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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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In this week's issue

FERC/Federal News

Utilities Seek Rehearing in FERC Interconnection Funding Proceedings

By James Downing


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A group of utilities have filed for *rehearing* of a show cause order FERC issued last month that could change the practice of who pays for interconnection lines at four ISO/RTOs. (See *FERC Issues Show-cause Order on TO Self-Funding in 4 RTOs*.)

The commission asked ISO-NE, MISO, PJM and SPP to explain why their tariffs that give utilities the first shot at paying for the transmission upgrades required by interconnecting generators are just and reasonable, or to submit changes.

Ameren Services, American Transmission Co., Duke Energy, Exelon, Northern Indiana Public Service Co. and Xcel Energy Services filed for rehearing of the show cause order this week. Ameren won a lawsuit involving MISO that started the practice back in 2018, but the District of Columbia Circuit Court of Appeals directed the commission to better explain its reasoning in 2022 after it had spread to the three other markets. (See *FERC Must Clarify MISO Transmission Funding Decision, DC Circuit Finds*.)

The 2018 decision from the same circuit court found that revoking transmission owners' right to self-fund network upgrades for interconnection and earn a right of return raised serious "statutory and constitutional concerns" due to compelling generator-funded upgrades on utility business models.

"The commission has now decided to take on those serious constitutional and statutory questions — and potentially take the historic step of compelling the construction, ownership and operation of interstate transmission facilities by private entities with no opportunity to earn a return — all on the unproven premise that doing so will actually save consumers money," the rehearing request said. "The show cause order is short-sighted and unwarranted. Investor-owned utilities investing private capital in exchange for a reasonable return is one of the most basic tenets of the century-old regulatory compact between government and the utility industry."

The constitutional issues come from the Fourth Amendment, which bars the government from taking private property for public use without compensation. Under the Federal Power Act, that has been interpreted to mean FERC cannot impose "confiscatory rates," which means utilities need to be able to earn a reasonable return on the value of property at the time it is being used to render service.

"It cannot be lawful to compel the construction, ownership and operation of utility-owned assets with no opportunity to earn any return," the rehearing request said. "On this basis, the proposal in the show cause order is per se unconstitutional."

FERC suggested the interconnection upgrades can be treated as "nonprofit appendages without jeopardizing total return," but the utilities argued it lacks the authority to eliminate equity returns from an entire class of rates represented by a major driver of new transmission investment. The utilities argued the decision could discourage much-needed investment in transmission expansion.

The commission has run multiple proceedings that led to the rules at issue, while the D.C. Circuit's 2022 ruling only required a better explanation as to why "generators' concerns about potential discrimination did not outweigh the transmission owners' enterprise-risk concerns."

The show cause order goes further and reopens the potential for discrimination in what appears to be an effort to "backfill the record that never materialized" in the proceedings leading to the currently effective rules across the four markets, the request said.

The dispute started in MISO with FERC proceedings stretching back to 2011 with multiple proceedings that wound up before the D.C. Circuit with the court vacating decisions empowering generators to override a transmission owner's self-funding choice.

The court concluded the commission had "distorted and dismissed" the transmission owners' fundamental argument that FERC's orders would require transmission owners "to act, at least in part, as a nonprofit business," and constituted an "attack on their very business model," creating a risk of deterring "new capital investment," the rehearing request said.

That 2018 decision found it was "at least uncertain" FERC would reach the same conclusion on remand after addressing the deficiencies identified by the court. FERC sided with the transmission owners on the remand order. American Clean Power Association then filed a lawsuit that led to the 2022 decision, which FERC did not deal with until the show cause orders issued in June. ■

FERC/Federal News

Demand Growth Takes Center Stage at NARUC Summer Policy Summit

By James Downing

From left: North Carolina Utilities Commission Chair Kimberly Duffley, former FERC Commissioner Tony Clark, Google's Briana Kobor, Constellation's Kathleen Barrón and PJM's Jason Stanek | *© RTO Insider LLC*

WEST PALM BEACH, Fla. — The return to demand growth in the electric power industry has been a major theme this year, and it dominated the discussion at the National Association of Regulatory Utility Commissioners' Summer Policy Summit last week.

"We're hearing more and more about the increase of load and demand on our system every day," FERC Chair Willie Phillips said. "Not just regular run-of-the-mill increases. … We're talking about sharp, material increases on our system."

The issue varies regionally, with some areas already feeling a tighter supply-and-demand balance because of the growth in data centers, reshoring of manufacturing, electrification of home heating and transportation, and increasingly extreme weather, Phillips said.

Thousands of Houston-area customers were without power for a week at the peak of summer after Hurricane Beryl, while other parts of the country were facing major heat waves, with D.C. seeing triple-digit temperatures as NARUC was meeting.

Conservative estimates have demand growing nationally about 1%/year, which over the next five years could add up to 5,000 TWh of new demand. FERC has issued a series of major rules, including Order 2023 on interconnection and Order 1920 on transmission planning and cost allocation, that Phillips said would help the situation. Order 1920 will help expand transmission to deal with those new drivers of demand while maintaining reliability and affordability, he said.

"I know that not every commissioner in this room has embraced Order No. 1920, or 1977," Phillips said. "Not every commissioner on FERC has embraced No. 1920."

But the industry needs to start moving forward on planning for the future, as demand is growing, and Phillips said the order's focus on long-term planning with a broad set of benefits will get much-needed steel in the ground.

"We have to consider grid-enhancing technologies as well," Phillips said. "So, there is a requirement both in Order Nos. 2023 and 1920 to consider grid-enhancing technologies as we build out our system."

Order 1920 was the subject of dissent from FERC Commissioner Mark Christie, whom Phillips called his friend from before their time as federal regulators. Phillips was on the D.C. Public Service Commission when Christie was on the Virginia State Corporation Commission, and the two neighboring state regulators regularly worked together at NARUC and the regional Mid-Atlantic Conference of Regulatory Utilities Commissioners.

Christie spoke at the conference after Phillips, and he basically agreed on the dominant theme of the event, though he framed it as reliability and said it was the states — much more so than FERC, or the ISOs and RTOs — that had the power to ensure it going forward. FERC does oversee reliability standards for the bulk power system, but it has limited authority when it comes to actually building needed infrastructure.

Section 215 of the Federal Power Act says FERC has no authority to order the construction of any utility asset, whether generation or transmission, Christie said.

"That's the states; you are the IRP [integrated resource plan] planners," he added. "When it comes to resource adequacy … that's under state jurisdiction. You're the ones who decide what generator units are going to get built. You're the ones who decide what generator units are ultimately going to be retired."

RTOs' primary role is to run the system and to make sure they can balance the grid, which is important. The organized markets will say when they see trouble brewing on the reliability front; Christie said many of their communications on those lines in recent years showed a brewing crisis for the grid.

"Yesterday at 4:30, PJM peaked on this hot day; PJM peaked at about 153 GW of load. … They had 9 GW in reserve. That's 6%," Christie said July 16.

July 15 was one of the hottest days of the year, and despite PJM using almost all its generation to meet the day's demand, the RTO is expecting to lose up to 50 GW in the coming years, Christie said. "That arithmetic does not work."

Other RTOs are also forecasting retirements and seeing thinner reserve margins, which Christie said is a recent phenomenon. For most of his tenure on the SCC, Virginia's utilities would come in with load growth projections that nobody believed because they were always flat from the previous data, and the numbers were coming at a time when PJM was very long on capacity.

That changed toward the end of Christie's tenure at the SCC and has continued during

FERC/Federal News

NARUC President Julie Fedorchak, of the North Dakota PSC, with author and energy expert Daniel Yergin | © RTO Insider LLC

his tenure on FERC. Virginia has been home to "Data Center Alley" for decades, and while that used to be focused around the D.C. area, it has stretched down I-95 to Richmond in recent years, Christie said.

"When you are doing load forecasts now, you've got to really get those things right," Christie said. "And then you've got to take seriously what they are showing."

Demand Growth Projections

Grid Strategies President Rob Gramlich presented his organization's report released late last year about the change in demand growth trends. (See *Grid Planners Predict Sharp Increase in Load Growth*.)

The five-year load growth forecast doubled in one year, Gramlich said, with some regions like Dominion Virginia Power and ERCOT seeing higher load growth than the average. The new load is coming from reshoring manufacturing, data centers and electrification. Data centers alone may contribute 1% demand growth annually.

Addressing that demand growth will require enhancing the distribution and transmission systems, as well as ensuring the grid has enough energy around the clock and important reliability services like inertia and ramping, Gramlich said.

While 1% load growth does not sound like that much, it is double what had been the norm in recent years, and over time, it can really add up, said former FERC Commissioner Tony Clark, senior adviser at Wilkinson Barker Knauer. The numbers also vary significantly by region.

"This is a paradigm shift that is probably perhaps not unlike the paradigm shift we saw with fracking and availability of natural gas in terms of impact on the industry itself," Clark said. "So, it's a big deal."

The new demand growth is coming at a time of traditional generators retiring, and the replacements tend to be renewables, which offer plenty of energy, but not nearly the same amount of capacity as traditional power plants, Christie said.

Clark brought up the same issues about replacing retiring generation, and he argued that no "silver bullet" exists to deal with the projected gap as demand grows.

"In all probability, to me, it looks like probably some sort of mix of natural gas and renewables in the near-term future because that's what we have available today," Clark said.

Other options, like long-term storage, small modular reactors or other kinds of advanced nuclear, are not immediately available, so serving the demand reliably is going to be a real challenge, he added.

The Impact of Vehicle Electrification

While forecasts always carry uncertainty, some of the load growth is already baked in, with Alliance for Automotive Innovation CEO John Bozzella saying California's rules on vehicle mileage, which have been adopted by states representing 40% of the market, will require 35% of their vehicles be electric in the coming years.

But many consumers have started to sour on electric cars because charging infrastructure has not kept up with demand. According to AAI's latest report, as of the first quarter this year, the U.S. had 167,213 charges for 4.7 million electric vehicles, for a ratio of 28 to 1, while 1 million are needed by 2030 to meet projected demand.

McKinsey & Co. has found that 46% of current owners are likely to switch back to gas-powered vehicles (compared to 29% globally), and the biggest reason is the lack of public chargers, Bozzella said.

The impact on the grid of electrifying medium- to heavy-duty vehicles represents much bigger loads. Environmental Defense Fund attorney Cole Jermyn said fleet managers are planning to transition a year or two ahead of time, which is shorter than most utility planning cycles.

"If they're a large fleet, that's a multi-megawatt load that, depending on the grid infrastructure, can take several years — well longer than the fleet actually knows their plan — to complete the substation, the feeder or transformers, or whatever it is that they need to actually bring their chargers online," Jermyn said. "So, ... the pace of the electrification is creating this disconnect that requires proactive efforts to prepare for."

It is possible for utilities to proactively plan for major fleet electrification because they are in specific neighborhoods, whereas light-duty vehicles are spread around utility territories, he added.

While estimates vary for how quickly both consumers and businesses will electrify their vehicles, even the low-end predictions represent significant new loads, said Ben Shapiro, manager of RMI's Carbon-Free Transportation team.

"Utilities understandably want to be sure, to the extent possible, that they're going to get cost recovery," Shapiro said. "And they don't have a ton of incentive to be more proactive in this space under the existing paradigm."

FERC/Federal News

That requires reducing the uncertainty to improve decision-making, shifting to a more targeted approach to addressing future load growth, and finding new ways to mitigate and share risk across parties, he added.

One area that can help improve load forecasting is "vehicle telematics" that show utilities where fleets are driving and parking now to inform future charging needs, Shapiro said. Another policy that would help is ensuring that the existing infrastructure is used efficiently to help avoid overbuilding distribution system upgrades.

The federal Joint Office of Energy and Transportation, which combines the efforts of both departments on the transition to EVs, has a plan to start working on expanding electrification around the country, said Jean Chu, an analyst for the office.

"Our intention is to capitalize public and private investment to accelerate the industry activity and to signal the utility and electric utility and hydrogen market to plan and deploy the necessary generation, transmission and distribution projects," Chu said.

The plan would prioritize areas likely to be early adopters of medium- and heavy-duty vehicle electrification first, and then link those regions together along the existing highway network. Once the biggest areas are connected in the next decade, the departments would shift their focus to electrifying the rest of the country, Chu said.

Data Center Expansion

Constellation Energy has the largest competitive retail business serving the commercial-and-industrial sector, but Chief Strategy Officer Kathleen Barrón said they do not have any better idea of what future demand will be than others presenting at NARUC.

Hydrogen was supposed to be a major driver of load growth, but issues around tax credits have at least delayed that, and the shift toward electrification has also waned in recent years. Now the latest issue is data centers scaling up as new technologies require more capacity from them. The Electric Power Research Institute released a report on data centers recently, and its forecasts vary widely, Barrón said. (See *EPRI: Clean Energy, Efficiency Can Meet AI, Data Center Power Demand*.)

"Some of the developers are looking at different sites for the same project, so I think

FERC Chair Willie Phillips addresses NARUC's Summer Policy Summit. | *© RTO Insider LLC*

FERC/Federal News

that they contribute to a little bit of double counting," Barrón said.

Data center developers are taking a page from the renewable industry, where they propose multiple projects to find out where it is cheapest to plug into the grid, with more expensive alternatives never coming to fruition.

"But in general, of course, we do see greater load growth moving forward than we have historically," Barrón said. "So the question is, how do customers plan to meet that demand? What we're seeing is an increasing number of them looking to power their operations with zero-carbon electricity."

Policies are pushing the industry cleaner, but many large data center customers want to go even further and power their operations with 24/7 clean electricity, she added. Constellation can meet their demands in a variety of ways, including linking multiple large customers as off-takers under power purchase agreements with new renewables, and it also owns and operates the largest domestic fleet of nuclear reactors.

The demand for data centers needs to be met with states offering incentives to site them in their jurisdictions and the federal government seeing the issue of artificial intelligence technology as a key national security issue, Barrón said.

While AI technology is more energy intensive than traditional internet use, Briana Kobor, Google's head of energy market innovation, noted that data centers are used every time customers surf the internet on their smartphones and are involved in huge parts of the economy generally.

"In 2020, the digital economy accounted for over 10% of U.S. GDP and [employed] nearly 8 million people," she added.

AI might currently be dominated by chat bots and the production of "funny pictures," but the technology could revolutionize how humanity deals with some of its biggest problems, Kobor said.

About 4% of PJM's overall load goes to serve data centers, as it is home to a large share of the 2,700 facilities around the country, with many of them in Northern Virginia, but also other areas the grid operator serves, such as Columbus, Ohio, said Jason Stanek, the RTO's executive director of government services.

While some of the projections could be influenced by speculative data centers, load is growing in ways that were unexpected just a few years ago. PJM is increasingly focused on figuring out exactly where the new data centers are actually going to plug into the grid, and it has surveyed the local delivery companies in its footprint to get better data in its load forecasts.

From left: DOE Assistant Secretary Gene Rodrigues; AAI CEO John Bozzella; Georgia Power CEO Kim Greene; Teresa Ho Kim, J.P. Morgan Asset Management; Brianne Miller, Microsoft; and New Hampshire PUC Commissioner Carleton Simpson | *© RTO Insider LLC*

"We ask our utilities within PJM to report back whether or not we need revisions to reflect large customers coming on board," Stanek said. "The question is whether or not these data centers are shopping around; we'll see multiple data centers show up."

The data PJM gets back from its member utilities will be included in a new forecast that is released in January 2025, he added.

Google agrees that there is likely some duplication in the amount of data center demand being projected, and it is important to get the numbers right; as a customer it wants to avoid overbuilding the system, Kobor said.

"We have a shared interest in making sure that we do not end up with an overbuilt system and get stranded costs at the end of this, just like any other ratepayer," she added. "So I encourage folks to continue that conversation with us as we continue down this journey. And I think we are likely in a point of greatest uncertainty, and we're going to start to see greater clarification as we move forward."

