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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: From left: Milt Doumit, Washington UTC; Pam Sporborg, PGE; Evie Kahl, CalCCA at the spring CREPC-WIRAB conference in Denver on April 25. *(Page 12)* | *© RTO Insider LLC*

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Former FERC Chairs Debate Scripted Open Meetings

By James Downing

From left: former FERC Chairs Richard Glick, Neil Chatterjee, Cheryl LaFleur, James Danly and Norman Bay, and moderator Susan Bruce, of McNees Wallace & Nurick | © *RTO Insider LLC*

WASHINGTON — The federal *Government in the Sunshine Act* was passed to bring decision-making into public view, but when it comes to FERC, it does the opposite, a panel of former chairs said at the Energy Bar Association's Annual Meeting last week.

Some level of agreement is helpful when the commission acts, but it is more difficult to negotiate when the law, enacted in 1976, forbids more than two commissioners from meeting with each other outside of open meetings, said Cheryl LaFleur (2013-2015 and 2017), now chair of the ISO-NE Board of Directors. In any other job, you would gather the decision-makers together in one place and hash out a complex issue, she said.

But "you couldn't do that; you have to meet one on one with your commissioners," LaFleur said. "You couldn't meet as a group. And I always say FERC is not like the Beatles, [who] grow up playing music [together]. It is like the Monkees or the Spice Girls: five individuals chosen separately, and they say, 'Go make music.'"

FERC used to effectively work on its orders through discussion during the open meetings — and some state regulatory commissions still do that to an extent, like the Texas Public Utility Commission. But now the meetings are almost entirely choreographed, with even the questions commissioners ask staff and the answers written down ahead of time.

Whether it would be a good idea to go back to the old way split the panel.

"I'm all about it," said James Danly (2020-2021), now a partner at Skadden. "I love deliberating at the horseshoe; it's my favorite part of the job. ... So I can't speak to that other era; I wasn't there for it. I think it would be helpful to have more discussion. I certainly was always happy to do so."

"I think increasingly, as markets are focused on the commission, people are watching very closely, and we're talking about billions of dollars in investments that the commission is deciding upon at these meetings," said Neil Chatterjee (2017 and 2018-2020), now a senior adviser at Hogan Lovells. "And if I'm a general counsel; if I'm a CFO of a company; if I'm a lawyer in the Energy Bar, I very much prefer a boring, stable, staged commission meeting. A curveball could potentially roil markets."

When Chatterjee was on the commission, it voted on a case involving United Airlines and master-limited partnership taxation, which caused companies' share prices to crash in real time during an open meeting, he added.

Having a debate could work sometimes when it is an issue around reliability, or another issue where politics are not a major factor, LaFleur said.

"What I wouldn't want to see is just an opportunity for like political grandstanding, where you weren't really deciding at the table — you just were kind of making speeches — because I think that would be a step in the wrong direction," she said.

Actually writing complex orders line by line during an open meeting could easily get chaotic these days, said Richard Glick (2021-2023), principal and co-founder of GQ New Energy Strategies. While the overly scripted nature of the open meetings can get tiresome, going off script has its pitfalls as well, with Glick recalling one time he asked staff an impromptu question and the results were not great.

"I feel badly about it," he said. "But it's important to have real give-and-take, real questions, as opposed to everything written down in front of you on a piece of paper, and you just go by a script."

Norman Bay (2015-2017), now a partner at Willkie Farr & Gallagher, also was against the idea of going back to less scripted meetings, noting that it could give the wrong impression of FERC.

"I think members of the bar want to see a commission that is collegial, that is bipartisan and that works well together, right?" Bay said. "Recognizing that there are going to be times when there are sharp policy differences among the commissioners ... I fear that if you do everything publicly, it may send the wrong signal in a way that Neil mentioned. So, I think it's actually better that we have these very vigorous debates in the background."

All the commissioners agreed earlier in the panel that it is generally better for FERC to act as one, with Danly saying that is especially true for its more "legislative" powers like rulemakings. But politics can sow division on the regulatory body.

When he joined the commission after being an aide to Sen. Mitch McConnell (R-Ky.), Chatterjee admitted he was still acting like a political operator, especially on the Notice of Proposed Rulemaking that the Department of Energy issued early in the Trump administration that would have paid coal plants extra money and torpedoed years of FERC's work around markets. He wound up voting against that in the end, but some of his communications to the press were a little too political, he said. (See *DOE NOPR Rejected, 'Resilience' Debate Turns to RTOs, States*.)

But now that the rubber is hitting the road when it comes to decarbonization of the grid, the politics are heightened for reasons outside of any commissioner's background or personality, Chatterjee said.

"I think larger factors have come into play as questions around decarbonization bump up against reliability," he said. "It just made it harder and harder to compromise on some of these issues." ■

Energy Lawyers Debate the Impact of Losing Chevron Deference

By James Downing

WASHINGTON — With the Supreme Court likely to overturn *Chevron* deference, the general counsels of FERC and the U.S. Department of Energy told the Energy Bar Association last week they doubt it would lead to massive issues with their agencies.

Under the doctrine, stemming from the 1984 case *Chevron v. NRDC*, if a statute's meaning is unclear, and the agency's action administering the law was reasonable, courts should defer to the agency. (See *Supreme Court Hears Oral Arguments on Overturning Chevron*.)

Chevron makes sense as a legal doctrine and provides judges with an easy way of affirming an agency's decision-making when there is ambiguity in the law, FERC General Counsel Matthew Christiansen said at the EBA's Annual Meeting. But underlying those decisions is some basic common sense being applied by the judges.

"Because I think that *Chevron* is largely deployed as a way of providing a compelling path to affirm an agency action, I'm not convinced that the loss of *Chevron* in many cases, if that is indeed what happens, is going to lead to wildly different outcomes," Christiansen said. "I'm sure it's going to lead to different outcomes on the margins. But at the end of the day, I'm a big believer in agencies' ability to still put forth compelling justifications."

Chevron has provided a lot of value over the decades, but the politics around have reversed completely since it was first decided, DOE General Counsel Samuel Walsh noted. The late Justice Antonin Scalia, a textualist, was a big fan of the doctrine, and Justice Clarence Thomas authored the *Brand X* decision in 2005 that extended deference to the Federal Communications Commission and kept internet service providers from being regulated as common carriers.

"Some of the most important *Chevron* cases were cases where agencies were using the flexibility afforded by deference to regulate in a more light-handed way, or maybe not at all," Walsh said.

The biggest area where DOE might be affected by the change in precedent would be on its ability to set efficiency standards for electric appliances, he said.

"But to my knowledge, we've only been upheld at *Chevron* step 2 once," Walsh said; step 1 is deciding whether the law's intent is clear from the text. "We've done hundreds of rules over the last four decades, and I think we've only benefited from it in a clear and explicit way once."

DOE has benefited from the law more in its other functions such as litigation around nuclear waste storage in the 1990s and in litigation against the federal power marketing administrations it oversees. The law that governs sales from federal dams specifically calls "municipalities" preferred customers, so in the early 1990s, some "clever" city governments asked the Western Area Power Administration to sell them cheap electricity, Walsh said. WAPA argued that the term "municipalities" meant municipal utilities, and *Chevron* helped it carry the day in court.

From left: Harvard Law's Andrew Mergen, DOE General Counsel Samuel Walsh, FERC General Counsel Matthew Christiansen, Georgetown Law professor Victoria Nourse and Jenner & Block's Anand Viswanathan at EBA | *© RTO Insider LLC*

Based on how the oral arguments went and other cases before the court, Victoria Nourse, a professor at the Georgetown University Law Center, said she thought *Chevron* deference would be overturned, as would the *Skidmore* deference that was used before *Chevron* was decided. The 1944 decision held that courts should defer to agencies' interpretation of a statute as long as they essentially show their work.

"There were a lot of negative comments by Justice [Brett] Kavanaugh, who is very, very powerful and influential in statutory interpretation," Nourse said. "A lot of the disruption is going to come because there are also FERC and other agency models that they may not consider. They'll probably have a safety valve."

Hopefully, she added, that safety valve allows courts to give some credence to agency expertise on areas where engineers and scientists are bigger experts than lawyers ever could be.

"This is a court that is a full employment bill for lawyers … because your clients can now challenge regulations, not only because they don't meet the best interpretation; anything that ever relied on legislative history is a no-no up there, and if it was *Chevron*," Nourse said.

Several of the appeals circuits lean so far on one side of the political spectrum that litigants now regularly engage in "forum shopping" by picking the circuit where their arguments are most likely to win out, Walsh said. Losing *Chevron* would only exacerbate that trend.

While the combination of polarized courts and the lack of deference to agencies could create significant issues for some parts of the government, Christiansen downplayed the risks in the electric and natural gas markets. Many of the major regulations FERC has issued have vastly influenced the industries it oversees.

"Maybe I'm overly optimistic, too sanguine," Christiansen said. "I'm not terribly concerned those foundational precedents that I think are the bedrock for the way the industry operates now are at great risk." ■

EBA 2024 Annual Meeting

Overheard at the Energy Bar Association's 2024 Annual Meeting

WASHINGTON — The ongoing turnover of the generation fleet to cleaner resources, the recent return of demand growth and the need to stitch all that together with transmission expansion all came up at the Energy Bar Association's Annual Meeting last week.

"We're at a major inflection point in the development and maturation of the electric utility industry," MISO Assistant General Counsel Michael Kessler said. "And there are many factors that we are experiencing that are impacting almost all aspects of the industry."

Studies by MISO and others have found that the grid can be reliably operated with even higher levels of intermittent resources, but until new technologies are available, those renewables will need to be balanced with more traditional, dispatchable resources, he added.

"There's a lot of uncertainty going forward in kind of managing this transition," said Analysis Group Principal Todd Schatzki. "And in many cases, the speed at which things are happening is very uncertain. Some things [that] we think are going to happen very quickly are taking longer. And some things we don't anticipate are suddenly coming in very quickly. The whole data center issue, AI and how that's changing things, is a classic example of that."

While the system is changing and regulators and the industry are working to address that, there is still substantial uncertainty about the pace of change, Alliant Energy Executive Vice President Raja Sundararajan said. Electric vehicle demand was supposed to grow at a steady clip, but now it varies by region and is slowing down in some, he said.

"There's a natural skepticism: Are we going to overbuild?" Sundararajan said. "And if you're going to overbuild, then you have the affordability issue that comes into play, where the regulators are saying, 'Why should ... customers pay a portion of the cost for [a] new set of customers? And how do I transfer the risk between existing customers and the new customer?'"

Basic regulatory processes need to speed up, he added, citing transmission and developing integrated resource plans.

FERC has a major rule coming May 13 aimed at improving transmission planning and cost allocation. Commissioner Mark Christie is a key vote there, but he declined to wade into the debate when asked after his speech at the conference. But he did make clear that he continues to favor a strong role for the states and wants to make sure the changes do not impose unneeded costs on customers.

While states have to site transmission lines, they do not get to decide what consumers will pay for them because that falls under FERC's regulatory territory, he said.

"I'm very adamant that in any transmission planning that FERC is going to mandate, if you're going to put policy-oriented projects in there, the states have to have the ability to consent to it," Christie said. "So, we can restore the balance, which we have not had really for 20 years, where state regulators have the role that they should have in determining the transmission costs and how they get passed on to consumers."

Risks are inherent in long-term planning, but it is still work that needs to be done, said Grid Strategies President Rob Gramlich.

"A lot of people sort of end the conversation and say, 'Well, we might be wrong,'" Gramlich said. "Well, of course. Look at this great industry that is still a marvel of modern society that has been developed and that we all inherited, where we can flip the switch and get the lights on. That was all planned. Guess what? Planners in the '50s, '60s and '70s didn't know what to expect."

A lot of transmission was built just 10 years ago in 2013, when different efforts such as MISO's first Multi-Value Projects and the Competitive Renewable Energy Zone lines in Texas came to fruition. But since then, it has "slowed to a trickle," Gramlich said. "If you care a lot about the pace of climate action and greenhouse gas reductions — well, 80% of the most historic climate legislation ever will not be achieved without doubling the pace of transmission."

FERC's transmission rule is the culmination of years of work, which includes the Joint Task Force with states, said Karin Herzfeld, senior transmission counsel to Chair Willie Phillips.

"The NOPR was silent as to what happens when states cannot come to an agreement on the cost allocation for any particular project," Herzfeld said. "And I know there's some friction here, but the chairman, as a former state regulator, is focused on keeping states front and center on this important issue."

Another issue on FERC's plate is what to do about dynamic line ratings, on which it has an open Notice of Inquiry. On that front, Herzfeld told the EBA crowd to "stay tuned." ■

— James Downing

FERC Commissioner Mark Christie addresses the EBA Annual Meeting. | *© RTO Insider LLC*

FERC/Federal News

DOE CITAP Initiative Aims to Permit New Transmission in 2 Years

Granholm: Department to Become Anchor Off-taker for 285-mile Idaho-Nevada Line

By K Kaufmann

The Biden administration on April 25 rolled out a *new initiative* to cut permitting times for interstate and other major transmission projects to two years and announced up to $331 million in support for a 285-mile line that could bring wind energy from Idaho to Nevada and California.

Under the new *Coordinated Interagency Authorizations and Permits* (CITAP) program, the Department of Energy will take the lead on permitting transmission projects and coordinate environmental and permitting processes between federal agencies, Energy Secretary Jennifer Granholm said during an April 24 press briefing.

DOE's final rule establishing the CITAP also requires project developers to have comprehensive community participation plans in place before they start the permitting process.

Granholm called the initiative "a huge improvement from the status quo because developers routinely have to navigate several independent permitting processes throughout the federal government."

Granholm also announced that DOE will start negotiating an offtake contract to purchase up to $331 million in electric power capacity from the Southwest Intertie Project-North (SWIP-N), a 285-mile line that will bring wind energy from Idaho to Nevada and California.

The 2-GW, 500-kV project will provide bidirectional capacity, allowing California and Nevada to send solar and geothermal energy to the Pacific Northwest, according to a DOE fact sheet. The project "will increase grid resilience, especially during wildfires," Granholm said.

Both announcements reflect DOE's "holistic, multifaceted approach to grid improvements and to grid expansions," both of which will be needed to reach a new administration goal of upgrading 100,000 miles of U.S. transmission lines over the next five years, she said during the press briefing.

CITAP

The effort to streamline and speed up transmission permitting began in May 2023, when DOE and eight other federal agencies and councils signed a memorandum of understanding expediting what had become a tortuous process for transmission developers — and a

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major bottleneck for interconnecting wind and solar projects to the grid.

Granholm pegged the average permitting time for transmission projects at four years, with some projects taking more than a decade. The poster project for ridiculously long permitting times, Pattern Energy's SunZia transmission line, now under construction, took 17 years to permit. (See *SunZia Project Wins Final Approval, Signs Offtakers*.)

CITAP's two-year limit on permitting is also in line with the Fiscal Responsibility Act, passed in June 2023, which mandated a two-year cap for environmental reviews required for any energy project on federal land under the National Environmental Policy Act (NEPA).

The CITAP program is targeted at "regionally or nationally significant transmission lines" of 230 kV or higher that cross state lines and are expected to require an environmental impact statement, according to DOE. Projects may also be eligible if they are approved by the director of DOE's Grid Deployment Office, are entirely located in ERCOT or are seeking a construction permit from FERC under specific provisions of the Federal Power Act.

One of the main features of the new program is "an interagency preapplication process to ensure that developer submissions for federal authorizations are ready for review on binding two-year timelines without compromising critical [NEPA] requirements," according to a DOE press release. The goal is for developers to collect all documentation needed for federal permitting before submitting applications.

The development of a community participation plan for each CITAP project as part of the preapplication process is intended to ensure "meaningful engagement with tribes, states, local communities and other stakeholders," according to DOE.

The department will coordinate with all relevant federal agencies to produce a single NEPA review to reduce duplication of efforts. The CITAP program will be open to state permitting authorities, which will be able to use final NEPA reviews in their own decision-making processes.

FERC/Federal News

However, CITAP will not affect state permitting authorities, according to a senior administration official speaking on background.

Coordination between agencies and developers will be handled via an online portal, where developers will be able to upload required documentation and other information. Federal agencies will then be able to review those submissions and provide feedback if changes or further information is needed.

"If you're a grid wonk, CITAP is the coolest thing since sliced bread," National Climate Advisor Ali Zaidi said during the press briefing. "What Secretary Granholm has done here is a very path-breaking and inventive approach to getting the grid built out at the speed and scale we need."

Southwest Intertie

SWIP-N will be the fourth project DOE has supported through its Transmission Facilitation Program (TFP), launched in October 2023.

At the time, DOE announced it would be investing $1.5 billion in federal funds to become an anchor off-taker for three interstate transmission projects that together could add 3.5 GW of capacity to the grid. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

Authorized in the Infrastructure Investment and Jobs Act, the TFP has a revolving fund of $2.5 billion to "help overcome the financial hurdles associated with building new, large-scale transmission lines and upgrading existing transmission lines," DOE said. Having the department as an anchor off-taker may both increase investor confidence and encourage other customers to purchase capacity from the project.

Developed by Great Basin Transmission, a subsidiary of LS Power, SWIP-N could add 2 GW of capacity to the Western grid. According to DOE's National Transmission Needs Study, an additional 3.3 GW of transfer capacity will be needed between the Mountain and Northwest regions by 2035; SWIP-N could cover 58% of that total, the department said.

SWIP-N is the final, northern section of a larger project including both the 60-mile Desert Link line and the 231-mile One Nevada project, both of which are in operation. Construction on SWIP-N will also include an upgrade for a key Nevada substation that could add another gigawatt of capacity on the One Nevada line.

Having DOE as an off-taker for SWIP-N could provide "an anchor that will allow us to move forward more quickly with procurement activities and securing slots for long-lead equipment, thereby proceeding to construction and placing the project in service faster than otherwise possible," said Paul Thessen, president of LS Power Development.

The company anticipates beginning construction on the project in 2025 and bringing it online in 2027.

Categorical Exclusions

In another move to streamline project permitting, DOE announced an additional *final rule* April 25 updating its guidelines for issuing "categorical exclusions" for environmental reviews of certain categories of clean energy projects.

A categorical exclusion is granted when DOE determines that a category or specific kind of project or action will have no significant environmental impact. Expanding the kinds of projects that qualify for exclusions will "reduce the cost and time for environmental analysis incurred by DOE, project developers and the public," according to the *announcement press release*.

In a major push for the updating of transmission lines, DOE widened the categorical exclusion for such projects by lifting the existing 20-mile cap on the length of a transmission line upgrade that can qualify for an exclusion. The new rule also allows exclusions for transmission upgrades involving a relocation within an existing right-of-way or within previously disturbed or developed land.

The rule specifically refers to reconductoring projects — installing advanced conductors to expand line capacity — as a kind of grid upgrade that could be given categorical exclusions.

For energy storage systems, the new rule allows for categorical exclusions for the construction, operation, upgrade or decommissioning of battery or flywheel storage systems located either within or adjacent to a previously disturbed or developed area.

DOE issued a categorical exclusion for solar photovoltaic projects on previously disturbed or developed land in 2011, limiting the exclusion to projects of 10 acres or less. This rule has been updated to remove the cap on project size.

The department noted it was basing the changes on its "years of experience evaluating the environmental impacts of these types of projects" but will "continue to look closely at each proposed project while being able to complete its environmental review in a faster and less expensive manner." ■

FERC/Federal News

Policymakers Chart FERC's History of Opening the Grid for Competition

By James Downing

FERC has worked to restructure the power industry for nearly three decades, and now it is poised to take another major step forward on that front with the transmission rule next month, panelists said on a webinar April 24 hosted by Americans for a Clean Energy Grid. (See *FERC Observers, Stakeholders Lay out What is at Stake with Tx Rule Looming*.)

Sen. Ed Markey (D-Mass.) addresses ACEG's webinar on April 24. | *ACEG*

Congress first started opening up the grid with the Public Utility Regulatory Policies Act in 1978, said Sen. Ed Markey (D-Mass.), noting that he supported the law just after being elected to the House of Representatives.

"For the first time, utilities had to buy power from qualifying small generators that were not utilities, but utilities didn't want to give up ownership of the transmission system," Markey said. "They didn't want anyone else to have real access. And we had won a battle on interconnection, but we had not won the war."

It took more than a decade for Congress to take up the Energy Policy Act of 1992, which included language requiring open access to utilities' transmission lines that Markey had worked to introduce from his seat on the Energy and Commerce Committee.

