delay is allowed if the utility can't find "a viable and available" RTO to join or determines that joining an RTO wouldn't be in the best interests of the utility and its customers.

PUCN opened a docket on the matter last year and, in January, ordered NV Energy to file comments by Feb. 16 answering several questions about how the commission should evaluate a request to join an RTO. Stakeholders had the opportunity to comment as well.

In NV Energy's filing, Deputy General Counsel Timothy Clausen noted the utility's promise in a 2013 proceeding to seek PUCN approval before participating in an RTO- or ISO-run market. But a procedure for seeking approval wasn't detailed at that time.

In 2014, NV Energy asked for approval to participate in the WEIM through an amendment to the portfolio optimization procedures in its energy supply plan (ESP).

NV Energy said the ESP could also be used to request approval to participate in a day-ahead market or RTO. But certain aspects of joining an RTO or day-ahead market might need approval through the IRP process, the utility said. Those could include building or procuring resources or transmission to meet resource adequacy requirements.

Day-ahead Market Timeline

Some commenters worried that PUCN rulemaking to create a new approval process could delay NV Energy's participation in a day-ahead market. CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+ day-ahead offering are both expected to launch in 2026.

"Any delay in obtaining permanent regulations can impact the timeliness of NV Energy joining a day-ahead market. This delay would affect NV Energy's customers who, in the interim, would miss out on benefits anticipated by joining a day-ahead market," Justina Caviglia, an attorney representing Google, said in written comments. The company has data centers in Nevada.

But Advanced Energy United argued against using the IRP or ESP process for evaluating a request to join a day-ahead market or RTO.

"The regulations governing ESP/IRP [do] not currently contain requirements or standards for the evaluation of several relevant criteria, including market pricing policies, transparency and oversight, stakeholder and policymaker engagement and input, or respect for state policy mandates," AEU director Brian Turner said in written comments.

And adding to the already complex subject matter of an IRP could be overwhelming for NV Energy, PUCN and stakeholders, AEU said.

If the commission starts rulemaking now, AEU said, regulations could be in place this summer or fall and NV Energy could apply for day-ahead market approval late this year or in early 2025. ■

Transmission line near Lake Mead in Nevada. | © *RTO Insider LLC*

CAISO/West News

WestTEC Transmission Effort Selects Stakeholder Committee

Members Drawn from Industry, Public Interest Groups, Ratepayer Orgs, Tribes

By Elaine Goodman

Western Power Pool (WPP) has announced the 24 members of a stakeholder group that will participate in the Western Transmission Expansion Coalition (WestTEC), a West-wide transmission planning effort.

The appointments to the Regional Engagement Committee (REC) complete WestTEC's organizational structure as the group dives into its work this year.

WestTEC's goal is to approach transmission planning across the West in a "holistic and coordinated manner" to meet the grid's future needs, according to a *concept paper* released last October. (See *Plan Seeks to Boost Prospects for New Transmission in the West*.)

WPP serves as the WestTEC facilitator.

"Having this last committee filled is a big step," WPP CEO Sarah Edmonds said in a statement Feb. 27. "We will bring the group together in the very near future so they can start their important work."

The WestTEC effort is being overseen by a Steering Committee consisting of representatives of transmission-owning utilities from across the West; WECC; and the region's three planning groups — CAISO, WestConnect and NorthernGrid. The steering committee is WestTEC's primary decision-making body.

A WestTEC Assessment Technical Team (WATT) will define the scope and approach for a transmission study, working with consultant Energy Strategies. WATT will receive guidance from the steering committee.

The REC will provide input to the steering committee and will play a "critical role" in WestTEC, according to Edmonds.

Among the REC's 24 members are four members of the WestTEC Steering Committee, who will "ensure continuity between committees," WPP said: Kris Bremer of PacifiCorp, Todd Fridley of Public Service Company of New Mexico, Ravi Aggarwal of the Bonneville Power Administration and Kris Raper of WECC.

In addition, REC will include representatives of the following sectors:

- consumer-owned utilities: four members, including Chris Heimgartner of Whatcom County (Wash.) PUD.
- public interest organizations: four members, including Vijay Satyal of Western Resource Advocates.
- ratepayer advocacy organizations: two members.
- tribes: one member.
- independent transmission companies: four members, including Robb Davis of GridLiance.
- independent power producers: four members, including Tashiana Wangler of Avangrid Renewables.
- industrial customers: one member, Heidi Ratz of the Clean Energy Buyers Association.

The REC's makeup changed from that outlined in the concept paper in response to stakeholder feedback, WPP said.

Western Power Pool's WestTEC was launched to spur planning for new transmission lines in the West. | *© RTO Insider LLC*

Representation was expanded from two to four members for some sectors, including public interest organizations, independent transmission companies and independent power producers. Other sectors, such as investor-owned utilities, were eliminated from REC due to their representation on the steering committee.

The state agency sector was removed from REC because states plan to engage with WestTEC through the Committee on Regional Electric Power Cooperation's Transmission Collaborative.

A full list of REC members is available in WPP's *release*. A list of Steering Committee and WATT members is *here*.

WPP gave a WestTEC update during a call Jan. 29. (See *Group Looks to Create 'Actionable' West-wide Transmission Plan*.) In addition, WPP said it plans to hold quarterly public webinars on the project. ■

CAISO/West News

FERC Challenges Market-based Rates for Idaho Power's Home Territory

By Rich Heidorn Jr.

FERC threatened to revoke Idaho Power's market-based rate authority in its home balancing authority area, citing the utility's failure of a key market power test.

The company, which provides electricity in a 24,000-square-mile territory in southern Idaho and eastern Oregon, submitted an updated market power analysis in October 2023, noting that it had increased its generation capacity in the Idaho Power BAA by 100 MW (*ER10-2126-008*).

Although the company passed the pivotal supplier indicative screen for its BAA, it failed the wholesale market share indicative screen in three seasons, FERC said.

The commission said the failures establish "a rebuttable presumption of horizontal market power" and required it to open a proceeding under Section 206 of the Federal Power Act to determine whether the utility's market-based rate authority in its home region remains just and reasonable.

FERC's Feb. 27 order to show cause (*EL24-62*) does not threaten Idaho Power's ability to charge market-based rates outside its home territory. The company said it passed the pivotal supplier and wholesale market share indicative screens in the Avista Corp., Bonneville Power Administration, Nevada Power Co., NorthWestern Corp., PacifiCorp-East and PacifiCorp-West balancing authority areas, as well as CAISO's Western Energy Imbalance Market.

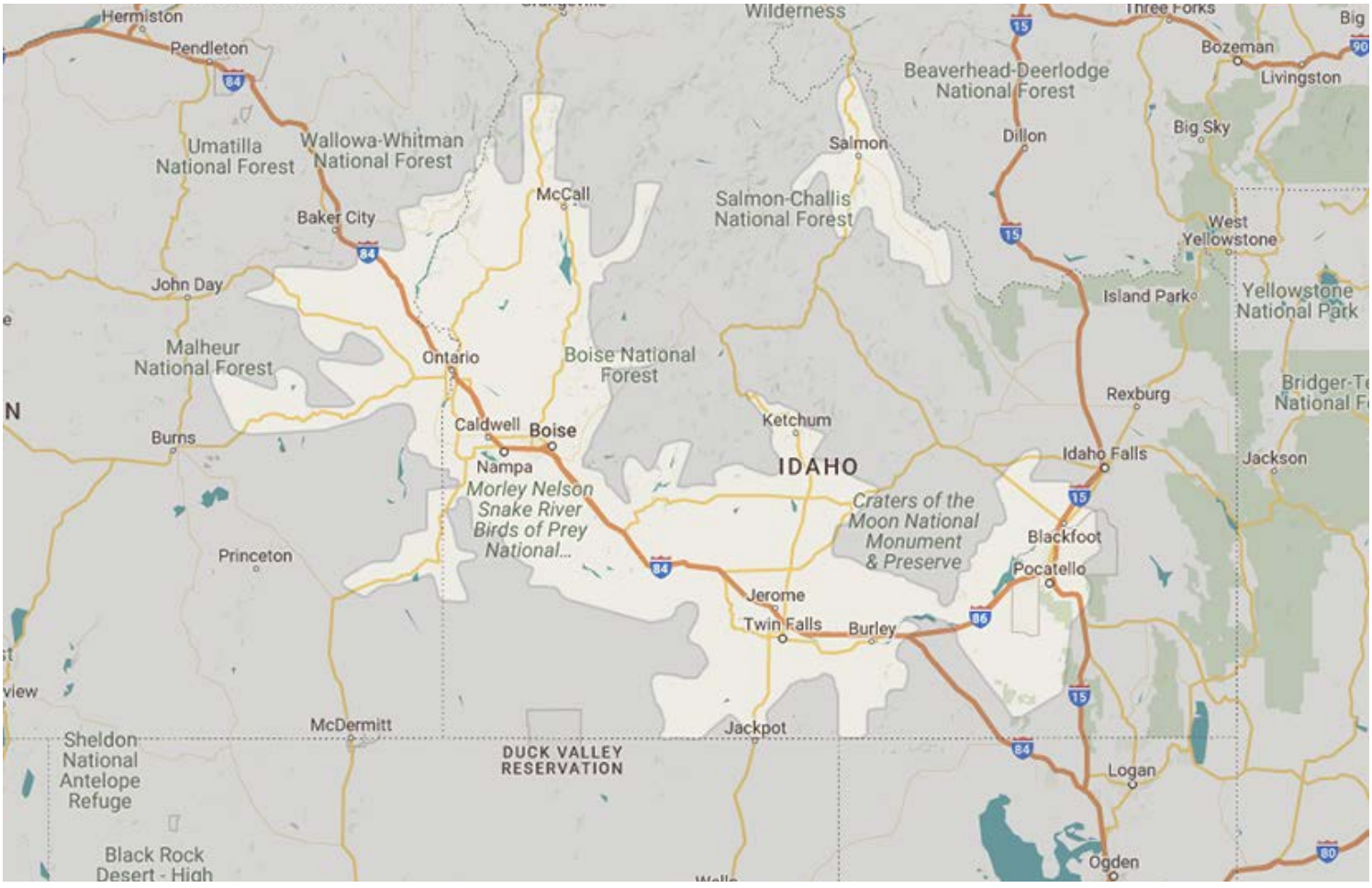
Idaho Power told FERC it increased its generation by 100 MW:

- In June 2023, it began taking delivery of the entire output of the 40-MW Black Mesa Solar facility under a long-term firm power purchase agreement that runs until 2043;
- in June 2023, it downgraded the capacity rating at its Langley Gulch Power Plant by 20 MW; and
- in July 2023, it energized its standalone 80-MW Hemingway battery energy storage system.

FERC gave the utility 60 days to respond to its order by either challenging the commission's threat to revoke its MBRA, proposing mitigation to eliminate its market power or accepting cost-based rates.

The commission said it already is examining a delivered price test analysis Idaho Power submitted to prove it lacked market power. It said the company can submit additional evidence that it lacks market power, such as historical sales and transmission data.

The company can continue charging market-based rates in the BAA — but will be liable for potential refunds — while the commission evaluates the delivered price test. ■



Idaho Power's service territory | *Idaho Power*

ERCOT News

ERCOT CEO Cool to Linking with Neighboring RTOs

Vegas Cites Economics

By Tom Kleckner

Pablo Vegas explains to his board the issues with interconnecting ERCOT to other grids. | *ERCOT*

ERCOT CEO Pablo Vegas on Feb. 27 threw cold water on the possibility of linking the ISO and the national grid's other two interconnections.

Reacting to "one of the important topics that comes up on a regular basis," Vegas told his Board of Directors that interconnecting the Texas grid with its neighbors is a complex issue requiring extensive analysis and input from legislators and regulators. Connecting with other grids is not just a reliability and resilience issue, he said, but one of economics.

"It's really a question as to whether it would be the most economical way to improve reliability and resiliency by interconnecting the grid to other grids, or would the dollars spent be better served and give us better reliability if we were to invest inside of Texas in additional transmission and other resources to help with reliability and resiliency," Vegas told the directors during their bimonthly meeting. "That's really the fundamental question. We're not debating that there could be reliability or resiliency benefits by having interconnections. The question is, is it the best way to spend the dollars to get them?"