Getting that clean supply from the grid can be complicated for data centers, which have a shorter development time than it takes to build new generators, interconnect them to the grid and expand transmission to deliver new power to load, Barrón said. That has driven interest in data centers and other large customers to link up directly to nuclear plants and avoid using the grid altogether.

The issue of data centers connecting directly at nuclear plants is pending in a case at FERC, in which Constellation has intervened to argue that the commission should let such deals happen — though others have said it could bring up issues around cost shifting and eventually even reliability. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

Locating at nuclear plants also avoids "NIMBYism" because they are always built on large swaths of land. Such deals also avoid building out the transmission and distribution systems to accommodate major new loads, avoiding socializing those costs to other customers.

Nuclear plants are currently benefiting from a tax credit that has prevented additional retirements, but that is going to sunset in eight years, and forecasters expect nuclear retirements will resume when it does, Barrón said.

"If you have a customer that was willing to commit to long term, you wouldn't have to be concerned about that," she added. ■

FERC/Federal News

Manchin-Barrasso Permitting Bill Would Give FERC Tx Siting Authority

Legislation Also Contains Requirements for Increased Interregional Planning

By James Downing

Sen. Joe Manchin (I-WVa.) | *© RTO Insider LLC*

Sens. Joe Manchin (I-WVa.) and John Barrasso (R-Wyo.) on July 22 introduced long-planned *legislation* on energy project permitting that would increase FERC's power to approve new electric transmission.

The two senators are chairman and ranking member, respectively, of the Senate Energy and Natural Resources Committee, and their Energy Permitting Reform Act of 2024 is meant to accelerate the permitting process for critical energy and mineral projects of all types.

"The United States of America is blessed with abundant natural resources that have powered our nation to greatness and allow us to help our friends and allies around the world," Manchin said. "Unfortunately, today our outdated permitting system is stifling our economic growth, geopolitical strength and ability to reduce emissions."

Manchin said that after more than a year of hearings and negotiations, he and Barrasso put together a bill that is meant to provide more certainty for energy and mineral projects going through the permitting process without bypassing protections for the environment and impacted communities.

"For far too long, Washington's disastrous permitting system has shackled American energy production and punished families in Wyoming and across our country," Barrasso said. "Congress must step in and fix this process. Our bipartisan bill secures future access to oil and gas resources on federal lands and waters."

The bill would end President Joe Biden's pause on processing natural gas exports, which was already stayed by a federal court decision. (See *Federal Judge Stays Biden's LNG Export Application*.)

On electric transmission, it would reform the existing backstop siting authority for interstate transmission lines and require interregional transmission planning.

The law would also let transmission developers ask FERC for permission to site lines that are in the national interest, in a process similar to how the commission already sites natural gas pipelines. The lines have to be used in "interstate commerce," which includes connecting offshore wind on the outer continental shelf to a state. States would still get one year to respond to siting applications before firms can go to FERC for siting.

FERC would have to find that such transmission lines are in the public interest, will cut congestion, benefit consumers and provide improved reliability. The transmission lines FERC sites will have to be consistent with national energy policy and will enhance energy independence.

States, tribes, private property owners and other interested parties would have to have a reasonable opportunity to present their views and recommendations on transmission siting before FERC, the bill said.

FERC would also have to approve proposals for allocating the costs of such lines to beneficiaries of the resulting improved reliability, lower congestion, lower power losses, greater carrying capacity, reduced operating reserve requirements and improved access to cheaper generation. Customers who get no benefits from transmission lines cannot be allocated any of their costs.

FERC would be able to approve utility compensation to communities where transmission lines are located. The commission would have to prioritize using existing rights-of-way and the use of advanced conductors.

Interregional Planning Requirement

The bill also requires interregional transmission planning between neighboring transmission planning regions, including RTOs/ISOs and those set up to comply with FERC Order 1000's regional requirements. The neighboring regions would need to use a common set of input assumptions and models on consistent timelines to pick projects based on a list of benefits around reliability and affordability.

Interregional plans would have to be submitted to FERC within two years of the process' enactment and then every four years.

The bill specifically exempts ERCOT from the interregional planning and siting requirements.

Beyond the transmission provisions, it would require FERC and NERC to assess any future federal regulations that impact reliability and file comments with the agency working on them.

The Secretary of the Interior would be required to hold one offshore wind sale lease and one oil and gas lease sale per year from 2025 to 2029, which would not happen under current law.

The bill shortens the timelines before, during and after litigation for all federal authorizations on energy and mineral projects. Opponents would have to file lawsuits within 150 days after final agency action, courts would be required to expedite such cases, and agencies would have a 180-day deadline to deal with any remands from the courts.

Industry Groups Support Permitting Legislation

Americans for a Clean Energy Grid welcomed the permitting legislation, with Executive Director Christina Hayes saying it would bolster grid reliability by allowing for the timely deployment of transmission infrastructure.

"Of particular importance, FERC gaining plenary authority for transmission siting — just like it has for natural gas — would represent an important change in how the federal government permits transmission infrastructure in a timely and transparent manner," Hayes said in a statement. "In combination with Order No. 1920 and the commission's responsibility for ensuring reliability for customers, FERC is well positioned to center our nation's efforts to build out the energy grid."

Advanced Energy United also wants to see Congress move permitting legislation based on the Manchin-Barrasso bill.

"It has long been too difficult to build some of the critical energy infrastructure America needs, and this bipartisan proposal provides a good foundation on which to build a comprehensive package of legislative reforms," AEU Managing Director Harry Godfrey said in a statement. "Both parties agree that unreasonable timetables and fragmented planning processes are making it too difficult to invest and build, providing Congress a unique opportunity to pass legislation that unlocks America's innovative industries and improves grid reliability and energy costs for households and businesses." ■

FERC/Federal News

FERC Approves Icahn Deal for AEP Board Seat

By James Downing

AEP's corporate headquarters in Columbus, Ohio | *Electric cat, CC BY-SA 3.0, via Wikimedia Commons*

FERC on July 19 approved granting voting rights to a member of American Electric Power's board of directors who was appointed by investment firm Icahn Group (*EC24-60*).

The commission is required by Federal Power Act Section 203 to approve appointments of investment company officers to public utilities' boards. AEP told FERC that it had agreed in February to add *Hunter Gary*, Icahn senior managing director, to its board, but that he was unable to vote until the commission gave its approval. Icahn, founded and controlled by investor Carl Icahn, was also able to appoint a new independent director and a non-voting observer to the board under the deal.

The commission found the arrangement met its rules around mergers; would not have any impact on competition, rates or regulation; and would not result in cross-subsidization.

Public Citizen filed a protest against the deal, arguing that the non-voting board members had already forced a change of control at AEP with their role in the "involuntary termination" of former CEO and board Chair Julie Sloat. (See *Interim CEO Fowke Explains AEP Leadership Change*.) The consumer group argued that FERC should find that the deal and subsequent firing of Sloat violated Section 203, which also requires public utilities to seek commission approval before any attempted change in control.

AEP argued that it met FERC's public interest requirements, and that Public Citizen's "inflammatory and unsupported allegations" should be dismissed. Icahn Group itself did not execute the removal of Sloat, which was in compliance with the law and the company's bylaws, AEP said.

FERC agreed with AEP, saying the issues Public Citizen raised "do not impact the factors addressed by the commission in evaluating" such deals. "Public Citizen does not present other evidence that the proposed transaction fails to satisfy our public interest criteria," it said.

But the commission did chide AEP for its late request, filed March 15, after Gary had already been appointed.

"Contrary to the requirements of FPA Section 203, AEP failed to file a timely request for approval of the appointment of the Icahn Group designee to the AEP board," FERC said. "AEP is reminded that it must submit required filings on a timely basis or face possible sanctions by the commission."

The order drew a concurrence from Commissioner Mark Christie, who agreed that the application met FERC's policies and regulations, but that investors' impact on public utilities is a growing area of concern that might warrant some changes in those rules.

Christie has said in other proceedings that utilities are not typical for-profit, shareholder-owned companies, and it is essential for regulators to ensure investors' interests do not conflict with utilities' public service obligations.

"Where there is the potential for a conflict — and there always is — it is the commission's responsibility, under Section 203, to ensure that transactions are consistent with the public interest," Christie said. "In my view, this must involve balancing consumer protection and potential impacts to reliability with the interests of investors in addition to evaluating traditional market power concerns."

Christie argued that the only reason investors seek board seats on public companies is to exert influence on their decision-making and actions. Even directors "independent" of firms like Icahn take actions to benefit utility shareholders, including those who got them the position, he said.

"Investor influence on public utilities and public utility holding companies continues to grow, and in ways that may conflict with public utility service obligations. It is incumbent on the commission to account for and address this influence," Christie said. "These issues are ripe for action, and I look forward to continued consideration of them with my colleagues."

Commissioners Lindsay See and Judy Chang, who recently joined FERC, did not participate in the order. ■

WEIM Governing Body Officially Changes Name

Name now Reflects Body's Jurisdiction over 'Western Energy Markets'

The CAISO Board of Governors and Western Energy Imbalance Market (WEIM) Governing Body voted July 17 to officially change the name of the latter organization to the Western Energy Markets Governing Body to better reflect its full scope of responsibility since it began overseeing the ISO's Extended Day-Ahead Market (EDAM) in March.

"The name simplification represents a huge step in expansion of Western electricity markets," body member John Prescott said during the joint meeting with the board.

Other members echoed the support.

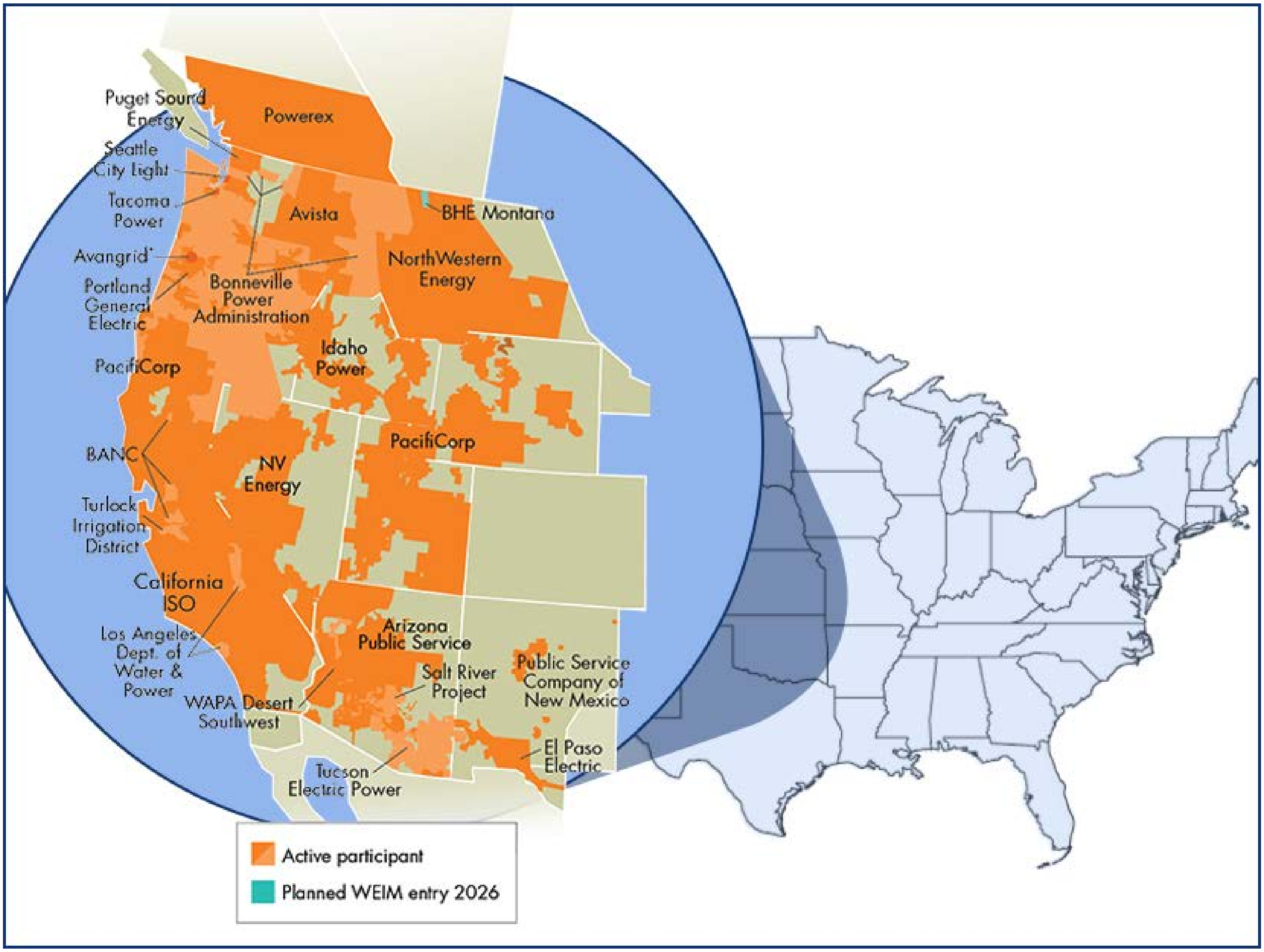
"We've looked at the growth [of the WEIM] over 10 years, and it's nothing short of phenomenal," body member Robert Kondziolka said. "It's now clearly made participants much more comfortable and be able to move forward into a day-ahead market and to be able to broaden this out, and so I think the name change is very positive."

The motion was directly approved by both entities. A vote by the board to amend CAISO's corporate bylaws, which also was required to change the name, passed unanimously.

The name will be reflected "as soon as practicable" in governing documents, according to a *memo* outlining the decision.

"Someone should be able to look at our name and say, 'We understand what you're responsible for and who you are,' and I think this name change actually exemplifies what we're responsible for and what we're doing," body member Anita Decker said. "I really support this change and appreciate the work that staff did to bring some iterations to us and land here." ■

— Ayla Burnett



Western Energy Imbalance Market | *CAISO*

CAISO/West News

CPUC Works to Revamp Tx Permitting Rules

Updates Seek to Streamline Process for Building, Upgrading Lines in Calif.

By Elaine Goodman

California regulators are overhauling rules regarding the permitting of electric transmission projects, and one proposal suggests creating a shortcut for projects already approved in a CAISO transmission plan.

The California Public Utilities Commission is updating General Order 131-D, which contains rules for the permitting of transmission and distribution lines, substations and generation facilities in the state. The goal of the update is to make the permitting process more efficient and consistent.

GO 131 was originally adopted in 1970. The most recent version, GO 131-D, was approved in 1994 and modified in 1995.

Since then, "there have been significant changes in both the physical configuration of the electric grid and the market structure for electricity in California," commissioners said in an order instituting rulemaking for GO 131-D.

In addition, *Senate Bill 529* of 2022 directed the CPUC to update the general order to streamline the approval process for extensions, expansions or upgrades to existing transmission facilities.

Under GO 131-D, transmission projects of 200 kV or more need a Certificate of Public Convenience and Necessity (CPCN), whereas projects between 50 and 200 kV must obtain a Permit to Construct (PTC), which involves a less complex approval process.

But SB 529 changed the requirement for a CPCN for transmission expansion projects. Those projects now may proceed with the simpler PTC, even if they're 200 kV or greater.

In Phase 1 of the proceeding, the CPUC updated GO 131-D to be consistent with SB 529.

An order incorporating the changes was approved and took effect in December, ahead of the Jan. 1, 2024, deadline set by SB 529.

Phase 2 Proposals

The proceeding has now moved into its second and final phase, in which additional changes to GO 131-D will be considered.

CPUC staff released a *Phase 2 proposal* on May 17.

One objective is to provide definitions for terms included in the Phase 1 additions. In particular, "extension," "expansion," "upgrade," "modification" and "existing electrical transmission facilities" aren't defined.

This has been "causing applicants to be uncertain about whether a particular project will require a CPCN," CPUC staff said.