"I had to negotiate with the Senate Energy [and Natural Resources Committee] chairman, Sen. Bennett Johnston [D] of Louisiana, who had a utility that was ... I'll put it like this: hesitant to adopt it," Markey said. "That's not their natural attitude down there in Louisiana and Arkansas to welcome competition, but it got included. But still, the utilities did successfully limit the scope of open access. So, if a small generator wanted transmission access, they had to file for it."

At that point, FERC stepped in and issued Order 888 in 1996 that required all utilities under its jurisdiction to have full open access of their transmission systems and led to the restructuring of the wholesale side of the power industry, he added.

"Look, 888 was a huge, great beginning," said former Commissioner Nora Mead Brownell. "But let's face it: Monopolies do not go well quietly into the night. So, when we got to FERC, there was the California energy crisis, which we had to solve."

The 2000-2001 energy crisis involved a lot of litigation and FERC creating the Office of Energy Infrastructure Security, the focus of which was underinvested in by California — making the crisis possible, Brownell said.

FERC always has commissioners appointed by both political parties, and while the commission in the early aughts had plenty of behind-the-scenes debates on specific policies, they were all moving in the same direction to open up the markets, she said. That commission, led by Chair Pat Wood III, approved new RTOs and helped to lay some of the basic rules for their markets out.

FERC's D.C. Headquarters | *© RTO Insider LLC*

Prior to his election to Congress in 2018, Rep. Sean Casten (D-Ill.) worked in the industry developing power plants. He recalled Congress' and FERC's work to raise nuclear plant capacity factors and roll out combined cycle plants around the country.

"Why did markets do that?" Casten said. "Well, they did that because regulated utilities are really good at reliability; they are really good at keeping the lights on. They are really bad at innovation and really bad [at] cost planning. That's not a criticism; the market needs both things."

Order 888 gave industry participants the ability to make money by deploying cheaper assets for the first time in the power industry's centurylong history, he added. It also proved to be a win for the environment, as it ensured coal plants would face competition, to which they lost, Casten said.

FERC has been tweaking the rules of markets ever since, but Casten said that so far, it has fallen short of major reforms to curtail market power and get beyond the still-often-fragmented nature of the grid.

"They've been really too slow in addressing interregional issues, cost issues [and] the growing interconnect delay on the system," Casten said. "Those are problems they have the jurisdiction to fix. And we're out of time for talk; we got to start moving forward."

Markey also called for further reforms, noting the country needs to double the pace of transmission expansion to fully use the incentives from the Inflation Reduction Act and build even more lines to hit net-zero targets.

Brownell wants to see FERC step up its monitoring abilities so it can get a better handle on market power issues but also be informed about the planning issues, on which it tends to default to the information provided it by the ISO/RTOs.

"I think we could use [the Department of Energy] as a backstop to validate some of the planning assumptions and plans that come out of the RTOs," Brownell said. "I think the RTOs are doing the best they can under the circumstances. I don't think we're rewarding them for the right things, and I don't think we're rewarding them for making progress." ■

FERC/Federal News

FERC Denies Permit for Pumped Storage Hydro on Navajo Land

Tribe Opposed Project; W.Va. Project Receives Preliminary Permit

By Michael Brooks

FERC on April 25 denied an application for a 3.6-MW pumped storage hydropower facility on the Little Colorado River in Arizona — near the Grand Canyon and entirely on Navajo Nation land — after the tribe protested that it had not been consulted by the developer (*P-15024*).

The order, approved unanimously at FERC's monthly open meeting, follows a commission policy issued in February saying it will not issue preliminary permits for projects proposing to use tribal lands if the affected tribe opposes the permit. Tribal lands are administered directly by the U.S. government, not by the states in which their territory lies. FERC said this makes the policy consistent with how it has treated permit applications opposed by federal land managers or similarly affected federal agencies.

"Because the proposed project would be located entirely on Navajo Nation land and the nation has stated that it opposes issuance of the permit, we deny the application," FERC said. "To avoid permit denials, potential applicants should work closely with tribal stakeholders prior to filing applications to ensure that tribes are fully informed about proposed projects on their lands and to determine whether they are willing to consider the project development."

The developer, Pumped Hydro Storage, argued that because it had filed its application in 2020, the new policy should not apply to it. It also claimed that gaining tribal approval is difficult before being granted a permit, but that gaining one would give it more "resources" to consult with the Navajo.

"We are not persuaded by Pumped Hydro's arguments," FERC said. "Pumped Hydro provides no support for its assertions that gaining tribal approval at the permit stage is particularly difficult and that issuance of a permit, which is simply a placeholding action, would provide any additional resources to a developer."

The developer had named the proposed project the "Navajo Nation Big Canyon Pumped Storage Project," but the text of the order omitted "Navajo Nation" from the name and refers to it simply as "Big Canyon" throughout. In an unusual footnote, FERC said the project was "not in any way affiliated with" the tribe, so it removed it from the name "to avoid the impression that the Navajo Nation is involved in developing the project."

Little Colorado River | *Shutterstock*

The project would have consisted of three new dams with walls spanning a collective 11,450 feet, a building to house nine 400-kW turbines and two double-circuit 500-kV transmission lines, among several other facilities. The Navajo Nation said it would adversely impact its water use and historic and cultural resources. Other commenters raised concerns about the fitness of the developer for such a project and the application's completeness. The commission did not address these concerns.

"This disastrous project could have devastated the Little Colorado River and pushed the world's last large source population of humpback chub toward extinction," Taylor McKinnon, Southwest director at the Center for Biological Diversity, said in a *statement*. "It's good news for these embattled fish that federal officials heeded the Navajo Nation's staunch opposition and rejected this project."

Cabin Run Permit Approved

FERC did approve a preliminary permit for Cabin Run Pumped Storage to study the feasibility of a 57.5-MW, closed-loop pumped storage hydropower facility near the Stony River in Tucker and Grant counties, W.Va. (*P-15318*).

The West Virginia Division of Natural Resources, Potomac Riverkeeper Network and Friends of *Blackwater* opposed the permit, arguing the project would adversely impact the river's habitats, especially those of the native brook trout.

The commission did not address these arguments, noting that "a preliminary permit does not authorize access to project lands or project construction. Therefore, addressing the commenters' concerns at the permit stage is premature."

"The purpose of a preliminary permit is to secure the permit holder's priority for filing a development application while it studies the feasibility of a project, including studying potential impacts, such as those identified by the commenters here," FERC said. "The commission will consider in any future licensing proceedings potential project effects on water quality, water quantity and nearby infrastructure. Accordingly, it would be prudent for the permittee to consider and study these issues during the term of the permit."

That term ends April 1, 2026. ■

FERC/Federal News

EPA Power Plant Rules Squeeze Coal Plants; Existing Gas Plants Exempt

Agency Issues Other Rules that Tighten MATS; Create Wastewater, Ash Requirements

By K Kaufmann

Coal-fired power plants nationwide will either have to close by 2039 or use carbon capture and storage or other technologies to capture 90% of their emissions by 2032 under EPA's long-awaited *final rule* issued April 24.

The 1,020-page document actually contains four different, "severable" rules:

- the repeal of the Affordable Clean Energy rule that the agency issued during the Trump administration;
- greenhouse gas emission guidelines for existing coal plants;
- new source performance standards for gas-fired plants built after May 23, 2023; and
- revisions to the performance standards for coal plants that undergo a large modification, matching the new emission guidelines.

EPA Administrator Michael Regan at Howard University on April 25 | *EPA*

Absent from the package are emissions guidelines for existing natural gas plants, as EPA proposed in May 2023. (See *EPA Proposes New Emission Standards for Power Plants*.) The agency first *announced* the change to its proposal in February. (See *EPA to Strengthen Emissions Regs for Gas Power Plants*.)

During a press conference April 24, EPA Administrator Michael Regan said those guidelines have been delayed because of feedback from both industry and environmental groups, which pushed the agency to "do better."

The agency has opened a docket and issued "framing questions to gather input about a more comprehensive approach to reduce greenhouse gases of existing gas combustion turbines in the power sector," Regan said. "We are committed to expeditiously proposing GHG emission guidelines for those units … and we're going to do it in a very transparent and engaging way."

An EPA analysis estimates the rule could cut 1.3 billion metric tons of power-sector carbon dioxide emissions by 2047 and provide climate and health benefits totaling $370 billion, or about $20 billion per year.

"In 2035 alone, that means preventing 1,200 premature deaths, 870 hospital visits, 360,000 avoided cases of asthma symptoms, 48,000 avoided school absences and 57,000 lost workdays," Regan said April 25 at a public announcement of the rules at Howard University in D.C.

Anticipating pushback from the electric power sector and fossil fuel organizations, Regan said the CO_2 rule will not only protect public health but also allow the power sector to "confidently prepare for the future by enabling strategic long-term investment and establishing an informed, multiyear planning strategy."

"Despite what you will hear and what they will say, we can do it all while ensuring the power sector can provide affordable, reliable electricity for the long term," he said.

In addition to the CO_2 rule, EPA issued pollution-reduction standards for wastewater and coal ash produced by power plants and updated the Mercury and Air Toxics Standards.

"Each of these rules contains transparency requirements, so that the emissions, the discharges and the compliance data are made available to the public, ensuring that power plants are held responsible and accountable for their activities," Regan said.

"The U.S. is closing in on its goal to cut greenhouse gas emissions in half by 2030," the Natural Resources Defense Council *posted* on X. "Now, the EPA needs to finish the job and limit emissions from already built gas power plants that continue to threaten communities and our planet."

Altered Deadlines

The final rules push up some compliance deadlines and extend others compared to last year's proposal.

For example, the deadline for coal plant closure or CCS abatement was 2040 in the proposed rule, and new baseload natural gas plants originally had until 2035 to reduce emissions by the 90% requirement, as opposed to 2032 in the final rule.

The rule also provides different compliance levels for existing coal plants depending on whether they intend to operate past Jan. 1, 2039:

- Plants intending to operate past 2039 will have until Jan. 1, 2032, to cut their emissions to a level based on a presumption that they will install a CCS system capable of capturing 90% of their emissions.
- The emission cuts for plants planning to close by Jan. 1, 2039, will be based on a presumption that they will shift their fuel mix to 40% natural gas by Jan. 1, 2030.
- Plants with a demonstrable commitment to shutting down before Jan. 1, 2032, will be exempt from the rule.

States will also be able to issue “variances” for individual plants that have “fundamentally different circumstances than those considered by EPA and … cannot reasonably achieve [the] required degree of emission limitation,” according to an agency *summary*.

The standards for new natural gas plants also vary based on a plant’s expected operation level:

- Baseload plants intending to generate at least 40% of their maximum annual capacity will have to comply with two standards: a first phase based on efficient design and operation, and a second phase assuming 90% carbon capture by Jan. 1, 2032.
- Intermediate-load plants planning to operate at 20 to 40% of their maximum capacity will only have to comply with the efficient design and operation standards.
- Plants expecting to operate at less than 20% of their maximum capacity — mostly peaker plants — will have to comply with a standard that assumes their use of low-emitting fuels.

The different levels for coal and natural gas are intended to reflect “the fact that the longer-running and more heavily utilized a power plant is, the more cost effective it will be to install controls for CO_2 emissions.”

States will be required to submit their plans for complying with the final rule within two years of its publication in the *Federal Register*. Regan said the rule allows for flexibility in state plans, for example, allowing coal and new natural gas plants to exceed the EPA limits if needed to provide short-term emergency power, for example, during an extreme weather event.

State plans can also allow for longer-term flexibility if a coal plant scheduled to shut down is kept in operation to ensure utilities or transmission operators can supply regional reliability. States may also seek one-year extensions to comply with specific standards because of “unexpected delays with control technology implementation that are outside the owner or operator’s control,” according to the summary.

The CCS Issue

The rule acknowledges concerns raised by environmental justice and community groups about EPA’s promotion of CCS as a best system of emissions reduction (BSER) under Section 111 of the Clean Air Act.

While still an emerging technology, CCS has received a range of federal support, with the Department of Energy funding several demonstration projects. These projects also may receive generous tax credits from the Inflation Reduction Act.

EPA argued its carbon pollution standards are “performance standards and do not require the installation or operation of any particular technology. Individual owners and operators will decide how best to meet the requirements laid out in the rule. … “EPA is committed to implementing its programs and working with federal partners to ensure that where CCS is deployed, it is implemented in a way that considers community input and is protective of public health, safety and the environment.”

Many of the criticisms lobbed in response to the final rules focused on CCS.

“The path outlined by the EPA today is unlawful, unrealistic and unachievable,” Jim Matheson, CEO of the National Rural Electric Cooperative Association, said in a statement. “The rule mandates the widespread adoption of technology that is promising but not ready for prime time.”

“CCS is not yet ready for full-scale, economywide deployment, nor is there sufficient time to permit, finance and build the CCS infrastructure needed for compliance by 2032,” said Dan Brouillette, CEO of the Edison Electric Institute.

The Electric Power Supply Association said the package “relies on unavailable technology and will stymie much needed investment in new, more efficient and cleaner power resources as older units retire.”

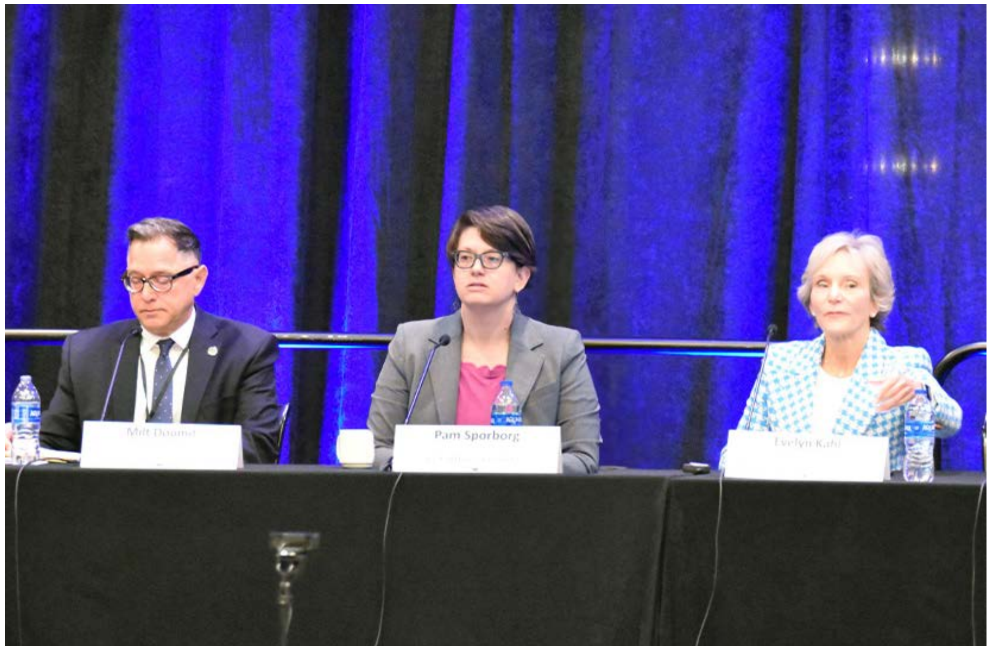
“While EPSA welcomed the EPA’s announcement that it had removed existing gas plants from its proposed emissions regulations, the final rule released today is still a painful example of aspirational policy outpacing physical and operational realities,” CEO Todd Snitchler said. ■

CAISO/West News

Pathways Initiative to Act Fast on 'Stepwise' Governance Plan

Backers of Western Effort Looking to Move on EDAM Oversight, Establishing 'RO'

By Robert Mullin



From left: Milt Doumit, Washington UTC; Pam Sporborg, PGE; Evie Kahl, CalCCA at the spring CREPC-WIRAB conference in Denver on April 25. | *© RTO Insider LLC*

DENVER — Backers of the West-Wide Governance Pathways Initiative want to move quickly on the first part of their proposed plan to shift CAISO's governance to an independent entity, leaders of the effort told Western state energy officials April 25.

The straw proposal released by the Pathways Initiative's Launch Committee on April 10 outlines a "stepwise" approach for gradually transitioning much of the authority of the ISO's state-run governance into an independent "regional organization" (RO). (See *Western RTO Group Floats Independence Plan for EDAM, WEIM*.)

Effecting that transition is the initiative's key mission as it attempts to lay the groundwork for a single Western electricity market that includes California and builds on CAISO's Extended Day-Ahead Market (EDAM).

"We're not talking about market design in this group, we're talking about governance, and that's been the box we've stayed in," CalCCA General Counsel and Director of Policy Evie Kahl, co-chair of the Launch Committee's Functions and Scope Work Group, said at the spring joint conference of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) in downtown Denver.

Kahl was speaking on a panel moderated by Washington Utilities and Transportation Commission member Milt Doumit — also a Launch Committee member.

"The problem we're trying to solve is a perceived lack of independent governance in today's CAISO Western Energy Imbalance Market [WEIM] and Extended Day-Ahead Market [EDAM]," Kahl said.

Step 1 of the proposal entails elevating the "joint" authority the WEIM's Governing Body shares with the ISO's Board of Governors over WEIM and EDAM matters to "primary" authority, a move that would require FERC approval but not a change to California law, according to legal analysis performed for the Launch Committee.

Launch Committee Co-Chair Pam Sporborg, director of transmission and market services at Portland General Electric (PGE), said Step 1 was built on previous work done by the WEIM's Governance Review Committee (GRC).

"And that's one of the reasons we've been able to move so quickly into a Step 1 recommendation, because so much of these challenges and discussions have taken place with the GRC," Sporborg said.

Step 2 would establish the RO as a legal entity and, after passage of required California legislation, transition the Governing Body's primary authority defined in Step 1 to "sole" authority seated within the RO.

Kahl told *RTO Insider* that Pathways backers are pushing for CAISO to this summer kick off the stakeholder process that would establish the Governing Body's primary authority, with the hope the ISO would complete the relevant tariff revisions by late fall.

Waiting on NV Energy

According to the straw proposal, CAISO's filing of those tariff changes with FERC wouldn't be triggered until EDAM obtains implementation agreements from a "set of geographically diverse" WEIM participants representing load equal to or greater than 70% of CAISO balancing authority area annual load in 2022.

"Assuming all the entities who have expressed an intent to join EDAM as of April 10, 2024, execute implementation agreements, only one additional utility representing at least 10,000 GWh of load and located in the Southwest would be required to trigger the Step 1 governance transition," the proposal says.

PacifiCorp on April 26 became the first Western utility to announce it will sign such an agreement. (See related story, *PacifiCorp Fully Commits to CAISO's EDAM*.) Other entities signaling their intent to join EDAM include the Balancing Authority of Northern California, Idaho Power, Los Angeles Department of Water and Power, and PGE.

"We are not counting NV Energy in [the assumed commitments], but NV Energy could trip the trigger," Kahl told state officials.

The Nevada-based utility is expected to decide on a market this year, multiple sources have told *RTO Insider*. A recent study by The Brattle Group indicated NV Energy would gain significantly more benefits from participating in EDAM than Markets+. (See *NV Energy to Reap More from EDAM than Markets+, Report Shows*.)

Sporborg said PGE's decision in favor of EDAM came down to an assessment of customer value based on studies by Brattle and Environmental+Energy Economics that examined benefits based on various market footprints.

CAISO/West News

"We found that the EDAM footprint would provide benefits to PGE's customers in all ranges of scenarios," she said. "We also found Markets+ would provide benefits, but to a lesser extent."

PGE also determined that unwinding its current participation in the WEIM would reduce its financial benefits by about $20 million annually.

Sporborg also noted PGE is a net purchaser in the electricity market and that "getting the right congestion protections for our load was incredibly important to us in our decision making."

First Step for Step 2

Kahl said Pathways backers will spend the latter part of the year working with California lawmakers to craft the legislation needed to fulfill Step 2 of the straw proposal, with a bill to be taken up in the 2025 session. Still, the group expects to stand up the new RO as a legal entity by the end of this year.

"We do not need legislation to do that," she said.

After establishing the RO, Sporborg said, Pathways could seat an independent board and begin to work through market oversight issues.

"I think that legislation helps smooth the path towards the RO's ultimate destination, but that we can do many things and take a lot of action absent a legislative change," Sporborg said.

Oregon Public Utility Commission Chair Megan Decker asked Sporborg and Kahl how the Pathways Initiative can sustain its efforts both "financially" and "administratively." The group, which so far has covered its budget from money pledged by supporters, recently was rejected for an $800,000 grant by the U.S. Department of Energy. (See *Pathways Initiative Rejected for $800K in DOE Funding*.)