During severe weather conditions, he said, ERCOT's neighbors would also likely be dealing with the same storms, making it less likely they could share energy with the Texas grid operator. Vegas also warned that the interconnections could have a "chilling" effect on new generation investment in ERCOT.

"[DC ties] could have the effect of making it less economically advantageous to build power plants inside of ERCOT," Vegas said. "You could see scenarios where it would make more economic sense to build them right outside of our economy, potentially benefiting from some of the capacity market and revenues that would be available in the SPP market or in the MISO market, and then selling that power back into ERCOT when market pricing is high.

"There's a lot of really important considerations," he added. "You really need to model the economic impacts ... between regions when [they're] interconnected to fully understand the cost benefit or the cost impact on the ERCOT market. Those models don't exist today. Those have to be developed and really assessed to understand the true economic impact inside of ERCOT and outside of our economy."

An economic study is coming, said University of Texas engineering professor Michael Webber. Webber *posted* during the board meeting that his research team has conducted an analysis of the economic, environmental and reliability benefits of connecting ERCOT to neighboring grids.

The study has been presented and will be published "soon," he said.

The calls for interconnection outside of Texas have grown since the 2021 winter storm. During that February, ERCOT was forced to shed load to keep the system balanced as generators dropped offline in the frigid temperatures.

U.S. Rep. Greg Casar (D-Texas) introduced a *bill* earlier this month mandating interconnections between ERCOT and its neighboring grids. He *says* the bill would reduce load shed like that during Winter Storm Uri and allow low-priced renewable energy to be sold outside the Texas grid.

The legislation was roundly derided by speakers at an ERCOT conference after it was released. (See "AC Link to National Grid Unlikely," *Overheard at Infocast's 2024 ERCOT Market Summit*.)

Texas does have four DC ties — two with the Eastern Interconnection and two to Mexico totaling about 1,200 MW — that are used for scheduled and emergency trades and are not treated as interstate interconnections.

A proposed DC tie, Pattern Energy's Southern Spirit 345-kV link into the SERC Reliability region, gained regulatory approval in 2022 after seven years of review. FERC has said the project, formerly known as Southern Cross Transmission, would not trigger its jurisdiction over Texas. (See "SCT Proceeding Closed," *Texas Public Utility Commission Briefs: Sept. 29, 2022*.)

The Public Utility Commission of Texas and ERCOT have both taken steps to address the issue. The PUC has opened a proceeding on DC ties' minimum deliverability and planning assumptions and asked stakeholders to submit feedback (*55984*). The commission is expected to discuss the item during its March 7 open meeting.

At ERCOT, stakeholders have tabled a revision to the planning guide (*PGRR105*) since September over cost-allocation concerns. The measure would add DC ties to the list of resources subject to minimum deliverability conditions.

Vegas told the board that any interconnections will require transmission infrastructure on both sides of the tie to "fully leverage and import the energy across them."

"You really need to think about the economic cost overall and the economic cost of having those ties and what it means to pricing between ERCOT and the other regions that it's connected to," he said. "When pricing is high in ERCOT and lower in areas outside, there is the potential that you could see benefit in lowering the cost to residents inside of ERCOT in that circumstance. The flip is also true. When pricing is higher outside and lower inside of ERCOT, you could see a raising of the pricing inside of ERCOT as the price arbitrage is normalized through these DC ties."

R Street Institute's Beth Garza, who doubted during the ERCOT market summit that Casar's bill would go anywhere, told *RTO Insider* she was "intrigued" by Vegas' questioning of whether interconnection costs would be reasonable compared to other actions to improve reliability.

"He and the ERCOT board have vigorously challenged the [Independent Market Monitor's] estimate of the cost of other reliability enhancements," she said, pointing to the ERCOT contingency reserve service product. The IMM has said the new ancillary service created artificial supply shortages that produced "massive" inefficient market costs totaling about $12.5 billion last year through Nov. 27. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

"We really need to look at the true cost, the economic impacts to the market, the economic impacts to the decision-making around generation and how generation would develop," Vegas said. "And those are important issues that should be worked through the Public Utility Commission."

There were no questions from the board when Vegas finished his comments. ■

ERCOT News

ERCOT Board of Directors Briefs

Record Solar Production Helps ISO Weather Winter Storm

ERCOT CEO Pablo Vegas said last week that the "interesting dynamic" of solar energy helped the Texas grid operator meet record demand during its most recent winter storm.

"We continue to see strong solar performance being a very critical part of the resource mix," he told ERCOT's Board of Directors during its Feb. 27 bimonthly meeting. "We had very strong solar generation during the days of this winter event."

ERCOT set a record for solar production at 14.84 GW during the storm's peak Jan. 16, accounting for about 23% of system demand at the time. That mark has since been extended several times to just shy of 17.20 GW.

As of January, the grid operator had 22.26 GW of solar capacity. According to ERCOT data, another 13.15 GW of capacity is projected to be operational in 2025.

Wind production varied between 1.9 GW and 24.4 GW during the storm. Of course, demand was tightest during calm mornings before the sun rose. Vegas said "incredibly strong performance" from the thermal fleet, storage providing about 1.5% of total energy needs during the storm's peak periods, and conservation calls helped make up for the missing renewables.

"We were right along the lines of what would be expected [for thermal outages] during that time of year and significantly improved over the performance we saw during Winter Storm Elliott," Vegas said. "Batteries ... are a growing resource on the grid that's going to continue to be a growing component of the resource mix during those times of need."

The grid operator set five new winter peaks during the storm, the record peak coming at 78.31 GW early Jan. 16. That was a 5.9% increase over the previous mark of 73.96 GW set during the December 2022 storm, itself a 27.7% increase over the prior record.

"So, a pretty significant increase over that period of time," Vegas said.

He also applauded the collaboration and preparation across the industry for the grid's performance during the storm.

"That was different than in prior storms," Vegas said. "The planning and preparation was far more extensive and much earlier than we've experienced in prior storms."

ERCOT's Dan Woodfin (center, back row) describes the grid's performance during the January winter storm as fellow executives Kenan Ögelman (left), Woody Rickerson listen. | *ERCOT*

Ögelman to Retire from ERCOT

Vegas devoted part of his CEO's report to the board in recognizing his "dear friend and colleague" Kenan Ögelman, who is retiring from ERCOT on March 30.

As vice president of commercial operations, Ögelman has overseen market operations, settlement and retail operations, and market design and development. He also led or supported several important initiatives, including various ancillary service products, Lubbock's integration into the ERCOT market, real-time co-optimization, scarcity pricing reforms, and securitization of credit and financing after the deadly 2021 winter storm.

"Not only were the mechanics of the development and the elegance of the solutions attributable to Kenan's leadership, but his ability to bring consensus together in these conversations was something that was really remarkable," Vegas said. "Honestly, the most difficult thing about working with Kenan is pronouncing his name correctly, because there is nothing difficult about working with Kenan."

For the record, Ögelman's name is pronounced Keh-naan Oh-gell-mun.

Jupiter Power's Caitlin Smith, who chairs the Technical Advisory Committee (TAC) where Ögelman represents ERCOT, offered her thoughts during her update to the board.

"I've known him, I think, my entire career in this industry," she said. "He's a great friend and mentor and I know that the stakeholders will miss him in this role."

The board and stakeholders present gave Ögelman a round of applause.

He is the most senior executive to leave the ISO after Winter Storm Uri since then-CEO Bill Magness resigned.

Ögelman joined ERCOT in 2015 from CPS Energy, where he was director of energy market policy and chaired TAC from 2011 to 2013. Previously, he was a senior economist for the Texas Office of Public Utility Counsel, which represents residential electric consumers.

IMM Again Critiques ECRS

ERCOT's Independent Market Monitor told the Reliability & Markets Committee that while the ISO managed the system reliably during the January storm and prices exceeded only $1,200/MWh, "excessively held" ERCOT contingency reserve service (ECRS) inflated prices during the event.

The IMM *said* prices cracked the $1,200 level even though reserves never fell below 5,000 MW during the storm and the operating reserve demand curve never exceeded $90/MWh.

"What we saw was large amounts of held ECRs likely drove some of that higher real-time pricing, particularly on Jan. 16," Wen Zhang, the IMM's deputy director, said, adding efficient prices could have lowered wholesale energy costs by about $90 million.

"This indicates that the concerns we raised about ECRS are still present," she said.

The IMM has said ECRS, the newest ancillary product added in June, likely cost between $675 million and $750 million for 2023. It says the product created artificial supply shortages that produced "massive" inefficient market costs of about $12.5 billion last year.

The monitor has been discussing potential changes to ECRS' deployment. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

Board Approves RR Remanded by PUC

The board agreed with the R&M committee's and staff's recommendations to approve a nodal protocol revision request (*NPRR1186*) regulating energy storage resources (ESRs) that was remanded by regulators back to the grid operator in January. (See "NPRR1186 Goes to Board," *ERCOT Technical Advisory Committee Briefs: Feb. 14, 2024*.)

As directed by the Public Utility Commission, staff removed language that set penalties for batteries without sufficient state of charge to meet their obligations when deployed.

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The directors also withdrew *NPRR1209*, which was designed to operate in tandem with NPRR1186's compliance provisions.

Storage developers vigorously opposed NPRR1186 as it went through the stakeholder process last year. SOC requirements will be addressed by existing protocols and revisions still in the pipeline, staff said.

The directors confirmed Smith and Oncor's Collin Martin as TAC's chair and vice chair and approved Enerwise Global Technologies as an adjunct member. The ISO gives adjunct membership to entities that don't meet the definitions or requirements to join as corporate or associate members.

The board also approved several other items that cleared the R&M committee Feb. 26 and previously were endorsed by TAC:

- Texas-New Mexico Power's *Pecos County Transmission Improvement Project*, a $114.8 million, 138-kV effort addressing reliability needs under maintenance outage conditions near Fort Stockton in the Far West weather zone.
- The second phase of the Aggregate Distributed Energy Resources (ADERS) pilot project. ERCOT has cleared seven additional ADERS to go through the qualification and validation process of commercial operations, joining the two that already are participating in the wholesale market. (See "ADERs now up to 9," *ERCOT Technical Advisory Committee Briefs: Jan. 24, 2024*.)