CPUC staff have also proposed a streamlining measure for transmission projects included in one of CAISO's annual transmission plans.

The CPUC process for issuing a CPCN includes a review under the California Environmental Quality Act (CEQA) and an evaluation of the need for the project and its cost.

CAISO also evaluates the costs and need for a project in its transmission planning process, the staff proposal noted.

The proposed change to GO 131-D would establish a "rebuttable presumption" that the project meets the CPUC requirement for need if it's an approved project in a CAISO transmission plan.

That would be consistent with *Assembly Bill 1373* of 2023.

A bill in the state legislature this year tried to take the rebuttable presumption a step further. *AB 3238* by Assemblymember Eduardo Garcia (D) would have created a rebuttable presumption that the benefits of a transmission project outweighed its environmental impacts if the project was included in a CAISO transmission plan.

The bill is still alive, but the rebuttable presumption provision was removed. (See *Bill to Streamline Transmission Development Advances in Calif. Senate*.)

The CPUC staff proposal also looks for ways to speed up the application and CEQA review processes.

One idea is to allow applicants to submit a draft environmental document for their project. That would cut out a step in which the applicant provides a proponent's environmental assessment, or PEA, which is followed by staff preparation of an environmental document.

The proposal would require applicants to consult with staff on the environmental document at least 12 months before submitting an application.

A comment period for the Phase 2 proposal ran through July 15. The CPUC expects to release a proposed order by Oct. 13. ■

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CAISO/West News

CAISO Kicks off Storage Bid Cost Recovery Stakeholder Initiative

BCR Rules Inefficient for Batteries, DMM Says

By Ayla Burnett

Batteries may be receiving excessive or inefficient bid cost recovery (BCR) payments in CAISO, an issue that could be exacerbated by the ISO's recent move to increase its soft offer cap to allow for higher bids by storage resources.

The issue was highlighted by CAISO's Department of Market Monitoring and Market Surveillance Committee on July 8 during the first workshop of a new Storage Bid Cost Recovery and Default Energy Bids initiative.

CAISO staff launched the effort to address concerns related to a rule change pending before FERC that would alter ISO rules related to FERC Order 831 by raising the soft offer cap from $1,000/MWh to $2,000/MWh, in part to accommodate opportunity costs and bidding strategies for storage resources. (See *CAISO, WEIM Boards Approve Proposal to Raise Offer Cap*.)

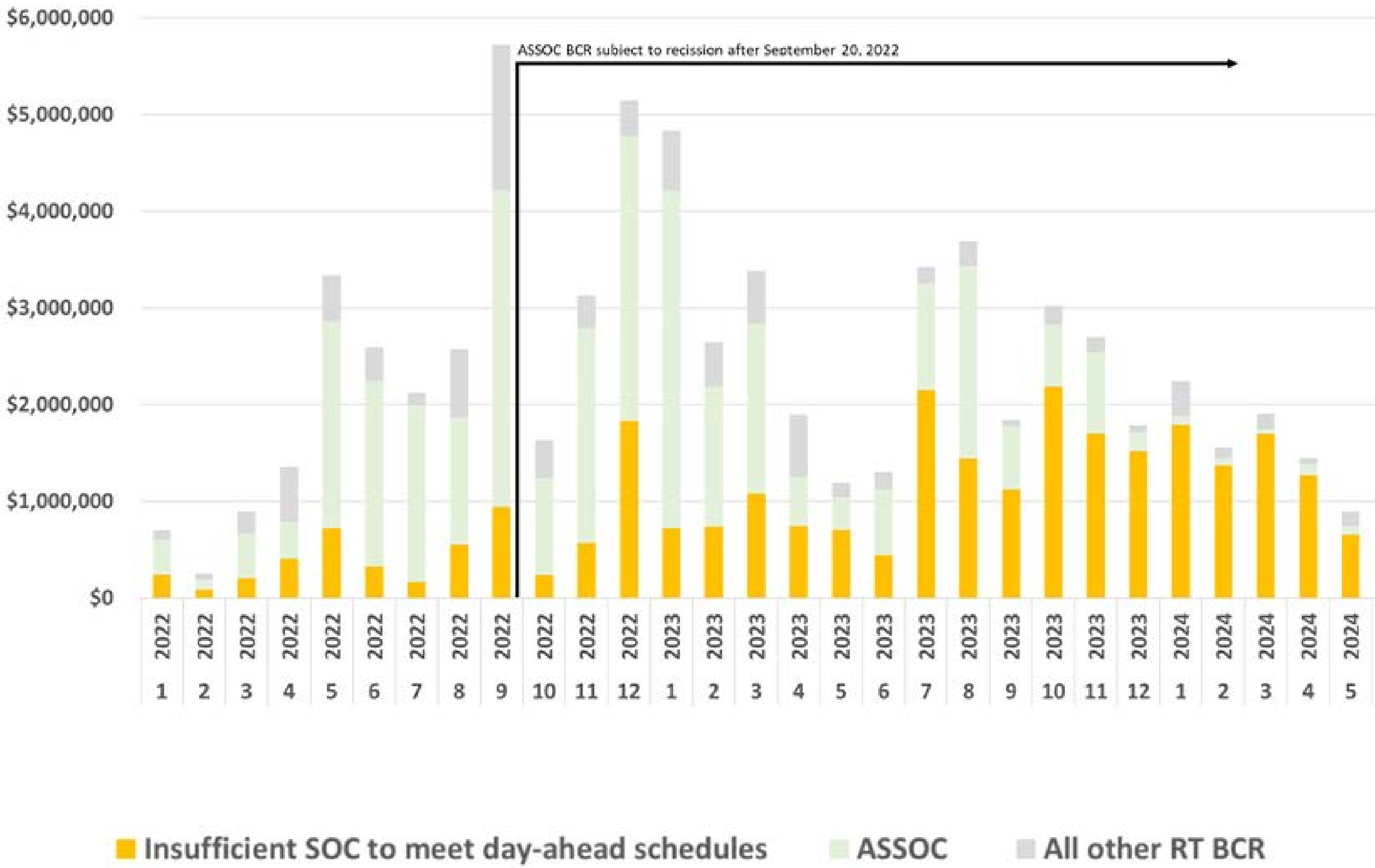
"BCR, as [with] many other elements of the CAISO tariff and the market, was initially designed with a thinking of conventional assets," Sergio Dueñas Melendez, storage sector manager at CAISO, said during the workshop. "This was something that was not developed in a manner or outlined with potential new technologies that could be integrated into the CAISO market *en masse*, particularly with storage."

BCR is intended to eliminate the incentive for resources to add a risk premium to their offers, which drives up bids, leading to higher overall energy costs and inefficient market outcomes. But the DMM noted that BCR payments to storage resources have materialized — specifically related to the buy- and sellback of day-ahead schedules — despite not being aligned with the intent.

"Assets might be incented to bid and operate in the [real-time] market in a manner that would trigger buy- or sellbacks of their [day-ahead] energy schedules in order to capture outsized BCR payments," Dueñas Melendez said.

Generating units can receive BCR payments if total market revenues earned throughout the day don't cover the sum of the unit's acceptable bids, which includes bids for startup, minimum load, ancillary services, residual unit commitment availability, day-ahead energy and real-time energy. Because batteries don't have startup, shutdown, minimum load or transition costs, they "lack the traditional drivers of BCR," according to a DMM *report* on battery storage from July 2023.

Batteries, however, can be subject to BCR because of their opportunity costs, incurred when a battery discharges during a particular



Graphic representation of real time bid cost recovery for batteries for April and May 2024. | *CAISO*

CAISO/West News

time of the day, usually from weather-related grid conditions. Discharging energy during low-demand hours, for example, could preclude discharging during hours of high demand, and the difference in market prices between low and high demand hours represents the opportunity cost of discharging in lower-priced hours.

"In the past, battery energy storage has received disproportionate amounts of BCR," Dueñas Melendez said. "In their comments, throughout the Order 831 process of bidding above the soft offer energy bid cap, DMM highlighted once more that those changes could exacerbate the challenges that they've identified regarding BCR. This perspective was also echoed by the Market Surveillance Committee, who recommended that ISO staff engage with stakeholders to review and restructure current BCR provisions for batteries, particularly given the changes around Order 831."

The July 2023 report highlighted that in 2022, batteries received nearly $30.5 million in payments, primarily in the real-time market, despite making up only 5% of CAISO's capacity.

'Aggressive Timeline'

Stakeholders expressed confusion about the root of the problem, specifically related to why batteries, in some cases, don't have the state-of-charge to fulfill a schedule.

"What caused the real-time state-of-charge to put us in the position of a buyback or a sellback? Was it the result of price or modeling issues? Was it the result of not co-optimizing in real-time ancillary services? Was it because of bidding behavior, and are there rules that need to be put around that?" asked Don Tretheway, managing director of EES Consulting and representing the California Energy Storage Alliance. "I don't think making these high-level statements helps anybody in terms of trying to understand where the solution is, especially given the speed at which you plan to make these changes."

Stakeholders also expressed concern about the "aggressive timeline" of the initiative, which Dueñas Melendez said is on an expedited schedule because of its "sensitive nature." Track 1, dedicated to refining BCR provisions for storage, initially gave stakeholders only three days to submit comments, but after significant pushback, the ISO extended the deadline to July 18.

"The fact that CAISO committed to working on this stuff in 2022 and didn't do anything for two years, and now we're going to do this in two months, it seems a little inconsistent with comments made to FERC about taking this as a priority," Tretheway said.

Alva Svoboda, principal of market design integration at Pacific Gas and Electric, echoed the concerns.

"This is obviously a very aggressive timeline, and in my mind, it implies only one kind of solution feasible for CAISO ... which is to essentially trigger periods in which batteries are not eligible for BCR and hence are completely unhedged against any price outcome in the market."

Rather than meeting to discuss the straw proposal scheduled for publication July 17, the ISO added an additional workshop July 22 to continue working through the issue with stakeholders. ■

Panelists Call for a More Holistic Approach to Advanced Tx Tech in Mass.

By Jon Lamson

Unlocking the full potential of advanced transmission technologies (ATTs) will be essential to limiting transmission costs associated with the clean energy transition in Massachusetts, a panel of experts said at a forum July 17.

The "pop-up forum" was convened by the Massachusetts Executive Office of Federal and Regional Energy Affairs and coincided with the state legislature's scramble to pass a climate bill before the end of the legislative session. If passed, the bill appears likely to include language requiring transmission and distribution owners to consider ATTs when proposing new infrastructure.

"You're taking up the topic at a critical time," said Sen. Mike Barrett (D), co-chair of the Joint Committee on Telecommunications, Utilities and Energy.

"Where do ATTs figure in?" Barrett asked the speakers in his opening remarks. "We really need to know if we're talking about something with a major set of implications for New England, or a more marginal set."

The terms ATTs and grid-enhancing technologies (GETs) refer to a range of technologies aimed at maximizing the capability of existing transmission infrastructure. These technologies can be used to address transmission constraints without requiring major new infrastructure.

"There's potentially billions of dollars of value here," said Lakshmi Alagappan of Energy and Environmental Economics (E3). Alagappan focused on five technologies that "exhibit strong potential" in the region: advanced conductors, dynamic line ratings, power flow controllers, storage-as-transmission-only assets and topology optimization.

While FERC *Order 1920* requires transmission operators to consider GETs in long-term planning, "there is a much broader opportunity to look more holistically" at the role that ATTs can play, Alagappan said.

Alagappan emphasized the importance of creating standards for software compatibility, amending rules to allow new technologies to participate in transmission solicitations and ensuring that studies account for the full scope of potential ATT benefits.

"Proactively taking these steps now will be critical," Alagappan said.

Representatives of Eversource Energy and National Grid, which own significant transmission assets in New England and electric distribution utilities in Massachusetts, said some of the technologies are already deployed in the region, but that more can be done to scale up their use.

"We're not starting from zero, but we're not at full capacity yet," said Vandan Divatia of Eversource, adding that the company frequently considers adding advanced conductors when replacing structures for asset condition needs.

Andrew Schneller of National Grid said the consideration of advanced conductors has become "somewhat of a standard," and noted that the company deployed DLR to achieve a 20 to 30% increase in the capacity of a line in Rhode Island.

Both Schneller and Divatia said tariff requirements for transmission owners to select the lowest-cost solution to isolated issues could be a barrier to deployment. ATT solutions may have a wider range of long-term benefits but still come in as the more expensive solution to the specific issue at hand, Schneller said.

Jacquelyn Bihrle of the Massachusetts Attorney General's Office said it is "encouraging from our perspective that these technologies are being deployed where possible," but she said that considering all possible ATT solutions to transmission needs should be "a routine, standardized part of the process." While Order 1920 "sets a floor" by requiring the consideration of ATTs, "it must be more than a check-the-box exercise."

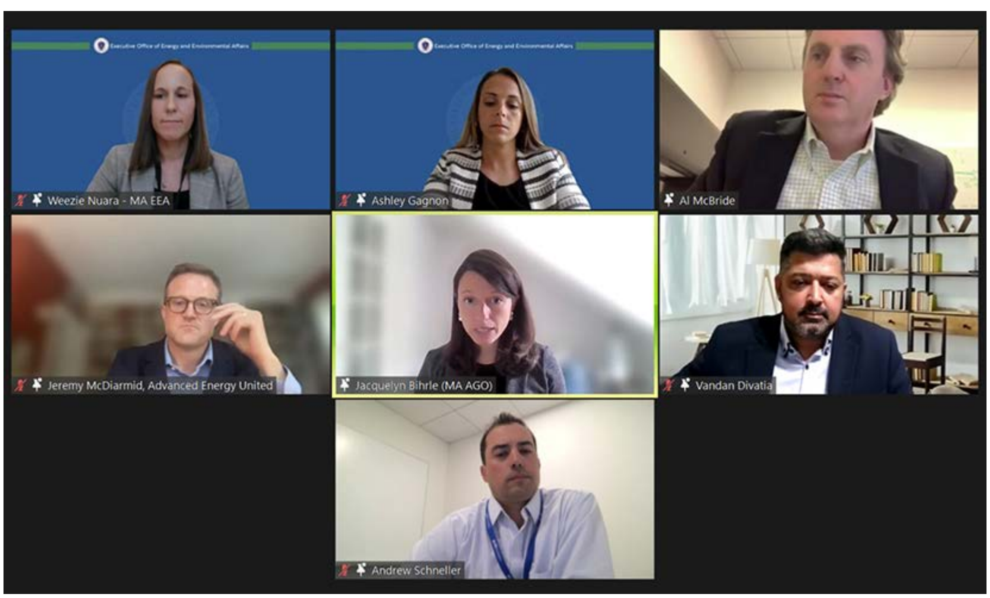
Bihrle called for increased accountability and transparency regarding how TOs evaluate ATT solutions. She highlighted the idea of an independent transmission monitor as "one way to achieve that level of scrutiny" and help address the "information asymmetry" between TOs and consumers.

Al McBride of ISO-NE said there may be a role for the RTO to help "explain to people what the likely use cases are for the different technologies."

He emphasized that ISO-NE solicitations are centered around selecting the lowest-cost solution, regardless of whether a solution is based on new technology or traditional infrastructure.

Separate climate bills recently passed by the Massachusetts *House* of Representatives and *Senate* include identical language requiring "due consideration" of ATTs for new transmission and distribution infrastructure.

Following the passage of the House bill on July 17, the bills now go to a conference committee, where legislators will try to quickly formulate a compromise bill to pass and send to Gov. Maura Healey (D) before the end of the legislative session July 31. ■



Clockwise from top left: Weezie Nuara, Massachusetts EEA; Ashley Gagnon, Massachusetts FREA; Al McBride, ISO-NE; Vandan Divatia, Eversource; Andrew Schneller, National Grid (bottom); Jacquelyn Bihrle, Massachusetts AGO; and Jeremy McDiarmid, Advanced Energy United | *Massachusetts Executive Office of Energy and Environmental Affairs*

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

Following its increase of the transfer limits on three interfaces in Maine, ISO-NE has *increased* the capacity import capability of the New Brunswick-New England (NB-NE) interface from 700 MW to 980 MW, Alex Rost of ISO-NE told its Planning Advisory Committee.