"We were disappointed not to receive a DOE grant, but we do have an opportunity to reapply, and based on the feedback we received [from the DOE], we think that we are in a much better position to have a more detailed and specific proposal," Sporborg said.

Sporborg added the group likely will seek more contributions from supporters.

"It's been a real challenge, honestly, to stand up a brand-new organization, without the kind of institutional budget that normally comes with a lot of these efforts," she said. "I think that's a unique part of this journey, and something that I've been really just glad about, which is the support we've gotten from a really diverse group of stakeholders." ■

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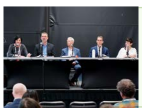

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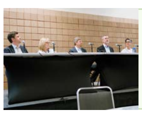

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PacifiCorp Fully Commits to CAISO's EDAM

Portland-based Utility is 1st Western Entity to Commit to a Western Day-ahead Market

By Ayla Burnett

PacifiCorp said April 26 that it will sign an implementation agreement to join CAISO's Extended Day-Ahead Market (EDAM), making it the first entity to formally commit to either of the two day-ahead markets being offered in the West.

The Portland, Ore.-based company, whose sprawling territory includes portions of six states, was the first utility to join the ISO's Western Energy Imbalance Market in 2014 and the first and the first to *publicly announce* its intent to join EDAM in December 2022.

EDAM is currently in a stiff competition for participants with SPP's Markets+.

"We are excited to formalize our agreement to become a participant in the EDAM," PacifiCorp CEO Cindy Crane said in a joint *announcement* with the ISO. "A modern, coordinated day-ahead market in the West is vital to optimizing the region's energy resources so we can continue to provide reliable and affordable power to our 2 million electricity customers across six states."

PacifiCorp serves electricity customers in California, Idaho, Oregon, Utah, Washington and Wyoming, owns 10,833 MW of generation capacity, and operates approximately 17,100 miles of transmission. The entity was the first to join CAISO's Western Energy Imbalance Market in 2014.

Anticipation continues to build in the West over which day-ahead market various entities will join. While PacifiCorp's announcement marks a major achievement for EDAM, the decision won't surprise participants in regional market discussions.

Four other entities have indicated interest in joining EDAM. In March, Portland General Electric and Idaho Power signaled their intent to join (See *CAISO's EDAM Scores Key Wins in Contested Northwest*.) The Balancing Authority of Northern California and Los Angeles Department of Water and Power have also informed the ISO of their interest in joining.

"The momentum we are seeing for participation in the EDAM is very gratifying, and PacifiCorp's formal commitment brings better definition to the vision of a regional day-ahead electricity market," CAISO CEO Elliot Mainzer said in the announcement. "This is a major piece of a truly collaborative effort to support reliability and affordability for electricity customers by leveraging resource diversity and transmission connectivity across the footprint of the Western grid. We now look forward to continuing working with additional valued partners in the West to take the next steps in a fully integrated regional market."

Markets+ notched a potentially big win earlier this month after Bonneville Power Administration staff recommended the federal power agency choose Markets+ over EDAM, although BPA won't issue a draft decision until this summer. (See *BPA Staff Recommends Markets+ over EDAM*.) ■

PacifiCorp is the first Western entity to formally commit to CAISO's Extended Day-Ahead Market | *PacifiCorp*

CAISO/West News

Participants 'Unwaveringly Committed' to WRAP, WPP CEO Says

Need to Delay 'Binding' Phase Shows Critical State of RA in West, Edmonds Contends

By Robert Mullin

Sarah Edmonds at the spring CREPC-WIRAB meeting in Denver on April 24. | *© RTO Insider LLC*

DENVER — Western Resource Adequacy Program (WRAP) participants still strongly support the program despite recently appealing to delay its "binding" penalty phase by one year based on concerns about capacity shortages, Western Power Pool (WPP) CEO Sarah Edmonds said April 24.

But Edmonds acknowledged the appeal clearly signals the RA situation in the West is much more critical than previously thought.

"[Participants] are still unwaveringly committed to WRAP, which is good news for us, because our belief in the urgency and the need for the program has not changed," Edmonds said during a panel discussion at the spring joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) in downtown Denver. "If anything, it's only increased in this era of heightened reliability risks and NERC [and] WECC assessments warning us for quite some time that we have a serious issue that we're facing," she said.

Edmonds' comments came two days after the WRAP's Resource Adequacy Participants Committee (RAPC) issued an April 22 letter saying program members would postpone binding operations to summer 2027 because some of them confront "significant new headwinds" in securing sufficient energy resources to meet their capacity obligations and avoid heavy penalties in the WRAP's FERC-approved tariff. (See *WRAP Participants Seek 1-Year Delay to 'Binding' Operations*.)

The letter cited problems with new resources' supply chains, forecasts for faster-than-expected load growth and "extreme weather events" that have challenged assumptions about the volume of resources needed to maintain grid reliability as key reasons the delay is required.

"The RAPC letter is an illustration of the fact that we are shorter than we thought as a collective, and there is not critical mass. And in terms of WRAP, we are facing more resource inadequacy going forward," Edmonds said.

Participants are looking to "revisit" WRAP "transition provisions" providing "discounts" to penalties and offer measures "that make it easier to become binding in this program," Edmonds noted.

WRAP entities face a May 31 deadline to commit to the binding phase beginning in summer 2026, but stakeholders determined the program would not obtain a "critical mass" of participation by that time, she said.

The WRAP's tariff allows WPP to commence binding operations anytime between 2025 and 2028. Participants will work to position the program for participants to commit in May 2025 for the summer 2027 binding phase, a change requiring stakeholder approval.

"I hope that's the last marker," Edmonds said. "Summer of 2028 is the very last moment — that's when everyone in this program who's still there needs to be fully binding."

Edmonds said the nonbinding phase of the program still offers "a lot of value."

"We're essentially in an informational stance where we're going through a lot of the processes — the forward-showing, planning process — and then essentially setting up an operational program that can track how it would really look in real life if we were in this program," she said.

"We could do better on all those pieces in terms of the quality of the data that we're receiving from participants, the amount of data the Western Power Pool is permitted to see in the tariff, and how we can then explain that data and turn that data into information that's useful for the region," she added. ■

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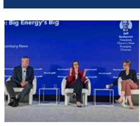

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CAISO/West News

Congestion Revenue Rents Still Underfunded, CAISO DMM Says

CAISO Staff and Stakeholders Consider CRR Underfunding Issue as a Stakeholder Initiative

By Ayla Burnett

Congestion revenue rights (CRRs) auctions averaged $62 million in losses between 2019 and 2023, down nearly $50 million since changes were implemented in 2019 but "still very high," said CAISO's Department of Market Monitoring (DMM) during the ISO's Annual Policy Initiatives Roadmap Process *meeting* April 22.

CAISO staff and stakeholders questioned if the consistent underfunding of CRRs should be taken up as an official initiative.

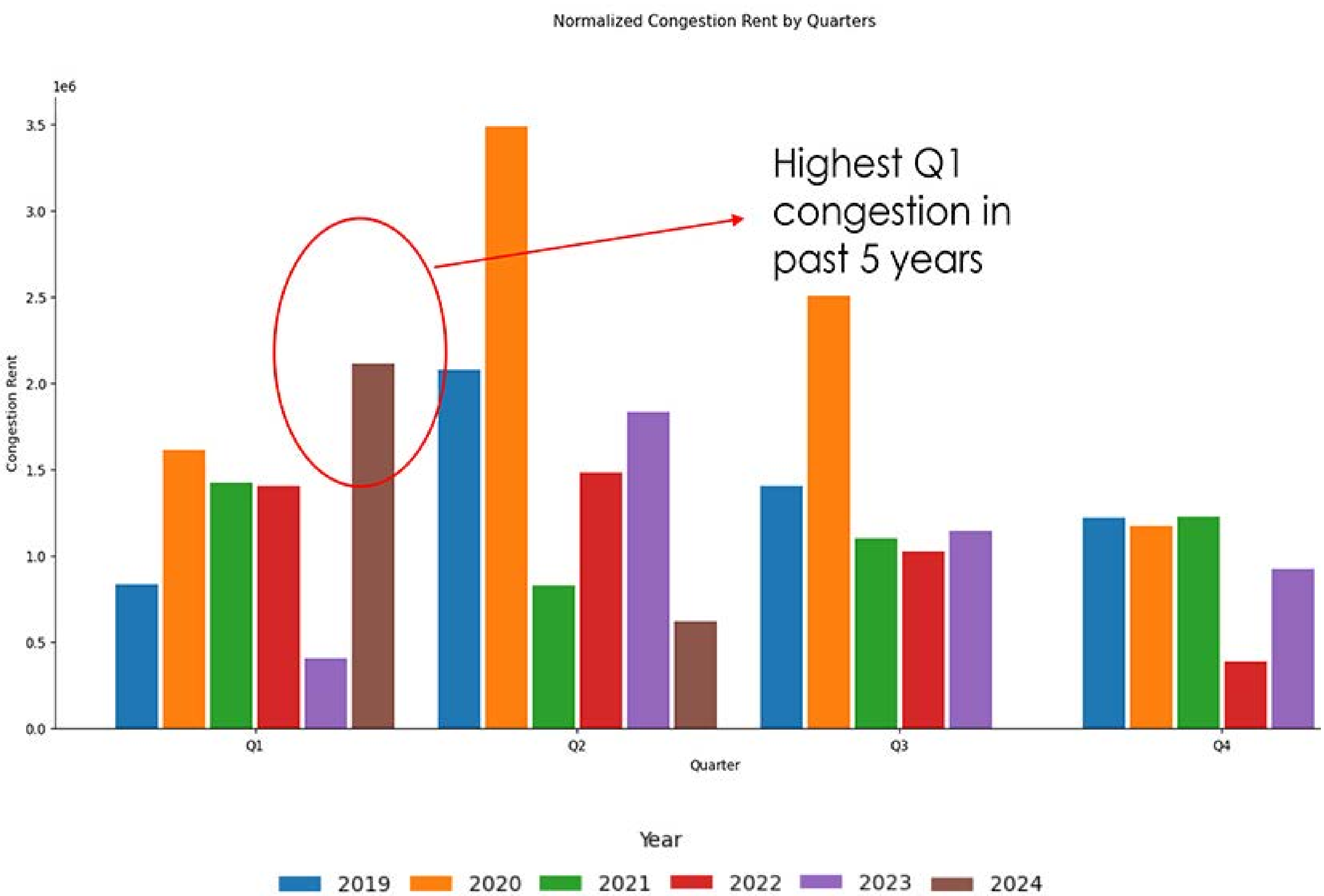
CRR auctions have been losing money for more than a decade, and CAISO has taken multiple steps to address the revenue inadequacy. In 2019, the ISO instituted rule changes meant to decrease the amount of money flowing from ratepayers to commodities traders, which reduced losses significantly, the DMM said. (See *CAISO CRRs Still Losing Money, but Less*.) Auction revenues for transmission ratepayers averaged 67 cents per dollar paid to CRRs since 2019, compared to about 48 cents before the changes. Almost all losses stem from rights bought by financial traders, according to the DMM.

In May 2020, CAISO released a *report* evaluating the rule changes and identified that an issue with the shift factor threshold — which is used to evaluate the effectiveness of energy bids to manage congestion in the clearing of the day-ahead market — was causing additional underfunding.

"Even though the CAISO did address that issue, we are still seeing quite a bit of revenue inadequacy and underfunding," Kallie Wells, senior consultant at Gridwell Consulting, said in her presentation on the issue.

The changes implemented to address the shift factor threshold primarily impacted low-voltage lines, Wells said, with recent CRR revenue inadequacy affecting higher voltages. However, 25% of low-voltage constraints still saw recent funding levels of just 20%. Underfunding appears to be related to more than just transmission derates, Wells added, questioning the root causes of the continued revenue inadequacy.

"The ask that we have of ... CAISO to include in terms of potential scope on a CRR enhancements policy is really getting at what are the root causes or drivers of the current revenue inadequacy," Wells said. "It's really unclear to us what those underlying factors are and



Congestion revenue rent auctions are still suffering significant losses, despite prior rule changes, according to CAISO staff and stakeholders. | *Gridwell Consulting* whether or not they continue to align with cost causation principles."

Because of how CRRs are allocated, rights are becoming a liability rather than a reliable source of revenue, Wells said. And congestion is increasing; she pointed out that the first quarter saw the most congestion in five years, further emphasizing the importance of CRRs in CAISO's market.

"The role that CRRs play is extremely important in an organized energy market, and if we're having this issue with how the shortfall is being allocated to the CRRs and causing the CRRs to be a risk or a liability for entities to hold and not functioning properly as a hedging tool, that's extremely concerning," she said.

Wells provided policy suggestions for addressing the problem, including capping underfunding and using more overfunding to offset deficits.

DMM Again Recommends Replacing CRR Auctions

The DMM continues to suggest that forgoing the CRR auction in place of a financial market based on offers from willing sellers could solve the underfunding problem.

"Ever since CRRs were implemented over 10 years ago, the auction revenues that are brought in in the auction fall way short of the congestion revenues that get paid out," said Eric Hildebrandt, the department's executive director. "So, from that perspective, there is a net loss to transmission ratepayers as a result of the CRR auction.

"The difference in the DMM proposal from the market that exists today is, rather than the ISO auctioning rights … there would be a financial auction in which those entities that held rights could offer them for sale to other entities."

Under the proposal, CRR allocations could remain unchanged, or alternatively, congestion revenues could be refunded to load-serving entities instead of being allocated. A purely financial CRR market would be run with other voluntary bids to buy and sell CRRs and "would be easier and less subject to errors than [the] current CRR model based on a physical network," Hildebrandt said.

But some stakeholders raised concern that replacing the auction with a financial market could stifle competition and liquidity.

"With auctions, the reason we have more than just load-serving entities participating in them is to inject competition into the market," said Noha Sidhom, an Energy Trading Institute board member. "And so, my concern when I hear some of this is I just worry about lack of competition and lack of liquidity."

Seth Cochran, head of strategic market policy at Vitol, echoed Sidhom's concerns.

"There's a strong assumption embedded in here that you can create a replacement market and everything will be fine," he said. "I know you're trying to put together a substitute here, but I can tell you from decades of experience in the market that you're just not going to be able to foster liquidity, and it's really going to leave the [independent power producers] out to dry. I know it might sound good on paper, but this is totally untested and unproven."

Because of prior commitments from the ISO and the Market Surveillance Committee to address the issue, the DMM recommended the topic not be taken up as a discretionary initiative and received stakeholder support. Hildebrandt did note, however, that while CAISO and the committee began discussion of CRR losses in 2023, they've "been silent since." ■

CAISO/West News

Western Officials Get Rundown on 'Irritating, Inefficient' Market Seams

CREPC-WIRAB Panel Focuses on Potential Boundary Between EDAM, Markets+

By Robert Mullin

From left: Gabriel Aguilera, New Mexico PRC; Scott Miller, WPTF; Johannes Pfeifenberger, The Brattle Group; Rachel Dibble, BPA; Kelsey Martinez, Public Service Company of New Mexico. | *© RTO Insider LLC*

DENVER — Utility staff responsible for real-time operations will be equipped to manage the seams between two Western day-ahead markets, but the situation will be far from ideal, state energy officials from across the West heard April 24 at the joint spring conference of the Committee for Regional Electric Power Conference and Western Interconnection Regional Advisory Body (WIRAB).

"I can say that I have a positive outlook that maybe you will be happy to hear: that system operators are going to make it work," Kelsey Martinez, director of regional markets and transmission strategy at Public Service Company of New Mexico, told the officials during a panel discussion on the potential impact of seams between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+.

"Even if we give them subpar designs regarding the seams, even if we give them amateur joint operating agreements [on] Day 1 with the seams, system operators will make it work. They will keep the lights on and there won't be any large reliability event that we can point to and say that 'Seams were the smoking gun on that,'" Martinez said on the panel, which was moderated by New Mexico Public Regulation Commissioner Gabriel Aguilera.

"That's the good news," according to Martinez, who based her views on five years' experience as a former system operator and three years managing real-time operations. "The bad news is that seams show up in all kinds of little irritating, inefficient ways in the control room."

Those irritants include:

- use of different sets of "situational awareness" tools and data sets among neighboring balancing authority areas (BAAs), making it difficult for operators to troubleshoot in real time;
- challenges for vendors in configuring those tools because they must translate different market rules among adjacent BAAs; and
- differing time frames among BAAs around when schedules are due and market operating runs take place and are published.

Dividing the West into two day-ahead markets also would roll back some of the gains system operators have seen from improved visibility into neighboring areas provided by widespread participation in CAISO's Western Energy Imbalance Market (WEIM), Martinez said. The WEIM now includes BAAs representing about 80% of the load in the Western Interconnection.

"Now there's going to be some visible information and then some invisible information, and that also includes communications," she said. "So, we're going to continue to get communications in real time from our market operator, but we may not be getting real-time communications from the other market operators that will affect our system."

Taken together, those issues add up to what Martinez called a "low-level reliability degradation."

"These aren't things that are going to represent huge events on the system, but what they will do is just create economic inefficiencies that are hard to measure but are very prevalent, and could be improved with mature seams operations," she said.

Perpetuating Inefficiencies

"Having one seam between two markets is a lot better than having 32 seams and no transparent pricing [and] no hourly trading," said Johannes Pfeifenberger, principal at The Brattle Group, referring to the current patchwork of BAAs that characterizes the Western grid. "But what you get with two markets is you have interties between the markets if that feature is enabled, at least, so there's a lot of work that needs to be done."

Bilateral trading faces the highest number of "hurdles" under a scenario with multiple BAAs in a non-organized market, Pfeifenberger said, while bilateral trading between two organized markets becomes more efficient due to increased transparency and liquidity.

He said market simulations have shown that an organized day-ahead market in the West would increase trading volumes by 20 to 30% (60 to 90 TWh) compared with the "bilateral" status quo. And while a scenario in which most Western entities participate in one market would bring the highest increase in trading, a two-market scenario still would provide a boost.

But based on evidence gleaned from Eastern RTOs, Pfeifenberger said, seams can "perpetu-

CAISO/West News

ate" five types of inefficiencies.

A key inefficiency is "largely ineffective" interregional transmission planning, and Pfeifenberger warned that coordinated planning in the West could decline under a two-market scenario compared with the status quo.

"Once you have these markets, that planning between the markets is almost worse than what you have now because these markets are so focused on their region, more so than individual utilities can afford to do," Pfeifenberger said. "The [West] has a better track record with regional planning than the East."

The other inefficiencies include:

- generator interconnection delays and cost uncertainty created by affected system impact studies;
- a reduced — or overlooked — value of resource adequacy at interties across seams due to restrictions on capacity imports and differences in RA accreditation across two markets;
- difficulties in managing loop flows through market-to-market coordinated flowgates; and
- inefficient trading across contract-path market seams.

Pfeifenberger said the last problem must be addressed by "intertie optimization," a mechanism that allows for bilateral traders across seams to respond to fast-changing real-time prices in adjacent markets.

Fondest Dream

But seams between day-ahead markets will pose problems beyond those experienced at the boundaries dividing the full RTOs in the East, said Scott Miller, executive director of the Western Power Trading Forum (WPTF).

Miller pointed to a recent study WPTF commissioned in partnership with the Portland, Ore.-based Public Generating Pool to examine the potential impacts on trading from a West divided between EDAM and Markets+. The study pointed to increased barriers to contracting across markets, inefficiencies related to greenhouse gas accounting and associated generation dispatch, and differences in market power mitigation approaches, among other issues. It also noted that, given the lack of BAA consolidation seen in RTOs, the two day-ahead markets still will contain "seams within seams." (See *Western Market Seams Issues to Differ from East, Study Finds*.)

"We found that, indeed, day-ahead markets are going to be different in many respects, and that the seams areas may present certain challenges that need to be addressed [in ways] that will be not informed by what the RTOs do," Miller said.

"And this is not to rain on the parade of day-ahead markets; this is definitely going to be an improvement on the status quo," he said. "But recognize you are talking to somebody whose fondest dream — at least professionally —would be that there is a single market [with] security-constrained economic dispatch across the West. But we are where we are, and we do things incrementally."

Past and Future Seam?

Rachel Dibble, vice president of power bulk marketing at the Bonneville Power Administration, cautioned against conflating day-ahead seams issues with what would happen in an "eventual RTO." BPA has been heavily involved in the design of Markets+ and its staff recently recommended the federal power agency select the SPP day-ahead market over CAISO's EDAM, a move criticized by some proponents of a single Western market. (See *BPA Staff Recommends Markets+ over EDAM*.)