Its consent agenda included 11 nodal protocol revision requests (NPRRs), two changes to the settlement metering operating guide (SMOGRRs), a system change request (SCR) and single modifications to the load planning guide (LPGRR), nodal operating guide (NOGRR), planning guide (PGRR), retail management guide (RMGRR) previously endorsed by the Technical Advisory Committee that:

- *NPRR1170*: define when a qualified scheduling entity (QSE) representing a resource that relies on natural gas as its primary fuel source should notify ERCOT about gas supply disruptions.
- *NPRR1179*: ensure that QSEs representing resources with an executed and enforceable transportation contract procure fuel economically and file a settlement dispute to recover their actual fuel costs incurred when instructed to operate because of a reliability unit commitment (RUC). This change also would adjust the RUC guarantee to reflect the cost difference between the actual fuel consumed during the RUC-committed intervals and the fuel burn calculated based on verifiable cost parameters and would clarify that fuel costs also may include penalties for fuel delivery outside of RUC-committed intervals.
- *NPRR1193*: change the ERCOT-polled settlement (EPS) design-proposal form's referenced location when it moves from the other binding document (OBD) list into the SMOG.
- *NPRR1195*: assign ERCOT-polled settlement metering facilities' maintenance and repair responsibilities to the facilities' owner if it is not a transmission and/or distribution service provider (TDSP).
- *NPRR1199*: revise the protocols to add definitions related to the Lone Star Infrastructure Protection Act (LIPA), a 2021 law that prohibits Texas businesses and governments from contracting with entities owned or controlled by individuals from China, Russia, North Korea or Iran if the contracting relates to "critical infrastructure." The measure also adds language reflecting ERCOT's statutory authorization to immediately suspend or terminate a market participant's registration or access if the ISO has a reasonable suspicion that the entity meets any of the LIPA's criteria, among other revisions.
- *NPRR1206*: clarify the QSEs required to have a hotline and a 24/7 control or operations center and reconcile the deadline by which QSEs representing resource entities that own or control resources must provide notice they are terminating their representation and the deadline that resource entities owning or controlling resources to change QSEs with a 45-day timeline.
- *NPRR1207*: permit the incidental disclosure of protected information and ERCOT critical energy infrastructure information during a tour or overlook viewing of the ERCOT control room provided to eligible persons who have signed nondisclosure agreements and complied with screening and other requirements before accessing the control room.
- *NPRR1208*: create a new daily ERCOT invoice report listing invoices issued for the current day and day prior at a counterparty level.
- *NPRR1210*: change the frequency of the next-start resource and the load-carrying tests from every five years to every four calendar years.
- *NPRR1211*: incorporate the OBD "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints" into the protocols.
- *NPRR1213*: amend requirements for distribution generation resources (DGRs) and distribution energy storage resources (DESRs) seeking qualification to provide ECRS. The NPRR also modifies requirements for ancillary service self-arrangement and ancillary service trades for DGRs and DESRs that provide nonspinning reserve on circuits subject to load shed.
- *LPGRR074*: align specific term language in the profile decision tree "definitions" worksheet with profile segment language that was added to the "segment assignment" worksheet with the Public Utility Commission's 2022 approval of *LPGRR069*.
- *NOGRR261*: incorporate the OBD "Procedure for Calculating Responsive Reserve Limits for Individual Resources" into the nodal operating guide.
- *PGRR109*: require interconnecting entities associated with inverter-based resources to undergo a dynamic model review process before the commissioning date and mandate that resource entities owning or controlling operational IBRs undergo a review process before changing settings or equipment that could affect electrical performance and necessitate dynamic model updates.
- *RMGRR179*: add a communication method so TDSPs can use Texas standard electronic transactions to inform retail electric providers of record which electric service identifiers are affected by a TDSP's mobile generation or temporary emergency electric energy facility deployment.
- *SCR825*: modify ERCOT's current control room voice communication configurations to give QSEs and their subordinate QSEs greater flexibility when assigning agents, including allowing sub-QSEs to assign agents different from those used by the parent QSE.
- *SMOGRR027*: Move the EPS metering design proposal from the OBD list into the SMOG, standardizing the approval process, and amend the design proposal form to require more information identifying all distribution service providers that have the right to serve a project.
- *SMOGRR030*: Move the EPS metering facility temporary exemption request application form from the OBD list into the SMOG to standardize the approval process. ■

— Tom Kleckner

MISO News

MISO Says 2nd LRTP Portfolio Should Run About $20B, Rate Mostly 765 kV

By Amanda Durish Cook

MISO on March 4 suggested an approximately $20 billion portfolio for its second long-range transmission planning (LRTP) effort, calling for several 765-kV line segments.

The grid operator *said* its second LRTP draft portfolio for MISO Midwest "focuses on creating a 765-kV transmission 'highway' within the MISO region to maximize value based on land use, line distances, transfer levels and costs." Together, MISO said the anticipated additions could range in cost from $17 billion to $23 billion.

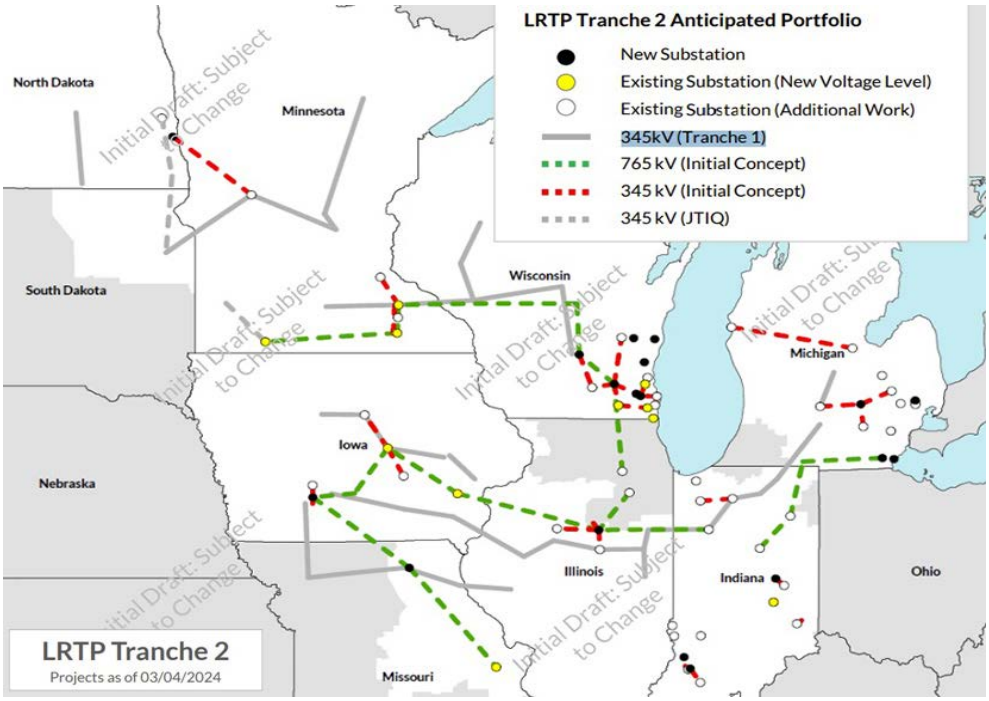
Several of the suggested 765-kV lines are located near 345-kV line routes approved as part of MISO's first, $10 billion LRTP portfolio, including routes through Iowa that have been cast into uncertainty by a recent court ruling finding the state's right of first refusal law unconstitutional. (See *MISO Asks Court for Injunction Reversal on Iowa LRTP Projects*.)

The proposed 765-kV network snakes through Missouri, Iowa, Illinois, Wisconsin and Minnesota. Another suggested 765-kV segment cuts through Southern Michigan into Indiana. The second LRTP draft proposal also calls for several substations and more 345-kV lines in Minnesota, Wisconsin, Michigan, Iowa and Illinois.

As with its first LRTP portfolio, MISO said it sought to minimize new rights-of-way permitting with state regulators to help head off environmental concerns.

At the Gulf Coast Power Association's MISO-SPP conference March 4, MISO CEO John Bear said the RTO hopes to finalize the second LRTP portfolio for approval by its board of directors at the end of the year.

MISO planners have long said "significant" overloads and congestion eventually will threaten the system if the RTO doesn't recommend a second set of Midwestern transmission solutions. (See *MISO Says Overloads and Congestion Loom Without 2nd Long-range Tx Portfolio*.)



Suggested 765-kV and 345-kV lines under MISO's draft proposal for its second long-range transmission portfolio | *MISO*

MISO's new line suggestions are premised on the RTO's *estimate* that it will need 369 GW of new, mostly renewable resources by 2042 based on its members' plans. MISO said the second LRTP portfolio is the next step to "developing a system needed to reliably and efficiently meet the load growth and resource evolution described in MISO's members' plans."

"This portfolio focuses on creating a regional backbone to meet the long-term needs of our region," MISO Vice President of System Planning Aubrey Johnson said in a press release. "Our transmission solutions — creating a sort of interstate highway system for electricity — enable the future resource plans of our states, utilities and members by addressing regional needs, while recognizing that local issues will continue to be addressed through our MTEP and generator interconnection queue processes."

"The future grid must be able to integrate new load growth and respond to extreme weather, and a robust transmission system is required to ensure this occurs reliably and efficiently," said Laura Rauch, executive director of transmission planning at MISO. "We know further transmission development can provide value and we will continue working with our stakeholders to refine this portfolio and ensure it is sufficiently robust."

MISO said it will continue analyzing the benefits of anticipated portfolio over the coming months and take stakeholders' suggestions for project alternatives through April 5.

MISO will hold its next LRTP workshop with stakeholders on March 15. ■

Midwest news from our other channels

Groups Ask Montana PSC to Consider Climate Impacts in Rulemakings — NetZero Insider

Sides Forming in Fight Over Michigan Renewable Siting Law — NetZero Insider

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

MISO News

MISO Wants $10K VOLL, a Nearly Threefold Increase

By Amanda Durish Cook

CARMEL, Ind. — MISO last week said its extensive analysis shows that its current $3,500/MWh value of lost load (VOLL) should be raised to $10,000/MWh.

The grid operator has made a renewed push in recent months to re-estimate its value of lost load after saying that its existing VOLL is dated, having been established in the 2008-2009 time frame. MISO's current VOLL reflects the willingness of the lowest-income residential customers in the RTO's footprint to pay for uninterrupted service.

During a Feb. 29 Market Subcommittee meeting, MISO's Chuck Hansen said the $3,500/MWh limit "can currently curtail valid market prices."

"When the system is in a more vulnerable state, prices should reflect the risk of diminishing reserves," Hansen said.

Three years ago, MISO's Independent Market Monitor *recommended* the RTO adopt a $10,000/MWh VOLL.

Hansen likened a well-thought-out VOLL to the "jolt" delivered from farmers' electric fences, which aren't meant to injure livestock.

"The goal isn't to shock the cows; the goal is to just keep them in the field," he explained.

Hansen said a raised value would almost counterintuitively moderate market volatility because market participants would take more actions to dodge the highest prices.

"With higher prices, we expect lower volatility and more preparation to avoid those kinds of real-time energy deficiencies," he said.

Hansen said MISO's current VOLL is "outdated and below industry willingness to respond to demand." He said a reasonable VOLL would properly discourage market participants from "these 'touching the electric fence' situations" and "potentially make them more rare than they already are."

New VOLL Means New ORDC

MISO said it also will seek to change how VOLL ties into its operating reserve demand curve (ORDC). MISO's ORDC is linked to VOLL, and the current curve mostly sits at $1,100/MWh and $2,100/MWh across two large steps before it tops out at $3,500/MWh.

Despite proposing a $10,000/MWh VOLL, MISO wants its ORDC to peak at $6,000/MWh and stay there until about 50% of cleared operating reserves materialize. From there, the curve would slope downward until MISO can confirm more than 80% of its cleared operating reserves, at which point the curve would become two steps: $1,100/MWh until 88% of reserves show up and $600/MWh until 100% of reserves turn up.

If MISO already had the new curve in place, Hansen said more than 90% of MISO's past shortages would have resulted in lower penalty prices. Most of the RTO's operating reserve shortages occur at 88% of reserves or higher. Historically, MISO has never experienced an operating reserve shortage below 50%.

"This is not just about raising VOLL and making prices higher. On the right side of the curve, we thought it was appropriate to lower prices," Hansen said.

Hansen said MISO would like to introduce an ORDC that is lower for small reserve shortages and results in higher prices for greater shortages.

"As reserves go away, we want prices to approach VOLL, but we don't want prices to be so high that they reach VOLL well before load shedding is initiated," Hansen said. Conversely, he added that the lower bound of the ORDC shouldn't be so low that it's cheaper for market participants to violate marketwide operating reserve requirement.

Hansen said MISO wants to continue to use an updated VOLL as a price cap for locational marginal prices, market clearing prices and during load shed events.

But he said MISO would like to sever the connection between VOLL and MISO's emergency demand response offer cap. MISO has called on its emergency demand response only once, more than 15 years ago. Today, MISO's emergency demand response averages less than 500 MW and is managed on a separate system from the RTO's markets. The product was introduced before MISO debuted its ancillary service market, and owners are under no obligation to be available. Hansen said MISO has debated retiring its emergency demand response product and urges market participants to move their offerings under the RTO's existing load-modifying resource and demand response programs.

Justification for $10K

Hansen said the current VOLL was established alongside the launch of MISO's ancillary services market and "that number has not changed in 15 years."

He said MISO has made hundreds of calculations to freshen its VOLL, including crunching numbers for different lengths of outages; nonsummer versus summertime periods; afternoon, evening or off-peak periods; and using different customer load classes, including small commercial, industrial, residential and manufacturing segments.