ISO-NE announced the Maine transfer limit increases to the PAC in June. (See *ISO-NE PAC Briefs: June 20, 2024*.) The increases were the result of changes to how the RTO calculates the limits, which now are "based solely on 'design contingencies' — loss of transmission lines, transformers, etc.," ISO-NE said.

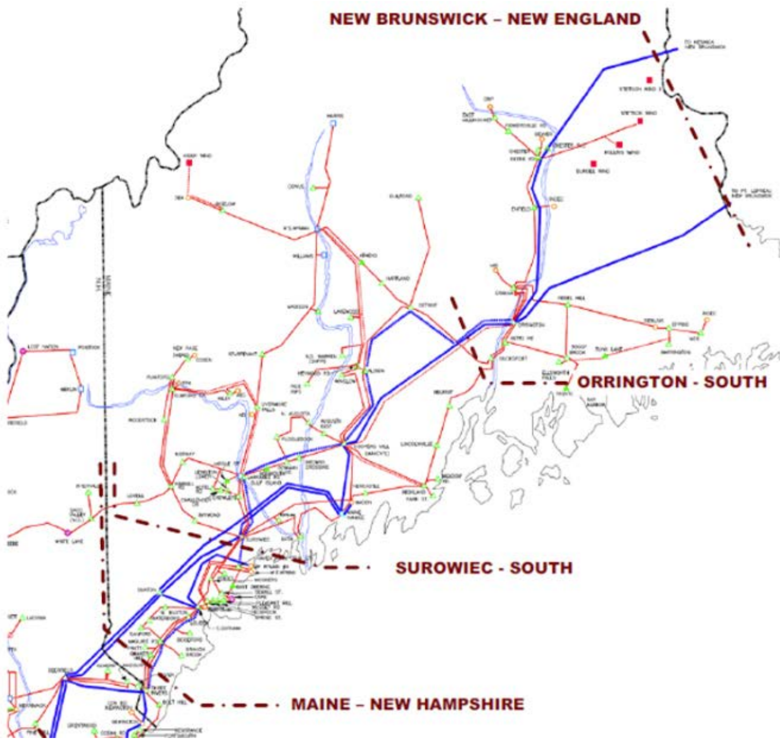
Capacity historically has been constrained in parts of Maine because of the interface transfer limits and existing capacity resources above the Maine interfaces, Rost said, adding that "the amount of capacity than can be transferred over the NB-NE interface has been limited to 700 MW out of a possible 1,000 MW for many years."

He noted that "proposed new capacity resources north of the Orrington-South interface have been unable to qualify for FCAs [forward capacity auctions] for many years," and new resources have faced similar problems above the Surowiec-South interface since 2016.

Responding to stakeholder questions, Rost said the import capability increase from New Brunswick likely means no new headroom will be made available for new capacity resources above these interfaces.

"I'm not going to give official overlapping impact analysis answers today, … but if you walk through the analyses and steps that we went through and you crunch the numbers, that would indicate that there is no headroom," Rost said.

Abigail Krich of Boreas Renewables expressed concern that increasing the import capability from New Brunswick but not increasing the limits on domestic capacity could lead to the increased transfer capabilities being "reserved and underused."



ISO-NE Maine interfaces | *ISO-NE*

When transfer limits are increased, "we reserve those for imports, instead of for domestic generation qualified to participate in the capacity market," Krich said. "We reserve them for imports regardless of whether they actually get used for imports. We often see that the New Brunswick interface, historically, even at 700 MW, has not been fully subscribed.

"This is something we should all be thinking about: How we can better utilize this transfer capability to ensure we're getting the most out of it?"

Rost also noted that ISO-NE likely will reassess the internal transfer limits once the New England Clean Energy Connect transmission line is in service to account for system upgrades associated with the line.

Eversource Asset Condition Project Cost Increase

Also at the PAC, Chris Soderman of Eversource presented a *cost and scope increase* of an asset condition project in Connecticut. The project now includes the replacement of 22 structures and is projected to cost $32.2 million, compared to the initial estimate of $11.6 million. The project has an estimated in-service date of the fourth quarter of 2025. ■

— Jon Lamson

Northeast news from our other channels

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ISO-NE News

NEPOOL Reliability Committee Briefs


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New Data Collection Standards

The NEPOOL Reliability Committee (RC) voted July 16 to support new data collection *standards* for distributed energy resources (DERs), intended to aid the RTO in both real-time operations and longer-term planning studies.

While ISO-NE currently collects data using voluntary submissions, the new standards would require data submissions from distribution providers and transmission owners related to DER size, location and operating characteristics, said Dan Schwarting of ISO-NE.

"Uniformity in data submission will lead to better accuracy of load forecasting and studies at ISO-NE," Schwarting said. The proposal now heads to the NEPOOL Participants Committee.

Affected System Operator Study Coordination

Brad Marszalkowski of ISO-NE *outlined* proposed tariff changes to coordinate affected system operator (ASO) studies with the new cluster study interconnection process, which was mandated by FERC Order 2023. (See *Clean Energy Groups Respond to ISO-NE Order 2023 Filing*.)

ASO studies are under the jurisdiction of the states and assess the impact of distributed generation projects on the transmission system and broader power grid. They are performed by the relevant transmission owner.

"ASO studies will have to coordinate with and respect ISO Cluster Studies," Marszalkowski said. "This will naturally establish windows for the start and completion of ASO studies."

Marszalkowski said the new ASO process would create a "state project submission window" that coincides with the ISO-NE cluster request window. ASO studies corresponding to each window would occur simultaneously with ISO-NE cluster studies. The studies would be required to account for ISO-NE interconnection requests and updated ISO-NE study information.

"ISO-NE will no longer consider one-at-a-time project additions," Marszalkowski noted. "Determinations will be made solely based on the total aggregate of all projects submitted during the submission windows that are electrically close based on the screening criteria."

Order 881 Changes

ISO-NE also discussed planning procedure changes associated with FERC Order 881, which requires transmission providers to adopt ambient adjusted line ratings for near-term transmission service requests and seasonal ratings for longer-term requests.

The commission accepted ISO-NE's compliance proposal in 2023, subject to an additional filing by November 2024 to specify "timelines for calculating or submitting AARs." The compliance will take effect in July 2025. (*ER22-2357*, see *Order 881 Timelines Need Explaining, FERC Says*.)

Michael Drzewianowski of ISO-NE said Order 881 compliance requires changes to the RTO's Planning Procedure 7 (PP7), which "provides the general assumptions to be used in the calculation of facility ratings."

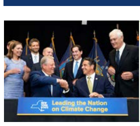
For seasonal ratings, ISO-NE plans to use 12 seasons corresponding to each month, said Drzewianowski, outlining the ambient temperatures the RTO will use for each month under normal and emergency conditions.

To account for changing seasonal load shapes, ISO-NE plans to shift to a long-time emergency (LTE) rating period of four hours across the entire year, instead of the current LTE ratings of four hours in the winter and 12 hours in the summer.

Drzewianowski said ISO-NE will review stakeholder comments and changes to the PP7 appendices at the August RC meeting, targeting a vote in September. ■

— Jon Lamson

Northeast news from our other channels



Audit Faults NY on Climate Act Progress

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MISO News

MISO Closing in on Final, $25B LRTP; Monitor Repeats Reservations

Mississippi and Louisiana Signal Opposition with Order 1920 Petition

By Amanda Durish Cook

CARMEL, Ind. — MISO's $25 billion, mostly 765-kV long-range transmission package for the Midwest region is nearing finalization, while the Independent Market Monitor continues to doubt the necessity of the projects.

The Monitor is penning a memo spelling out his concerns with MISO's assumptions behind its long-range transmission planning.

Despite that, the lines are advancing to MISO's business case testing, where they will be analyzed against its nine benefit metrics. MISO will release the business case for the portfolio in September.

"The benefits metrics process has been well reviewed," Executive Director of Transmission Planning Laura Rauch told the Organization of MISO States' board of directors July 16. She said MISO solicited extensive stakeholder feedback and is "fairly comfortable" with the metrics it is advancing.

Rauch said MISO will hold multiple workshops with stakeholders to go over the business case for the new batch of LRTP lines.

"We're at the stage, using an airplane analogy, where we've landed and we're on the tarmac," Director of Economic and Policy Planning Christina Drake told stakeholders on a July 17 teleconference.

MISO has yet to factor in the cost of underbuild projects into the second LRTP portfolio.

Drake said MISO's first, $10 billion LRTP portfolio in MISO Midwest minimized the need for underbuild projects to support the second portfolio. MISO uses the term "underbuild" for the secondary, lower-voltage transmission upgrades necessary to support a 765-kV network in the Midwest region without worsening existing constraints.

While MISO considers its benefit metrics a done deal, the Monitor still harbors serious concerns over the metrics and says two should be outright deleted. (See *MISO IMM Knocks LRTP Benefit Calculations; RTO Poised to Add More Projects*.)

This month, IMM David Patton said he scheduled meetings with MISO planners to outline his concerns with the metrics, though he acknowledged little progress on a compromise.

"I don't think the MISO board understands how serious these concerns are," Patton told the Board of Directors' Markets Committee on July 11. "We haven't seen a lot of movement to address either the concerns on the [second transmission future] — which we view as very unrealistic — or MISO's benefits process."

Patton said he remains hopeful that MISO is open to altering its project portfolio to assemble the "most least-regrets" collection of transmission projects.

He called MISO's second transmission planning future "completely inconsistent" with its new, availability-based capacity accreditation and its invitation for members to develop resources with more steadfast attributes.

MISO is using its second transmission planning future as a basis for this LRTP portfolio. It assumes that by 2042, the RTO will manage 466 GW of installed capacity with a fleet that emits 96% less carbon pollution than it did in 2005 and have a 145-GW peak load that occurs in January rather than July.

Patton said MISO's goal of least-regrets transmission planning is only possible when it uses "valid benefit metrics and explores the gamut of possible futures."

MISO has proposed using nine benefit metrics to establish a benefit-to-cost case for the portfolio, including avoided capacity costs, capacity savings from reduced line losses, congestion and fuel savings, reduced transmission outage costs, energy savings from reduced losses, lower risks during extreme weather, mitigation of reliability issues, avoided transmission investment and decarbonization.

Patton has said it is not appropriate for MISO to place a value on decarbonization when the government already does through tax credits. He also has said the RTO should not presume that the lines will save members money on additional capacity that would otherwise have to be built.

At the workshop, MISO was adamant that the second LRTP portfolio will accommodate Midwest members' fleet transition plans and load growth.

MISO said on a 20-year horizon, the Midwest should also see $3.2 billion in adjusted production cost savings, an 8.5% (20.4 million MWh) reduction in curtailment, savings to the cost of serving load and decreased price separation. The RTO also said LRTP II resolves 60% of the Midwest's 200-kV and above constraints that could trigger contingencies and more than 70% of thermal violations for all voltage levels.

Xcel Energy's Drew Siebenaler said his utility's ambitions now more closely resemble MISO's third, 20-year transmission planning future, not the second. He asked whether MISO would test the second LRTP portfolio against its most aggressive, third planning future, as rapid load growth and fleet transformation have made it appear the most probable.

Drake said MISO remains committed to testing the second portfolio against the "low-end bookend" and using the second transmission planning future. But the RTO is aware that the portfolio will not enable all the generation contemplated in the future. She said that's why MISO will pursue a companion portfolio next year, with proposed lines likely popping up in the western portion of MISO Midwest.

La. and Miss. Regulators Open Offensive Against Order 1920

Meanwhile, Louisiana and Mississippi state regulators have called on the 5th U.S. Circuit Court of Appeals to examine FERC's recent landmark transmission planning rule.

Attorneys for the Louisiana Public Service Commission and Mississippi Public Service Commission filed a petition for review July 15 of FERC's *Order 1920* (24-60355).

Both state commissions claimed they are "aggrieved" by the order, which requires transmission providers to conduct transmission planning on 20-year horizons every five years.

Former FERC Commissioner Allison Clements has said the commission used MISO's existing planning as a model for portions of the wide-ranging transmission planning rule. (See *MARC 2024 Displays Mixed Feelings on Transition Feasibility*.)

Louisiana and Mississippi, both part of MISO's South region, have not been the focus of MISO's LRTP planning efforts yet. The RTO has so far only proposed multibillion-dollar LRTP portfolios for its Midwest region. MISO, clean energy groups, MISO South state regulators and Entergy are currently in disagreement over how LRTP cost allocation should be handled in the South. (See related story, *Clean Energy Orgs Push Entergy Players to Consider Broader Cost Allocation*.) ■

MISO News

Michigan Utilities Call for Opt-Out on MISO DER Affected System Studies

By Amanda Durish Cook

CARMEL, Ind. — A band of Michigan utilities wants the option to decline MISO's affected system-style studies on distributed energy resources, arguing the RTO's studies create an unnecessary layer of bureaucracy and hinder DER expansion.

Consumers Energy, DTE Energy, ITC Holdings and Wolverine Power approached MISO at the July 17 Planning Advisory Committee, asking for an opt-out provision on the RTO's affected system studies for DER additions that might impact the transmission system.

Wolverine Power Vice President of Regulatory Affairs Tom King said the Michigan-based parties believe MISO's DER affected system study process limits efforts to integrate DERs on the grid.

Last year, MISO decided it would evaluate the need for a review of DERs when they can inject 5 MW of power at the substation level during system peak load and if they can force a 1% change in line loading. Transmission owners screen for the 5-MW injection capability, while the RTO ascertains whether the DERs could influence a 1% line-loading change.

If the DER is shown to impact both reliability criteria, MISO issues a report that triggers its existing facilities study and could lead to network upgrades. (See *MISO Creating Means to Gauge Impacts of DER Interconnections*.)

At a July 17 Planning Advisory Committee meeting, King said MISO's DER affected system study process and fee requirements "are burdensome, duplicative of the more comprehensive existing TO studies, create unnecessary costs and have the potential to significantly limit DER deployment." He said TOs already study the potential for DERs to worsen thermal and voltage issues that MISO tests for. He added that TOs' studies in many cases are superior to MISO's.

Transmission owners pay a $60,000 study deposit to MISO per substation that is required to be studied for DER impacts. MISO refunds any portion it doesn't use for the studies.

"MISO obviously has a fee to perform these studies, which has to be coordinated with the TO and then coordinated or not coordinated with the DER," King told stakeholders.

King said the Michigan utilities developed their opt-out recommendation with help from Michigan Public Service Commission staffers.

Tom King, Wolverine Power | © *RTO Insider LLC*

He asked that MISO treat DERs as load-serving additions or changes, not as generation that causes third-party impacts to the MISO system. That way, King said MISO could view DER additions as end-user facilities seeking to make "qualified changes" under its facility interconnection studies process.

MISO could step aside for transmission owners to perform their more extensive thermal and voltage analyses, King said. He said TOs would continue to "carefully evaluate trickle-up impacts" on the transmission system by DERs and notify MISO of impacts when they submit a transmission upgrade as part of the RTO's annual Transmission Expansion Plan to mitigate added stress on facilities.

King said he'd like MISO and stakeholders to prepare an opt-out provision as soon as this fall. He said there's considerable support for DERs in Michigan, with new legislation designed to encourage more of them. He said that trend is likely to occur in other jurisdictions in the footprint.

Last year's Michigan Clean Energy and Climate Action package contained a provision to raise utilities' distributed generation program caps from 1% to 10% of their in-state peak load average of the last five years. King said prior to the legislation, utilities were outstripping the 1% limit.