"I just want to clarify that the seams that exist today between balancing authorities, transmission service providers and transmission operators — [they] will still exist in a day-ahead market," Dibble said. "Now, there are efficiencies that Kelsey [Martinez] and Scott [Miller] both talked about, even with the day-ahead market that can improve things, but those things don't go away with a day-ahead market."

Dibble said she would expect "experienced and responsible" market operators (that is, CAISO and SPP) to work together to "find the efficiencies to be able to allow power to flow across those boundaries in the most efficient way possible and bring participants into that discussion."

She added that BPA has "a lot of experience" working with CAISO on seams issues, considers the ISO a "valued business partner" and is a WEIM participant.

Dibble noted that BPA negotiated a coordinated transmission agreement with CAISO when PacifiCorp joined the WEIM as the market's first member in 2014, "long before" BPA joined.

"And that was essentially a seams agreement that identified ways that we could operate efficiently and address that seam and going across," Dibble said. "So, yes, I agree, it's a big seam. It's a seam that's there today and may be there in the future as well."

"We can't really tackle this until we know where the boundary is," Miller said. "And so, when we get to that point, I think sometime this year, then we can engage meaningfully in what we can do to manage the seams that are unique to the day-ahead market."

Uncertainty is part of the landscape, according to panel moderator Aguilera.

"Many of you in one way or another are thinking about this in your job, which is whether a utility should join a day-ahead market, and we're hoping that this session will confuse you further," Aguilera joked with his fellow commissioners. "We're not hoping for that, but I believe that our panelists will give you more to think about." ■

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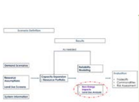

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CAISO/West News

Ariz. Looks to Public Safety Power Shutoffs to Prevent Wildfires

ACC Reviews Fire-prevention Strategies as APS Prepares for PSPS Events

By Elaine Goodman

Arizona Public Service is prepared to implement public safety power shutoffs for the first time this year, and another utility in the state is laying the groundwork to use the wildfire prevention technique.

"It is a tool that we expect to use very, very seldomly, but one that we are prepared to use if conditions warrant," said Scott Bordenkircher, APS forestry and fire mitigation director.

Bordenkircher's comments came during an Arizona Corporation Commission workshop April 23 on electric utilities' summer preparedness.

Salt River Project is also evaluating the possibility of a public safety power shutoff (PSPS) program.

"We are in the development stages and looking at what that could look like for SRP," Jace Kerby, director of transmission line design, construction and maintenance at SRP, said during the workshop.

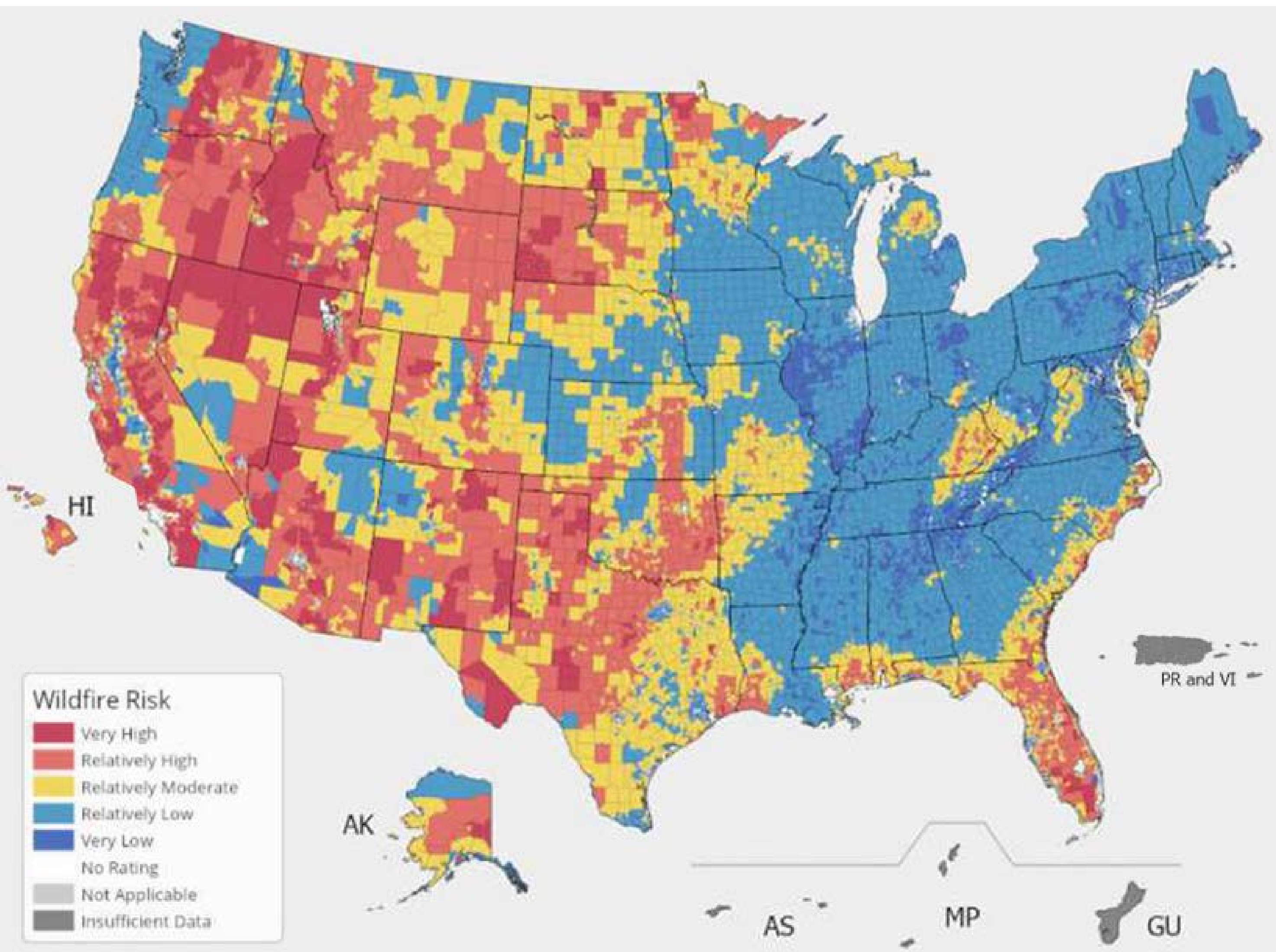
The utility has brought in a vendor to help model wildfire threat in SRP's service territory — information that would be key in designing a PSPS program, Kerby said.

Utilities in other Western states have used PSPS as a wildfire prevention technique. In California, there have been 72 preemptive shutoffs since 2018, according to a California Public Utilities Commission *dashboard*.

Oregon's first PSPS event was in 2020. (See *High Fire Danger Prompts First Oregon PSPS Event*.)

Xcel Energy implemented the first PSPS in Colorado in April in response to a severe windstorm forecast. The shutoff affected an estimated 55,000 customers April 6-7.

After the event, Gov. Jared Polis (D) *criticized* the utility for failing to minimize outages and effectively communicate with customers. The Colorado PUC has opened an investigation into Xcel's use of PSPS and will explore potential regulation of prescribed outages.



Wildfire risk is growing across the nation, and more utilities are considering public safety power shutoff (PSPS) programs. | *FEMA*

CAISO/West News

As the risk of wildfire increases nationwide, some predict that more states will be facing public safety power shutoffs.

"Ultimately, it's a national push. This will happen very likely with all utilities in the nation very soon," Commissioner Nick Myers of the Arizona Corporation Commission said during a wildfire mitigation town hall meeting April 4.

PSPS Design

Bordenkircher at APS said the utility has targeted 13 circuits in high fire-risk areas in Yavapai, Coconino and Gila counties for potential power shutoffs.

He said shutoffs would occur during "really bad fire weather," when high temperatures, low humidity and strong winds elevate the risk of wildfires igniting and spreading quickly. He estimated that a shutoff would last about 20 hours, from when winds pick up in the afternoon and evening until crews could get out the next morning to inspect power lines for damage. Customers would be alerted four days in advance of a potential shutoff.

Kerby said SRP is exploring circuit segmentation to reduce the number of customers affected by an outage if the utility proceeds with PSPS.

Utilities are taking other steps to reduce wildfire risk, with two goals: to prevent utility equipment from starting wildfires and to protect utility infrastructure from wildfires of any origin.

Kerby at SRP said vegetation management "has got to be the biggest key component to helping drive down the risk when it comes to wildfire mitigation." Utilities are clearing vegetation from rights-of-way, removing trees at risk of toppling onto lines and clearing space around power poles.

Another strategy at SRP is replacement of wooden poles with steel in its transmission and distribution systems. Tucson Electric Power (TEP) also has a pole-replacement program.

High-tech Approaches

Other wildfire mitigation efforts are more high-tech.

SRP has installed 12 artificial intelligence smoke-detection cameras on its transmission system as part of a research project. The cameras learn the topography in a 10-mile radius and send an alert if smoke is spotted. A limitation is that transmitting the data requires cellular service, Kerby said.

TEP is also testing a fire detection system in the Gila National Forest and in grassland areas around Fort Huachuca.

APS is adding weather stations and cameras to its circuits to better monitor conditions.

The utility is using covered conductors in high fire-risk locations and undergrounding lines "where it makes sense," APS' Bordenkircher said, noting the difficulty of digging through granite prevalent in parts of the state.

Another upgrade in fire-prone areas is expulsion-limiting fuses, which contain sparks rather than letting them fall to the ground. APS is using the fuses, as is TEP.

Kerby said SRP partners with APS on a "no reclosing program" for circuits in high fire-risk areas. If a fault occurs on one of those circuits during periods of high fire danger, it will remain out of service until it's been inspected and found to be in good condition, he said.

Ultimately, Kerby said, "It should be every utility's end goal to not need a PSPS," and measures including equipment replacement, system hardening and vegetation management will help make that possible.

"[So] that ultimately our system is in a good enough shape and the environment around the system is in a good enough shape that it can withstand the environmental conditions that could come its way," he said. ■

CAISO Receives FERC Approval to Increase Soft Offer Cap

A Higher Soft Offer Cap Would Better Reflect Inflation and Maintain Reliability, CAISO States

By Ayla Burnett

FERC has approved CAISO's request to increase its capacity procurement mechanism (CPM) soft offer cap from $6.31 per kW-month to $7.34, which CAISO states would better reflect inflation, labor rights and higher bilateral capacity prices (*ER24-1225*). The increase also would better position the ISO to maintain reliable grid operations in the summer, the order reads.

The soft offer cap, referenced when load-serving entities bid offers into the market to resolve resource adequacy deficiencies, is based on fixed operation and maintenance costs, ad valorem taxes and insurance costs of a reference unit, plus a 20% adder.

According to its tariff, CAISO is required every four years to conduct a stakeholder process and evaluate whether to update the CPM soft offer cap. In May 2023, the California Energy Commission provided CAISO with a study demonstrating CAISO's soft offer cap doesn't adequately reflect fixed costs and should be increased to $7.34 per kW-month.

"CAISO contends that the proposed soft offer cap is also high enough to ensure contributions to fixed cost recovery and low enough to provide appropriate market power mitigation," the April 25 FERC order states. "CAISO adds that the proposed soft offer cap will create greater incentives for resources to accept voluntary CPM designations."

Motions to intervene were filed by consumer advocacy organization Public Citizen, Calpine, Pacific Gas and Electric, the California Department of Water Resources' State Water Project, the city of Santa Clara and the Northern California Power Agency. CAISO's Department of Market Monitoring filed comments supporting the tariff provision.

FERC on April 25 Approved CAISO's Request to Increase its Capacity Procurement Mechanism Soft Offer Cap. | *Sandia National Laboratories*

"DMM supports the proposed tariff revision to better position the CAISO to maintain reliable grid operations and increase incentives for resources to accept voluntary CPM designations," DMM's letter to FERC reads. "In addition, accepting the amendments will allow for the CAISO and its stakeholders to focus on a more comprehensive set of changes needed in the overall CPM and resource adequacy framework."

CAISO plans to implement the changes by early June. ■

ERCOT News

ERCOT Board of Directors Briefs

Controversial IBR Rule Change Remanded Back to TAC

More than 12 months of negotiations and meetings between ERCOT staff and stakeholders have failed to resolve their differences on a rule change imposing ride-through requirements on inverter-based resources.

ERCOT's Board of Directors on April 23 punted the issue back to the Technical Advisory Committee, directing that the Nodal Operating Guide revision request's (*NOGRR245*) language be modified to address reliability concerns.

"I don't think it's ready for approval in its current state," Director Bob Flexon, chair of the Reliability & Markets Committee, said April 22 after staff and stakeholders made presentations to the R&M. "I'd like to see kind of less daylight between the two positions that are out there."

"I'm agreeing that this is not a finished discussion," Director Linda Capuano said.

The board unanimously approved R&M's recommendation to remand the NOGRR to TAC. The Office of Public Utility Counsel abstained from the vote.

Eric Goff, who has served as the lead spokesperson and represented the interests of renewable developers during the process, asked for direction from R&M as to whether TAC should bifurcate new versus existing resources within the NOGRR.

When ERCOT first proposed the guide change in January 2023, it specified ride-through requirements for existing IBRs and required strengthened obligations for future IBRs by requiring compliance with the Institute of Electrical and Electronics Engineers' standards as soon as reasonable.

"All our disputes so far have been about existing resources," he said. "TAC did not bifurcate at ERCOT's request previously. I think it would be helpful to know if you want us to do that."

"TAC needs to work with ERCOT," Flexon responded. "[We'll] let you guys work it out, since you're all the experts."

The revision request already has generated nearly 80 filings. It's meant to align the grid operator's rules with NERC reliability guidelines and the most relevant parts of the IEEE's *standard* for IBRs interconnecting with the grid. Two IBR-related voltage disturbances in West

New IMM Director Jeff McDonald makes his first appearance before the ERCOT board's Reliability & Markets Committee. | *ERCOT*

Texas in 2021 and 2022, dubbed the Odessa Disturbances I and II, have added urgency to the measure's eventual passage. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

Stakeholders have proposed software changesfixing the issues NERC and ERCOT have identified and have said continued regulatory uncertainty could put a damper on further investment in Texas. Unable to reach a compromise with ISO staff, TAC in March approved amended language that stakeholders pushed through over ERCOT's objections. (See *ERCOT Technical Advisory Committee Briefs: March 27, 2024*.)

"It appeared that we had reached a point where additional progress between ERCOT and joint commenters was unlikely based on the foundational differences in language that came to the March TAC meeting," Oncor's Collin Martin, TAC's vice chair, said.

ERCOT staff again focused their comments on grid reliability, saying the NOGRR's latest version does not address the "current, critical" reliability risk they sought to mitigate. Dan Woodfin, vice president of system operations, said stakeholders' proposed exemption process from the new standard for existing IBRs would leave up to 30 GW of resources that wouldn't have to comply with the new standard.

"The whole point of trying to do this going forward is that that standard is better than what our current standards are," he said. "Under the TAC-approved version, if a unit fails to meet [its] currently applicable requirements, they can request an exemption that sets a new standard going forward. If they fail to meet that, then they can ask for another exemption.

"And my question is, what is the point of a standard when anytime you fail it you can ask for an exemption to set a lower standard going forward?"

"At the end of the day, resource owners, operators, manufacturers and investors want the same thing as ERCOT: to rely on and support a reliable grid," said Sara Parsons, Avangrid's vice president of development. "To succeed in that, however, we need clear and understandable rules for reliability based on both engineering principles and economic principles that enable plants to keep operating and businesses to keep investing."

IMM's McDonald Meets R&M

Jeff McDonald, director of the ERCOT Independent Market Monitor, made a brief

ERCOT News

appearance before the Reliability & Markets Committee to brief directors on his first five weeks on the job.

He said the IMM team's work has been focused on changes to ERCOT contingency reserve service, an ancillary services study, and preparations for supporting the performance credit mechanism's development. On May 1, the IMM plans to share its annual report on the state of ERCOT's market with the PUC for its review.

"To the extent I've been involved in those conversations, I've seen fantastic cooperation between PUC staff or ERCOT staff and the IMM staff," he told the committee. "Those efforts have been fantastic to watch, with everyone coming together and trying to move forward."

McDonald was *named* the IMM's director in March. He replaced Carrie Bivens, who resigned from the position in November after 3 ½ years following several disagreements with PUC and ERCOT leadership. (See *Bivens Resigns as ERCOT's Market Monitor*.)

McDonald has 22 years of experience monitoring wholesale markets. He has led ISO-NE's Internal Market Monitoring Unit and was senior manager of CAISO's Market Monitoring Unit. Previously, he was vice president of Concentric Energy Advisors and principal of Libertas Market Analysis.

ERCOT Manages Total Eclipse

Woodfin told R&M that ERCOT breezed through the April 8 solar eclipse. Sort of.

"It wasn't quite as easy as what I read in the newspaper, but we did make it through," he said.

Solar generation dropped from 13.8 GW to about 700 MW at its low point at 1:36 p.m. CDT. Solar production once again hit 13.8 GW by 3:10 p.m.

Woodfin said ERCOT procured extra ancillary services, committed extra generation and took some manual actions to ensure there was enough headroom as various resources ramped up and down. Cloudy skies in portions of the state also reduced the eclipse's effect.

"It was certainly less than a clear-sky-type day," Woodfin said.

Board OKs $435M Project

The board approved several items already endorsed by TAC:

- The $435 million San Antonio South Reliability II Project that addresses reliability issues south of the city. (See "$435M San Antonio Project OK'd," *ERCOT Technical Advisory Committee Briefs: April 15, 2024*.)
- Two price corrections to real-time prices that met the criteria for review when any single counterparty's absolute value effect is either 2% and greater than $20,000 or 20% and greater than $2,000. (See "ERCOT Reviews Price Corrections," *ERCOT Technical Advisory Committee Briefs: March 27, 2024*.)

The board also approved two nodal protocol revision requests (NPRRs) and a change to the Retail Market Guide (RMGRR) that:

- *NPRR1197*: Enables resources to separately meter and settle loads located behind ERCOT-polled settlement meters at their points of interconnection.
- *NPRR1205*: Strengthens ERCOT's market entry eligibility and continued participation requirements for counterparties by clarifying minimum credit quality qualifications for banksissuing letters of credit and insurance companies issuing surety bonds on behalf of market participants.
- *RMGRR177*: Clarifies a customer's lease agreement option when a competitive retailer tries to remove a switch hold applied to a premise it is seeking to enroll. ■

— Tom Kleckner

ERCOT News

ERCOT Works to Address Loss of San Antonio Units

CPS Energy's Retirement Plans Would Lead to Reliability Issues

By Tom Kleckner

ERCOT is searching for alternatives to replace capacity that will be lost with the planned retirement of three gas-fired units near San Antonio.

The Texas grid operator issued a *market notice* April 22 saying it plans to issue a request for proposals for must-run alternatives (MRA) to avoid a more expensive reliability-must-run contract with CPS Energy.

"Any decision on whether to enter into an RMR or MRA service agreement must evaluate the costs and benefits of the service," ERCOT said.

The San Antonio municipality told the ISO last month that it planned to "indefinitely suspend operations" in 2025 of three gas-fired units at its V.H. Braunig facility. The three steam turbines, dating back to the late 1960s, have a combined summer seasonal net maximum sustainable rating of 859 MW. (See *CPS Energy Plans to Retire 859 MW of Gas Resources*.)

Spokesperson Milady Nazir said in an emailed statement that the units' retirement is part of the municipality's board-approved generation plan and that the units were nearing their "operational end of life."

However, ERCOT's reliability analysis identified "performance deficiencies" without the CPS resources on the system and determined the power plants are needed to support system reliability. In a *filing* with the Texas Public Utility Commission, the grid operator's staff said the units' retirement would load existing transmission facilities above their normal ratings under pre-contingency conditions.

ERCOT says CPS Energy's planned retirement of three units at its V.H. Braunig facility will cause reliability issues. | *CPS Energy*

ERCOT has asked the PUC for a good-cause exception from its *protocols' timeline* for RMR and MRA deadlines because of resource constraints.

"We would prefer to come up with a different timeline that still meets all the technical requirements in the protocols but gives us a little bit more time to get that RFP out and work with CPS on what a budget might look like for those units," General Counsel Chad Seely said at the Board of Directors' Reliability & Markets Committee.

"We will continue to have collaborative discussions with ERCOT during their review process," Nazir said.

Seely said the ISO's exit strategy for the RMR will "ultimately be a transmission solution."