Chuck Hansen, MISO | © *RTO Insider LLC*

MISO News

MISO found that for a one-hour outage occurring off-peak in summer, VOLL will run $4,337/MW for residential customers and up to nearly $81,000/MW for small commercial and industrial customers. For an eight-hour outage occurring off-peak in summer, a residential VOLL will run about $8,107/MW, while small commercial and industrial customers' value runs more than $266,000/MW.

"We've been studying a range of numbers, many numbers," Hansen said.

MISO found that its highest VOLL occurs during off-peak periods with small commercial and industrial customers the most exposed to risks of lost revenue. Larger commercial and industrial customers often have access to more capital to prepare to bounce back more quickly from an outage, staff said.

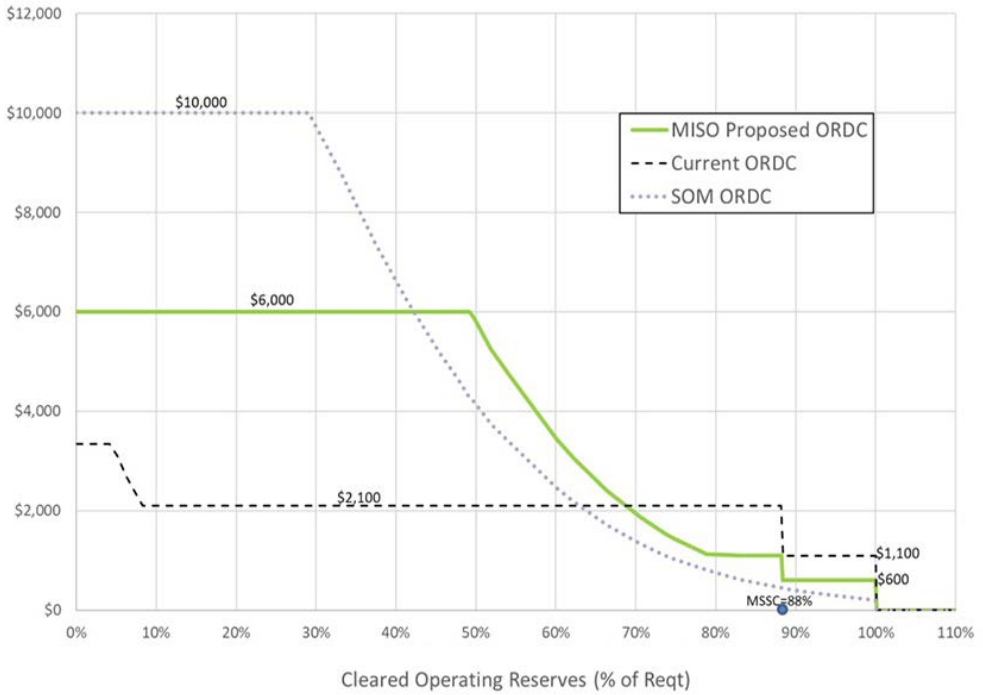
When MISO made its 2007 FERC filing to create VOLL, it used the average of the $1,470/MWh median value of its residential class and the $15,250/MWh lowest median value of the small commercial and industrial class. The resulting VOLL was weighted 85% toward residential customers.

Using that same 2007 calculation, Hansen said the 2023 VOLL for a summertime, one-hour outage occurring off peak should be $13,640/MWh.

"What we're proposing is actually on the conservative side," Hansen said.

Hansen reminded stakeholders that MISO isn't in charge of which customers are affected by outages when it orders load shedding. The RTO simply tells local balancing authorities how many megawatts it needs off the system. MISO said a recent survey of its local balancing authorities shows that when instituting rolling blackouts, customers dropped on average are 48% residential, 30% large commercial and industrial, and 22% small commercial and industrial.

Hansen said a $10K VOLL reflects that industrial customer load is also shed alongside residential load during dire circumstances. ■



MISO's proposed ORDC. The 'SOM' curve refers to the Independent Market Monitor's past recommendation for a new curve. | *MISO*

MISO Names New Chief Information Security Officer

By Amanda Durish Cook

MISO announced it has promoted Eric Miller to chief information security officer and the RTO's newest vice president.

Miller joined MISO in 2020 as an executive director of digital technology. Prior to signing on with MISO, Miller held IT and cybersecurity leadership roles at Ascension Technologies, the health care company's IT division.

Miller is based out of MISO's Carmel, Ind., headquarters and is now *responsible* for managing the RTO's physical security, cybersecurity, and technology infrastructure and operations.

"I look forward to stepping into this new role at MISO," Miller said in a March 1 press release. "I'm excited about leading a world-class team of professionals who are committed to a safe, secure and reliable bulk electric system."

Former Chief Information Security Officer Keri Glitch left MISO last year to join Fortis, where she serves as the vice president of information technology.

Miller has a master's degree in systems engineering from Johns Hopkins University and a Master of Business Administration from Bowling Green State University. He also was a commissioned officer in the U.S. Army.

MISO said Miller recently completed the CISO Executive Education and Certificate Program from Carnegie Mellon University's Heinz College of Information Systems and Public Policy, in addition to holding multiple other cybersecurity certifications. ■

MISO CISO Eric Miller | *MISO*

MISO News

MISO: New Capacity Accreditation Filing Imminent

By Amanda Durish Cook

CARMEL, Ind. — MISO is determined to file with FERC by the end of March to introduce a probabilistic capacity accreditation that's controversial among stakeholders.

MISO stakeholders continued to lobby for a deferral during a Feb. 28 Resource Adequacy Subcommittee meeting, again telling the RTO it hasn't shared enough information on its loss of load-oriented accreditation style. (See *MISO Set on March Accreditation Filing, Stakeholders Push for Slowdown*.) A filing in March seems destined to gather several protests.

But Senior Manager of Market Design Neil Shah said MISO has now shared enough data from its analyses to give stakeholders a "broad indication" of their future capacity credits to adjust generation plans accordingly.

"The filing needs to happen now for stakeholders to make those adjustments," Shah said.

MISO doesn't intend the accreditation to take effect until the 2028/29 planning year.

Shah said "the beauty of" MISO's method is that it measures the reliability contribution of all resources across "hundreds and hundreds" of simulated risky hours.

Under the new method, generators' capacity credits would be determined by a combination of individual past performance and resource-class average performance during hours with tight conditions and modeled loss-of-load hours for different types of generation. Most resources' credits would shrink under the new accreditation. Resources would be divided by fuel type: gas, coal, hydro, nuclear, energy storage, pumped storage, wind and solar. MISO at first didn't commit to listing resource types in its tariff filing with FERC.

Shah likened MISO's accreditation change to his homeowner's insurance policy recently increasing by a few hundred dollars based not on him, but on his neighbors filing more claims recently. He said his insurer took the growing claims as proof of rising risk in his neighborhood and reassessed. MISO, Shah said, is no different with this new accreditation direction.

Many MISO stakeholders have argued the loss-of-load accreditation would inject too much uncertainty into the MISO market, disrupting integrated resource plans and investment decisions. At the RASC meeting, some said they don't have adequate insight into how capacity credits would differ by resource type and questioned whether MISO's proposed resource classes would sufficiently represent all types of resources in MISO.

Shah said MISO is prepared to make a future filing if new technology necessitates the RTO add new resource classes but said MISO has landed on a "good representation of resources classes" in the footprint today.

Shah also noted that during the three-year transition period, MISO wouldn't apply the accreditation but would publish indicative accreditation results for resource classes, as well as anticipated local reliability requirements and planning resource margin requirements based on the direct loss-of-load accreditation method. MISO wouldn't share unit-level capacity values publicly; market participants would need to request those from the grid operator.

MISO has said the new accreditation would better ensure seasonal reserve requirements are met, shape long-term investment and retirement decisions "by accurately representing the capacity value of a resource in the prompt year," and incentivize resources to show up during times of the greatest system need. It has characterized the new accreditation style as a "consistent accreditation methodology for all resources, capturing the reliability contribution during times of highest risk."

MISO's Zak Joundi has said MISO members would "have plenty of time to adjust" to the new rules. ■

MISO's Neil Shah discusses accreditation at the Feb. 28 Resource Adequacy Subcommittee | © *RTO Insider LLC*

NYISO News

NYPA and NYU Partner to Scale up Transformer Monitoring Study

NYPA's AGILe to Prototype NYU Tandon's Techniques to Reduce Winding Deformations

By John Norris

The New York Power Authority (NYPA) and the New York University Tandon School of Engineering on Feb. 22 *announced* a partnership that could help state utilities prevent costly and time-consuming large power transformer outages through a novel monitoring technique.

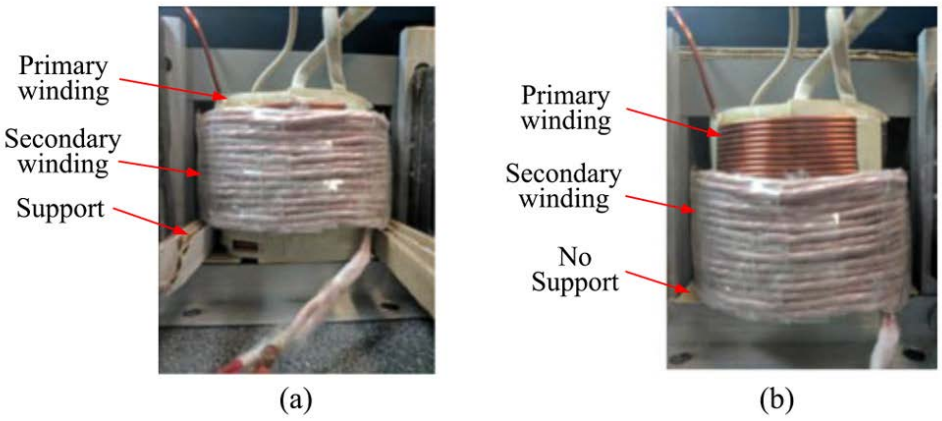
NYPA will test NYU Tandon's "Online Detection of Winding Deformations in Large Power Transformer" *study* at its Advanced Grid Innovations Laboratory for Energy (AGILe) *simulation facility* to assess if the school's technique can be scaled up for the wider New York grid to improve the detection of transformer-winding deformations without statewide interruptions.

"NYU Tandon aims to integrate into NYPA's AGILe processes by developing a comprehensive model encompassing various common deformations in transformer windings," Shayan Behzadirafi, a project engineer on NYPA's Research, Technology Development and Innovation team, told *RTO Insider*.

The partnership, supported by a nearly $190,000 grant from the New York State Energy Research and Development Authority's Future Grid Challenge *program* — itself funded through the nearly $2.4 billion *Clean Energy Fund* — aims to digitally monitor NYPA's large-scale transformers by continuously tracking the voltage and currents of transformers while accurately calculating its leakage impedance (*14-M-0094*).

Con Edison transformer explosion in Queens from December 2018 | *@prasad2011 via X*

"The idea is to scale up the technique, which was tested with a 1-kVA lab transformer, to the NYPA large transformers of hundreds of megavolt-amperes," Francisco de Leon, a NYU Tandon professor of electrical and computer engineering and one of the study's authors, wrote in an email to *RTO Insider*. "If the project is successful, the condition-monitoring device will save money in unnecessary tests when the transformer is healthy or prevent catastrophic failures when the transformer has been damaged."



Experimental setup for winding deformation diagnostics system test; normal transformer (right), deformed transformer (left) | *NYU Tandon, IEEE Transactions on Power Delivery (April 2018)*

NYPA estimates that if the technique prevents many of the diagnostics required once a transformer is taken out of service because of winding deformations, the state could save about $15,000 per day and up to $1.5 million per incident.

"Basically, what we are doing for transformers is giving them a smartwatch," de Leon said in an interview with *RTO Insider*. "It is something that is monitoring all the time and giving real-time analysis of some of [the transformer's] components without having to disconnect the transformer."

This has big implications for NYPA, the largest state public power organization in the U.S., as it operates more than 1,400 circuit-miles of transmission lines, has 16 generating facilities

NYISO News

— including the hydroelectric *Niagara Power* and the *St. Lawrence-FDR Power* projects — and produces more than 80% of its electricity from renewables.

Transforming the Future

NYU Tandon's paper, published in the journal *IEEE Transactions on Power Delivery* in 2018, emphasizes how transformers' windings, which consist of metal coils wound around the transformer's core, "are subjected to strong electromagnetic forces" that can cause deformations.