King also noted that the EPA recently awarded Michigan $156 million to reduce the cost of community and rooftop solar projects for low-income households and that Gov. Gretchen Whitmer's "*MI Healthy Climate Plan*" recommended utilities "increase options for customer-driven renewable energy, such as rooftop solar and voluntary green pricing programs." ■

MISO News

MISO: Hurricane Beryl Caused Electrical Island in Texas

By Amanda Durish Cook

CARMEL, Ind. — MISO said damage wrought by Hurricane Beryl triggered an overnight electrical island in a Southeastern Texas load pocket.

MISO reported an approximately 400-MW energized island existed in the Southeastern Texas (SETEX) load pocket from late on July 8 into the early morning of July 9.

At a July 18 Reliability Subcommittee meeting, MISO South Manager of Reliability Coordination Jeff Sundvick said Beryl's damage was extensive enough that a single 345-kV line — Rocky Creek to Crocket — connected the SETEX load pocket to the bulk electric system. Sundvick said despite MISO and Entergy's best efforts to balance the power flow on the line near zero megawatts in case it also went down to keep the island stable, the line tripped late at night, creating an energized island. MISO and Entergy ultimately resynchronized the island about 3:30 a.m. CT on July 9.

"We worked approximately four to five hours with Entergy to keep the island stable," Sundvick said, adding that Entergy operators at the Montgomery County Power Station maintained frequency by adjusting power in 1-MW increments.

Sundvick said MISO filed an Electric Emergency Incident and Disturbance Report to document the islanding event with the U.S. Department of Energy.

As the Category 1 storm barreled through Texas and weakened, MISO declared a local transmission emergency for SETEX in the early afternoon of July 8. It initiated a restoration protocol that night after Beryl battered transmission and distribution systems. MISO also declared conservative operations from July 8-10 for the South region.

MISO reported the hurricane caused the loss of 73 lines rated 230 kV or 138 kV. It said "out-of-service transmission infrastructure and a general degradation" of the bulk electric system led it to declare the transmission emergency that lasted until the evening of July 11.

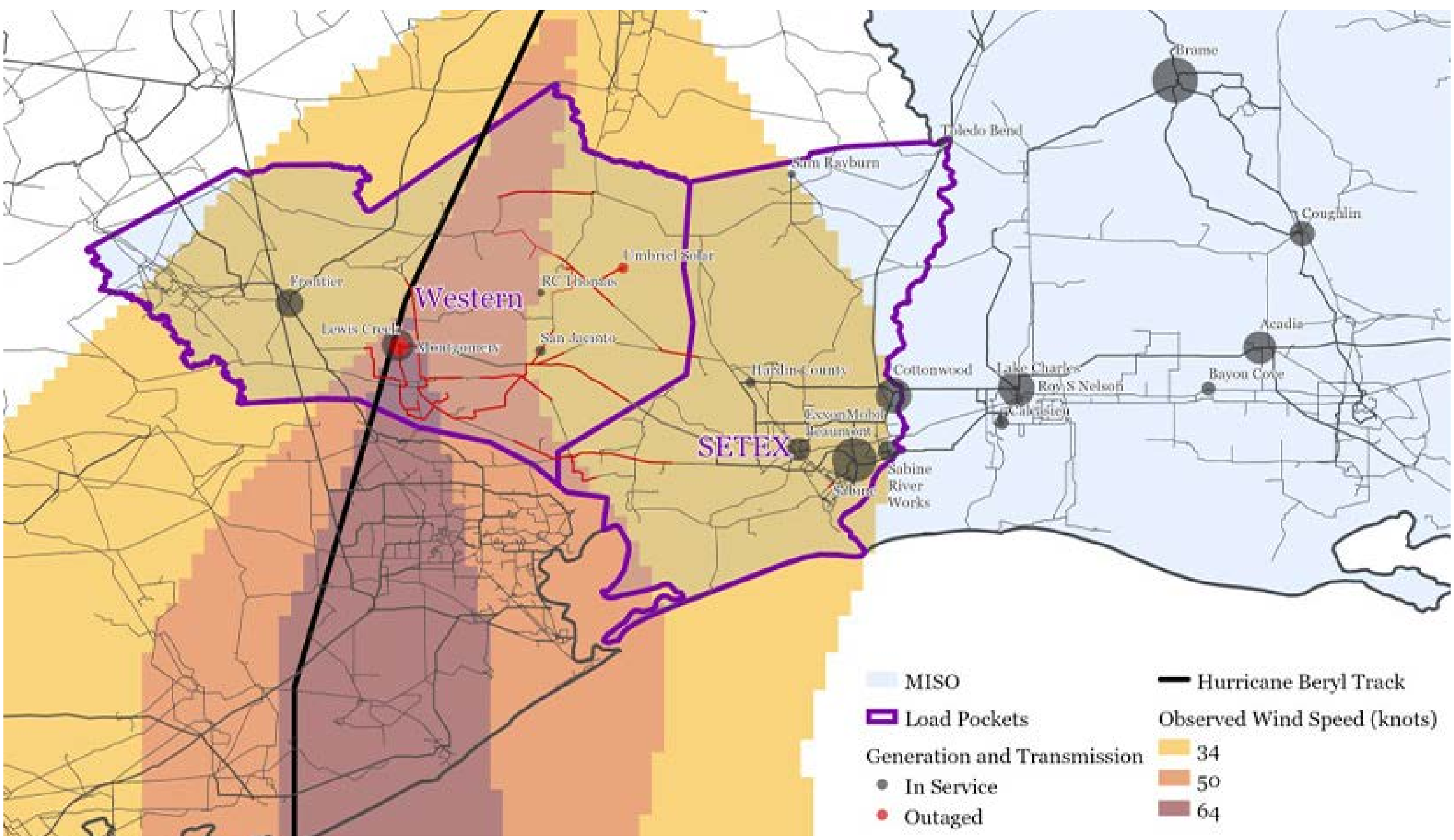
Sundvick said the last remaining outage in Entergy Texas's service area, the 138-kV Oak Ridge to Porter line, was restored July 17.

Unrelated to the hurricane, the grid operator enacted conservative operations again alongside a capacity advisory July 15 for the entire footprint as hot temperatures, forced generation outages and transfer limitations challenged operators.

MISO also announced it experienced real-time price spikes on June 19 due to a shortage of operating reserves. MISO said the shortage occurred over three pricing intervals as 108 GW of afternoon peak load coincided with a ramping down of wind and solar. The operating reserve shortage led to $1,400/MWh energy prices.

Last week, MISO's Dustin Grethen said MISO expects to encounter shortages more frequently as the system adds renewables and that staff are thinking about the RTO's "posture" in these events.

"We're looking at all the factors and evaluating what our options are," Grethen said. ■



Hurricane Beryl's entry into Texas on July 8 | *MISO*

MISO News

Longtime MISO President and COO Moeller to Retire

No Replacement on Horizon

By Amanda Durish Cook

MISO has announced that its longtime second in command will retire at the end of the year.

President and COO Clair Moeller will leave the grid operator effective Dec. 31, MISO revealed in a July 18 press release. Moeller joined MISO in 2004, a year before the grid operator opened its energy markets. Prior to that, he was with Xcel Energy for 25 years.

MISO said Moeller's transition will begin immediately and he will serve as a strategic adviser for the remainder of the year.

On Jan. 1, 2025, CEO John Bear will again assume the role of president. MISO confirmed to *RTO Insider* that it has no plans at this time to open a search for a chief operating officer and will function without one for the foreseeable future.

The MISO Board of Directors in 2017 promoted Moeller from executive vice president of operations to president and COO. As part of his role, Moeller was prepared to step in and act as CEO if necessary. (See *MISO Board Promotes Moeller, OKs 2018 Budget*.) It's unclear where MISO's executive succession plan stands following Moeller's retirement. In a statement to *RTO Insider*, MISO said it has a "robust long-term succession plan and regularly engages in succession planning discussions with the Board of Directors." However, it did not elaborate on who might take on the CEO position in unforeseen circumstances. MISO has *several* senior vice presidents and vice presidents.

MISO President Clair Moeller speaks on the importance of long-range transmission planning in 2021. | © *RTO Insider LLC*

"It is because of our dedicated and hardworking employees and the support of our stakeholders that we have been able to provide reliable power across 15 states and to 45 million Americans," Moeller said in a press release. "As I reflect on the last 20-plus years, I am so proud of what MISO has accomplished, and I extend my deepest thanks to John, the board and everyone at MISO for the opportunity of a lifetime."

"Clair's contributions to MISO and the greater electricity sector are distinguished and truly remarkable," Bear said. "Having worked with Clair for more than 20 years, I can say with conviction he has been instrumental in building our organization. His passion, knowledge and unwavering commitment to MISO and our members have helped define the electricity system across our footprint. On behalf of all of us at MISO and our membership, we thank Clair for his invaluable contributions."

Moeller led MISO's grid operations, forward markets, system planning, external affairs and information technology divisions. Going forward, Senior Vice President of Planning and Operations Jennifer Curran and Chief Customer Officer Todd Hillman will report directly to Bear. ■

Clean Energy Orgs Push Entergy Players to Consider Broader Cost Allocation

By Amanda Durish Cook

| Entergy

Clean energy nonprofits continued trying to persuade Entergy and MISO South state regulators to embrace a broader view of cost allocation for an upcoming long-range transmission plan (LRTP) portfolio the RTO intends for the subregion.

The Sustainable FERC Project and the Southern Renewable Energy Association (SREA) took turns during an Entergy Regional State Committee (E-RSC) teleconference July 12 attempting to convince the company and its regulators to open their recommended allocation method to more transmission benefits.

Lauren Azar, a consultant for the Sustainable FERC Project, said if MISO South doesn't create a functioning cost allocation for regional lines, the South will continue to exclusively construct expensive local projects "that are bubbling up in the [integrated resource planning] process."

"Local projects cannot cost-effectively replace regional projects, but regional projects may cost effectively replace local projects," Azar told the E-RSC.

In early February, the E-RSC Working Group unveiled a preferred allocation for the upcoming LRTP portfolio of projects that will focus on MISO South. It involves assigning 90% of costs based on adjusted production cost savings and avoided reliability projects; the remaining 10% will be charged to new generation that interconnects in MISO South based on a flow-based methodology. (See *Entergy States Debut Long-range Tx Cost Allocation Proposal, MISO Members Unconvinced*.) Additionally, the E-RSC wants costs of transmission projects designed to further decarbonization goals solely assigned to jurisdictions that proposed those targets.

The Entergy states want the allocation assigned to upcoming LRTP projects in MISO South. By comparison, MISO Midwest is using a simpler, 100% postage stamp allocation to load for the same class of projects. Entergy states have been adamant that they won't support any postage stamp allocation component for the third LRTP portfolio.

The E-RSC has said its allocation method would dole out costs as specifically as possible based on cost-causation and beneficiaries-pay principles. MISO, on the other hand, has proposed to allocate 50% of South LRTP projects to the subregion using the load-ratio postage stamp rate, and 50% to the smaller zones where projects are located. The E-RSC has publicly opposed the plan. (See *Entergy Regulators Mount Challenge to MISO South Cost Allocation*.)

Azar said MISO South's local projects cannot account for the "economies of scope and scale" that regional, interstate transmission projects can capture. She cautioned that the South's trend of relying on utilities' IRPs for transmission planning instead of turning to MISO for comprehensive, cost-shared solutions will cost customers money in the long run.

Because regional lines benefit so many, there are many parties to "bicker" over how the costs of lines should be divided, she said. "Literally the flows on the system are changing minute-by-minute."

Azar said the E-RSC seems to be hamstringing itself by maintaining an overly restrictive benefits philosophy that prevents it from considering other real benefits of transmission.

Arkansas Public Service Commission consultant Keith Berry disagreed that the E-RSC's cost allocation principles are boxing its working group in from formulating adequate benefit metrics.

But Azar said the E-RSC Working Group has so far been able to come up with just two benefit metrics that will almost certainly fail to meet FERC's standard that costs be portioned out roughly commensurate with benefits.

"You're going to have to come up with different ways to meet that legal standard," she said.

MISO Midwest's 100% postage stamp allocation based on a load ratio share is often misunderstood as an "everybody pays the same rate" allocation when it's really a rate based on grid usage, Azar said.

SREA Executive Director Simon Mahan said MISO South's failure to settle on a cost allocation direction with the RTO may have kept it from reaping the benefits of major transmission projects.

"It's my view that if we had a cost allocation for MISO South in place … we might have been able to move faster on the planning side," he said.

Mahan also said FERC's recently authorized Order 1920 is essential for MISO South states, whose IRPs are largely silent on long-term, regional transmission.

Mahan said Order 1920 is "based heavily on what MISO already does" for MISO Midwest. He said MISO South can use FERC's planning directives "to help fill a gap" that exists in the South's long-term transmission planning.

Though Order 1920 prescribes long-term planning on a five-year cycle, MISO South should undergo regional planning every three years, Mahan continued. That would pre-

MISO News

vent the yearslong "drought" MISO Midwest experienced between its last market efficiency project and the introduction of the long-term transmission portfolios, he said.

"You can go back at MISO's old transmission planning futures and see how drastically things have changed," Mahan said in support of speedier planning cycles.

Six years elapsed between MISO's last successful market efficiency project — the $156 million, 345-kV Huntley-Wilmarth line in southern Minnesota — and its 2022 *approval* of its first, $10 billion LRTP for MISO Midwest.

Mahan pointed out that MISO South has never hosted a market efficiency project, and MISO's only attempt at one in the South proved unsuccessful.

MISO canceled the $130 million, 500-kV Hartburg-Sabine Junction project in East Texas in 2022, five years after recommending it. At the time, Texas' ultimately unconstitutional right-of-first-refusal law introduced questions over who could construct the line. Entergy in the meantime built the 993-MW Montgomery County Power Station in southeast Texas, and made plans for the 1.2-GW natural gas and hydrogen-powered *Orange County Advanced Power Station* by 2026, rendering the line unnecessary, according to MISO's analyses.

Since then, Entergy has proposed billions in transmission projects to serve reliability needs. MISO South accounted for nearly half the cost of MISO's record-breaking, $9.4 billion Transmission Expansion Plan, including a $1.1 billion, 150-mile 500-kV line and substation project Entergy proposed for southeast Texas.

Bill Booth, a consultant to the Mississippi Public Service Commission, pushed back on the notion that MISO South's nonexistent allocation has put a drag on MISO planning. He argued that an unfinished cost allocation couldn't have been holding up regional transmission because MISO hasn't begun planning the third LRTP portfolio.

Booth said it seemed like Mahan was trying to argue that the South should be more like the Midwest. He also said MISO South is in the construction phase of several million dollars of transmission investment.

But Mahan said those investments are set to produce only local lines that don't cross state lines.

Mahan made the case that there are parallels to be drawn between MISO South and Midwest. He said that while the South doesn't have the impending coal retirements that the Midwest is staring down, it does have aging, legacy gas units. He also said the South boasts utilities with zero-carbon goals, corporate interest in load growth, escalating extreme weather events and growing renewable fleets.

"While we're not the same as the North, there are a lot of solutions where transmission can help," Mahan said, adding that the South region is woefully behind on attending to its regional system.

"There are things that beg a larger planning than what we've been engaging in the past decade or so," he said. "We do need to fill in this gap about what we do on long-range transmission planning."

Azar warned Entergy and regulators against crafting an allocation with FERC's Order 1000 in mind. By the time MISO pulls together South LRTP projects — likely in 2026 — Azar said Order 1920 will be the prevailing transmission rule. ■

NYISO News

NYISO Proposes Changes to Special-case Resource Program

By Vincent Gabrielle

NYISO is proposing to increase the required duration of *special-case resources'* load curtailment from four hours to six following a survey showing stakeholder support as part of the ISO's Engaging the Demand Side initiative.

SCRs are demand-side *resources* connected to a load that is capable of being interrupted at NYISO's direction, including on-site solar. These resources may also have a local generator that is behind the meter and rated at 100 kW or higher that can be used to reduce load. They are activated when operating reserves are forecasted to be short; when there are actual operating reserve deficiencies; or in case of another emergency to balance load and generation. SCRs from aggregate resources must be within the same zone.