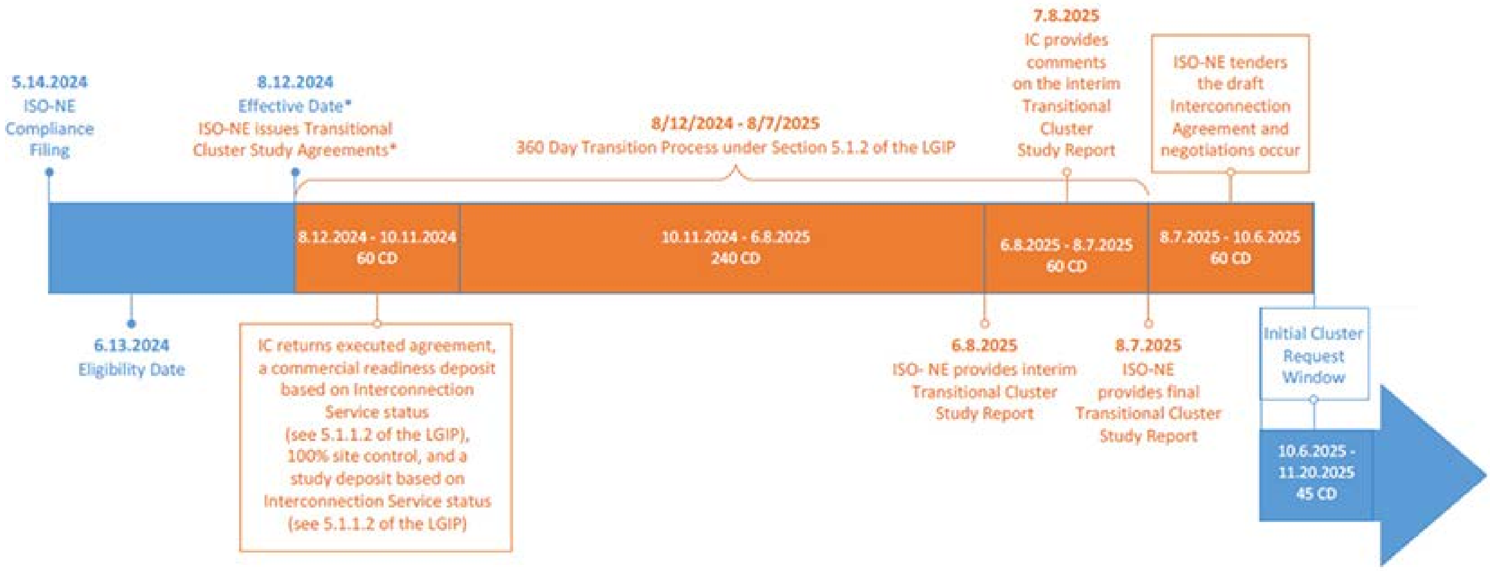
"Now, if there are other resources that could fulfill an MRA, that would give us the equivalent, then we can substitute for those, and that's part of the process here," he told the R&M committee.

The board on April 23 approved the $435 million San Antonio South Reliability II project that addresses issues south of the city. It approved another reliability project last August, proposed by CPS Energy at a projected cost of $329 million, that addresses thermal overloads in the area. (See "$435M San Antonio Project OK'd," *ERCOT Technical Advisory Committee Briefs: April 15, 2024*, and "Members Endorse $329M CPS Energy Reliability Project," *ERCOT Technical Advisory Committee Briefs: July 25, 2023*.)

An RMR contract would be ERCOT's first since 2016. ERCOT entered into an agreement with NRG Texas Power over a previously mothballed gas unit near Houston. The RMR contract ended in 2017, thanks partly to transmission facilities that increased imports into the region. (See *ERCOT Ending Greens Bayou RMR May 29*.)

Because RMR and MRA determinations support ERCOT's transmission reliability, costs incurred under either agreement are shared by all market participants that serve load. Costs are allocated on a load-ratio basis. ■

NEPOOL Transmission Committee Briefs



ISO-NE's updated transitional cluster study timeline | *ISO-NE*

The NEPOOL Transmission Committee has voted to approve updates to ISO-NE's Order 2023 compliance proposal to account for Order 2023-A.

Order 2023-A, issued in late March, made some minor changes to the original order in response to rehearing requests and extended the compliance deadline. (See *FERC Upholds, Clarifies Generator Interconnection Rule*.)

"None of these changes appear to materially impact the New England Order No. 2023 compliance proposal," ISO-NE wrote in a *memo* responding to the order. "The revisions, however, will need to be taken into account in the compliance proposal and the incremental changes to it will need additional NEPOOL votes."

ISO-NE now *plans* to submit two filings to FERC on May 14: its Section 206 compliance proposal and a Section 205 filing that would align the procedures for small generators and elective transmission upgrades with the new cluster process.

"While this filing is an integrated proposal, its components are independent to allow for the commission to direct changes," said Al McBride of ISO-NE.

The updates would push back the timeline for ISO-NE's initial "transitional cluster study." The RTO now proposes an "eligibility date" of June 13, which would be the due date for interconnection customers to have a valid interconnection request (IR) to be eligible for the transitional cluster.

"The ISO will not accept IRs submitted after the eligibility date until the first cluster entry window opens in 2025," McBride said.

ISO-NE now plans to proceed with late-stage system impact studies until Aug. 30, with the aim of limiting the number of projects that need to enter the transitional cluster study. If these studies are not complete by this Aug. 30 deadline, the projects still could enter the transitional cluster.

The timeline for the capacity network resource (CNR) group study, which is aligned with the schedule of the 2024 interim reconfiguration auction qualification process, will not be moved forward. This interim process would allow new resources that complete their system impact studies by June 30 to qualify for reconfiguration auctions through the 2027-28 capacity commitment period.

"Aside from the transitional CNR group study, the timeline for the remaining Order No. 2023 transition items has been updated to account for the delay caused by Order No. 2023-A," McBride said.

The updated proposal passed April 25 with no objections and now heads to the Participants Committee for a vote on May 2.

DASI Conforming Changes

Dennis Cakert of ISO-NE outlined ISO-NE's *proposal* to change the tariff definition of "self-schedule" to conform with its day-ahead ancillary services initiative (DASI).

"The ISO proposes to modify the definition of "self-schedule" to state that self-scheduled (SS) external transaction (ET) purchases (imports) are priced at the offer floor and SS ET sales (exports) are priced at the external transaction cap in the [day-ahead market]," Cakert noted.

The Transmission Committee will vote on the proposed changes May 16.

FERC Denies Waiver Request

Also on April 25, FERC denied a waiver request by Moscow Development Co. (MDC) related to a missed deadline to withdraw an interconnection request to receive a partial refund on its $50,000 initial deposit (*ER24-1295*).

MDC argued it received incomplete information at the scoping meeting, causing it to miss the deadline. The company requested a waiver to let ISO-NE return the unapplied part of its deposit.

ISO-NE supported the request, noting that "without the waiver, the ISO cannot return the unused portion (approximately $48,000) of the deposit to MDC."

However, despite ISO-NE's support, FERC denied the request "on the basis that it is prohibited by the filed rate doctrine." The filed rate doctrine prohibits the commission from making changes to previously filed and approved rates. ■

— Jon Lamson

ISO-NE News

New Initiative Focuses on Interregional Tx Coordination in the Northeast

By Jon Lamson

An early-stage collaboration between the Acadia Center and Nergica is intended to bring together communities, tribes, nonprofits, companies, RTOs and government officials from the northeastern U.S. and Canada to increase coordination around interregional transmission.

Dubbed the *Northeast Grid Planning Forum* (NGPF), the effort is aimed at changing the conversation around transmission planning throughout the broader region to help unlock infrastructure investments, improved planning processes and market changes to help facilitate the clean energy transition.

"If you look out at what states and provinces are trying to achieve with meeting climate goals," Dan Sosland, president of the Acadia Center, told *RTO Insider*, "there is a tremendous amount of potential complementary benefits that could be obtained if we step back and look at how the grids might coordinate in a more intentional way."

The entire region faces the potential for massive load growth over the coming decades, coupled with significant changes in how and where electricity is generated. Hydro-Québec *anticipates* its demand will double by 2050, while ISO-NE *forecasts* its peak load to reach up to 57 GW, compared to the 24-GW peak experienced in 2023.

The transmission investments needed to meet this load growth will be pricey: Hydro-Québec has proposed to invest $45 billion to $50 billion by 2035 to expand its transmission capacity, while ISO-NE has estimated that transmission upgrades needed by 2050 could cost up to $26 billion. (See *ISO-NE Analysis Shows*

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ISO-NE News

Benefits of Shifting OSW Interconnection Points.)

"We need to think about the grid in a different way," Sosland said, adding that transmission infrastructure throughout the Northeast has been developed largely project by project, leading to projects scattered across the map like "a game of pick-up sticks."

Meanwhile, several studies have found that increased interregional transmission capacity throughout the Northeast could bring cost, reliability and decarbonization benefits to ratepayers.

The U.S. Department of Energy specifically highlighted congestion issues between New York and New England in its *2023 National Transmission Needs Study*, which found the need for an additional 3.4 to 6.3 GW of transfer capacity between the regions in scenarios with moderate load growth and high renewable energy penetration.

Along with resource adequacy benefits as intermittent renewables proliferate, increased interregional transmission capacity "provides resilience and consumer savings during extreme weather events," the study wrote.

The study cited an *analysis* by Grid Strategies which found that during the "bomb cyclone" cold snap in the winter of 2017/18, ISO-NE, NYISO and PJM each "could have saved $30 [million to] $40 million for each GW of stronger transmission ties among themselves or to other regions."

Analyses have also projected significant cost benefits of increased two-way transmission capacity between Quebec and the northeastern U.S., with hydropower balancing out intermittent resources and limiting the need to overbuild clean energy.

One 2021 *study* found this bidirectional flow could reduce overall power costs by about 5 to 6% on a future grid with high levels of renewables. (See *Québec, New England See Shifting Role for Canadian Hydropower*.)

Notably, the nonprofits behind the effort represent both sides of the border; the Acadia Center is based in New England, while Nergica is based in Québec.

Frédéric Côté, general manager of Nergica, said one of the key goals of the forum is to help projects that address pressing transmission needs to overcome the hurdles that have caused cancellations and delays in recent years.

Transmission planning historically has occurred "mostly jurisdiction by jurisdiction," Côté said. "We feel that there is a need to rethink how it is done."

"Time is of the essence if we want to achieve carbon neutrality by 2050," Côté said. "We think we need to bring as many people as possible around the table to put together a road map for the region."

In 2023, a coalition of states launched the Northeast States Collaborative on Interregional Transmission, which has since grown to 10 states. (See *Northeast States Detail Early Efforts on Interregional Tx Collaborative*.) The NGPF is not intended to replace or be redundant with this collaborative, but instead is aimed at engaging a wider set of communities and stakeholders, the organizers said.

The forum is initially envisioned as three roundtables focused on different themes: environmental justice and community mobilization, interregional planning, and clean energy procurement and markets development.

Reflecting on the recent struggles of projects like the Twin States Clean Energy Link, Côté called for a greater focus on tangible community benefits, as well as on market reforms to better facilitate bidirectional power exchanges across the U.S.-Canada border. (See *National Grid Backs out of Twin States Clean Energy Link Project*.)

"It's not that easy to envision bidirectional exchanges in the current market state," Côté said.

Rob Gramlich, president of Grid Strategies, said there is no "magic bullet" to prevent project cancellations, "but having greater regional buy-in on new lines sure would help."

"Ideally, we need the key policymakers that are engaged in that forum to have some high-level conceptual agreement on a plan and a way to allocate the costs," Gramlich said.

The forum's organizers say they hope to hold in-person roundtables over the coming fall or winter and have met with different stakeholder groups to plan and gauge interest.

"We're in Phase 1 of really testing ideas and getting input," Sosland said. "We will then do an internal assessment in early May about whether there's enough interest and support to expand this into a larger phase."

While nothing is set in stone, Sosland and Côté said they're encouraged by the feedback they've received.

"We're getting really exciting responses to this," Sosland said. "If things proceed, we want to be very optimistic about the interest in moving this into an actual forum, actual roundtables and actual discussions." ■

MISO News

Missouri Zone Comes up Short in MISOs 2nd Seasonal Capacity Auction, Prices Surpass $700/MW-day

All Other Zones at 75 cents to $34/MW-day

By Amanda Durish Cook

MISO said its second seasonal capacity auction returned sufficient capacity in all zones except a portion of Missouri, where prices soared to more than $700/MW-day in fall and spring.

Save for Missouri's Zone 5, all local resource zones cleared at $30/MW-day in the summer, $15/MW-day in the fall, $0.75/MW-day in the winter and $34.10/MW-day in the spring. MISO published results at the close of business April 25.

Zone 5 — which contains local balancing authorities Ameren Missouri and the city of Columbia, Mo.'s Water and Light Department — cleared at the $719.81/MW-day cost of new entry (CONE) for generation in the spring and fall, then followed other zones in clearing at $30/MW-day in the summer and $0.75/MW-day in the spring.

MISO said its auction showed Zone 5 didn't have enough capacity to meet its local clearing requirements in the shoulder seasons and that large coal retirements played a factor in the capacity deficiency. CONE, the equivalent value of building new generation, is the maximum price MISO's tariff will allow the auction to clear.

MISO said while the auction indicates it will meet most of its 2024/25 planning year resource adequacy requirements, "pressure persists with reduced capacity surplus across the region and a shortfall in Zone 5." MISO's planning year begins June 1 with the summer season.

"Once again, our seasonal construct worked as designed by identifying the highest risk periods on the system," MISO President and COO Clair Moeller said in a press release. "These results continue to provide real-world examples of the urgent and complex challenges to the electric grid in the MISO region."

The grid operator said year-over-year, capacity surpluses in MISO receded by 30% in summer, especially in MISO Midwest. The opposite was true in winter, where all zones are due to experience higher surpluses than last winter.

This fall, Zone 5 is set to experience an 872-MW shortfall; in 2023, it experienced a 2.4-GW surplus. Zone 5's local clearing requirement for fall rose by more than 2 GW year over year.

Overall, MISO said it experienced a 4.6-GW capacity surplus this year, down from last year's nearly 6.5-GW surplus.

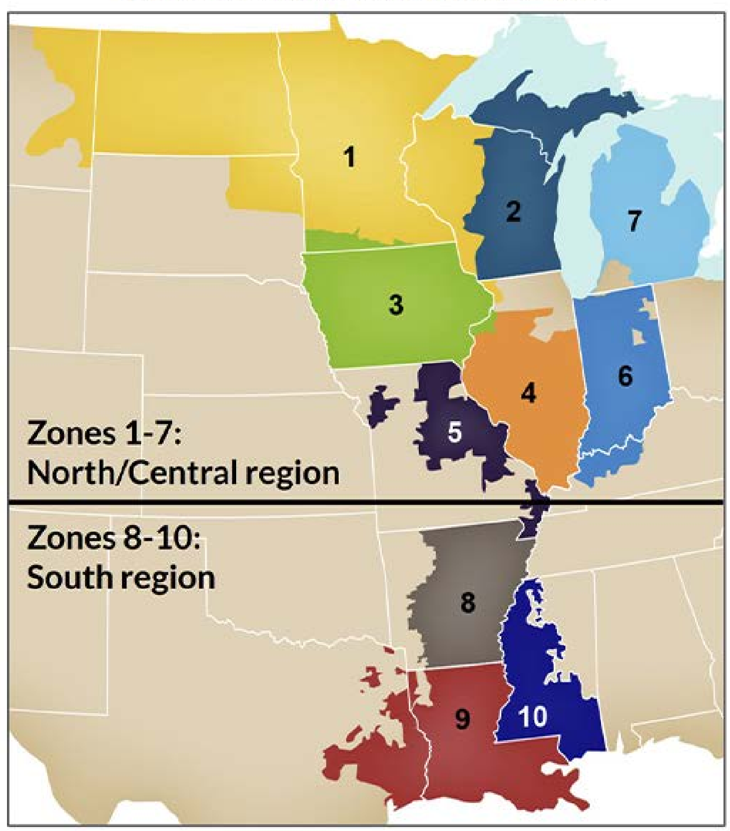
Last year, MISO zones cleared mostly at $2/MW-day in winter, $10/MW-day in summer and spring, and $15/MW-day in fall. Zone 9 in Louisiana and southeast Texas was an

2024 PRA Results

Zone	Local Balancing Authorities	Summer	Fall	Winter	Spring
			(Price $/MW-Day)		
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	30.00	15.00	0.75	34.10
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	30.00	15.00	0.75	34.10
3	ALTW, MEC, MPW	30.00	15.00	0.75	34.10
4	AMIL, CWLP, SIPC, GLH	30.00	15.00	0.75	34.10
5	AMMO, CWLD	30.00	719.81	0.75	719.81
6	BREC, CIN, HE, IPL, NIPS, SIGE	30.00	15.00	0.75	34.10
7	CONS, DECO	30.00	15.00	0.75	34.10
8	EAI	30.00	15.00	0.75	34.10
9	CLEC, EES, LAFA, LAGN, LEPA	30.00	15.00	0.75	34.10
10	EMBA, SME	30.00	15.00	0.75	34.10
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	30.00	15.00	0.75	34.10

Highlighted values are CONE pricing

MISO Resource Adequacy Zones



MISO's 2024-25 Planning Resource Auction clearing prices and zones | *MISO* outlier and cleared at $59.21/MW-day in fall and $18.88/MW-day in winter due to price separation to meet requirements. (See *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

MISO was required to meet a total 135.7-GW summer planning reserve margin requirement. Its 9% summer 2024 planning reserve margin is higher than the 7.4% annual planning reserve margin used in last year's Planning Resource Auction (PRA). (See *MISO Crunching Data for 2nd Seasonal Capacity Auction*.)

"Retirements, reduced imports and higher requirements are insufficiently offset by new capacity," MISO reported, adding a warning that its withering surplus, paired with the ongoing clean energy transition and new load demands, will continue to strain resource adequacy.

MISO said only load-serving entities that entered its PRA without enough capacity to meet their resource adequacy requirements are exposed to auction clearing prices. The RTO said the auction's impacts on consumer costs "will depend upon the shortfall amount and other factors, such as wholesale purchase agreements or retail rate arrangements with state regulators."

"This year's results amplify the need and urgency for MISO's efforts around resource availability and market redefinition," Moeller said. "We will continue working with our member utilities and states to hone regional planning processes and market mechanisms to meet the needs of our evolving fleet."

MISO said its proposals before FERC to install a *sloped demand curve* in the auction and to *accredit* capacity based on generators' expected availability, alongside its ongoing work to stimulate critical generating *attributes*, should help states ensure resource adequacy.

MISO's Independent Market Monitor has reviewed the offers and results of the 2024 PRA and has certified the results.

This is the second year MISO has separated its capacity auction by season. FERC in 2022 gave the RTO the go-ahead to establish four seasonal capacity auctions with separate reserve margins. (See *FERC Oks MISO Seasonal Auction, Accreditation*.)

MISO will discuss the auction results again at its May 22 Resource Adequacy Subcommittee meeting.

A 'New Risk Paradigm'

During an April 26 teleconference to discuss auction results, Senior Director of Resource Adequacy Durgesh Manjure said the auction results show MISO is entering "a new risk paradigm."

Manjure said the planned closure of a coal plant by fall affected Zone 5's capacity supply, seemingly referencing Ameren Missouri's Rush Island, which is slated close by mid-October per a court order for years of illegal air pollution. (See *Court: Ameren Still Without Remedy for Years of Rush Island Air Pollution*.)

He said Missouri's capacity picture also is "aggravated" by planned generation maintenance outages in the zone during fall.

"We do believe we're at the front end or early stages of this evolving risk," Manjure said, calling the reliability dangers "embryonic." He said the "unsurprising" effects of generation retirements, increasing planning reserve margins and shrinking imports will continue to intensify.

"And all of this was insufficiently offset by new capacity," Manjure said of the 2024/25 results.

"We believe the changes we see this year in results are very important. These results signal the need for continued due diligence in our region," Director of Resource Planning Scott Wright said, referencing the reduction in the Midwest region's capacity surplus.

Sustainable FERC Project's Natalie McIntire asked if generation owners in Zone 5 can shift planned maintenance outages to free up generation in the fall.

"It's really up to the asset owner … and frankly, after-the-fact changes, we haven't dealt with those before. We'll have to see," Majure said.

He added that the auction results are "only a piece of the puzzle" and that MISO has been in a shortage situation before for its entire Midwest region in the 2022/23 planning year. In that case, MISO didn't experience a loss-of-load scenario, he said. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

Manjure said Zone 5's shortage doesn't "immediately" mean shortfalls in the fall and spring, pointing out that imports and non-firm energy can assuage the situation.

