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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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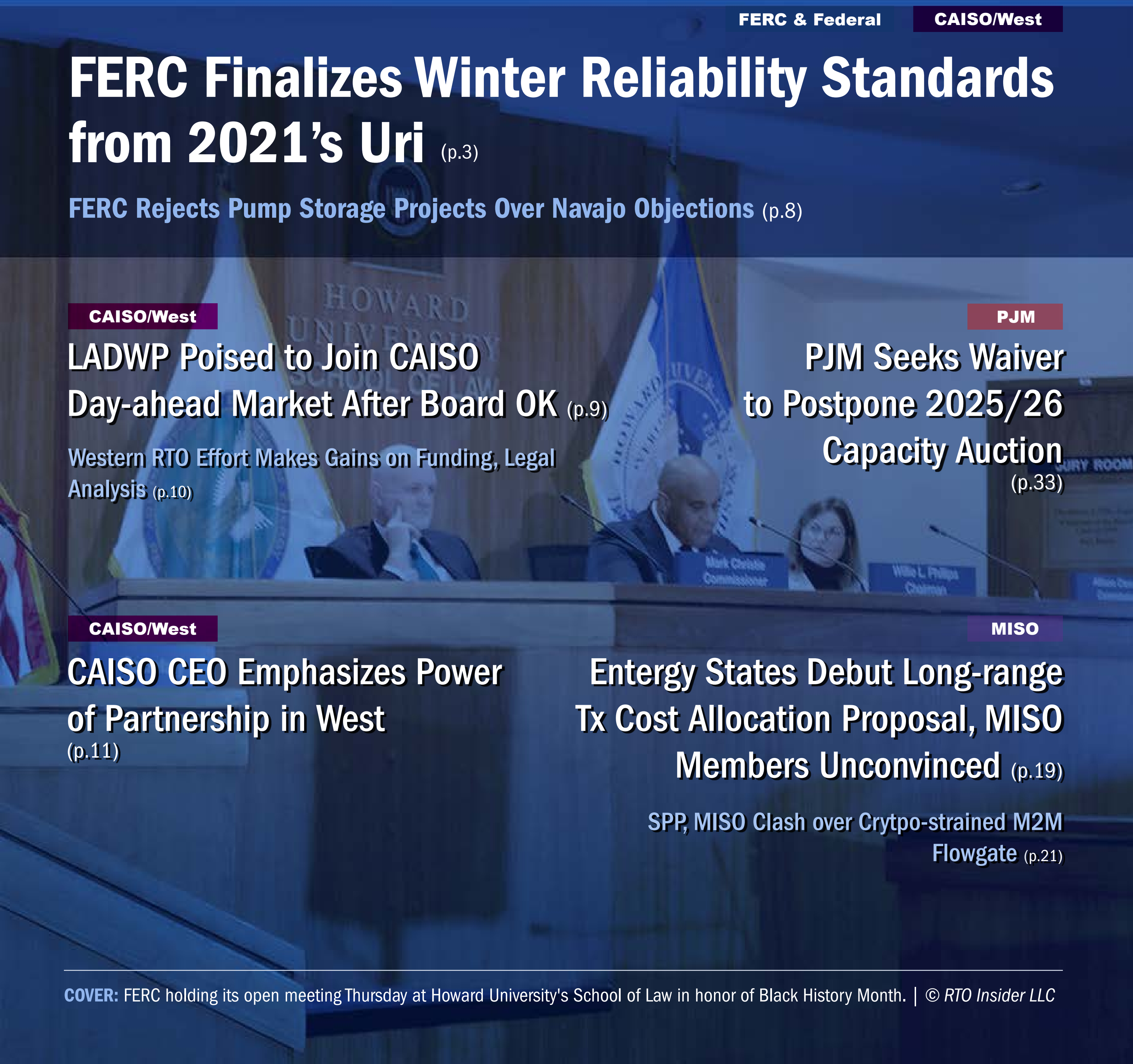

COVER: FERC holding its open meeting Thursday at Howard University's School of Law in honor of Black History Month. |

RTO Insider
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In this week's issue

FERC/Federal News

FERC Finalizes Winter Reliability Standards from 2021's Uri

Commission also Approves Changes to Make Enforcement Process More Efficient

By James Downing

WASHINGTON — FERC has *approved* new mandatory reliability standards on weatherization that implement recommendations that came out of its and NERC's joint report on the 2021 outages caused by Winter Storm Uri.