Currently NYISO requires SCRs to curtail load for at least four consecutive hours. Increasing the requirement to six hours would "provide the opportunity for SCRs to earn additional revenue for load reduction and enhance NYISO grid operators' ability to balance supply and demand," Michael Ferrari, ISO market design specialist, told the ICAP Working Group on July 15.

"Multiple Intervenors supports this particular change, and that support is really driven by the vast chasm of compensation between four- and six-hour resources with respect to NYISO's capacity accreditation initiative," said Mike Mager, an attorney for Multiple Intervenors, a large energy customer organization. "I will note, however, that that's not unanimous."

Some stakeholders asked whether NYISO would consider creating SCR categories with different durations.

"It is certainly easiest to have a single class for SCR, where it is one duration, and resources can just be dispatched by zone," Ferrari said. "It is certainly more burdensome for two different classes of SCRs. But given the feedback on the desire for more flexibility, it's something I think we can consider."

"I appreciate that a one-size-fits-all approach is easiest for you," said Kevin Lang, of law firm Couch White. "I would just note that for your suppliers, you don't have one-size-fits-all approaches."

"It's not so much that it's burdensome," explained Zach Smith, vice president of system and resource planning for NYISO. "It's remembering that this is a manually activated program, which is very different from every other supplier."

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Ferrari told the working group that NYISO is also considering shortening the activation notice period for the SCR down from 21 hours. The final, shorter duration would still be roughly a day-ahead notice, but the final time has not been decided.

"On a preliminary basis, the feedback we've gotten from our members" is they prefer "a fixed-time approach sometime comfortably prior to the close of business the day before," Mager said. "By 1 p.m. or 2 p.m., they would know whether the call was happening or not."

One stakeholder reminded NYISO that certain engineers and professionals that manage building and industrial infrastructure would not be available after 3 p.m. because their days start much earlier than the traditional "start of business."

NYISO is also proposing changing the method for determining SCRs' baseline load values from average coincident load (ACL) to customer baseline load (CBL). Ferrari said that CBL would allow the ISO and market participants to more accurately look at the energy available to reduce load. Some stakeholders noted that this would be more difficult to calculate and potentially be confusing for operators.

"I would note that all of the changes being proposed have the effect of seemingly making performance more difficult or challenging for participants," Mager said.

Others noted that the CBL was already being used in the installed reserve margin study to estimate the amount of relief from using an SCR.

NYISO plans to deploy these revisions to the SCR program in the 2026/27 capability year with possible phased implementation. Several stakeholders expressed disappointment that the six-hour duration could not be deployed sooner.

"We certainly understand the request and the desire and the disappointment that this cannot be made sooner," Smith said. He explained that to implement the change for 2025/26, a software update would be needed by February. "We did not ask to have software development as part of the work for this year, and the two months that we have to deploy this is insufficient for even just" a change of two hours.

Smith said NYISO would continue to evaluate whether that could be accelerated. ■

NYISO News

NYISO BIC/OC Briefs

Ancillary Service Manual Updates

NYISO's Business Issues and Operating committees met last week to discuss and vote on *updates* to the ISO's Ancillary Services manual. Both committees approved the proposed revisions unanimously.

The revisions consist of changes to the Voltage Support Service section of the manual. "Qualification Package" was given its own subsection with clarifying language under section 3.2, and "Identical Treatment Units," "Testing Periods" and "Testing Coordination" were broken out into their own subsections under section 3.6.

SIS for Cryptomining Expansion

The committee also unanimously approved the *system impact study* scope of a project to expand Digihost Technology's cryptocurrency mining facility in North Tonawanda.

The facility has drawn fire from local residents for noise and air pollution. On July 16, two days before the OC's meeting, the city's Common Council approved a *two-year moratorium* on new data center operations and the expansion of existing facilities.

The controversy did not come up during the committee's meeting. Digihost has proposed an in-service date in December, according to the scope.

The OC also approved five interconnection study reports, most of which were for solar and wind projects.

Market Reports for June

Rana Mukerji, NYISO senior vice president of market structures, presented the BIC with the monthly market performance *report* for June.

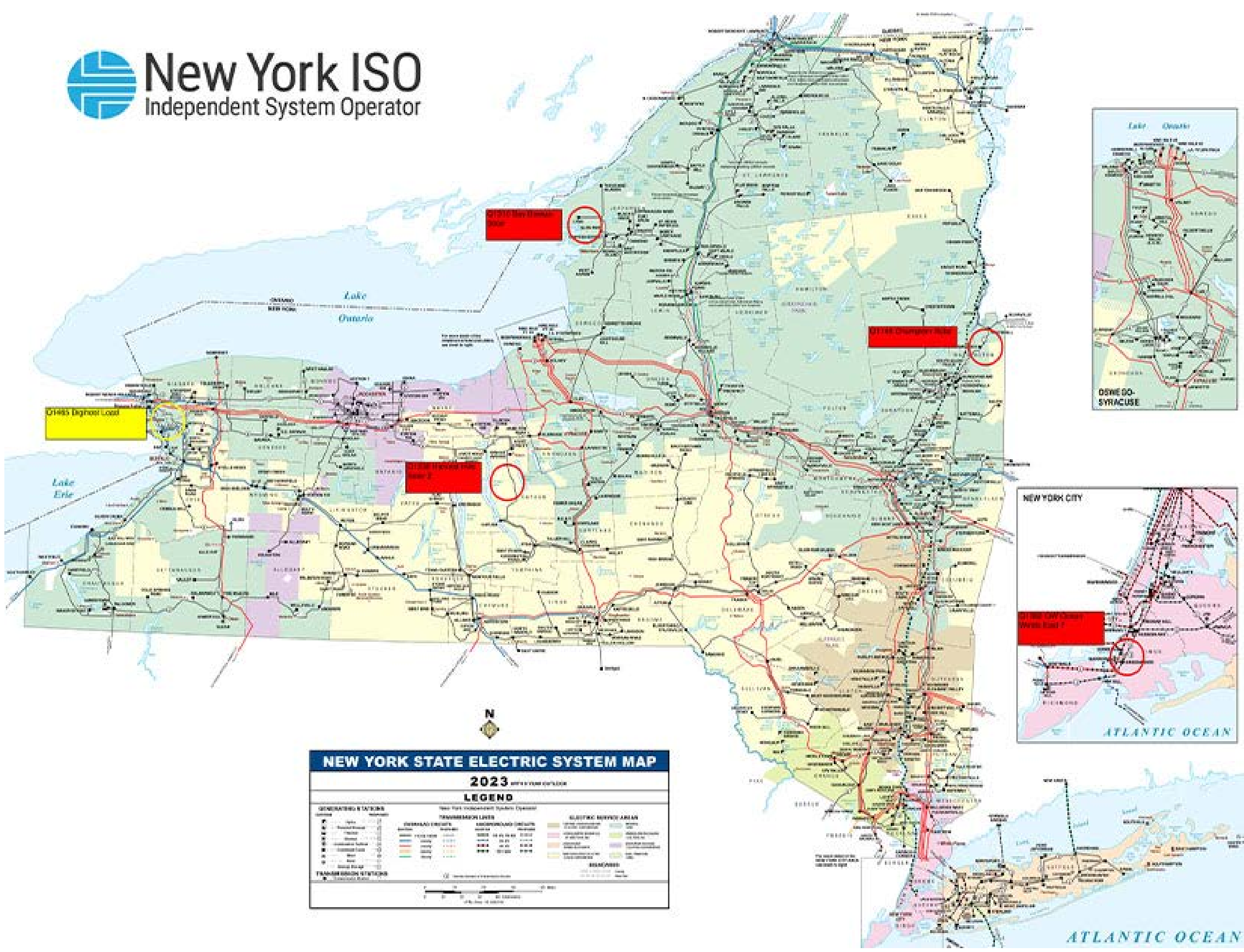
The average locational-based marginal price was $39.68/MWh, exceeding both May's $28.36/MWh and the $29.85/MWh for June 2023. Day-ahead and real-time load-weighted LBMPs were both higher compared to the previous month. The average daily send-out of 455 GWh/day is also up from last month and the year before. And the average year-to-date monthly cost of $40.78/MWh is 4% higher than last year's.

Aaron Markham, NYISO vice president of grid operations, presented the OC with the monthly operations *report*. He said high temperatures in June resulted in higher-than-average demand for the month.

"Peak load was mitigated by demand response activations," Markham said. "The heat moved through the state. It was hotter upstate early in the period, and then the heat moved downstate. Not having simultaneous high temperatures across the state mitigated the peak load."

Peak load for the month occurred June 21 at 28,245 MW, about 90% of the baseline forecast, Markham said. ■

— Vincent Gabrielle



| NYISO

PJM News

PJM Presents Revised Reserve Requirement Study Values

By Devin Leith-Yessian

PJM presented its Planning Committee with *revisions* to the 2023 Reserve Requirement Study (RRS) to reflect the marginal effective load carrying capability (ELCC) analysis approach the RTO uses for most resource accreditation.

During the July 16 special meeting, PJM's Patricio Rocha Garrido said the results of the reanalysis recommend increasing the installed reserve margin (IRM), which sets the targeted capacity level above expected loads, to 18.6%, up from the 17.6% stakeholders endorsed in the original study last year. The forecast pool requirement (FPR), which accounts for generator accreditation, would decrease from 11.65% to 9.37%. (See "Stakeholders Endorse Reserve Requirement Study Values," *PJM PC/TEAC Briefs: Oct. 3, 2023*.)

The majority of resource classes saw a relatively minor change between their 2025/26 ELCC ratings and the 2026/27 target year for the 2023 RRS, with most increasing or decreasing within 2%. Gas combustion turbines saw the largest change, increasing 6% due to the number of CTs that have announced their deactivation. The overall impetus for rating changes across resource types was a small shift towards risk being concentrated in the winter.

The new values are being brought to the July 24 Markets and Reliability Committee and Members Committee meetings for a same-day first read and endorsement vote.

The marginal ELCC approach was one of several capacity market redesigns drafted through the Critical Issue Fast Path (CIFP) process last year and approved by FERC in January 2024. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Patricio Rocha Garrido, PJM | *© RTO Insider LLC*

The CIFP filing also revised three formulas central to the RRS analysis, including:

- calculating the IRM by reducing total installed capacity (ICAP) by the capacity benefit of ties (CBOT);
- determining the FPR by multiplying the IRM by the pool-wide average accredited unforced capacity (UCAP) factor, rather than forced outage rates; and
- making the average accredited unforced capacity (UCAP) factor the ratio of UCAP to installed capacity (ICAP).

Stakeholders endorsed an earlier round of revisions to the RRS to reflect the impact of those design changes earlier this year. (See "Revised Reserve Requirement Study Values Endorsed," *PJM MRC/MC Briefs: March 20, 2024*.)

Garrido said PJM also updated the assumed resource mix to include planned resources that submitted a notice of intent to offer into the 2026/27 Base Residual Auction. Gas generators that submitted dual fuel attestations were sorted into the corresponding ELCC classes, and resources that are scheduled to deactivate prior to the start of the delivery year were removed from the analysis. Generators expected to operate on reliability-must-run (RMR) contracts through the delivery year were included in the resource mix.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said some RMR contracts do not require the generator to respond to PJM capacity deployments and should not be included in the resource mix.

"I think we're actually overstating the amount of capacity that's going to be there," he said, adding it would distort market signals.

Sotkiewicz also questioned the assumption that outside capacity could be available for import during emergencies, saying that PJM has been consistently exporting during "emergency events and high load days."

Garrido said PJM aims to model the system as it's expected to exist in the target delivery year and that RMR resources should be included if they're contracted to remain in operation. He stated any impact on the reliability requirement would be small. ■

PJM News

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings July 24. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

RTO Insider will be covering the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed conforming *revisions* to Manual 12: Balancing Operations to implement provisions of a package to establish fuel assuredness requirements for black start resources approved by stakeholders last year. The changes would add two exemptions from penalties for fuel-assured black start resources that fall below their minimum fuel inventory due to capacity calls or storage inspections, as well as reworking the verification process. The revisions being voted on July 24 were inadvertently left out of the language approved last year despite being included in the approved package matrix. (See "Stakeholders Endorse Revisions to Manual 12 for Black Start Fuel Requirements," *PJM OC Briefs: July 11, 2024.*)

Issue Tracking: *Fuel Requirements for Black Start Resources*

C. Endorse proposed *revisions* to Manual 13: Emergency Operations drafted through the document's periodic review. The changes clarify communication processes between RTO control rooms, adding language that local load shed directives do not initiate a performance assessment interval (PAI), and remove member actions stating that gas generation owners should notify PJM of whether they have or plan to procure fuel to meet day ahead reserve commitments.

Endorsements (9:10-10:50)

Enhanced Know Your Customer (9:10-9:30)

PJM's Anita Patel and Eric Scherling will *present* more stringent "know your customer" requirements that would require some members to provide more information about key decisions makers, owners and beneficiaries. The proposal was endorsed by the Risk Management Committee on May 21. (See "First Read on Expanded 'Know Your Customer' Rules," *PJM MRC/MC Briefs: June 27, 2024.*)

The committee will be asked to endorse the proposed solution and corresponding tariff revisions.

Issue Tracking: *Enhanced Know Your Customer (KYC)*

Performance Impact of the Multi-Schedule Model in the Market Clearing Engine (9:30-9:50)

Constellation Energy's Adrien Ford is set to make a motion for the committee to endorse a joint PJM/GT Power Group *proposal* to establish a formula to select one offer into the energy market for each resource to be forwarded to the Market Clearing Engine (MCE). The proposal is intended to facilitate PJM's goal of implementing multi-schedule modeling without causing a significant increase in MCE computation times. The proposal to be voted on July 24 was turned down by the MRC in December when the committee endorsed a different PJM proposal, which ultimately was rejected by FERC. (See "Stakeholders Discuss Path Forward on Multi-Schedule Modeling," *PJM MIC Briefs: June 5, 2024.*)

The committee will be asked to endorse the proposed solution and corresponding revisions to the tariff and Operating Agreement.

Issue Tracking: *Performance Impact of multi-schedule model in Market Clearing Engine (MCE) in nGEM Enhanced Combined Cycle (ECC) and Energy Storage Resource (ESR) models*

Reserve Certainty (9:50-10:10)

PJM's Emily Barrett will present two *proposals* to rework how PJM determines its reserve procurement targets and how those resources are deployed. The first would replace the static 3,000-MW 30-minute reserve requirement with a formula that takes load forecasting, forced outage rates, the largest active gas contingency and the primary reserve requirement into account. It also would permit PJM to increase the 30-minute, synchronized or primary reserve requirements independently of the other two. The second proposal would send reserve deployment instructions through resources' basepoints as the primary notification that they are being called on to provide reserves. (See "First Read on 2 PJM Proposals to Revise Reserve Markets," *PJM MRC/MC Briefs: June 27, 2024.*)

The committee will be asked to endorse the proposed solutions and corresponding tariff, Operating Agreement and manual revisions.

Issue Tracking: *Reserve Certainty and Resource Flexibility Incentives*

Enhancements to Deactivation Rules (10:10-10:30)

Philip Sussler, of the Maryland Office of People's Counsel, and Clara Summers, of the Illinois Citizens Utility Board, will present *amendments* to the Deactivation Enhancements Senior Task Force (DESTF) issue charge to expand its scope to include proposals that create more cost-effective alternatives to reliability-must-run (RMR) contracts, which are offered to generators whose requested deactivation would prompt transmission violations. The widened scope also includes education about alternative transmission technologies that could allow violations to be resolved faster and processes in use by other grid operators. (See "Consumer Advocates Seek Wider Scope for Deactivation Task Force," *PJM MRC/MC Briefs: June 27, 2024.*)

The committee will be asked to approve the amended issue charge.