This is the second year MISO has separated its capacity auction by season. FERC in 2022 gave the RTO the go-ahead to establish four seasonal capacity auctions with separate reserve margins. (See *FERC OKs MISO Seasonal Auction, Accreditation*.)

MISO will discuss the auction results again at its May 22 Resource Adequacy Subcommittee meeting. ■

MISO News

FERC Sticks with MISO on Queue Penalties over Clean Energy Groups' Rehearing Attempt

By Amanda Durish Cook

Clean energy groups were unsuccessful with FERC in their challenge of automatic withdrawal penalties in MISO's interconnection queue.

The commission decided April 25 that MISO is clear to continue use of an automatic and escalating penalty structure despite a joint rehearing request from the American Clean Power Association, the American Council on Renewable Energy, the Solar Energy Industries Association and Clean Grid Alliance (*ER24-340*).

"Commission precedent and the record in this proceeding demonstrate that interconnection withdrawals create a generalized harm in MISO that more than inconveniences remaining interconnection customers in MISO's interconnection queue," FERC wrote to justify MISO's penalty setup.

Under the penalty schedule, MISO can keep 10% of a developer's per-megawatt milestone fees at the queue's first decision point, 35% by the second decision point, 75% by the time their project reaches the third and final phase of the queue and, finally, 100% if they drop out during the negotiation stage of the generator interconnection agreement.

The penalty fees were imposed early this year as part of a package of rules meant to downsize MISO's interconnection queue and discourage speculative projects. On April 24, MISO announced it received 123 GW of project proposals under its 2023 queue cycle, less than the 171 GW it fielded in 2022. (See related story *MISO Reports 123-GW Roster for 2023 Interconnection Queue Cycle*.)

The clean energy groups had argued the penalties would have a chilling effect on generation entering the MISO queue because the fees would rack up before developers receive meaningful study results from MISO on the feasibility of their projects. They argued FERC treaded on its own philosophy that penalties shouldn't discourage interconnection customers from lining up projects or withdrawing them in an orderly fashion. (See *Clean Energy Groups Seek FERC Re-evaluation of Automatic Penalties in MISO Queue*.)

However, FERC said the penalties will persuade developers to withdraw nonviable projects "before MISO has expended significant resources studying such requests." It also said its precedent doesn't necessarily prohibit automatic fines.

"We find that neither the establishment of an automatic withdrawal penalty nor the amount of the penalty creates a barrier to enter MISO's interconnection queue; rather, such a penalty reinforces an existing consequence of withdrawing an interconnection request," FERC said. "While it is true that [penalties] may discourage the submission of speculative interconnection requests or encourage earlier withdrawals to avoid higher penalties, those outcomes are not unreasonable barriers to entering the interconnection queue."

| *NextEra Energy Resources*

FERC also agreed with MISO that automatic forfeitures will serve as an "appropriate mechanism to disincentivize speculative interconnection requests from entering the queue." ■

MISO News

MISO Reports 123-GW Roster for 2023 Interconnection Queue Cycle

RTO Claims Stricter Ruleset Kept Submittals from Climbing Higher

By Amanda Durish Cook

CARMEL, Ind. — MISO announced April 24 that 123 GW of new generation spread across 600 applications are vying to enter its generator interconnection queue under the 2023 cycle.

The 2023 intake, composed nearly exclusively of renewables and storage facilities, is almost 50 GW smaller than the 2022 application cycle MISO has been processing. MISO said while the number of proposed megawatts is still "significantly higher than historical averages," 2023's submittals were tempered due in part to its new, FERC-approved suite of tougher conditions on entrants.

Of the 123 GW of 2023 entrants, MISO said 115 GW (93%) represent wind, solar, storage or a combination of renewables and storage facilities. New solar projects account for 50 MW, storage projects total 29 GW, wind projects clock in at 19 GW, and hybrid renewable and storage projects about 17 GW.

MISO said if all the 2023 submittals are certified and accepted, the MISO queue will grow to 348 GW.

MISO required developers of the latest submittals to pay double in entrance and staged queue study fees, be subject to automatic and escalating penalty charges, and confirm they've obtained land for projects. The RTO had delayed opening its 2023 queue application window until March to obtain FERC approval to implement the new requirements. (See *FERC Rejects MW Cap, Approves MISO's Other Stricter Interconnection Queue Rules*.)

MISO said its stricter requirements will allow for quicker network upgrade studies because it cuts down on the number of speculative projects entering the queue and then dropping out. It said it expects "higher-quality and more viable projects entering the queue."

"Although these changes have resulted in a reduction from the previous cycle, it still represents a large number of projects for the team to study," Director of Resource Utilization Andy Witmeier said in a press release. "We will continue working with our stakeholders to refine the queue process."

Witmeier also pointed out that MISO is awaiting about 50 GW in approved generation projects that have yet to complete construction due to "financing, supply chain issues, delays in permitting and power purchase agreement negotiations." (See *MISO: Reliability Risk Upped by 49 GW in Approved but Unbuilt Generation*.)

At an April 24 Planning Advisory Committee meeting, MISO staff said the RTO still plans to file again to implement an annual megawatt cap on project submittals to the interconnection queue. FERC rejected MISO's first attempt to cap its queue entries annually based on a formula. (See *MISO to Try Again for Interconnection Queue MW Cap, Open Window for 2023 Requests*.)

The RTO has said annual queue entries as large as 2022's 171 GW aren't sustainable for a system that peaks at about 125 GW in the summer.

At the Gulf Coast Power Association MISO-SPP conference in March, MISO's Scott Wright said the RTO worries about the queue "getting killed by volume," where it's nearly impossible to process projects because the queue is in essence "sabotaged" by scores of low-quality projects that aren't fully fleshed out before being entered. ■

The interior of AES Indiana's Advancion battery storage array, which has been operating since 2016 at its Harding Street Station | *AES Indiana*

MISO News

Prices, Load Down in MISO March Operations

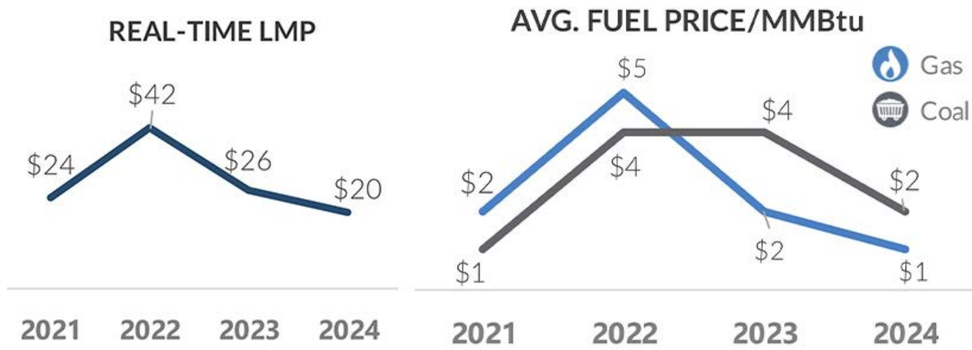
By Amanda Durish Cook

MISO energy prices plunged on record-low natural gas prices in March while the RTO managed a comparatively lower, 68-GW average systemwide load.

March average load was lower than MISO's 71-GW averages in 2022 and 2023, MISO *reported*.

The footprint peaked for the month at 84 GW on March 19, lower than March 2023's 89-GW peak and in line with previous March peaks in 2021 and 2022.

Real-time locational marginal prices were about $20/MWh for the month as the footprint experienced $1/MMBtu natural gas and $2/MMBtu coal prices. Real-time prices were lower than March 2023's $26/MWh and less than half of 2022's $42/MWh.



MISO real-time energy prices in March compared to fuel prices | *MISO*

MISO's average 48 TWh of supply came from a mix of 19 TWh of natural gas, 11 TWh of wind, 10 TWh of coal and 7 TWh of nuclear generation. The system again set an all-time solar generation record March 23 when arrays supplied 5.3 GW, or 6% of load at the time. MISO solar generation peaks have become commonplace as more solar projects clear the interconnection queue.

The RTO averaged 49 GW of daily generation outages over March, more than March 2023's 45-GW average. ■

MISO's Sloped Demand Curve Plan Draws 2nd Deficiency Letter

By Amanda Durish Cook

FERC has once again said it needs more information on clearing price caps before MISO can proceed with sloped demand curves in its capacity auctions.

The commission issued a second deficiency letter April 23 on MISO's plan to swap in sloped demand curves for its current vertical curve in its seasonal capacity auctions (*ER23-2977*).

FERC asked about the sloped demand curve design's opt-out provision to preserve state authority and lack of clearing price caps, among other details, late last year. (See *FERC Wants More Detail on MISO Sloped Demand Curve Plan*.)

This week, the commission again zeroed in on MISO's removal of its annual price cap for auction clearing prices as part of the move to sloped demand curves. It said it needs more explanation behind the RTO's proposal to eliminate the yearly cap.

MISO has said that once it implements the new curve design, the total annual price for a local resource zone could reach as high as four times the cost of new entry (CONE), depending on whether capacity shortages occur in all four seasons of the auction. However, the RTO has not explicitly listed an annual price cap in its new tariff language, telling FERC it is not necessary because its plan is clear that clearing prices will be capped at the seasonal CONE. It also said there is only a small chance that a zone would experience shortage conditions in all four seasons and that if that occurred, the more-than-$1,300/MW-day prices that ensue would properly reflect an "extreme" situation.

MISO's Carmel, Ind., headquarters | © *RTO Insider LLC*

MISO's current auction design employs a 1.75-times-CONE price cap for a local resource zone. This year's CONE *averages* $330/MW-day. The RTO has said its sloped demand curves would not allow prices to automatically jump to CONE values for small capacity shortages below reserve requirements, unlike the current, unyielding vertical demand curve.

Nevertheless, FERC asked MISO to shed more light on why it believes it is appropriate for prices to go as high as four times the cost to build new generation and how those price signals could incent more generation to show up.

FERC also asked for MISO to better explain why its current CONE cap would "degrade market efficiency and transparency when implemented with price-sensitive demand curves" like its sloped demand curve. The commission said it needed to hear more justification for the four-times-CONE construct versus the existing annual cutoff. It also questioned MISO's stance that any "ex post adjustment of prices could lead to suboptimal resource adequacy outcomes." ■

Entergy Earnings Call Focuses on La. Resilience Plan, Nuclear Outage and Settlements

By Amanda Durish Cook

Entergy's CEO touched on several recent developments on a first-quarter earnings call April 24, including the utility's recently approved grid-hardening plan for Louisiana, an outage at the Waterford 3 nuclear plant and New Orleans' acceptance of a settlement concerning Grand Gulf nuclear station.

Entergy CEO Drew Marsh said Entergy over the quarter made strides in "risk reduction efforts that will benefit our key stakeholders" during the call.

Entergy *reported* first-quarter earnings of $230 million ($1.08/share) compared to first-quarter 2023 earnings of $311 million ($1.47/share).

Entergy CFO Kimberly Fontan said the lower-than-expected earnings can be attributed to mild weather, planned generator maintenance outages and lower sales to cogeneration customers, among other factors.

Marsh framed the Louisiana Public Service Commission's April 19 approval of the utility's $2 billion grid-hardening plan in the state as a positive development.

"A more resilient grid will also serve as a catalyst for growth as it bolsters confidence for customers seeking to locate or expand in our service area," he said.

The PSC approved Entergy Louisiana's plan just four days after the utility submitted it; consumer advocate groups blasted the process as rushed and only in Entergy's interest. (See *Louisiana PSC Adopts Nearly $2B Entergy Resilience Plan*.)

Marsh said the plan includes 2,100 transmission and distribution projects that will be crucial to communities, and Entergy Louisiana plans to start work immediately.

Marsh noted Entergy Louisiana also filed for PSC approval of its Bayou Power Station, a $411 million, 112-MW "quick-start, nonbaseload" natural gas power station. He called it an "innovative solution to meet the power needs in a challenging area on the edge of the Eastern Interconnect."

The power plant is planned to sit atop a barge in a southern Louisiana canal and could rise with storm surges.

Marsh drew attention to the New Orleans City Council on April 18 agreeing to a $252 million settlement to resolve its longstanding allegations of mismanagement and poor performance at the Grand Gulf nuclear station in in Port Gibson, Miss.

The city council *settled* with Grand Gulf operator and Entergy subsidiary System Energy Resources, Inc. on three fronts: $116 million to resolve allegations around SERI's mismanagement; $138 million to settle allegations of dubious tax accounting; and $500,000 to lay concerns over reliability to rest.

"This agreement is consistent with SERI settlements with Mississippi and Arkansas, both of which were approved by FERC and determined to be fair and reasonable. … With the addition of New Orleans, SERI has resolved roughly 85% of its litigation risk," Marsh said.

Rod West, president of Entergy utility operations, said Entergy has a shot at pursuing a settlement with Louisiana "in the near term" over Grand Gulf operations now that New Orleans' litigation is over.

The Louisiana PSC has been a holdout on a settlement, maintaining ratepayers are owed hundreds of millions of dollars because Entergy mishandled plant operations, undertook an expensive and excessive plant expansion, and engaged in improper accounting and tax violations that shifted costs to ratepayers. (See *Former Employee Details Failures at Entergy's Grand Gulf*.)

Marsh also delivered an update on the offline Waterford 3 nuclear generating station in St. Charles Parish. He said the plant is "working to recover" from a shutdown following a transformer failure. He said the failed transformer was 20 years old, halfway through its expected lifespan.

"Early indications point to equipment failure as the cause," Marsh told shareholders.

In the meantime, Entergy plans to outfit Waterford 3 with an interim, spare transformer to bring the plant to 90% capacity over the summer until a fully compatible replacement transformer arrives, Marsh said.

"We're working diligently to bring the plant back online in the coming weeks," he said.

Finally, Marsh said Entergy utilities will submit by the end of May six projects furthering the clean energy transition for funding consideration from the U.S. Department of Energy's Grid Resilience and Innovation Partnership program. Entergy received letters of encouragement on six of the eight preliminary proposals it submitted late last year. Marsh said federal support stands to lower customers' capital costs. (See *Entergy Highlights Data Center and Industrial Load Growth in Q4 Earnings*.) ■

Waterford 3 nuclear station in Killona, La. | *Entergy*

PJM News

PJM Board Asks Members to Consider Endorsing RTO Filing Rights over Planning

By Devin Leith-Yessian

Dave Anders, PJM | © *RTO Insider LLC*

VALLEY FORGE, Pa. — The Markets and Reliability Committee discussed a request from the PJM Board of Managers that stakeholders consider endorsing revising the RTO's governing documents to transfer filing rights for regional transmission planning from the membership to the board. (See "TOs Considering Handing PJM Transmission Planning Filing Rights," *PJM MRC/MC Briefs: Feb. 22, 2024*.)

The *proposal* comes as members of the Transmission Owners Agreement-Administrative Committee (TOA-AC) discuss similar revisions to the Consolidated Transmission Owners Agreement (CTOA) — moving filing rights over planning matters from the Operating Agreement (OA) to the Tariff.

Any changes to the CTOA would require the approval of the TOA-AC and the Board of Managers, which requested the Members Committee vote on the changes in an April 17 *letter* to the Organization of PJM States Inc. (OPSI). That vote is slated for the MC's May 6 meeting.

PJM Director of Stakeholder Affairs Dave Anders said the board's determination that members should weigh in on the change came after stakeholders voiced concern about how a significant change to the balance of authority between the RTO and its members is being considered, including through letters sent to the PJM board by *OPSI* and the *Consumer Advocates of the PJM States* (CAPS).

Jessica Lynch, PJM associate general counsel, said the *changes* would delete Schedule 6, which details the Regional Transmission Expansion Plan (RTEP) protocol, from the OA and add largely matching language to a new Schedule 19 in the Tariff.

General Counsel Chris O'Hara said if the MC endorsed the revisions and the Board of Managers opted to pursue them, the TOA-AC still would need to agree to corresponding changes to the CTOA. He said the PJM board has not ruled out making a Federal Powers Act (FPA) Section 206 filing asking FERC to grant the RTO filing rights if the MC voted against endorsing the proposed language.

Asked where PJM staff stands on the proposal, Vice President of Planning Paul McGlynn said expanding the RTO's filing rights could allow it to make necessary planning decisions as the grid faces new realities.

"The system is changing dynamically right now. We're seeing load growth like we have not seen in years, new generation retiring, new generation interconnecting … I do think it's appropriate and I'm supportive of moving the protocol into the tariff," he said.

CAPS Executive Director Gregory Poulos said advocates remain frustrated by the pacing of the changes and the lack of information about their potential impact on transmission costs, one of the largest portions of consumers' electric bills, he said.

"I think there's a significant amount of frustration that this is being pushed or rushed upon them," Poulos said of consumer advocates.

Anders said the Board of Managers has asked that members vote on the changes in May to inform its thinking as the TOA-AC aims to conduct its own vote on the CTOA changes, also in May. Poulos questioned why the timeline the TOA-AC has set for itself appears to be defining the time the board and membership have to deliberate.

Adrien Ford, Constellation Energy's director of wholesale market development, said it's important PJM members be provided an opportunity to convey their perspectives to the Board of Managers through an endorsement vote.

Paul Sotkiewicz, president of E-cubed Policy Associates, questioned what members would have to gain by giving up filing rights and said the main difference in having the filing rights in the Tariff over the OA would be granting PJM the ability to override stakeholders with an FPA Section 205 filing.

McGlynn responded that PJM still would intend to go through the full stakeholder process to vet proposals, but that it would more appropriately complement PJM's role as an independent planner to have filing authority.

Asim Haque, PJM senior vice president of governmental and member services, said last year's critical issue fast path (CIFP) process focused on resource adequacy underlines how holding filing rights can allow PJM to conduct a stakeholder process to solicit proposals from membership to inform its thinking, but still have the authority to bring a filing to FERC if consensus cannot be found. That power could address goals pursued through the stakeholder process, including bringing renewable generation onto the grid, limiting the number of costly reliability-must-run contracts and reducing the backlog of resources in the interconnection queue.

Sotkiewicz argued the CIFP process is a cautionary tale for stakeholders, as the filings PJM ultimately brought to the commission varied significantly from the options the Members Committee most supported.

"To me you're making an argument to keep everything in the OA," he said. ■

PJM News

Monitor and Consumers Protest Indian River Compensation Settlement

By Devin Leith-Yessian

The Maryland Office of Peoples Counsel and the Independent Market Monitor for PJM are urging FERC to reject a settlement to compensate NRG for keeping a portion of its Indian River coal-fired generator online under a reliability-must-run (RMR) contract (*ER22-1539*).

The *agreement* would pay NRG $263 million to continue operating the 410-MW Indian River Unit 4 between June 2022, the generator's initial deactivation date, and the end of the RMR term on Dec. 31, 2026. The payment is split between $35 million for project investment costs and a $228 million "black box" sum, which combined amount to a $164 million cut to the $357 million NRG had requested for RMR service in its initial filing April 1, 2022.

In addition to decreasing the RMR compensation, the settlement would reduce the notice PJM must provide NRG to terminate the contract early, include the Monitor in reviewing new project investments and create a requirement that updates be provided at least three quarters before transmission upgrades are completed to resolve the reliability violations created by Indian River's retirement. The terms were signed onto by NRG, the Delaware Public Service Commission, Old Dominion Electric Cooperative, Delaware Municipal Electric Corp., the Delaware city of Dover and PJM. The settlement also states that it was not opposed by the Delaware Energy Users Group, Delaware Division of the Public Advocate, Maryland Public Service Commission and Southern Maryland Electric Cooperative.

The Maryland OPC and Monitor both argued the black box nature of the settlement figure prevents the commission from evaluating the merits of the compensation and that about half of the payment would be for sunk costs that NRG already had written off as impaired investments in 2013 and 2017.

The Monitor *argued* that PJM's tariff has two pathways for recovering costs incurred to provide RMR service, neither of which allow for sunk costs from prior to the start of the RMR period. In an affidavit, Monitor Joseph Bowring argued the proposed compensation would include $115,862,358 in sunk costs.

NRG's Indian River Generating Station in Delaware | *NRG*

"The goal of the tariff language is to ensure that a generation owner who operates a unit past its intended retirement date for reliability reasons is compensated for all the costs that it incurs in order to provide that service. Part V service has the limited purpose of allowing PJM time to complete transmission upgrades needed to ensure the reliable operation of the system after a unit deactivates," the Monitor wrote, citing PJM's tariff.