"To avoid crucial damage, it is necessary to detect winding deformation at an early stage," the paper reads.

New York has experienced transformer-related outages, explosions and fires, often because of equipment failures, which led to extended disruptions and costly repairs.

Notable incidents include the December 2018 transformer *explosion* at a Consolidated Edison plant in Astoria, Queens, which painted New York City's skyline bright blue. A 2021 incident captured on *video* in which a man in Queens survived a transformer explosion directly beneath him, and in January, another Con Ed transformer in Queens *reportedly* exploded, knocking out power for hundreds of customers for hours.

Transformers with deformed windings are typically taken out of service for a frequency response analysis to test the mechanical integrity, but the technique being studied at AGILe could reduce the frequency of these occurrences and the need for such service interruptions.

"Traditionally, bringing transformers out of service for frequency response tests is the norm," Behzadirafi said. "However, if NYU Tandon's methodology proves successful, it would eliminate the need for such disruptive measures.

"By enabling the detection of transformer issues while the unit remains in service, the study offers a substantial improvement in minimizing downtime, increasing efficiency and enhancing the overall reliability and performance of the energy infrastructure."

New York Stays AGILe

Launched in 2017 in Albany, AGILe is described as a "a global center for electric grid research," *responsible* for developing and testing "new and off-the-shelf clean energy technologies" to strengthen the state's electric grid by fast-tracking their commercialization.

It also helps utilities better understand the potential impacts of new technologies or techniques on the state's grid.

"Through this study, we hope to be able to give utilities confidence that this technique is reliable and will work for full-size transformers in the field," said Alan Ettlinger, NYPA's senior director of research, technology development and innovation.

Behzadirafi elaborated on how NYU Tandon's developed prototype would be evaluated. "Leveraging AGILe's hardware-in-the-loop facilities, we will test the developed hardware against the deformation models to assess its performance and ensure its effectiveness in real-world applications."

"NYPA will conduct the study by evaluating whether the developed hardware can effectively detect various winding deformations using information provided by the software model," he said. "The success of the study will be determined by the alignment between the outputs generated by the software model and the actual data obtained from the transducers, as well as hardware's ability to detect, ensuring that the hardware reliably detects winding deformations in practical applications."

The prototype being assessed by AGILe identifies changes in short-circuit impedance, a key transformer health indicator, using advanced techniques like Lissajous curve methods to track winding deformations in real time.

If found to work, the digital tool will detect emerging transformer winding deformations caused by stress from short-circuit events and send a warning alarm to an operator informing them the unit has a leakage reactance higher than the standard 3% recommended by the Institute of Electrical and Electronics Engineers.

"If the outcome of this collaboration proves successful, NYPA is considering a potential second phase, which involves implementing the detector relay in conjunction with a real transformer," Behzadirafi said. "Additionally, there is a possibility of engaging popular relay manufacturers to contribute to the development of the relay during the practical phase in the real-world scenario."

"My dream," NYU's de Leon said, "is that our technique is found to be successful and viable, since then we can partner with a relay manufacturer to produce a new relay prototype that is equipped with our tools and is then commercialized."

"Unique research collaborations like this one with NYU Tandon, supported by NYSERDA, enable the Power Authority and New York state to innovate and modernize its electric grid for the benefit of all New Yorkers," NYPA CEO Justin Driscoll said. ■

NYISO News

Hydrogen Getting Resource-specific Rules in NYISO Markets

Final 2024/25 Capacity Accreditation Factors and Resource Classes Posted Online

By John Norris

NYISO on Feb. 29 took the first steps to creating market rules enabling hydrogen to participate in its marketplace, after *kicking off* the market design concept for the clean energy resource.

The ISO's current rules do not cover how an emissions-free generator co-located with a load resource like an electrolyzer, producing clean hydrogen using energy from a nearby solar or wind facility, could participate in New York. NYISO proposes investigating if it can enable this either by creating new, or modifying existing, participation models.

NYISO estimates its clean hydrogen market participation models will be deployed in 2027 but acknowledges hydrogen is a nascent technology and so any proposed enhancements must be adaptable to innovations.

Aaron Breidenbaugh, senior director of regulatory affairs at CPower Energy Management, sought clarification on whether the final proposals, though tailored to hydrogen, could apply to a range of future resources. CPower aggregates demand response and distributed energy resources, advocating for NYISO to always incorporate evolving technologies into its proposals. (See *Providers See 'Mixed Signals' on Demand Response in NYISO*.)

Harris Eisenhardt, a market design specialist with NYISO, responded that the ISO's objective is to propose a final market concept that is "technology-agnostic" and "suitable for other use cases as well."

New York has devoted less attention to developing hydrogen and other less prominent fossil fuel alternatives, like nuclear or bioenergy, because they can be controversial among climate activists. (See *Take the Long View on Clean Energy, NY Legislators Urged*.) Instead, the focus has been on yet-unknown technologies that NYISO collectively terms dispatchable emission-free resources (DEFRs). These DEFRs are not yet commercially available, prompting the state's Public Service Commission to explore clean energy technologies, including hydrogen, bioenergy, nuclear power and carbon capture (*15-E-0302*). (See *NY Drills Down on Statutory Meaning of 'Zero Emissions'*.)

New York has, however, seen some actions recently promoting hydrogen development. State senators have introduced a handful of bills this year to facilitate its deployment (*S378A*) (*S8455*); Gov. Kathy Hochul (D) announced several multimillion-dollar investments in hydrogen initiatives across the state last year (*14-M-0094*); and New York now leads a multistate regional clean hydrogen hub competing for federal funds. (See *NY Moves to Boost Hydrogen Production and Development* and *Vermont Joins Northeast Clean Hydrogen Hub*.)

The Nine Mile Point Nuclear Station in Oswego, N.Y., has generated clean hydrogen via nuclear power since 2023. | *Constellation Energy Corp*

Additionally, Constellation Energy's Nine Mile Point Nuclear Plant in Oswego, N.Y., started *producing* hydrogen with nuclear energy last year. (See *Constellation Expands Nuclear Clean Energy Matching*.)

NYISO plans to review its draft market design concepts with stakeholders in the second quarter of this year and expects to finalize the proposal by the end of the third quarter.

Capacity Accreditation

NYISO also *informed* the ICAP/MIWG that the final capacity accreditation factors (CAFs) and capacity accreditation resource classes (CARCs) for the 2024/25 capability year are published *online*.

CAFs calculate the marginal reliability contribution of "representative" generators for each CARC, a differentiation based on technology and operating characteristics. The CAFs reflect factors such as energy duration limitations and correlated unavailability due to weather or fuel supply limitations and were used alongside resource-specific derating factors to account for differences in a unit's output from the modeled CARC profile.

Last year, NYISO addressed issues in its capacity accreditation modeling, such as misrepresented marginal reliability contributions of some resources, leading to inaccurate CAF and CARC calculations. (See "Capacity Accreditation," *NYISO Finds No Need for New Capacity Zones* and "Capacity Accreditation Modeling," *NYISO BIC Stakeholders OK Modeling, Market Design*.)

ICAP suppliers who notice a discrepancy in their assigned values must notify NYISO by 5 p.m. March 18, when CAF assignments will be considered official. ■

PJM News

PJM Rejects Storage as Alternative to Brandon Shores RMR

By Devin Leith-Yessian

PJM is rejecting a study that suggests it could avoid extending the 1,295-MW Brandon Shores generator's life by installing storage and reconductoring several lines outside Baltimore.

The *analysis*, conducted by GridLab and Telos Energy, found that installing a 600-MW battery at the Brandon Shores point of interconnection and reconductoring several 115-kV lines could provide the grid services offered by the generator and be in place in time for the 2025 retirement requested by plant owner Talen Energy.

The study estimated the battery would cost $452 million after tax credits and could produce $348 million in net revenues over 20 years. Comparing Brandon Shores to other generators that have received RMR contracts, the study estimated that continuing to run Brandon Shores could cost $258 million per year.

"We think this is a model that could be exported throughout PJM and even in other ISO regions as well: opportunities to replace retiring generation with storage as a means to avoid an RMR and … have a stronger system, a more reliable system, instead of paying for an uneconomical plant to stay online for several more years until transmission upgrades come in," Gridlab Senior Program Manager Casey Baker said.

PJM is in talks with Talen Energy to keep the generator running until its $796 million Grid Solutions Package is completed in 2028 to address expected reliability violations. The project includes a new 500-kV substation, a new 500-kV line between the Peach Bottom and Graceton substations and a 230-kV line from Graceton to a new 230-kV Batavia Road substation outside Baltimore. (See *FERC Approves PJM RTEP Projects over State Protests*.)

PJM spokesperson Jeff Shields told *RTO Insider* that a battery installation is not a viable alternative to an RMR for Brandon Shores. (See "Brandon Shores Deactivation to Require $786M in Grid Upgrades" *PJM PC/TEAC Briefs: June 6, 2023*.)

"PJM does not believe that a battery solution would address the comprehensive reliability needs in the BGE and surrounding areas, be able to be put in place by 2025, or be economically feasible," Shields said in an email. "The Brandon Shores RMR is a must to maintain regional reliability until any additional enhancements could even be considered in the future."

Sierra Club Senior Attorney Casey Roberts said she believes there is time for PJM to consider alternatives to keeping Brandon Shores online.

"The deactivation dates are June 2025, so we think there's actually a pretty good amount of time for PJM to look at alternative solutions and see what else can be implemented. PJM has expressed some urgency with nailing down an RMR agreement with Talen for Brandon Shores as soon as possible, but in our view it's better to take a little bit of extra time to make sure you have the most cost-effective and reliable solution rather than rushing to the thing you've always done," she said.

She pointed to the example of the Petersburg Generating Station retirement owned by

The Brandon Shores coal-fired power plant | *Talen Energy*

PJM News

AES Indiana, where the utility is planning on switching two of the four coal units to natural gas, retiring the other two and installing an 800-MW battery.

"We have definitely seen examples of coal plant sites and interconnection rights being repurposed for varying forms of clean energy, also for natural gas, but it's essentially a way of seamlessly replacing the grid services provided by a retiring asset by something else. … Some of those examples are storage," Roberts told *RTO Insider*.

Roberts said that RTOs can be limited by a status-quo bias that pushes them to prefer solutions and resources that their staff have prior experience with.

"PJM doesn't see itself as being in the business of procuring generation, so in the example where an RMR could be avoided by the installation of wind or solar, for example, PJM just doesn't see that as a tool in their toolbox right now. They see their only tool as to procure transmission technologies ... or to pay the retiring generator to stick around for a few more years," she said, adding that other RTOs do have processes to procure the reliability services provided by thermal resources. She noted that the Maryland Public Service Commission had protested PJM's Grid Solutions Package filing, arguing that the RTO's proposed solution had not considered a state law requiring the development of 3 GW of storage in the state, which the PSC argued provided an opportunity for PJM to work with the state to find alternatives (*ER23-2612*).

Tori Leonard, spokesperson for the PSC, said the commission appreciates the study and understands that PJM will be providing a full assessment of its findings.

To conduct the study, GridLab and Telos consulted with PJM to perform their own reliability analysis, confirming that the deactivation of Brandon Shores without any modifications to the grid would result in reliability violations. The most severe line overloads were found under summer peak load conditions with an unplanned outage occurring during a maintenance outage — an N-1-1 scenario.

The worst voltage collapse contingency was seen during an extended winter peak with high generation or transmission outages, such as the December 2022 Winter Storm Elliott. Baker said that the modeling showed that if the summer violations were resolved, winter needs would also be met.

In an *announcement* of the analysis, the Sierra Club argued that storage combined with the line reconductoring identified could not only meet the needs until the Grid Solutions Package's completion, but that the battery's characteristics could bring added reliability over the retiring coal generator.

"The battery storage solution can also be more reliable than the coal solution, since batteries can start up and inject power far more quickly than a coal plant. Many reliability events arise on short notice due to unexpected outages of other power facilities, so the quick response of the battery could make all the difference in keeping the lights on," the announcement said.