The outages caused by cold weather that week were worst in Texas, though other grids suffered shorter outages. Overall, 4.5 million people lost power and 210 people died during the storm.

NERC adopted a two-phase process to implement recommendations from the FERC/NERC joint report on Uri, and FERC's order Feb. 15 deals with the second phase.

The EOP-011-04 standard requires utilities to include critical natural gas infrastructure on their load-shedding plans so they are not shut down due to a lack of power, exacerbating electric outages during cold weather, as happened in Texas. Balancing authorities must develop, maintain and implement operating plans with provisions for excluding critical gas infrastructure from interruptible load, curtailable load and demand response during cold weather.

NERC also sought approval of standard TOP-002-5, which requires balancing authorities to have an operating process for weather events that includes a method for identifying extreme cold conditions, a method for determining a proper reserve margin for such conditions that takes into account operational limits of generators and a method for determining a five-day hourly forecast that accounts for all relevant operational considerations.

FERC said ensuring natural gas infrastructure works during cold weather is an improvement over current rules.

"Doing so will help ensure that deploying these programs in extreme cold weather conditions will not exacerbate natural gas fuel supply issues, which could constrain generating unit capacity and thereby threaten the reliable operation of the bulk power system," FERC said.

The proposal gives distribution and transmission providers 30 months to develop a plan, with the clock starting later this year. That led FERC in its order, and commissioners at their regular open meeting, to ask entities that can do so to comply earlier.

FERC holds its open meeting Feb 15 at Howard University's School of Law in honor of Black History Month. | © RTO Insider LLC

"Utilities that can comply early with the mandatory implementation date, please, I implore you: Do so," Chair Willie Phillips said.

Commissioner Allison Clements seconded the call at the open meeting and in a concurrence to the order, noting some of the improvements are not required to be in place until more than three years from now.

"The grid and customers won't experience the full extent of these protections for at least three more winters," Clements said. "I appreciate that NERC has worked hard to improve reliability standards and that the implementation timeline here is responsive to some concerns in the stakeholder process, which is important. But as I've stated at past open meetings, waiting years for new reliability standards to kick in, whether they be cold weather or cybersecurity requirements, is not reflective of the urgency these issues demand."

The industry has seen other cold winter events since Uri, with NERC and FERC *working* on another joint report from the cold weather experienced in January.

FERC Delegates Settlement Authority to Enforcement Director

FERC also issued a *policy statement* tweaking how it handles enforcement actions that delegates authority to open settlement talks with subjects of investigations to the director of the Office of Enforcement. Previously, staff had to get permission from FERC commissioners themselves to take that step.

The change is meant to streamline the settlement process so enforcement investigations are resolved more efficiently.

"If and when enforcement staff receives a viable settlement offer from the subject, it will negotiate the applicable terms and thereafter present the written offer of settlement to the commission for formal voting," FERC said in its policy statement. "Importantly, while the new process grants enforcement staff new discretion to commence and engage in settlement negotiations, it does not change the fact that it is the commission that ultimately determines whether a settlement of an investigation is in the public interest and should be approved." ■

FERC/Federal News

FERC Meets at Howard Law School and Gets Update on OPP Activity

By James Downing

WASHINGTON — FERC got a presentation of its Office of Public Participation's 2023 Annual Report at its monthly open meeting Feb. 15, which was held at Howard University's School of Law.