Issue Charge: *Enhancements to Deactivation Rules*

IRM and FPR Results for 2026/27 Delivery Year (10:30-10:50)

PJM's Josh Bruno will *present* revised installed reserve margin (IRM) and forecast pool requirement (FPR) values for the 2026/27 delivery year to reflect market design changes made since the 2023 Reserve Requirement Study (RRS) was completed. Drafted through the Critical Issue Fast Path (CIFP) process last year, the market changes include accrediting nearly all resources through a marginal effective load carrying capability (ELCC) approach and alterations to the IRM and FPR formulas.

The committee will be asked to endorse the IRM and FPR results upon first read at this meeting. Same day endorsement may be sought at the Members Committee. (See "Stakeholders Endorse Revised RRS Values," *PJM PC/TEAC Briefs: Feb. 6, 2024.*)

Members Committee

Endorsements (2:40-3:00)

Bruno will *present* revised installed reserve margin (IRM) and forecast pool requirement (FPR) values for the 2026/27 delivery year.

The committee will be asked to endorse the new figures upon first read. ■

SPP News

BPA Stepping up Participation in Pathways Initiative

Move Doesn't Signal Pull-back from Staff 'Leaning' in Favor of Markets+, Agency Emphasizes

By Robert Mullin

The Bonneville Power Administration is ramping up its engagement with the West-Wide Governance Pathways Initiative, an executive with the federal power agency said July 18.

That means BPA will shift from a previous stance of mostly monitoring developments in the Pathways Initiative to fully participating in its looming efforts to change California law to relax some provisions of CAISO's state-run governance and shape a new "regional organization" (RO) to oversee a Western electricity market based on the ISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM).

However, the stepped-up involvement in Pathways doesn't signal a change in BPA staff's "leaning," issued in April, recommending that the agency choose SPP's Markets+ over EDAM when it opts to join a day-ahead market, according to Doug Marker, an intergovernmental affairs strategist at BPA. (See *BPA Staff Recommends Markets+ over EDAM*.)

"This does not represent a change in our staff recommendation, nor an endorsement of EDAM or the Pathways conclusions, but we feel it's important to be involved to understand the issues that are shaping the structure of Pathways," Marker said during a BPA day-ahead markets workshop.

"At the end of the day, should this be successful — and obviously we share the objective for bringing independence to CAISO market governance — we will have customers who are served through the markets that are governed through this process, and we will at least be a neighboring entity for the market," he said.

Marker said BPA declined to participate in Step 1 of the Pathways effort, which crafted a plan to elevate the authority of the WEIM's Governing Body to the greatest extent possible without altering California law, because it was heavily involved in drafting a tariff for Markets+. SPP filed the proposed tariff with FERC in late March. (See *SPP Files Proposed Markets+ Tariff at FERC*.)

CAISO last month kicked off the stakeholder process for adopting the Pathways Step 1 proposal, and Marker noted that BPA had submitted *comments* after the first meeting in that effort. (See *CAISO Kicks off Stakeholder Process for Pathways Initiative*.)

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BPA is expanding its engagement just as Pathways begins to pursue parallel "work streams" in Step 2 of its effort. (See *Busy Summer Ahead for Pathways Initiative*.) Marker said the agency assigned staff to four of the initiative's six newly created workgroups, including those dealing with CAISO tariff analysis, stakeholder processes, RO governance and public interest issues, "which is really talking about the role of a states committee and possibly consumer advocates in the governance structure for the RO."

"We've said we want two viable options, and so we are participating from the perspective of improving the viability of the EDAM alternative," he said.

'Material Difference'

Marker said it's important to BPA that Pathways' discussions "be done as transparently as possible," echoing a criticism that some stakeholders have shared with *RTO Insider*: that much of the effort has been developed in closed-door meetings, punctuated by monthly public progress reports. (Pathways participants have pointed out that all votes by the group will be held publicly.)

"So, we urge the Pathways' Launch Committee to make the workgroup meetings open. It was a decision for us to participate even if the meetings are not open, but we think that the open meetings improve the transparency and the ultimate strength of the proposals that emerge from it," Marker said.

That last comment prompted a sharp response from Launch Committee Co-Chair Pam Sporborg, director of transmission and market services at Portland General Electric.

"I'll note that Pathways is not a decision-making body," Sporborg said. "We're a temporary volunteer group that is coming together to suggest ideas and concepts to formal decision makers across the west, to the CAISO board, California elected officials and to the broader West. We're not drafting a tariff like Markets+. We're not a formal stakeholder process. We have turned over our recommendations to that formal [CAISO] stakeholder process, which is ongoing, as you noted."

Sporborg pointed out that BPA has participated in efforts with a similar process of public and non-public meetings, such as the Western Power Pool's Western Resource Adequacy Program (WRAP) and Western Transmission Expansion Coalition (WestTEC).

"It seems interesting to call out Pathways uniquely, given that Bonneville's participation in those other structures that really have a steering committee focus and do hold those kinds of private coordinating meetings with separate and intentional opportunities for public engagement," she said.

BPA Director of Market Initiatives Russ Mantifel, who's been leading the agency's day-ahead markets process, countered that he thinks the process for developing Markets+ was transparent from the beginning, with publicly noticed meetings and open invitations to any concerned parties.

"In terms of WRAP and WestTEC, I don't think it's Bonneville that is asking for those things not to be public. In addition to [the Western Markets Exploratory Group], as well, we were open to everything being open," Mantifel said, adding that Bonneville is required to be transparent and that "raising the bar" on transparency "is what we should be doing."

"I also think that the Pathways Initiative is explicitly trying to develop a market that will set the prices for every consumer in the Western Interconnection," he continued. "At least that's what we've heard: that the goal is to create a single market and the benefits are assuming a single market that's serving load to every retail load in the West. So, I think that that is a material difference." ■

SPP News

DC Circuit Finds for SPP in Wind Farm Dispute

By Tom Kleckner

The D.C. Circuit Court of Appeals on July 19 rejected a wind farm's challenge of FERC's decision to allow SPP to charge more than $100 million for upgrades needed to connect the facility to the grid operator's system.

In a unanimous ruling, the court found the commission's decision to assign mitigation costs to Tenaska Clear Creek Wind to be reasonable because the project caused operational issues for SPP that would not have existed but for the facility itself (*22-1059*).

Clear Creek's appeal stems from a September 2022 order in which FERC ruled that SPP correctly assigned the facility about $66 million in network upgrade costs during a restudy of a Missouri wind project. The commission denied in part a rehearing request in December 2022, although it directed the RTO to restudy the project with different planning models. (See "Split Decision for Tenaska in SPP Complaint," *FERC Rules in Three SPP Disputes*.)

The network upgrade costs eventually were set at $102 million.

The appeals court said it was "unpersuaded" by Clear Creek's challenges in its review request. The wind farm argued that FERC's order violated its cost-causation principle; that SPP's cost allocation was inconsistent with the commission's "but for" policy; and that FERC ignored the RTO's interconnection study and allocation practices used firm service when the facility was not taking service or seeking deliverability.

The D.C. Circuit said FERC was able to show its finding "comports with its precedent and the cost-causation principle," thus proving the order was based on reasoned decision-making. It said the commission's reasoning was "simply that the project caused operational issues for SPP that did not arise prior to its operation, so it is reasonable to assign the costs of mitigation to Clear Creek."

The court also concluded SPP's methodology aligns with the "but for" principle and the commission's determination was consistent with "reasoned decision-making."

"Substantial evidence supports the commission's determination here that the disputed upgrades were not intended to address regional transmission planning, as opposed to interconnection, needs," the appeals court wrote.

Finally, the court said FERC "reasonably" explained why Clear Creek couldn't meet the burden of demonstrating that SPP's use of firm service, or network resource interconnection service (NRIS), was unjust, unreasonable, unduly discriminatory or preferential. It said the commissioned identified precedent that was just and reasonable and that it "expertly pointed out" how Clear Creek's NRIS request supported SPP's justification for conducting its interconnection study at the NRIS level.

Clear Creek is a 242-MW facility that is interconnected to SPP neighbor Associated Electric Cooperative Inc.'s transmission system. The upgrade costs were assigned as part of an affected system study.

The facility became operational in May 2020. ■

Tenaska's Clear Creek Wind project | *Tenaska*

SPP News

SPP Markets and Operations Policy Committee Briefs

Stakeholders Approve 2 Key Resource Adequacy Policies

TULSA, Okla. — SPP's Markets and Operations Policy Committee endorsed recommended revision requests from two stakeholder groups as part of the RTO's effort to strengthen resource adequacy.

A fuel assurance policy (*RR621*) that further emphasizes conventional resources' performance during a season's most critical hours and reduces the socialization of the planning reserve margin's capacity allocation passed easily with 92% approval during the July 16-17 meeting.

However, a second revision request (*RR622*) that establishes base planning reserve margins (PRMs) for summer 2026 summer and winter 2026-27 passed with three-fourths approval, but only after MOPC rejected an amendment to the motion that would have set the winter PRM at 36% instead of 33 (ironically, with only 33% approval). The summer PRM would be raised to 16% from 15.

During its June meeting, the Resource Energy and Adequacy Leadership (REAL) Team approved a 36% PRM over stakeholders' concerns that the requirement was too soon and unrealistic to meet. (See *SPP's REAL Team Approves Base PRMs, Sufficiency Value Curve*.)

SPP staff pointed out that the 33% PRM brought forward by the Supply Adequacy Working Group (SAWG) technically meets a 1-in-10 reliability standard; they intend to bring both PRMs to state regulators and the RTO's board during their August meetings.

Omaha Public Power District's Colton Kennedy, the SAWG's chair, said the PRM's requirement is intended to ensure that load-responsible entities are appropriately planning for capacity in both seasons. SPP's 2023 loss-of-load study was the first in which staff directly analyzed seasonal risk beyond summer; it found a 15% PRM would not meet a 1-in-10 LOLE in either season.

"The complexity, the scope and the extent of questions by SAWG members by far surpassed all previous studies," Kennedy said. "We didn't previously have that in the historical [record] with an [LOLE] model. The inclusion of correlated outages, the inclusion of winter peak variability are the driving factors and are very reasonably supported. Very demonstrable, very objective in the work that we're doing."

He said SPP staff was very consistent with the 36% winter PRM recommendation, which created debate and discussion within SAWG related to the transition to a higher PRM by entities without sufficient capacity.

MOPC's leadership faces a long table of members in a setting one attendee likened to a long dinner table in a British comedy. | *© RTO Insider LLC*

"They're concerned about the generation interconnection process and being able to study resources and get them through this process [quickly]," Kennedy said.

Regardless of the final number, individual entities will have to step up, said Bill Grant, formerly with Southwestern Public Service and back on MOPC as a representative for XO Energy.

"The resources are out there. That doesn't mean that there's not some entities that have to scramble to meet this requirement," Grant said. "Remember, if you approve these numbers, you are impacting utilities' ability to get generation connected before any individual changes. There is an impact, and it's kind of hidden."

"For a regulated investor-owned utility, there's not enough time to get new generation in," Oklahoma Gas & Electric's Brad Cochran said.

The fuel assurance policy stems from the 2021 winter storm, when SPP was forced to shed load for the first time in its 83-year history. Casey Cathey, the grid operator's engineering vice president, said several heavily vetted approaches to fuel assurance failed before stakeholders coalesced around what he said is effectively "somewhat of a weight towards conventional resources during capacity critical hours in the winter season, in particular."

Under the policy, an "after-the-fact" weighting will be applied to performance-based accreditation resources, based on critical system periods. The mechanism is designed to encourage increased performance by those conventional, or thermal, resources by quantifying their contributions to system reliability.

Noting that there can be a 100-degree differential between the northern and southern states in SPP's footprint, Cathey said one thought holds that nonperforming resources should be targeted for their failures rather than raising the PRM.

"This revision request and this policy [help] directly address that socialization of planning reserve margin," he said. "So rather than kind of go down this path of potentially having separate zonal planning reserve margins ... this particular revision request and policy [help] to address that in a different way such that the northern resources that may already have winterization during extreme conditions and perform during those types of extreme conditions do not necessarily have to carry additional planning reserve margin accredited capacity

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beyond where the regional risk is."

DISIS Waivers Endorsed

The committee endorsed staff's proposal to file waiver requests with FERC that delay the start of the 2024 generator interconnection (GI) study's first phase and pause the opening of the 2025 study cluster, easing conflicts with the RTO's effort to clear the GI queue's backlog and transition to a new planning process.

SPP staff said delaying the 2024 definitive interconnection system impact study (DISIS) cluster's first phase will save customers up to $3 million by avoiding additional studies and will allow more accurate information for customer decisions. The 2024 DISIS first phase would begin after the 2023 DISIS second phase's restudy is completed and posted in August 2025; without the waiver, it would start before the second phase of the 2022 and 2023 clusters and likely lead to unplanned restudies, staff said.

Natasha Henderson, senior director of grid asset use for SPP, said that if the 2024 DISIS Phase 1 began on schedule, it would assume $35 billion of transmission upgrades would be built from previous studies. "We know that's not likely," she said.

Pausing the 2025 DISIS' open window will allow "additional optionality" for the grid operator's transition to the consolidated planning process (CPP), scheduled to begin in late 2026 after a transition period. SPP said opening the 2025 DISIS would mean the cluster's generation would "significantly" overlap with the CPP's transition study and first annual assessment.

Golden Spread Electric Cooperative's Mike Wise, who arrived for the MOPC meeting from the NARUC Summer Policy Summit, said FERC Chair Willie Phillips' comments made it apparent he favors quickly connecting generation and building out transmission to support the new resources. Wise said words such as "delay" and "waiver" send the wrong message and could make commission approval difficult.

Staff said they believe they have agreed on messaging that should gain FERC's signoff if the waivers are submitted as a package. They are also planning to schedule a meeting with commission staff.

"I think it's going to be important that we convey the fact that this is not a pause," Cathey said. "The message here is we can do things a little bit more efficiently. We're not asking to pause the DISIS ... it's to try to accelerate and actually reduce the churn of the restudies."

Advanced Power Alliance's Steve Gaw (third from left) discusses issues with other renewable interests. | *© RTO Insider LLC*

MOPC Chair Alan Myers struggled to get a second for the waiver requests from members who had previously expressed concerns about not having enough time to consider the proposal. Eventually, Evergy's Derek Brown bravely raised his name tent to second the motion. It passed with 80.6% approval.

FERC's approval of the waivers would enable the timely completion of backlog studies and allow time to further develop CPP. SPP in June posted its second study of the DISIS 2017-002 cluster, clearing the way for the 2018 DISIS' second restudy.

The grid operator has 416 requests in the GI queue totaling about 84 GW in proposed capacity. That's down from the original backlog of 1,139 requests for 221 GW of capacity. The backlog will be cleared when the 2023 cluster's second restudy is posted in September 2025.

SPP staff and stakeholders have been working on the CPP and its associated cost-sharing mechanism since 2021. (See *SPP's Consolidated Tx Planning Just Beginning*.)

MOPC in April approved a task force's *recommended policy* for the CPP's entry fee. A transition study to the new process, comprised of SPP's current 20-year assessment and the first annual CPP analysis, is slated to begin this year and will set the first $/MW entry fee. The study is intended to align technical assumptions and scopes, yielding a "more robust" cost-sharing model that sets a specific frequency to avoid late charges.

SPP Adds Context on April Event

SPP told MOPC members that it is recommending several changes to its operational procedures following an April emergency event in Southwestern Public Service's (SPS) New Mexico region that resulted in a 150-MW load shed lasting about two hours. (See "SPP, SPS Reviewing April Outage," *SPP Board of Directors/MC Briefs: May 7, 2024*.)

Staff said they saw contingencies begin to develop April 28 as wind dropped from 16 GW to nearly 5 GW and load began to increase. Derek Hawkins, the RTO's director of system operations, said that shortly after 7 p.m., an exceedance occurred on an SPP-SPS tie line.