"Unfortunately, PJM lacks a framework to evaluate alternatives like this to RMR agreements. Instead of clearly defining the reliability need and seeking the most cost-effective solution, PJM assumes only the retiring generator can provide reliability, and will pay whatever it takes to keep them online ... PJM's approach reflects a missed opportunity to uphold its responsibility to ensure bulk power system reliability while also supporting state clean energy policies." ■

PJM News

FERC Rejects Complaints from IMM, W.Va. PSC Arguing for Access to PJM Liaison Committee

By Devin Leith-Yessian

FERC has denied a pair of complaints against PJM from the Public Service Commission of West Virginia and the RTO's Independent Market Monitor arguing that denying them access to the RTO's Liaison Committee violates its governing documents and FERC orders on transparency and board independence (*EL23-45*, *EL23-50*).

The PSC complaint, filed March 8, 2023, argued that language in PJM's Operating Agreement (OA) detailing the structure of standing committees includes the LC and mandates that nonvoting ex officio members, such as state utility commissions, be permitted to attend. Excluding them from the room while representatives of the five PJM member sectors meet with the RTO's Board of Managers prevents PSC staff from fully understanding PJM's decision-making process and may enable FERC-regulated utilities to advocate for market rules that are not in the state's interest before the board, the regulator argued. (See *W.Va. PSC Files Complaint over PJM Meeting Policy*.)

The Monitor stated that the LC often discusses market issues that pertain to its monitoring role. Tariff Attachment M — which details the Monitor's role in PJM — grants it access to the full stakeholder process, including working group and committee meetings, when it "deems appropriate or necessary to perform its function." The Monitor's complaint was filed on March 24, 2023.

"Excluding the Market Monitor from stakeholder meetings compromises the ability of the Market Monitor to perform its function by depriving it of information exchanged in such meetings and the opportunity to state its independent views. The Market Monitor cannot effectively perform its function when it is excluded from stakeholder meetings. In addition, the Market Monitor has a direct interest in hearing communications and responding to communications from a member or members to the Board that concern the Market Monitor's performance of the market monitoring function and the terms and conditions of its retention by PJM," the Monitor's complaint said.

The commission's March 1 order rejected the Monitor's complaint, stating it had not demonstrated the LC is a part of the stakeholder process under Attachment M, nor established it is part of the Board of Managers' decision-making process requiring the Monitor's access. The order says the Monitor has sufficient access to the board through multiple stakeholder process meetings and direct meetings with the board that are closed to stakeholders.

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

The Organization of PJM States Inc. (OPSI) submitted comments supporting the Monitor's complaint, saying state regulators rely on the Monitor's analysis when considering the effects RTO decisions could have on their rates. By preventing the Monitor from participating in the LC —which it argued is among the most important committees where stakeholders meet with PJM's Board of Managers — OPSI said the Monitor's ability to provide state utility commissions with fully informed opinions is inhibited.

State commissions, FERC staff, the Monitor and OPSI had been permitted to attend the LC until September 2018, when the Members Committee voted to enforce a provision of the LC's charter limiting attendance to PJM members and its board. (See *PJM Stakeholders Table WVa PSC Attendance at Liaison Committee*.)

In rejecting the West Virginia complaint, the commission cited PJM's argument that the LC is not a standing committee under the OA but instead was formed through a joint effort of the Board of Managers and MC, putting it outside the stakeholder process and not mandating the attendance of state commissions or the Monitor. FERC also said state commissions have adequate access to the board through meetings with PJM through OPSI and at stakeholder meetings with board participation, such as the Members Committee.

Responding to the PSC's complaint, PJM compared the LC's formation to the memorandum of understanding signed with OPSI to hold regular meetings with the Board of Managers without the participation of other stakeholders.

Transmission owners and the PJM Power Providers (P3) Group argued that keeping the committee closed is appropriate to allow market participants to have candid conversations with the Board of Managers, while the West Virginia commission argued it violates

PJM News

the transparency and board independence provisions of FERC Orders 2000 and 719. The Monitor argued that positions made by PJM members before the board should stand regardless of who is in attendance.

P3 also argued that allowing the participation of consumer advocates, who are ex officio members with voting rights at the Members Committee, but not state committees, is appropriate because the LC provides an opportunity for voting members to express their views on issues they may be voting on before the board.

Christie Dissents

Commissioner Mark Christie dissented from the order's rejection of the Monitor's complaint, arguing that the majority had focused too much on Attachment M and not considered its relation to the Monitor's role in PJM, causing it to "miss the forest for the trees." He argued that even if no votes are taken at the LC, meeting to express views on issues faced by PJM and its members is one in a series of actions that culminates in board decisions.

Christie concurred with the order's stance on the West Virginia complaint and stated he believes the result is correct but cannot join in the reasons the order gave.

He argued that whether the Monitor has sufficient access to the board was not at issue in the complaint, but rather whether the Monitor was justified in believing that issues raised at the LC are pertinent to the Monitor's functioning. Christie also said state regulators often are reliant on the Monitor's analysis and understanding of PJM's markets and proposed changes.

"The IMM is given very specific and vitally important duties, both in Order No. 719, which devotes an entire section to the importance of independent market monitoring in all RTOs, as well as, more specifically, in PJM's specific [Open Access Transmission Tariff] Attachment M. If attending these meetings is 'necessary or appropriate' to the IMM doing its job, then the IMM should be allowed to make that decision," Christie wrote.

On the PSC West Virginia complaint, Christie said he believes the state commission failed to meet the burden of proof to file the complaint, but stated he believes there's a larger issue of states not having adequate influence at RTOs when wholesale market or transmission changes can directly affect consumer rates.

"There exists a much broader issue concerning RTO governance and decision-making that deserves attention, however, that unfortunately is not teed up in this proceeding, which I regard sadly as a missed opportunity ... that broader issue is the very real and compelling need to redefine and elevate the roles and authorities of state regulators in all RTOs. State regulators regulate the retail rates paid by consumers, the rates that actually determine the monthly power bills that consumers must pay," Christie wrote.

He described the order's consideration of whether the LC is a standing committee as "'how many angels can dance on the head of a pin, legalistic hairsplitting," but stated he does not believe granting state commissions access to the LC would have done much to advance their standing at RTOs even if the complaint had been granted. ■

SPP News

SPP: Integrated Marketplace Yields $10.2B in Savings

SPP marked the 10th anniversary of its day-ahead, real-time Integrated Marketplace by saying it has provided more than $10.2 billion in savings to members since its launch in 2014.

The grid operator *said* the market's value "far surpassed" initial expectations, noting initial studies projected the marketplace would deliver up to $100 million in annual benefits to its 14-state footprint. In its first year, the market delivered $380 million in net savings, and in just four months, it covered its development costs, SPP said.

In 2023 alone, the Integrated Marketplace provided the RTO's members with $2.25 billion in savings, the grid operator said.

The Integrated Marketplace replaced SPP's seven-year-old energy imbalance market. It combined SPP's 16 legacy balancing authorities into a consolidated BA and added congestion-hedging components. The market became financially binding for its initial 103 participants at 12:05 a.m. March 1, 2014.

"The Integrated Marketplace is an important tool in SPP's toolbelt," CEO Barbara Sugg said. "It allows us to provide low-cost, reliable generation and additional economic benefits to the region."

The market also was expected to facilitate the further integration of renewable resources in SPP's region.

SPP says its Integrated Marketplace has provided $10.2 billion in savings since 2014. | *WER Architects-Planners*

Heading into last summer, the RTO had 32.22 GW of nameplate wind capacity, but only 1.4 GW of solar capacity. However, SPP's *interconnection queue* includes 37.51 GW and 24.29 GW of solar and wind projects, respectively, and an additional 20.98 GW of energy storage projects. ■

— Tom Kleckner

National/Federal news from our other channels

Whitehouse: Best Defense for IRA is Funding, Building More Projects — NetZero Insider

EPA Tackles Port Pollution With $3B in IRA Funds — NetZero Insider

DOE Announces $366M for Rural, Tribal Clean Energy Projects — NetZero Insider

Utilities Facing Increased Scrutiny over Political Activities — NetZero Insider

ACORE Panel: IRA Is Safe, but Trump Could Decimate DOE — NetZero Insider

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SPP News

'Bigger Stuff' is Coming for SPP's REAL Team

Staff, Stakeholders Deepen Their Knowledge of Resource Adequacy

By Tom Kleckner

DFW AIRPORT, Texas — SPP's Resource and Energy Leadership (REAL) Team last week marked the one-year anniversary of its formation with yet another discussion of resource adequacy issues and the various metrics used to determine a reliability standard.

But not to worry. Major developments are on the horizon.

"The bigger stuff is coming later," said SPP's Casey Cathey, senior director of grid asset utilization, following the Feb. 21 meeting.

That would be the winter planning resource margin (PRM) and a reliability standard based on expected unserved energy (EUE). However, it may take time.

"I think we need some time to bake in more of an understanding about the interrelationship between EUE and the fuel mix, as well as the load changes," Cathey said. "We do need to work towards an accelerated standard, but we've never enforced an EUE limit before. It's always been PRM. As we're continually seeing the fuel mix change and the loads are also under a lot of scrutiny, with more resources that are underperforming and more extreme events, I think the fear is to put a standard without it being potentially well thought out could be extremely costly."

To ease that fear, the REAL Team contracted last year with firms 1898 & Co. and Astrape Consulting to conduct a future resource mix study. The study focused on five- and 10-year projections for PRM and renewable resources' effective load-carrying capability values as providing better forward-looking information than the standard loss-of-load expectation (LOLE) studies.

It also considered EUE as a new metric, given resource adequacy's shift from "capacity adequacy" to "energy adequacy." SPP staff said they have found a divergence in EUE and LOLE as the system evolves more toward an "energy-limited" resource portfolio.

The *study* found the existing 0.1 LOLE reliability target continues to contribute to an increased EUE and "unacceptable reliability" and that as renewable capacity increases, the winter season becomes dominant. Implementing reliability metrics separated by season helps meet the annual LOLE/EUE target, it said. found the existing 0.1 LOLE reliability target continues to contribute to an increased EUE and "unacceptable reliability" and that as renewable capacity increases, the winter season becomes dominant. Implementing reliability metrics separated by season helps meet the annual LOLE/EUE target, it said.

SPP's Casey Cathey, monitoring a recent REAL Team meeting, says SPP needs more time to fully understand expected unserved energy. | © *RTO Insider LLC*

However, the study found a last-in allocation methodology "may allocate more accreditation than appropriate to certain technology types due to synergies between resources. It said more studies are required to confirm the appropriate level of a normalized EUE as a reliability standard.

Brian Despard, 1898 & Co. | © *RTO Insider LLC*

"We have a natural breakdown that winter events are longer, deeper and they have more amounts of energy per event than you do in the summer," 1898's Brian Despard said. "If you add more renewables, you're shifting from summer events to winter events and there's naturally more unserved energy in the winter. So, we have to install a standard that says, 'Let's keep unserved energy the same instead of keeping the number of events the same.' We're going to have a secondary and complementary requirement that says, 'I will get a credit for the ability to maintain those standards as well.'"

The REAL Team will continue its discussion of the PRM and EUE metric when it gathers at SPP's headquarters in Little Rock, Ark, March 22.

"That's March Madness," said Kristie Fiegen, chair of both the REAL Team and the South Dakota Public Utilities Commission and an apparent fan of college basketball's annual postseason tournament.

Still, the meeting will go on.

"More education is needed across the board for members, for the Regional State Committee, for REAL," Cathey said.

The REAL Team reports to the RSC, which is composed of SPP state regulators. Also, it is working in tandem with the Supply Adequacy Working Group (SAWG) and the RSC's Cost Allocation Working Team.

SPP News

"We're kind of working to educate on the EUE, but to also help that education form how we might best establish our very first separate winter planning reserve margin," Cathey said. "Even though we don't have a standard — and this is what's a little bit confusing — we still understand that we shouldn't just let EUE be this massive number. We have to use the data from the loss-of-load expectation study to best inform how we balance the risk between winter and summer for upcoming 2026 binding season."