Based on figures included in NRG's initial RMR filing, the OPC *stated* that about 43% of the compensation would be for investments made prior to the start of the RMR period. It argued that would put consumers in the position of being asked to pay for losses Indian River experienced during its time as a merchant generator or face increased reliability risk if the resource retired prematurely.

"NRG's proposition to the commission embedded in the proposed settlement, to the affected states, and to affected electric consumers — boiled down to its essence — is that absent securing the windfall of recovery of a substantial and disproportionate quantum of its already-written-off investment, it will retire the plant, thereby putting at risk operation of the electric grid. The commission cannot and should not endorse this. The plant can be fully compensated for those ongoing operating costs incurred so the plant remains in service during the RMR period without providing it a windfall for sunk investments that it had no investment-backed expectation to recoup years following their write-off," the OPC wrote.

If sunk costs were allowed to be included in RMR compensation, the OPC argued an incentive would be established for aging generators with poor capacity factors to deactivate early to pursue compensation far higher than what they could receive in PJM's markets. It estimated the Indian River RMR would come out to about four times higher than recent Base Residual Auction (BRA) clearing prices for the DPL South zone.

"The distorted incentives resulting from possible recognition of an inflated rate base due to sunk, fully loss impaired, investment, for RMR service units will only accelerate this process. The recent filings by Talen Energy … seeking RMR service for the Brandon Shores and Wagner power plants in the constrained (Baltimore Gas and Electric Locational Deliverability Area) is an exponential exacerbation of this problem," the OPC wrote (*ER24-1787*, *ER24-1790*).

In initial *comments* on the settlement, FERC trial staff stated the settlement is "fair, reasonable and in the public interest" and recommended Settlement Judge Stephanie Nagel certify the agreement.

"The settlement reflects reasoned negotiations undertaken by all participants in good faith and resolves all issues in this proceeding. The settlement provides lower rates through a reduction in the monthly fixed cost charge and elimination of carrying charges in the project investment tracker," trail staff wrote.

PJM stakeholders are considering two proposals to rework rules around generation retirement requests through the Deactivation Enhancements Senior Task Force. A PJM package would increase the amount of time generation owners must provide of their intent to shutter a resource ahead, while the Monitor introduced a proposal to establish a formula for calculating RMR compensation based on going-forward costs. (See *PJM Stakeholders Considering Changes to Generation Deactivation Compensation and Timelines*.) ■

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PJM News

PJM MRC Briefs

Stakeholders Defer Vote on Long-term Planning Proposal

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee delayed voting on a *proposal* establishing a multiscenario long-term transmission planning process to allow stakeholders to first see what action FERC may take on regional planning. The motion to defer received 78% sector-weighted support.

The proposal would create two reliability-focused scenarios identifying transmission violations eight and 15 years in advance; two policy scenarios looking at new generation development backed by state legislation eight to 15 years out; and an additional policy scenario including higher generation entry not backed by signed legislation. It also would expand PJM's two-year planning cycle to three years to accommodate the increased number of scenarios. (See "Stakeholders Long-term Regional Transmission Planning Proposal," *PJM PC/TEAC Briefs: March 5, 2024*.)

FERC announced it intends to vote on an order related to cost allocation for regional transmission expansion during a May 13 special meeting. (See *FERC Observers, Stakeholders Lay out What is at Stake with Tx Rule Looming*.)

Paul Sotkiewicz, president of E-cubed Policy Associates, said the proposal is deficient from both policy and process standpoints, arguing it would replace the ideal of having markets driving planning decisions with PJM picking "winners and losers." By constructing the proposal through workshops, rather than committees, he said the stakeholder process was bypassed, preventing the language from being fully vetted by members.

"There are some real deep concerns from a process standpoint and from a concept standpoint," he said.

Sotkiewicz introduced the motion to defer to a month after FERC is expected to issue the order on the basis that members should have time to understand how it may interact with PJM's proposal.

"This is a major change. You've got a FERC rulemaking sitting out there that's going to come out in three weeks. There's no reason to vote on this now," he said.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said advocates are frustrated that alternatives to the standard stakeholder process increasingly are being used to seek endorsement of changes with reduced stakeholder input.

Denise Foster Cronin, of the East Kentucky Power Cooperative (EKPC), said the proposal could lead to significant costs for market participants and should be implemented by revising the governing documents rather than by edits to Manual 14B and Manual 14F alone.

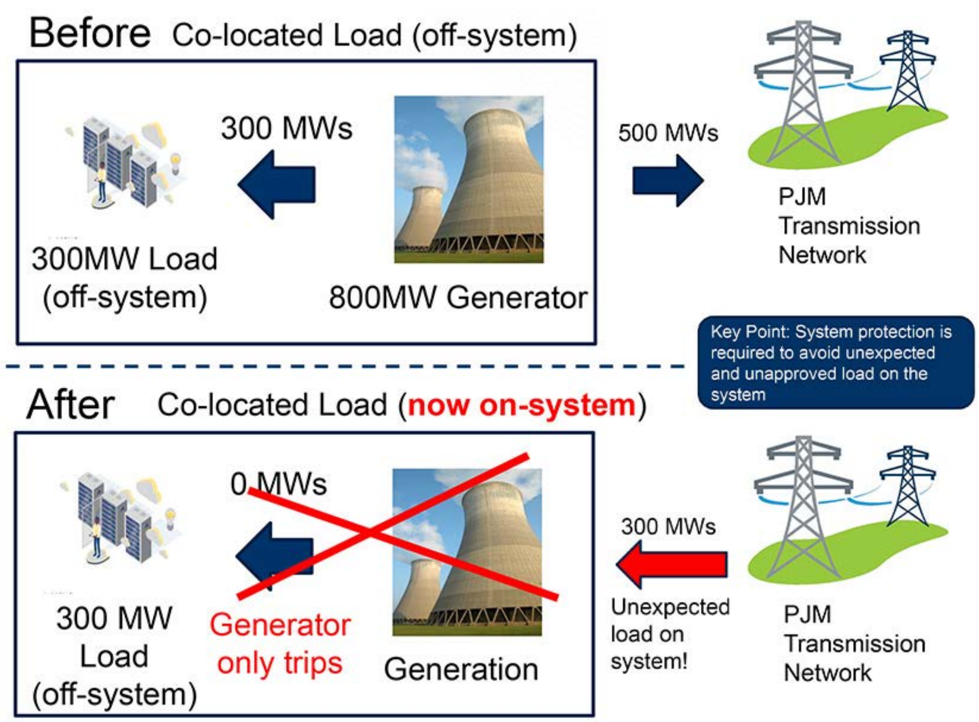
PJM argued a delay was unnecessary as its proposal is in line with the notice of proposed rulemaking (NOPR) the commission issued in April 2022 (RM21-17). PJM's Jason Connell clarified that expectation is entirely based on the NOPR, and RTO staff has not discussed the contents of the order with FERC.

The RTO's Michael Herman told the committee that if it endorsed the proposal without a deferral, a competitive window could be opened in 2025, whereas a delay could compromise its ability to implement the new process on its envisioned timeline.

PJM CEO Manu Asthana admitted there could be unintended consequences, such as PJM projecting too much load growth and overbuilding transmission, but the reliability needs outweigh the risks.

"There's many risks, but not doing this is a bigger risk," he said.

Ryann Reagan, of the New Jersey Board of Public Utilities (BPU), said the scenario-based planning paradigm is a major improvement that could relieve the interconnection backlog and contribute to proactive planning connect generation to the grid at the most cost-effective locations.



PJM presented updated guidance on the requirements for co-located load and how different configurations should interact with the grid. | *PJM*

PJM Re-evaluating CONE Inputs

Rising interest rates and construction costs have prompted PJM to initiate a *re-evaluation* of the inputs used to calculate the cost of new entry (CONE) for the reference resource in the quadrennial review. That parameter is a factor used to determine demand curve scaling. (See *FERC Approves PJM Quadrennial Review*.)

The new analysis will be for the values used in the quadrennial review accepted by FERC on Feb. 14, 2023, effective for the 2026/27 Base Residual Auction (BRA) scheduled to be run in December 2024. The Brattle Group has been hired as an independent consultant for the review; the firm also was brought in for the initial quadrennial review.

PJM's Pat Bruno said initial analysis of the change suggests updated figures could lead

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net CONE to increase between $50 and $100/MW-day. He said the review will be limited to the inputs used to calculate the reference resource CONE and will not affect other values produced by the quadrennial review.

Several stakeholders questioned why the energy and ancillary service (EAS) offset is not also being reconsidered given the potential for forward energy prices to change significantly between the quadrennial review's completion and the BRA. Two significant changes made in the most recent quadrennial review were shifting the reference resource from a combustion turbine to a combined-cycle generator and using a forward EAS offset, which uses forward energy forecasts to estimate revenues a market seller will receive outside the capacity market.

Stakeholders also suggested that developing a trigger for PJM to review quadrennial review figures or periodic reviews could increase transparency.

Additional Guidance on Co-located Load

PJM has revised its *guidance* for generators with co-located load clarifying how it conducts grid impact studies, the difference between co-located load configurations where the load is connected to the PJM grid or only the generator, and the circumstances under which generators with a capacity obligation can serve non-network load.

The guidance initially was posted in March and presented to the Market Implementation Committee on April 3. PJM updated the language with feedback received from stakeholders and reposted the document April 17. (See "PJM Provides Guidance on Co-located Load Configurations," *PJM MIC Briefs: April 3, 2024*.)

PJM's Tim Horger *presented* the revised guidance, saying the RTO's preference is that co-located load be interconnected with PJM, which provides firm service and subjects consumers to all service charges. However, the guidance acknowledges that jurisdictional constraints prevent it from requiring that configuration.

The alternative configuration is for the co-located load to be behind the generator's meter and not directly connected to the PJM grid, thereby not receiving firm service and allowing it to avoid service charges. The generator's capacity interconnection rights (CIRs) would be reduced by the amount of non-network load being served.

If the generator trips offline or otherwise cannot serve non-network load, the configuration must prevent the load from being able to draw from the PJM grid instead. A portion of the generator's committed capacity can serve non-network load; however, it must be approved to go on forced outage by PJM, which could expose the unit to capacity performance penalties if it is dispatched by PJM and does not switch its output to the grid.

The revised guidance clarifies how backup generators submit forced outage requests and adds that energy-only resources always will be approved for an outage to serve non-network load but still must request an outage to provide visibility to operators.

The co-located load is required to reduce its consumption to zero before the generator can coordinate with PJM to switch from the primary resource to the backup generator.

Adrien Ford, Constellation Energy's director of wholesale market development, said the requirement that load power down before being served by the backup generator ignores technologies for which the load could remain online while the power source is switched over without risking the load inadvertently drawing off the PJM grid, such as battery storage.

Under both configurations, PJM requires a network impact study be completed before co-located load comes online so PJM can analyze any potential reliability issues that arise, such as a need for more reactive power capability. If grid upgrades are required, the costs would be assigned to the generator.

"We need to know about these configurations. If there's co-located load coming onto the system, we need to know it's out there, so it needs to go through the proper interconnection system," Horger said.

Connell said it typically takes fewer than nine months to complete network impact studies on co-located load requests, depending on the configuration, with simpler arrangements often being completed much quicker.

Horger said PJM plans to draft manual revisions addressing co-located load over the next sixth months with the aim of arriving at governing document revisions. As the amount of co-located load has increased, he said it started to affect PJM planning and operations, necessitating clear rules.

Stakeholders voted on rule change packages for co-located load in October 2023, but none received adequate support. One of the core sticking points between the proposals was whether capacity resources should be permitted to retain their CIRs while serving non-network co-located load if that load could be quickly curtailed to allow the generator to meet its capacity obligation.

Quick Fix for Dual-fuel Classification Endorsed

Stakeholders endorsed a quick-fix *proposal* from Calpine Energy to adjust the qualifications for a generator to offer capacity as a dual-fuel resource to include gas units that can operate on an alternate fuel after starting on gas.

Calpine's David "Scarp" Scarpignato said the change would be implemented in the 2026/27 BRA due to how far into pre-auction activities the 2025/26 BRA is. The quick-fix process allows a proposal to be voted on concurrently with an *issue charge* and *problem statement*. (See "Calpine Proposes Changes to Dual Fuel Classification," *PJM MRC/MC Briefs: March 20, 2024*.)

Scarp said many combustion turbines and combined-cycle units capable of operating on an alternate fuel still consume gas to start, but the amount is so miniscule they could start multiple times on residual fuel in the pipeline even if supply was so compromised that they couldn't use gas as their primary fuel.

Erik Heinle, Vistra director of PJM market policy, said the change addresses an oversight in the governing document language establishing dual-fuel classification, leading to no dual-fuel combined-cycle generators being offered for the 2025/26 auction.

Stakeholders Endorse Additional ELCC Data Posting

The committee endorsed a PJM *proposal* adding a paragraph to Manual 33, which pertains to administrative services, allowing PJM to post aggregated forced outage data broken down by effective load carrying capability (ELCC) class.

PJM's Pat Bruno said manual language requires that any aggregated data must include four or more generation owners to be posted, which could prevent PJM from publishing outage data for ELCC classes in some hours. The revisions would allow PJM to post data for those hours while excising data for ELCC classes for hours in which the four-generation owner threshold was not met.

Heinle said the data could help market sellers better understand their ELCC accreditation and performance as PJM shifts to using marginal ELCC to determine the amount of capacity they can offer into the market.

Independent Market Monitor Joe Bowring said posting aggregated data would be a major departure from PJM's practice of posting such

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data only after major events, such as storms resulting in high outage rates. He said the difference in forced outage rates could allow identification of which resource went online and the revealing of market-sensitive data.

Changes to Capacity Assignments for Large Load Additions Contemplated

PJM's Pete Langbein *presented* a first read of a proposal revising how capacity obligations are assigned for serving large load additions (LLAs) — forecast load interconnection requests not captured in PJM's economic forecasting. (See "Stakeholders Endorse Proposal on Large Load Capacity Obligations," *PJM MIC Briefs: April 3, 2024*.)

The Tariff and Reliability Assurance Agreement (RAA) revisions would rework how PJM calculates capacity obligation assignments to exclude LLAs included in Table B-9 of the load forecast from base zonal scaling factors and add those LLAs back when determining the obligation peak load input.

Bowring argued that PJM's processes for reviewing LLA submissions and assigning capacity need a deeper look as they can result in consumers buying excess capacity if forecast load does not manifest in the expected delivery year.

Michael Cocco, of Old Dominion Electric Cooperative, agreed with Bowring but said LLAs receive some high-level review by the Load Analysis Subcommittee and PJM staff, which ultimately accept or reject the LLAs.

PJM's Andrew Gledhill said the RTO has rejected LLA submissions and would retain the power to review and ultimately determine whether they are incorporated into the load forecast and translated into capacity obligations.

Alex Stern, Exelon director of RTO relations and strategy, said the proposal aims to ensure capacity assignments accurately reflect the load that's expected to materialize in a region.

"This seems to be an enhancement to the load forecasting process and that's a primary goal and objective of what we do here, which is making sure we're investing in what we need to invest in, but also making sure that costs on the transmission and generation side are properly allocated to all customers," he said.

Other MRC Business

Stakeholders endorsed with 67% sector-weighted support a set of *revisions* to PJM's governing documents drafted through the Governing Document Enhancement and Clarification Subcommittee (GDECS), with the most notable being lowercasing the term "end-use customer" in the language detailing load management participation in the capacity market. Bowring and some stakeholders argued the change could significantly alter which entities can participate in demand response and said the change should have been made through the stakeholder process. (See "Governing Documents Revisions Endorsed Through GDECS Process," *PJM MRC/MC Briefs: March 20, 2024*.)

The committee endorsed by acclamation governing document and manual *revisions* adding definitions of three synchronous condenser parameters — condense startup costs, condense-to-generate costs and condense energy use. PJM's David Hauske said the parameters are in use and the new language codifies ongoing practice. (See "Other Committee Business," *PJM MRC/MC Briefs: March 20, 2024*.)

PJM reviewed revisions to *Manual 3*, which details transmission operations, and *Manual 36*, pertaining to system restoration, following the documents' periodic review. Both proposals are slated to be voted on by the MRC at its May 22 meeting.

The changes to Manual 3 would include a requirement that transmission owners notify the Operating Committee prior to implementing dynamic line ratings (DLRs) and rules for rescheduling canceled transmission outage tickets.

Manual 36 revisions update the list of TOs within PJM and the list of TO deadlines for submitting annual restoration plan reviews. ■

— Devin Leith-Yessian

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SPP News

SPP Markets and Operations Policy Committee Briefs

Staff Reveals Error in GI Queue Studies; Backlog Clearing Still on Course

AURORA, Colo. — SPP staff publicly alerted stakeholders last week that it failed to conduct a tariff-required analysis of several generator interconnection queue study clusters as they reduced the backlog of GI requests dating back to 2017.

SPP's Casey Cathey, senior director of asset utilization, quoted his late father, a salesman, as he broke the news some members already were aware of during the Markets and Operations Policy Committee on April 16. He said SPP discovered it "inadvertently" failed to conduct a contingent facility review for five clusters, beginning with the 2017-001 grouping through the 2020-001 collection.

"[My father] would say, 'You don't lose customers by making mistakes; you lose customers in how you handle those mistakes,'" Cathey said. "We made a mistake. That's just plain and simple."

SPP plans to handle this mistake using two processes dependent on the cluster study's progression. Once SPP has determined which interconnection requests in the affected clusters are contingent on previously assigned network upgrades, it said generator interconnection agreements will have to be amended to include the contingent facilities.

Until then, GI requests in the affected clusters that were not identified by SPP during the study process may be contingent. Those projects may be subject to limited operations until the contingent facilities are in service. Additionally, requests in the clusters in question could be assigned the cost of those facilities should higher-queued GI requests not build them.

"This is a big deal, and it's a big deal with a number of tentacles to it," the Advanced Power Alliance's Steve Gaw said. "When this first came out, it really did send shock waves through the developer community. We are still in the mode of dealing with, 'What does this do?'

"What we want we don't know yet, and what's going to be yet to develop is what the ultimate impacts are to the generation that's in this queue, and to the investments that have already occurred," he added.

The grid operator includes clearing the GI backlog of all requests submitted through 2022 by the end of the year as a priority for 2024. According to a timetable, it would post the last contingent facilities remedy, for the 2020-001 cluster, in August. The active queue contains 421 requests for 87 GW of capacity; it numbered 1,139 requests for 221 GW when the backlog-clearing effort began.

"We're still very much pushing to make that goal by the end of this year," Cathey said. "We have to resolve this. We recognize how important this is and we have to resolve that in a way that minimizes the impact to the customers."

He said SPP will post contingent facilities cluster study reports and amend GIAs as required.

SPP MMU's Keith Collins listens to responses during the MOPC meeting. | © RTO Insider LLC

Developers with GI requests should review all their projects, especially those in affected study groups, he said. Those nearing commercial operating dates or subject to 0 MW due to contingent facilities can request the RTO perform a limited operation system impact study (LOSIS), with a group LOSIS offered to those in service or expected to be in service within 18 months.

"This is a serious error and we're working with the developer community to come up with a very tight remedy plan to rectify this," Cathey said, adding that he welcomes other novel ideas to accelerate the plan.

Record Tariff Changes?

Members took up 26 tariff revision requests during the two days, leading MOPC chair and ITC Holdings' Alan Myers to posit that the number may be a record. The committee took no action on one of the RRs, but the other revisions and voting items passed with an average 96% approval.

A proposed revision incorporating western entities into SPP's resource adequacy process when they join the RTO's markets failed initially, securing only 53.4% of approving votes. When the motion's language was amended to clarify that deliverability across the DC ties would only include firm transmission service, the motion passed with 83.1% approval.

MOPC also delayed action on *RR620*, which would implement SPP cost-allocation policies for Joint Targeted Interconnection Queue (JTIQ) projects. However, the RTO's staff, transmission owners and SPP's JTIQ partner, MISO, have been unable to reach consensus over the rate template in pursuit of a more efficient "direct billing" approach. The committee agreed to a conference call April 26 to wrap up the tariff revision, but the meeting was cancelled April 22. Staff said the work to finalize RR620 is ongoing.

SPP and MISO have agreed to assign 90% of the JTIQ portfolio's $1.06 billion in costs for its five projects to generation. Load will cover the remaining 10%. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

The committee endorsed five other RRs that, if approved by the board, would:

- *RR600.8*: Add an incremental market-efficiency use charge to provide revenue offsetting incremental DC tie operations costs due to their market dispatch. The charge would be levied proportionally to all

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market participants' activity, including those with export and virtual transactions.