Hawkins said his operators exhausted all available options within the constrained time frame in trying to address potential instability and were forced to shed load because of "immediate circumstances" and "evolving conditions." SPP directed SPS to drop 150 MW of load at 7:43 p.m. to mitigate the unsolved contingencies. Load was restored by 9:41 p.m.

Hawkins said a post-event analysis revealed the importance of clear communication, robust coordination agreements and improved data integrity practices. He said operators were rebuffed twice when requesting energy from switchable units with ERCOT, which was dealing with its own tight conditions.

The recommendations include emphasizing timely and clear communications, evaluating improvements to operating procedures with

SPP News

ERCOT, and discussing coordination plans with neighboring entities.

Jarred Cooley, Southwestern Public Service, offers comments on April load shed event. | © RTO Insider LLC

SPS' Jarred Cooley, director of strategic planning, said his own conversations with Hawkins and C.J. Brown, SPP's senior director of system operations, policy and performance support, were beneficial and useful for the entire RTO footprint.

"We've met multiple times, had pointed, real in-depth discussions, and those were really useful for where we are with the recommendations," Cooley said. "Obviously, it's up to all of us to help support staff to have the tools that they need in real time so they act appropriately and that we can ensure good reliability for the system."

Storage Self-charging Change

Members approved a pair of tariff revisions recommended by the Market Working Group related to storage and system dispatch.

RR635 would ensure market storage resources' self-charging is identified and charged appropriately. The MWG said the change will increase alignment with FERC Order 841's requirements for identifying and charging equitably for self-charging and will ensure that MSRs are subject to unreserved use when self-charging.

The FERC order found that energy storage resources should not be charged transmission costs when providing a market service. SPP currently dispatches MSRs based on economics and resource parameters; if the MSR is providing a market service, no transmission service is required.

RR628 would dispatch the system based on the system's true obligation and price by removing load shed and emergency purchases. It would restore the load shed amount's requested congestion prices from each forecast area to reduce the effects.

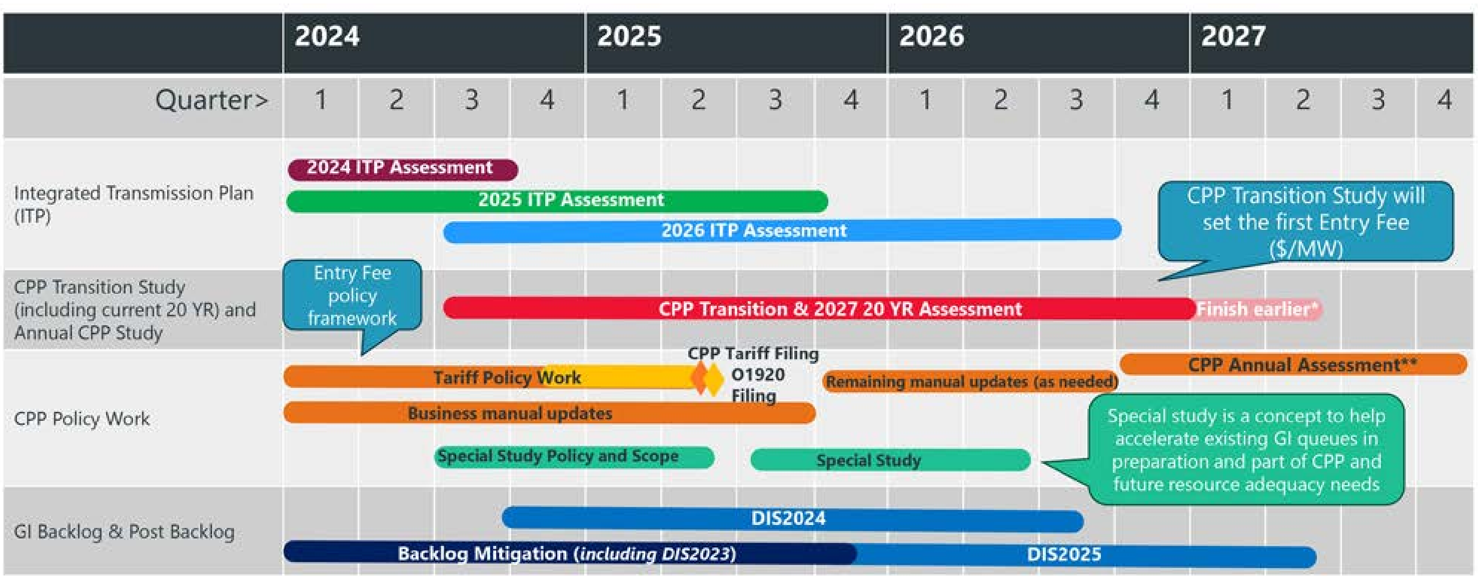
The RR635 and RR628 passed with 90 and 95% approval, respectively.

The unanimously approved consent agenda included nine other tariff changes that, if necessitating approval from the Board of Directors, would:

- RR595: Allow make-whole payments for instructed real-time incremental energy costs for day-ahead market committed and self-committed resources for offers under FERC Order 831 (adds changes after original MOPC approval in April 2024).
- RR602: Add process structure, tracking and improved criteria for evaluating potential transmission reconfigurations.
- RR610: Allow third-party cost estimate information and/or engineering judgment when creating a conceptual cost estimate to be used during a project study.
- RR615: Changes the RTO's credit policy to introduce a portfolio-level mark-to-auction mechanism within the transmission congestion rights collateral requirement, thus mitigating default risk by updating collateral requirements to reflect the portfolio's most recent valuation.
- RR619: Add application programming interfaces as an acceptable submittal process.
- RR623: Deploy a compensation mechanism to incentivize continued operation of resources whose studied retirements have identified one or more network upgrades as necessary to address reliability impacts that are unable to be completed prior to the projected retirement date. A unique contract will be developed for each retiring resource that details the eligible costs and a new schedule will be created detailing the allocation of the contract costs.
- RR627: Clarify that the turnaround ramp rate factor applies to energy and contingency reserve.
- RR631: Ensure consistent governing language and address corrections to previously published settlement calculations in RR613, RR556, RR578 and RR596.
- RR633: Clarify how SPP recalculates real-time balancing market outages and extends the repricing notifications.

The consent agenda also included the retirement of a remedial action scheme near Rapid City, S.D., upgrades to terminal equipment at one 115-kV and two 345-kV substations, and cost increases for a Western Farmers' and an Omaha Public Power District's projects. ■

— Tom Kleckner



SPP's current timetable for transition to a consolidated planning process. | *SPP*

Company Briefs

Clean Grid Alliance Welcomes Former Iowa Legislator Brown

Clean Grid Alliance last week announced that former Iowa Sen. Waylon Brown will join the alliance as regional policy manager.

Brown served in the Iowa Senate from 2017 to July 2024 leading the Commerce Committee, which oversees energy policy.

More: *Clean Grid Alliance*

SunPower Stock Collapses as Company Halts Leases, Installations, Shipments

SunPower's stock collapsed 70% last week after the company informed dealers it will no longer support new leases, installations or product shipments, with analysts saying the company is on the verge of going out of business.

SunPower stock has lost nearly all its value in the last 12 months, with the shares down 93% to trade at 79 cents on July 19. Guggenheim Securities has slashed its price target to $0 from $1.

One analyst said the decision to effectively suspend operations is the result of SunPower's weakened cash flow and balance sheet, as well as its inability to tap capital markets because the company is not current with the Securities and Exchange Commission.

More: *CNBC*

Woodside Doubles down on US, LNG with Tellurian Takeover

Australia-based Woodside Energy said July 22 that it said it intends to acquire Tellurian and its proposed LNG development in the southern U.S. for about $900 million.

Tellurian owns the planned Driftwood LNG development near Lake Charles, La. Woodside said Tellurian's directors support the transaction and that it aims to complete a deal in the final three months of this year.

The deal for Tellurian deepens Woodside's commitment to the U.S. where it majority owns the Shenzi oil-and-gas field, about 120 miles off the coast of Louisiana.

More: *The Wall Street Journal*

Federal Briefs

DC Circuit Court Allows EPA Rule on Coal-fired Plants to Remain

D.C. Circuit Court of Appeals last week ruled that a new EPA regulation aimed at limiting carbon emissions from coal-fired power plants can stay in place.

A three-judge panel rejected the request to block the rule, saying the groups had not shown they are likely to succeed on the merits. The judges also rejected the claim of immediate harm, saying compliance deadlines do not take effect until 2030 or 2032.

Industry groups and some Republican-led states had asked the court to block the rule on an emergency basis, saying it was unattainable and threatened reliability of the nation's power grid. The rule, announced in April, would force many coal-fired plants to capture 90% of their carbon emissions or shut down within eight years.

More: *The Associated Press*

EPA on Deadline to Spend on Climate Grant Program

EPA has until Sept. 30 to spend $27 billion to reshape impoverished areas of the U.S. by financing the installation of renewable energy and improving buildings' energy efficiency.

However, the initiative has a shoestring operating budget, and the program is now facing charges of empty oversight and potential waste — and the prospects of a Republican feeding frenzy over the Inflation Reduction Act if the program stumbles. Analysts say out of all the programs authorized in the IRA, this one has the smallest amount of money allotted to hire staff and track spending.

EPA has chosen 68 entities to use the money to underwrite projects. The agency is negotiating contracts with those recipients and has promised the money will be delivered before the IRA's deadline.

More: *POLITICO*

Washington Man Arrested, Charged for 2022 Attacks on Oregon Facilities

Zachary Rosenthal, 33, from Tacoma, Wash., was arraigned on federal charges last week for allegedly damaging two energy substations in Clackamas County in November 2022.

Rosenthal is accused of damaging the Sunnyside Substation in Clackamas and the Ostrander Substation in Oregon City. The attacks were part of a national series of attempted disruptions to the grid that law enforcement warned had possible ties to extremist groups. Justice Department officials have not said if they have identified a motive.

More: *Oregon Public Broadcasting*

National/Federal news from our other channels

EPA Announces $4.3B in Climate Pollution Reduction Grants — NetZero Insider

NERC Submits Final Performance Assessment — ERO Insider

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

State Briefs

ARIZONA

Strata Clean Energy Enters BESS Agreement

Strata Clean Energy last week announced it has secured a 20-year tolling agreement with Arizona Public Service for its 150-MW Justice Energy Storage project in Phoenix.

The project is expected to be completed in April 2026.

More: *Energy Global*

GEORGIA

Plant Vogtle's Unit 3 Back Online After Valve Issue

Unit 3 at Plant Vogtle, which had been offline since July 8 due to a "valve issue," is back online, Georgia Power said last week.

The unit was shut down after a valve malfunctioned on one of the pumps that supplies "feedwater" to the steam generator, the company said. Feedwater removes heat from the reactor and is used to produce steam, which spins the generator's turbines to create electricity.

More: *The Atlanta Journal-Constitution*, *The Telegraph*

ILLINOIS

Plan to End Natural Gas Hookups Dies on City Council Desk

Chicago Mayor Brandon Johnson's proposal to end natural gas connections in new homes and buildings is dead after a majority of city council members opposed the idea.

Johnson's *climate-fighting initiative*, the Clean and Affordable Buildings Ordinance, is sitting in the council's Rules Committee and doesn't appear to be moving after at least 31 alderpersons signed on to a public statement opposing the plan.

The plan would largely ban new gas hookups for cooking, heating and hot water tanks and require electric power for new construction, including homes and large additions.

More: *Chicago Sun-Times*

State Establishes Moratorium on CO2 Pipelines

Gov. **JB Pritzker** last week signed legislation that will establish a two-year moratorium on the construction of carbon dioxide pipelines.

The moratorium would run until July 2026 or when the federal Pipeline and Hazardous Materials Safety Administration adopts revised safety regulations, whichever comes first. The law also requires pipeline companies to show their pipelines will lead to net reduction in climate pollution and don't add co-pollutants in the atmosphere.

The bill passed the House (78-29) and the Senate (43-12) along party lines.

More: *Springfield State Journal-Register*

LOUISIANA

Appeals Court Sends LNG Terminal Project Back to FERC

The U.S. Court of Appeals for the D.C. District last week determined FERC did not adequately assess the cumulative and direct environmental and health impacts from the Commonwealth LNG terminal and will have to reconsider its review.

FERC originally approved the project in November 2022. Commonwealth's plan calls for construction to begin on the 150-acre site on the Calcasieu Ship Channel in the first half of 2025 and LNG production to start by the end of 2028.

Neither FERC nor Commonwealth immediately commented on the ruling.

More: *Louisiana Illuminator*

MASSACHUSETTS

DEP Says Holtec Can't Dump Nuclear Wastewater into Cape Cod Bay

The Department of Environmental Protection last week said that Holtec, the company decommissioning the former Pilgrim Nuclear Power Station, cannot discharge the wastewater into the Cape Cod Bay because is protected under the Ocean Sanctuaries Act.

Holtec had hoped to dump 1.1 million gallons of treated water into the bay. The water had been used to cool spent nuclear fuel rods. The process is legal and deemed safe provided the water does not exceed radioactivity levels set by the Nuclear Regulatory Commission.

Pilgrim went offline in 2019, and Holtec has begun the process of dismantling the plant and cleaning up the property.

More: *WBUR*

House Approves Bill to Boost Renewable Efforts

The House last week approved a bill that will help boost the state's reliance on renewable energy by streamlining the state and local permitting process for projects that shift away from fossil fuels.

The measure would consolidate both state and local permitting and set 12- to 15-month limits for considering all final permitting decisions. It also calls for procuring additional clean energy resources and allows future offshore wind and clean energy contracts to be extended up to 30 years.

The bill's approval comes just weeks after the Senate approved its own bill to help the state meet its climate goals, including reaching net zero greenhouse gas emissions by 2050.

More: *The Associated Press*

PENNSYLVANIA

Pittsburgh Officials Find no Evidence of Gas Equipment Causing Explosion

The Public Utility Commission Safety Division last week found no evidence linking public utility natural gas equipment to an August 2023 house explosion in Allegheny County.

Six people were killed, several others were injured and three homes were destroyed because of the explosion.

More: *KDKA*

TEXAS

Gov. Abbott Gives CenterPoint Deadline to Fix Power Outages

Gov. **Greg Abbott** last week gave CenterPoint Energy until the end of July to develop a plan to minimize future outages or face unspecified executive orders to address its shortcomings.

Abbott's directives require CenterPoint to provide the governor's office with plans for removing all vegetation that threatens power lines, how it will prepare for future tropical storms, and specify action it will take to position personnel "to immediately respond to any power outages that may occur for any tropical storm that hits their service region." The Public Utility Commission and a newly appointed Senate committee will also investigate the company's actions related to the outages.

CenterPoint has taken the brunt of criticism for 2.2 million Houston-area customers who lost power after Hurricane Beryl slammed the state. The company has said 98% of those customers have had their power restored, but that still left nearly 300,000 customers without power as of July 16.

More: *USA Today*, *Houston Chronicle*

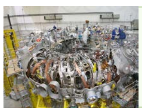
Restaurants Sue CenterPoint over Hurricane Beryl Response

Houston-area restaurants last week filed a class action suit seeking more than $100 million from CenterPoint Energy, alleging incompetence and negligence in the utility's efforts to restore power quickly following Hurricane Beryl.

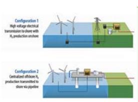
Tony Buzbee, a lawyer on behalf of the plaintiffs, said the case makes claims for negligence and gross negligence for "CenterPoint's repeated failure to do what any reasonable and competent electricity provider would do and should do."

More: *The Dallas Morning News*

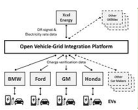
National/Federal news from our other channels



Report: Companies Say Fusion will be Online by 2035 — NetZero Insider



Reports Examine Economics of Clean Hydrogen — NetZero Insider



DOE, AAI Reports: VGI Critical to Managing New EV Power Demand — NetZero Insider

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California Reaches Funding Agreement to Launch Hydrogen Hub — NetZero Insider

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