The REAL Team directed SAWG to consider EUE associated with an LOLE metric to determine winter and summer PRMs, recommend an EUE standard, and place the expectation of that effect on the 2025 LOLE study.

Evergy's Colton Kennedy, SAWG's chair, agreed that more education and analysis is needed.

"There's a separate conversation around what [we] are establishing as a region for an EUE standard. I think honestly, we don't need that to set the PRM, to recommend PRM," he said. "I think we know that there are gaps. We know that the EUE is something that needs to be incorporated into the target. I don't think we have enough information to say this is the appropriate risk tolerance for this region."

Separately, the team approved a tariff change (*RR605*) intended to clarify resource availability expectations for both the summer and winter seasons. The measure adds a definition of authorized outages and more requirements for availability during the two seasons when not on an authorized outage, and it clarifies when load-responsible entities and generation owners should submit resource adequacy capacity to meet their requirements.

"It's not the most complicated policy, but it's fairly important. If we didn't do it, we will be shooting ourselves in the foot," Cathey said.

The revision's language is seen as meeting FERC's expectation that SPP consider expedited proceedings for any future filings on the winter season RA requirement. The commission in November rejected the grid operator's first attempt at a winter resource adequacy requirement; the RTO plans to refile the requirement, nonbinding until the 2026-27 winter, in April. (See "FERC Rejects Winter Requirement," *'Therapy Session': SPP REAL Team Reviews Draft LOLE Study*.)

The REAL Team also endorsed a pair of initiatives by staff and stakeholders:

- The Market Working Group's development of potential availability market constructs and other incentive-based mechanisms. The MWG explored five options before determining that, based on staff's evaluation, a performance credit mechanism (PCM) similar to ERCOT's and an energy availability market would provide the largest economic and reliability benefits. The group is monitoring ERCOT's PCM development process and will reevaluate the need for additional mechanisms once resource adequacy policies are implemented and evaluated.
- Staff's pursuit of a price-formation policy that dispatches the system based on the true obligation and prices the system during a scarcity event using the obligation without the effect of load shed and emergency energy assistance. Staff plans to secure approval from stakeholders, regulators and the board in April and May, and then take the revision request to the same bodies in July and August. ■

SPP News

IMIP Sends Markets+ Tariff on to SPP Board

By Tom Kleckner

The panel of independent directors overseeing SPP Markets+'s development in the Western Interconnection lent its approval to the market's *draft tariff* March 1, the culmination of months of drafting and refinement.

The tariff still must be approved by SPP's Board of Directors before it can be filed with FERC by the end of the month. The board will hold a webinar March 25 to review the tariff.

"Moments like this, sometimes they can be understated. This is really a momentous occasion," Steve Wright, chair of the Interim Markets+ Independent Panel (IMIP), said during the virtual meeting March 1. "This is a huge project that has significant implications for how the West will operate over the coming years. It shows an incredible amount of dedication and commitment on the part of the various market participants to be able to move this forward and get to this point."

To move forward, though, the IMIP agreed to temporarily pull language specific to Western Area Power Administration's *Desert Southwest Region* (WAPA-DSW), which produces hydro power for customers in Arizona, southern California and southern Nevada.

Antoine Lucas, SPP's vice president of markets, told the IMIP that staff received a letter from WAPA-DSW on the morning of March 1 that asserted the federal agency's intention to terminate its Markets+ Phase 1 funding agreement.

"There are certain special provisions included in the Markets+ draft tariff that are only included in the tariff specifically for WAPA, given their status as a federal entity," Lucas said. "The special provisions included in the tariff on behalf of WAPA-DSW are very much contained into very specific, discrete areas of the tariff. We do not think they will impact any other aspects of the tariff."

IMIP chair Steve Wright calls the tariff's completion a "momentous occasion." | © *RTO Insider LLC*

Working in real time, staff and stakeholders agreed to set the language — found in Article 2, Section 6.4 — aside for the time being.

The section's language will have to be deleted before the tariff is filed with FERC to ensure its approval, Lucas said. The Markets+ legal subgroup will review the WAPA language and provide a recommendation on its inclusion.

Lucas declined to give reasons for WAPA-DSW's withdrawal from Markets+'s first phase of development and whether it eventually would join the market. He said his interpretation of the letter was that it is a "formal request" to terminate the agreement.

SPP attorney Chris Nolen said the Markets+ participation agreement anticipated a participant terminating their agreement and then joining the market after it goes live. It includes provisions that ensure participants who chose that route still would have to pay what would have been their share of Markets+'s costs.

"We've crafted that agreement so that we would avoid the potentiality that some parties might not want to take the risk of a substantial time pending at FERC," Nolen said, noting the market's $500,000 monthly run rate.

"The agreement was crafted where if someone leaves before Phase 2, not only do they have to pay their fair share when they come back in, they don't get any credit for what they paid in Phase 1," Nolen added. "That just goes to the market bucket to offset the cost of Markets+, so there was a disincentive built into the Phase 1 funding agreement."

The IMIP easily approved several other pieces of tariff language, including greenhouse gas settlement and substantive and non-substantive items.

"We're looking at a pretty good pathway to getting this filed by the end of March," said The Energy Authority's Laura Trolese, chair of the stakeholder-driven Markets+ Participant Executive Committee. ■

Company News

Interim CEO Fowke Explains AEP Leadership Change

Sloat out After 14 Months in Company's Top Spot

By Tom Kleckner

Julie Sloat | © *RTO Insider LLC*

American Electric Power's leadership on Feb. 27 added further color to its board's decision the day before to *remove Julie Sloat as CEO* and replace her with former Xcel Energy CEO Ben Fowke on an interim basis.

Ben Fowke has stepped in to serve as AEP's interim CEO. | *AEP*

In his scripted remarks to financial analysts during the company's quarterly conference call, Fowke said the decision was not an easy one, but "in the best interest of AEP and its stakeholders to do so."

Fowke and other AEP executives appeared to indicate they were unhappy with several regulatory outcomes. They pointed to the disallowance of recovering some deferred fuel costs in West Virginia and the probable disallowance of certain capitalized costs associated with a Louisiana power plant as a hit to earnings.

One analyst pressed Fowke over the *earnings presentation's* "leaning" on AEP's successes and growth rate capital expenditure numbers ($43 billion over five years). "What do you see is broken?" the analyst asked.

"I don't think I would use the word 'broken.' I think there's areas where we can do better," Fowke said. "We also recognize that we can do better on getting constructive regulatory outcomes. So strategically, our priorities remain the same. We're going to look at the people, the process and the planning that goes into that those constructive outcomes, and we're going to do it through the lens of what's important to our local leaders and stakeholders ... and then you get into that virtuous circle where invested capital now is good for customers in the community."

Fowke said more than once that the leadership decision was made by the full board. "You need the full board to make a decision to remove the CEO," he said.

AEP recently *increased the board's size* by adding two directors after entering into an agreement with activist investor Icahn Capital. The board also invited Icahn to place a portfolio manager as a nonvoting observer during its meetings.

"The additional board members came after discussions with the Icahn team and AEP team," Fowke said. "We actually welcome their perspective. They share the opinion, as we do, that AEP shares are undervalued, and we want to work together to unleash shareholder value."

In the Feb. 26 *press release* announcing the leadership change, AEP said the board had determined after discussions with Sloat that it was "time to identify a new CEO to lead the company's next chapter." The company said the decision was not a result of any disagreement with Sloat over AEP's operations, policies or financial performance and "was not made for cause or related to any ethical or compliance concern."

AEP will conduct an external search for its next CEO. Fowke said AEP will be an "attractive destination" and that he expects the candidate list to be a long one.

"I think it's going to be great to pick from that talent. Ideally, you get somebody that is a seasoned executive in the utility industry and is well known in the investor community," he said, adding that it would be ideal if the next CEO has multijurisdictional experience.

Fowke retired from Xcel in August 2021 after more than a decade as its CEO. He joined the AEP board in February 2022.

Sloat, a 23-year AEP veteran, replaced Nick Akins as CEO in January 2023.

The company *reported* year-end earnings of $2.21 billion ($4.26/share), a drop from 2022's performance of $2.31 billion ($4.51/share). Fourth-quarter earnings were also down, at $336.2 million ($0.64/share), a drop from the same quarter the year prior of $384.3 million ($0.75/share).

After saying in its earnings announcement that it made "positive progress" toward the $9.4 billion in regulated renewables in its five-year capital forecast, AEP issued another *release* about the sale of its 50% interest in New Mexico Renewable Development's solar assets. The transaction will net the company about $104 million in cash after tax, transaction fees and other adjustments.

The company's share price closed at $80.77 on Feb. 26 but shot up to $83.39 in after-hours trading following the CEO change's announcement.

It closed at $84.07 on Feb. 27, a 4.1% gain on the day. ■

Company News

Constellation Reports Strong Financials, Bright Nuclear Future

CEO Says Nation's Largest Emissions-free Fleet Important to Energy Transition

By John Cropley

Constellation Energy Corp. is setting high financial goals for the rest of the decade, confident its mix of clean and reliable energy generation gives it an excellent market position amid renewed support for nuclear power.

The *company reported* strong 2023 financial results Feb. 27 and investors liked what they heard — its stock price closed 16.9% higher in heavy trading.

CEO Joe Dominguez focused heavily on Constellation's nuclear fleet in a conference call with financial analysts.

Constellation *also operates* oil, gas, solar, wind and hydroelectric generation, but nuclear accounts for 60% of its installed capacity and 86% of its output — without emitting any zero greenhouse gases in the process.

Nuclear has the highest capacity factor of any power generation, Dominguez said, and Constellation has not only the largest but the best-performing nuclear portfolio in the nation, operating at a capacity factor of 94.6%.

This puts Constellation in an excellent position at a time of growing demand for electricity and a soaring desire for clean electricity. Combined with the nuclear production tax credit contained in the IRA, he said, Constellation can confidently predict consistent earnings growth for years to come.

"In the changing power markets, we provide something that I think others struggle to do, and that's carbon-free energy and reliability together," Dominguez said. "We think that's going to be the bedrock of the future for the country."

Part of this speaks to the intermittent nature of solar and wind compared with the fossil fuel generation they are replacing.

Constellation's commercial-industrial customers are committed to renewables, Dominguez said, but they need power around the clock. Nuclear is a nonfossil resource dispatchable at scale when the sun does not shine or the wind does not blow.

Just in the PJM system, he said, the day-to-day swing in renewable generation can equal the output of five nuclear plants.

Dominguez noted another key factor in Constellation's favor: growing bipartisan policy support for nuclear power, a longtime pariah for many on the left and some on the right because of its cost and the risks of radioactivity.

"Years ago, we couldn't get customers to look at nuclear, regardless of its economics, its reliability or its environmental benefits, but that's changed," he said. "Once customers see what we can do from affordability and time-match perspective, they like it."

Constellation said it holds a 21% share of the U.S. competitive commercial/industrial market, the most of any operator.

Which is not to say nuclear power is without problems.

The *first commercial reactors* built from scratch in the United States in decades — at Plant Vogtle in Georgia — are by some estimates the most expensive power generation ever built, coming online years behind schedule and many billions of dollars over budget.

Dominguez said this only makes a stronger *business case* for an existing fleet of well-run reactors.

"Our assets are the best in the world, run by the best people. This company can't be replaced — there's simply not enough nuclear out there to replace it. And we all know, from having seen Vogtle, what the cost of new nuclear is."

In February, Constellation asked the Nuclear Regulatory Commission to *extend its license* for the Clinton Power Station in Illinois from 2027 to 2047.

The 1.08-GW plant came online in 1987. Actually running it until 2047 would depend on market and/or policy support, Constellation said when it announced the decision Feb. 15.

But Dominguez said Feb. 27 that age is not an issue — most of the fleet could run at least 40 more years. "I say 'at least' because we believe that some of our plants could actually run to a hundred years — much longer than existing wind and solar operating today and also longer than all the renewables that are being built right now."

In mid-2023, Constellation twice raised the earnings guidance it offered financial analysts. The year-end results released Feb. 27 were higher yet.

Constellation reported 2023 GAAP net income of $1.62 billion, which compares with a 2022 loss of $160 million. It had a fourth-quarter 2023 loss of $36 million, compared with income of $34 million in the same period a year earlier.