- RR605: Define an authorized outage and criteria, add requirements for resources' availability during both the summer and winter seasons (unless on an authorized outage), help load-responsible entities and generation owners better understand when to submit resource adequacy (RA) capacity when providing workbooks to meet the RA requirement.
- RR608: Allow new generation resources to operate with fewer restrictions during seasons where interconnection studies did not identify transmission constraints prior to the completion of all network upgrades, while still restricting those generators in seasons where interconnection constraints were identified.
- RR612: Modify the multiday economic commitment to allow long-lead resources to receive market commitments for purposes beyond reliability.
- RR616: Ensure any outage not approved by the SPP balancing authority and not an outside management control event is accounted for in performance-based accreditation (PBA).

MOPC also approved separate measures imposing resiliency options and correlated changes to the 2025 Integrated Transmission Plan and removing the voltage stability analysis from the 2024 ITP study. It also endorsed a price-formation policy to dispatch resources based on the true obligation and price the system using the obligation without the impact of the load shed and emergency pricing assistance.

SPC OKs Forecasting Task Force

Meeting after MOPC, the Strategic Planning Committee endorsed staff's recommendation to create a task force to improve regional load forecasting that tends to come up short.

Staff said even its lowest scenarios for peak load in winter forecasts exceed members' load expectations for resource adequacy. Summer load forecasts during ITP submissions exceed the lowest growth assumptions and remain below trends for more rapid growth, they said.

"Can we be better?" SPP's Cathey asked, drawing responses of agreement from several members. "From a regional perspective, it's 100% driven by the responsible entities and populated by members, so it's fully through member input. The question is, how can we put a little bit more attention to this to get a little bit more accuracy in the use cases and providing better data with changing, unconventional loads?"

Pointing out that some members have more sophisticated tools than others, "depending on the size of their shop," Cathey said staff has reached out to some members as well as SPP's fellow grid operators to gather data for the task force. He said SPP intends to keep the task force's membership small, but open, and focused on employees with planning responsibilities.

Cathey said staff believes defining improvements to regional planning would take eight months. He promised a checkpoint at year's end, with some long-term solutions handed to other stakeholder groups.

The SPC meeting was conducted with a somewhat unusual seating arrangement. The committee's leadership headed a U-shaped arrangement with SPP's rostered members. Behind the main table, another U-shaped arrangement gave interested onlookers a view of the backs of the committee leadership's heads.

"Sorry, I have worked my way up from coach in the back," quipped SPP's Robert Fox, director of enterprise architecture, as he belatedly joined the main table to comment.

Last MOPC for Dowling

The MOPC meeting was the last for Midwest Energy's Bill Dowling, who is retiring after 39 years sitting in the committee and other SPP meetings — or, as Midwest's vice president of engineering and energy supply said in referring to the number of years he has spent with the RTO, "a lot."

Myers began the meeting by singling out Dowling for recognition. Like Myers, Dowling has served as the committee's chair.

"I've gotten to know a lot of really great people," he said. "It's been a pleasure working with some really smart people. It makes me look good."

Committee Consents to 19 RRs

MOPC's unanimous approval of the consent agenda endorsed 19 RRs, 10 of which will go to the board for further consideration:

- RR555: Adds requirements to the operating criteria addressing FERC cold-weather recommendations.
- RR600.7: Integrates western entities seeking RTO membership under SPP's terms and conditions with updates that include a DC tie access charge.
- RR600.9: Adds a separate balancing authority area (BAA) on the western side of the DC ties to the SPP BA.
- RR600.10: Awards auction revenue rights and transmission congestion rights to the alternating current (AC) portion of transmission service that cross DC ties between the Western and Eastern Interconnections. Settling the rights will occur in two stages, with the AC portions settling in the respective interconnection.
- RR600.11: Renames the tariff's Attachment AN to Addendum 1 and adds language specific to western entities joining SPP as members of the West BAA.
- RR600.12: Includes a separate BAA on the western side of SPP's DC ties and other necessary market design clarifications adding policies necessary to integrate western parties into SPP.
- RR600.13: Bases some rates for point-to-point and network service on the western side of the DC ties and the associated revenue distribution on the amount of annual transmission revenue requirement specific to the facilities in an interconnection. This accommodates Western Area Power Administration's Upper Missouri and Rocky Mountain Region zones, which have facilities in both interconnections.
- RR600.14: Adds language clarifying West DC ties as constraints, similar to other transmission constraints that are part of the market power test and frequently constrained areas validations.
- RR600.16: Revises contract services agreements with WAPA-Upper Great Plains by removing language related to the Western Energy Imbalance Service market and narrowing the list of WAPA-UGP facilities to only those that are and will remain in the NorthWestern Energy BAA.
- RR607: Implements the Regional State Committee's change to the tariff's safe harbor provisions, from 125% to 100% plus the higher of summer or winter season planning reserve margin plus 10% (but not less than 125%).

Nine other endorsed RRs don't require board approval: RR590, RR596 , RR604, RR609, RR613, RR614, RR617, RR624 and RR625. ■

— Tom Kleckner

SPP News

SPP, Members Close in on Fuel Policy, Base PRM

By Tom Kleckner

Casey Cathey discusses resource adequacy efforts as Western Farmers Electric Cooperative's David Sonntag, SPP's Chris Haley listen. | © *RTO Insider LLC*

SPP and its stakeholders appear to be nearing consensus on two key parts of their resource adequacy work: establishing separate planning reserve margins (PRM) for the summer and winter seasons and setting up a fuel assurance mechanism.

The Supply Adequacy Working Group on April 22 overwhelmingly approved two revision requests and a so-called transition motion, all related to resource adequacy (RA). The first (*RR621*) would install a fuel assurance mechanism and the second (*RR622*) would set winter and summer PRMs of 33% and 16%, respectively.

Given SAWG's approval of the two reserve margins, members also endorsed a transition motion that, should the PRM be increased, bases the deficiency payment on the sufficiency valuation curve for up to two years from the effective season. The Cost Adequacy Working Group (CAWG) also recommended consideration of a longer sufficiency valuation curve method if a higher PRM is approved.

"This, to me, looks like a win across the board. It's not just a win for fuel assurance, it's a win for the planning margin and a win for the transition [motion]," American Electric Power's Richard Ross said during an April 26 education session held by the Resource and Energy Adequacy Leadership (REAL) Team.

"A lot of staff hours and stakeholder hours … went into [the PRM policy], a lot of discussion. And it took a lot of work to get to where we were," said SPP's Chris Haley, who is responsible for developing and managing RA policy items in the RTO's footprint.

CAWG also took several straw polls — as did the REAL Team in its previous meeting — gauging members' comfort with the winter PRM. They split, 9-9, on whether staff's 36% and 16% PRMs are appropriate when determining seasonal balance of risk. Seven members voted to impose those PRMs and keep the sufficiency valuation curve in place for three years; seven others favored a 33%/16% base PRM for 2026 that transitions to 38%/17% in 2028 or 2029.

Casey Cathey, senior director of asset utilization, while pleased with the work so far, focused on approvals yet to come.

"I think the real straw poll we will seek is official approval by the REAL coming in this May time frame," he said. "It really comes down to the overall seasonal balance of risk and making sure that we're covering what real-world scenarios were already seen in the winter time frame and where the risk is shifting."

The REAL Team next meets May 24 and again in June. It intends to bring both PRM options to the Board of Directors and Regional State Committee in August.

"We're just trying to bring you some of our major policies and to educate everybody and try to bring everybody up to speed," said the REAL Team's chair, South Dakota Public Service Commissioner Kristie Fiegen. "Some of it's really detailed, but I kind of feel like sometimes it needs to be detailed for us to understand it."

The team met April 18-19 in Denver for what Fiegen called a "family conversation." It was a candid discussion, after which REAL took straw polls on some of the issues discussed.

REAL Team members agreed a fuel assurance policy is needed and supported SAWG's direction. They selected, in a 9-4 vote, a 36%/16% base PRM and favored developing a voluntary load-shedding provision as an option for making deficiency payments. Finally, the team supported a 50% incremental cold-weather outage.

Cathey said if a 33%/16% or 33%/18% base PRM ends up being a "palpable option" to stay within a 0.1 day/year loss-of-load metric, SPP needs to avoid "setting an anchor" for the 2026/27 time frame that would place the grid operator behind the curve in two or three years.

"The recommendation would be to spend the time to make sure that we're all appreciative of what risk we're actually taking on at both the 33%/16% or the 36%/16% positioning for seasonal balance of risk," he said, "and trying to cover where the risk of the region is starting to shift." ■

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Company News

Wildfire Litigation Poses Threat to Xcel Earnings

By Tom Kleckner

Xcel Energy said it expects to incur a financial loss from Texas wildfires that could have a "material adverse effect" on the company's bottom line.

The Minneapolis-based company has acknowledged distribution poles belonging to its Southwest Public Service Co. subsidiary sparked the February Smokehouse Creek fire in the Texas Panhandle north of Amarillo. The fire, the largest in state history, consumed more than 1 million acres before being contained.

"I've been to the Panhandle, and I've witnessed the impacted areas," Xcel CEO Bob Frenzel told financial analysts April 25 during the company's first-quarter earnings call. "I can speak for the entire Xcel Energy team when I say that we are saddened by the losses and we will stand with the Panhandle community as we recover, rebuild and renew that area as we have for over 100 years."

Xcel has disputed claims that it acted negligently in maintaining and operating its infrastructure. It faces 15 lawsuits from the fire and is processing the 46 loss claims it has received. The company recorded a pretax charge of $215 million to cover losses before insurance.

But if the company is liable and must pay damages, the amount could exceed insurance coverage of roughly $500 million for 2024 wildfire losses and "could have a material adverse effect on our financial condition, results of operations or cash flows."

The Texas House of Representatives created an investigative committee on the wildfires and has held several public hearings. It plans to issue a report in early May.

Frenzel said the $215 million loss is a preliminary estimate that reflects the low end of a range and is subject to change. He said Xcel is responding to the wildfire risk by accelerating pole inspections and cutting power to lines during dangerous weather, among other measures.

"Like all utilities, we are experiencing profound changes in weather- and climate-related impacts on our operations," Frenzel said. "As a result, we must continue to evolve our operations for these unparalleled dynamics."

The Smokehouse Creek fire, the largest in Texas history, burned more than 1 million acres. | *Texas A&M Forest Service*

Xcel reported earnings of $488 million ($0.88/share) for the first quarter, compared with $418 million ($0.76/share) in the same period last year. The company said the results reflected increased infrastructure investment recovery and lower operations and maintenance expenses, partially offset by increased interest charges and depreciation. ■

NextEra: Solar and Storage Best Bet to Meet Load Growth

By Jon Lamson

Projected load growth nationwide from data centers, electrification and increased domestic manufacturing will drive increasing demand for renewables through the next decade, NextEra Energy CEO John Ketchum said during the company's first-quarter earnings call April 23.

"We believe the U.S. renewables and storage market opportunity has the potential to be three times bigger over the next seven years compared to the last seven, growing from roughly 140 GW of additions to approximately 375 to 450 GW," Ketchum said.

| *NextEra Energy*

Ketchum said the domestic solar supply chain is "much improved from two years ago," asserting that manufacturing capacity has increased and inflationary pressures are easing.

"The U.S. will need a significant and growing amount of electricity over the next decade and beyond, a large part of which will be powered by new renewables and storage," Ketchum said.

Ketchum said the ability to put solar and battery resources wherever needed will make them especially valuable in meeting demand from data centers in coming years.

The company reported that subsidiary Florida Power & Light placed in service 1,640 MW of solar in the first quarter, while NextEra Energy Resources had its best quarter for solar and storage origination, adding 2,765 MW to its backlog.

CFO Kirk Crews said FPL now owns and operates over 6,400 MW of solar resources, "the largest utility-owned solar portfolio in the country."

FPL's 2024 10-year plan also doubled its battery storage deployment target compared to 2023, with the target now totaling 4 GW. The utility also plans to deploy 21 GW of solar over the 10-year time frame.

Crews also announced that NextEra Energy Partners plans to repower an additional 100 MW of wind capacity, increasing its wind repowering target to about 1,085 MW through 2026.

Responding to a question about the potential of small modular reactors to help meet data center demand, Ketchum said he is "a real skeptic in SMRs coming into the picture to satisfy data center demand anytime in the near future. … SMRs are still a decade to 15 years away."

NextEra reported GAAP net income of $2.27 billion ($1.10/share) for the quarter, an 8.72% increase over the same quarter last year. This was off a 14.67% decrease in total revenue for the quarter from last year's $6.716 billion. ■

Company Briefs

Eversource Energy Sells Stake in Sunrise Wind to Ørsted

Eversource Energy last week finalized an agreement to sell its 50% stake in the 924-MW Sunrise Wind project to Ørsted.

Eversource will separately remain contracted to lead the project's onshore construction after closing. In this role, Eversource will be a service provider to Ørsted and will not have any ongoing ownership of the project.

More: *North American Windpower*

BW Solar Sells NY Solar Portfolio to Catalyze

BW Solar on April 23 said it has sold 12 New York community solar projects with a combined capacity of 76.7 MW to Catalyze.

The companies said the transaction includes six 38.2-MW preconstruction projects and another group of six 38.5-MW projects in early-stage development in upstate New York.

More: *POWER Magazine*

Company Says Mountain Valley Pipeline 'Largely Completed'

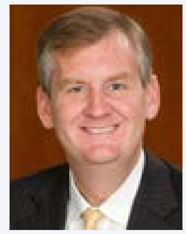
The Mountain Valley Pipeline is largely completed, the company said April 24 in requesting federal approval for it to be placed in service.

Although some work remains, the company asked FERC to issue an order by May 23 allowing it to begin operations, as it has completed projectwide waterbody and wetland crossings.

The news marks a near-final milestone for the project, which has been delayed repeatedly over the last six years by controversy and lawsuits taking issue with its environmental impact.

More: *The Roanoke Times*

Calpine Chief Thad Hill Elected EPSA Board Chair



Calpine CEO **Thad Hill**, has been named chair of the Electric Power Supply Association (EPSA) Board of Directors following his election at the board's annual spring meeting April 22.

Mark Sudbey, CEO of Alpha-Gen, was elected vice chairman. Jim Ginnetti, representing Energy Capital Partners, will serve as secretary-treasurer.

More: *EPSA*

Federal Briefs

US Energy-related CO2 Emissions Decreased by 3% in 2023

U.S. energy-related carbon dioxide emissions decreased by 3%, or about 134 million metric tons (MMmt), in 2023 compared to the prior year, according to the EIA's U.S. Energy-Related Carbon Dioxide Emissions report.

Although emissions decreased across many sectors, more than 80% of U.S. energy-related CO2 emissions reductions in 2023 occurred in the electric power sector. These reductions were caused largely by reduced coal-fired electricity generation, as natural gas and solar power made up a larger portion of the generation mix.

Emissions also decreased in the residential and commercial sectors by a combined 6%, to about 561 MMmt, due to milder weather reducing energy demand.

More: *EIA*, *EIA*

Major US Solar Manufacturers Call for Strict New Panel Tariffs

First Solar and Qcells, the two largest American solar panel manufacturers, have joined a coalition of domestic suppliers calling for new tariffs on below-cost and state-subsidized panels imported from Cambodia, Malaysia, Thailand and Vietnam.

The coalition, the American Alliance for Solar Manufacturing Trade Committee, filed petitions with the U.S. International Trade Commission and the Department of Commerce. The cases are intended to spur an investigation into the trade practices of manufacturers in those four countries and how they are harming the U.S. solar industry. The other petitioners include Convalt Energy, Meyer Burger, Mission Solar, REC Silicon and Swift Solar.

The coalition is accusing the four countries selling products in the U.S. for less than in its home market or less than its full cost of production.

More: *Canary Media*

Report: US Seeing Rise in Climate-related Power Outages

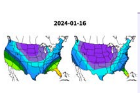
High winds, rains, winter storms and tropical cyclones including hurricanes accounted for 80% of all U.S. power interruptions over the last 20 years, a new report from nonprofit research group Climate Central shows.

Over the last decade, severe storm outages increased by 74% compared with the decade prior.

Texas had the most weather-related outages, followed by Michigan, California and North Carolina.

More: *The Guardian*

National/Federal news from our other channels



FERC, NERC Review January Winter Storm Performance

ERO Insider

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

State Briefs

COLORADO

United Power to Leave Tri-State G&T

United Power announced it will cut ties with Tri-State Generation and Transmission, effective May 1.

The departure follows years of conflicts between the cooperative and Tri-State over the power supplier's rates, what critics considered an overreliance on coal and restrictions on how much power members could independently generate.

United Power must pay $627 million to end its contract early.

More: *Greeley Tribune*

ILLINOIS

Wind Power Takes Dip, Could be Lessened by Climate Change

The amount of electricity generated from wind power — the state's biggest source of renewable energy — took a 6% dip from last year. Meanwhile, natural gas-generated electricity had a 43% jump in 2023, government data showed.

A pressure system in Canada was a big reason wind power decreased, as shifting wind directions affected how much power the state's turbines generated.

Scientists have been trying to understand how much climate change is affecting wind speed. Global warming affects wind and different regions are likely to experience it differently. Scientists hope to better understand how these shifts affect the Midwest, which has an abundance of wind farms.

More: *Inside Climate News*

MAINE

Gov. Mills Vetoes Bill Requiring Clean Energy Developers to Work with Unions

Gov. **Janet Mills** (D) on April 26 vetoed a bill requiring that companies leasing state land for clean energy projects work with unions.

The bill was aimed at the offshore wind power terminal and manufacturing facility the Mills administration aims to build in Searsport. Mills said she vetoed the bill because it contained ambiguous language and was too far-reaching, saying it was unclear whether it applied only to construction work or extended to all types of clean energy projects.

More: *Portland Press-Herald*

MASSACHUSETTS

Bourne Tidal Turbine Test Site Awarded FERC License

The Marine Renewable Energy Collaborative (MRECo) on April 26 was awarded an eight-year pilot license by FERC to test marine renewable energy generating tidal turbines at the Bourne Tidal Test Site.

The license will allow MRECo to manage tidal turbine testing in the Cape Cod Canal's ocean waters. The testing includes turbine efficiency, generation capacity, durability and potential environmental effects.

More: *Renewable Energy Magazine*

NORTH DAKOTA

McLean County Rejects Wind Farm Permit

The McLean County Commission on April 18 unanimously voted to deny a preliminary project area permit for what would be the state's largest wind farm.

Residents' concerns about the project's potential impacts to roads, farming operations, a local airport and wildlife were cited by the commission as reasons for denying the permit. The permit was just the first regulatory approval needed for the 94-turbine, 30,000-acre project.

More: *The Bismarck Tribune*

OHIO

Bill Seeks to Expand on Political Transparency

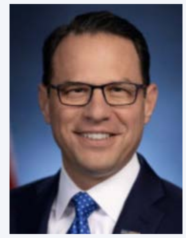
A bill introduced in the House Government Oversight Committee would ban public utilities from recouping their costs for political expenditures from customers, require companies to report their political expenditures and fine companies that don't follow the rules.

The fines would be placed in a fund for those needing assistance with their utility bills.

More: *WOSU*

PENNSYLVANIA

Gov. Shapiro Commits to Purchasing Half of Agencies' Power from Solar



Gov. **Josh Shapiro** (D) on April 22 announced that half of all power used by 16 state agencies will soon be solar generated.

Through the Pennsylvania Project to Utilize Light and Solar Energy (PA Pulse) initiative, the state has committed to purchasing half of its electricity from 10 in-state solar arrays. Shapiro says the state will purchase 361,000 MWh through a 15-year fixed price agreement.

More: *WHTM*

TEXAS

PUC OK Rules for Natural Gas Incentive Program

The Public Utility Commission on April 25 cleared one of the final hurdles for the Texas Energy Fund, a $10 billion voter-approved program crafted during 2023's legislative session, by establishing rules allowing companies to be reimbursed an estimated 10% of the cost to build eligible natural gas power plants completed before June 1, 2026.

The commission will begin accepting applications for the loan program in June. The program will remain open until the end of 2025. The PUC will open applications for the completion reimbursement program Jan. 1, 2025. Eligible power plants must have a capacity of at least 100 MW.

More: *The Dallas Morning News*

VIRGINIA

Hecate Secures Permit for 150-MW Solar Project

The Cumberland County Board on April 24 granted renewables developer Hecate Energy a permit to build a 150-MW solar park.

The solar farm will be installed across nearly 1,000 acres and is set to be complete in 2030. It will be capable of generating more than 300,000 MWh annually.

More: *Renewables Now*