Its market capitalization has been increasing steadily since Exelon completed its spin-off of Constellation. The share price is 194% higher than when it began trading in February 2022. ■

Constellation's nuclear power plant in Clinton, Ill., is shown. The company on Feb. 27 reported strong 2023 earnings and projected strong growth in large part due to its nuclear fleet. | *Constellation Energy*

Company Briefs

Former FERC Chair, Commissioner Danly Rejoins Skadden

Skadden on Feb. 13 announced that **James Danly**, former commissioner, chair and general counsel of FERC, has rejoined the firm as a partner and head of its Energy Regulatory Group.

Danly was an associate at Skadden prior to joining FERC in 2017.

More: *Skadden*

NAESB Advisory Council Names New Chair

The North American Energy Standards Board (NAESB) Advisory Council on Feb. 26 elected interim chair Timothy Alan Simon the next chair.

Simon has served as a council member since 2013 and vice chair of the group since July. He replaces Bruce Ellsworth, who passed away last fall.

More: *NAESB*

LG Chem, GM Sign Battery Material Deal

South Korean battery maker LG Chem and General Motors have announced a deal to source EV battery material.

GM plans to spend nearly $19 billion over the next 10 years sourcing EV battery material from LG Chem, while Chem will supply GM with more than 500,000 tons of cathode materials through 2035.

More: *WKRN*

Apple Cancels Electric Car Project

Apple has reportedly ended its plans of building a self-driving electric car.

Apple executives on Feb. 27 informed teams working on the vehicle, called Project Titan, that hundreds of employees who worked on the car will be shifted to divisions working on artificial intelligence, according to reports. Others are expected to be laid off.

Apple declined to comment.

More: *NPR*

Ford EV Owners Can Now Charge on Tesla's Network

Owners of Ford EVs can now use much of Tesla's charging network in the U.S. and Canada but will need to get an adapter that Ford will provide for free in April.

Tesla has more than 26,000 plugs and nearly 2,400 Supercharger stations across the U.S. and Canada. Ford said its owners will have access to about 15,000 fast-charging plugs that are located along travel corridors but won't be able to use some older Tesla plugs.

Ford is offering the adapters for free to the owners, who can sign up on Ford's website to reserve them until June 30. The company will provide one free adapter per vehicle.

More: *The Associated Press*

Sunflower Electric Power Corp. Selects President, CEO

The Sunflower Electric Power Corp. Board of Directors on Feb. 28 selected Steve Epperson as its president and CEO, effective immediately.

Epperson has been interim president and CEO since July. Previously, he been CEO of Pioneer Electric Cooperative and Southern Pioneer Electric Company — two of Sunflower's seven distribution member-owners — since 2011.

More: *Sunflower Electric Power Corp.*

Federal Briefs

House Approves Bipartisan Bill Aimed at Bolstering Nuclear Energy

The House on Feb. 28 voted 365-36 to approve bipartisan legislation that aims to bolster nuclear energy production by speeding up environmental reviews for new nuclear reactors and reducing fees for advanced nuclear reactor licenses. It would also extend a law that limits the industry's legal liability for nuclear accidents by 40 years.

While it has bipartisan support in the House, it's unclear whether the bill will advance as is, since the Senate has its own nuclear energy bill.

More: *The Hill*

BLM Approves Alta Wind Battery Energy Storage Project in California

The Bureau of Land Management on Feb. 29 approved the Alta Wind Battery Energy Storage System in Kern County, Calif.

The project is designed to deliver 150 MW to CAISO, store up to 1,200 MWh, and increase the reliability and availability of clean power produced by the existing Alta Wind Energy Center.

More: *Bureau of Land Management*

Analysis: Solar Program Poised to Help 700k Low-income Households

Solar for All, an Inflation Reduction Act program, is poised to benefit more than 700,000 low-income households across the nation, according to analysis from nonprofit Clean Energy States Alliance.

Solar for All is a competitive grant program created under the IRA's $27 billion Greenhouse Gas Reduction Fund. Administered by EPA, Solar for All aims to deliver the savings, resiliency and health benefits of small-scale solar and solar-plus-storage systems to low-income households and households in disadvantaged communities. EPA plans to announce up to 60 awards in March to support Solar for All programs.

More: *Canary Media*

State Briefs

CALIFORNIA

Palo Alto Stops Enforcing All-electric Building Requirement

The Palo Alto City Council on Feb. 26 unanimously agreed to stop enforcing its ban on new gas infrastructure. The council made the decision to comply with a recent decision by the Ninth Circuit Board of Appeals, as the court last year struck down a similar prohibition on gas infrastructure in Berkeley.

Even though the new code will strongly encourage the adoption of electric water- and space-heating appliances, builders will have more flexibility when it comes to installation of gas stoves and outdoor equipment.

More: *Palo Alto Online*

SCE to Settle Claims from 2017 Thomas Fire

Southern California Edison will pay $80 million to settle claims on behalf of the U.S. Forest Service connected to the 2017 Thomas fire that destroyed more than a thousand structures.

The utility agreed to the settlement without admitting wrongdoing or fault in connection with the fire, the U.S. Attorney's Office said.

Investigations found utility equipment sparked the fire in two canyon locations on Dec. 4, 2017. The fire burned 439 square miles in Ventura and Santa Barbara counties.

More: *The Associated Press*

COLORADO

Bill Seeks to Cut Industrial Emissions, Expand AQCC

Legislation filed Feb. 28 calls for significant revisions to new rules meant to cut greenhouse emissions from large industrial sites and would force regulators to scrap a provision allowing companies to meet the requirements by paying into a state-managed fund.

The proposal would also expand the Air Quality Control Commission, which finalized and approved the new rules in September. The legislation would require the governor to appoint a climate scientist and a resident of a heavily polluted area as commissioners to the eight-member panel.

The House Energy and Environment Committee will take up the legislation.

More: *Colorado Public Radio*

ILLINOIS

ComEd Bribery Sentencings Postponed; SCOTUS Reviews Indiana Case

U.S. District Judge Harry Leinenweber on Feb. 29 agreed to postpone the sentencings of four people convicted last year for bribing former Illinois House Speaker Michael Madigan until after the U.S. Supreme Court rules on an Indiana corruption case.

The decision from Leinenweber is in line with the call made earlier this year by U.S. District Judge John Blakey, who agreed to delay Madigan's trial until October for the same reason. The Supreme Court is reviewing the corruption conviction of James Snyder, a former mayor of Portage, Ind. His case revolves around a bribery statute dealing with programs receiving federal funds. Madigan and the ComEd defendants were also charged under that statute. The question before the court is whether that statute criminalizes gratuities without any quid pro quo agreement.

The Supreme Court is expected to hear arguments in the Snyder case April 15 and rule by summer.

More: *Chicago Sun-Times*

MICHIGAN

PSC Approves Consumers Energy Rate Hike

The Public Service Commission on March 1 approved a $92 million rate increase for Consumers Energy.

The new rate will result in a $1.53 monthly increase for residential customers, effective March 15.

Consumers Energy said the increase will cover investments in generation and distribution assets, safety and legal compliance, and enhanced technology, as well as rising operations and maintenance expenses and higher financing costs.

More: *The Detroit News*

Trenton Channel Power Plant Demo Date Postponed

Demolition of the old Trenton Channel power plant smokestacks, which DTE Energy said had been planned for March 1, has been delayed until later this month.

The company had said that the March 1 target was tentative, but decided to change the date, a calculation spokesperson Cindy Hecht said was based on various factors. A new date has not been set.

The nearly 100-year-old coal-fired facility has been idled since 2022. It is slated to be redeveloped with a second phase of demolition set for May 17, which also may change, depending on weather and other conditions.

More: *Detroit Free Press*

NEVADA

Consumers to Foot Bill for NV Energy's Over-budget $2.9B Tx Project

In testimony filed with the Public Utilities Commission on Feb. 27, NV Energy disclosed that Greenlink Nevada's expected costs, as of July, have risen from about $2.5 billion to $2.9 billion and that most of the costs are likely to be covered by NV Energy's customers. It is a 17.8% increase from Greenlink's initial price tag.

According to a company spokesperson, the increase in costs is based on the economic fallout and impact of the COVID-19 pandemic on construction. The costs will be split between NV Energy's wholesale transmission customers and its two state customer bases.

More: *Las Vegas Review-Journal*

NEW YORK

AG Files Suit Against Meat Producer over Misleading Climate Claims

Attorney General Letitia James on Feb. 28 filed a lawsuit against meat producer JBS USA Food Co., accusing it of making misleading claims about its greenhouse gas emission goals to boost sales among environmentally conscious consumers.

The lawsuit alleges the company claimed it will achieve net zero greenhouse gas emis-

sions by 2040 despite having no viable plan to meet that goal. James is asking a court to require JBS to end its "Net Zero by 2040" campaign and to return profits "traceable to its fraudulent, deceptive or illegal acts or practices." The suit also seeks civil penalties of up to $5,000 per violation.

More: *The Associated Press*

OHIO

Former Speaker Householder Files Appeal

Former Ohio House Speaker Larry Householder on Feb. 26 filed an appeal against his guilty conviction and 20-year sentence by alleging the bribe he accepted, which he claims was not a bribe, was within his First Amendment rights.

In the 105-page document filed in the U.S. Court of Appeals for the Sixth Circuit, Householder's attorneys said he was "scapegoated" by the federal government. In March 2023, a jury found Householder and former GOP leader Matt Borges guilty for their respective roles in the scheme.

The U.S. Attorney's Office will issue its response against the appeal.

More: *WEWS*

SOUTH DAKOTA

Pipeline Bill Returns Rulemaking to Counties Unless PUC Objects

The House Commerce and Energy Committee on Feb. 26 voted 8-5 to update a carbon pipeline bill to have counties retain the rights to regulate pipeline setbacks, but allowed the Public Utilities Commission to overrule if counties' pipeline rules are too burdensome.

In its original form, the bill would have removed the right to require minimum setbacks between pipelines and property from counties altogether. The update, added to the bill on a 7-6 vote by the committee, returns the right to regulate setbacks to counties. A big addition is the word "must" to a section on the authority of the PUC, as in the past it has had the right to strike local pipeline regulations if they are deemed unreasonable. The amendment would take away their discretion. If the rules are "unreasonably restrictive in view of existing technology, factors of cost, or economics, or needs of parties," or if those rules are preempted by federal law, the commissioners would have to overrule the counties.

The bill then passed the full House on a 40-30 vote.

More: *South Dakota Searchlight*, *Sioux Falls Argus Leader*

VIRGINIA

Appalachian Power Seeks Approval for Battery Storage Project

Appalachian Power has filed with the State Corporation Commission seeking approval to build a battery storage system in Southwest Virginia to improve service reliability on what the utility says is one of its worst-performing circuits.

The $57.3 million project would create two battery storage sites totaling 7.5 MW. Appalachian said the circuit accumulated over 4.2 million customer minutes of interruption in 2022, making it one of the worst-performing distribution circuits in the company's system.

More: *Cardinal News*

WASHINGTON

Puget Sound Energy Proposes Rate Hikes to Pay for Hydro, Wind Power

Puget Sound Energy has proposed its two-year rate hike to the Utilities and Transportation Commission.

Under the proposal, the typical residential electricity customer would see a monthly bill increase of $7.84 (17%) starting in 2025 and an additional $11.20 (20%) in 2026. The typical natural gas customer would see a $13.96 increase in 2025 and $1.51 in 2026.

Puget said the increases are intended to pay for a variety of investments, including around $430 million in upgrades to its hydroelectricity dams on the Baker River and a $530 million wind farm in Montana.

More: *Seattle Times*

WEST VIRGINIA

Appalachian Power Seeks $37.2M Rate Increase

Appalachian Power and its partner, Wheeling Power, filed Feb. 29 for a $37 million rate increase with the Public Service Commission.

Appalachian said the money will help keep three coal-fired power plants running. It needs to add environmental protections at their Amos, Mountaineer and Mitchell plants and will help them meet EPA rules until 2040.

The PSC is expected to decide in the next few months.

More: *WVNews*