The law school was founded in 1869, at a time when there was a great need for lawyers who would help Black Americans protect their newly established rights, Chair Willie Phillips said at the start of the meeting, held in a moot courtroom at the school.

"As the first Black chairman of FERC, as a graduate of this esteemed law school and as a great-grandson of a slave, it is not lost on me the significance of this moment," he added. "And so, it is indeed a pleasure to be here with you, to be here with my colleagues, and to present this meeting and to conduct the business of the Federal Energy Regulatory Commission in front of the next generation of energy lawyers and practitioners."

In addition to Howard Law students and faculty, the audience included former FERC Commissioner Colette Honorable, now executive vice president of public policy at Exelon, and recently retired FERC Secretary Kimberly Bose, who is also an alumna.

In addition to reaching out to potential future energy lawyers, FERC heard from its *Office of Public Participation* and how it is reaching out to the public after being founded in 2021.

"Our Office of Public Participation is key to our continued efforts to involve members of the public in FERC proceedings that are important to them," Phillips said. "Hearing from the public is essential to ensuring the commission continues to make decisions that are in the public interest."

FERC Chair Willie Phillips addresses the crowd at Howard University Law School. | *© RTO Insider LLC*

The OPP is meant to empower, promote and support public voices in FERC proceedings, said acting Director Nicole Sitaraman.

"Public participation is our sole focus, and to remind public attendees here today: OPP is a non-decisional office and has no role in FERC decision-making and contested proceedings," she added. "This allows us to interact fully with the public, which includes open and contested cases."

In 2023, the office participated in more than 160 meetings all around the country with constituents including landowners, tribes, environmental justice leaders, university researchers, environmentalists, consumer advocates and small business owners. It also developed video workshops on the natural gas prefiling process, the fundamentals of intervening in a FERC proceeding and the process for filing comments.

OPP also developed 15 educational resource documents, which were praised by commissioners for helping to translate the dense technical language it deals with into everyday English.

"The explainers, in case you haven't read them, are taking concepts like: How does an energy market work? How does a capacity market work?" said Commissioner Mark Christie, "and trying to put those extremely difficult, complicated concepts into something that someone who's not in this business for years and years and years can understand."

The report also included the most common questions OPP gets when it is dealing with the public, which includes how to participate in FERC processes, how to deal with post-construction impacts of regulated facilities on private property and how to engage with FERC when projects it regulates bring up environmental justice concerns. ■

FERC/Federal News

State Regulators Debate Reliability and Transmission at House Hearing

By James Downing

House members and their state regulator witnesses split Feb. 14 over how much an expanded transmission grid could enable a reliable transition to a low-carbon future.

"Threats to electric grid reliability are growing due to environmental regulations, policies from state legislatures and agencies, bans on fossil fuel generation, and market distortions," said Rep. Jeff Duncan (R-S.C.), chair of the House Committee on Energy & Commerce's Subcommittee on Energy, Climate and Grid Security. "These factors are contributing to premature retirement for most of our reliable and dispatchable resources. Because of the increasingly interconnected nature of the grid, policy decisions that affect grid reliability have a much wider impact than ever before."

Rep. Scott Peters (D-Calif.), who also sits on the subcommittee, has introduced legislation to help address some of those reliability concerns by requiring minimum transfer levels between regions. (See *Hickenlooper and Peters Introduce Big WIRES Act*.) He agreed with Republicans on the committee that policymakers need to address resource adequacy with growing demand from electrification, data centers and new industries.

"Multiple analyses recently from MIT and Columbia have shown that the Big Wires Act, which I and Senator Hickenlooper introduced, would save customers hundreds of millions of dollars while keeping the lights on during natural disasters and other challenges," Peters said. "These costs and reliability benefits are driven by the ability of high-demand regions to use energy from other regions that don't need it at that time."

Duncan doubted that increased transmission could be a cure-all for the country's reliability woes, calling instead for maintenance ofexisting dispatchable generation.

"Systems must be overbuilt to ensure there's power when the sun is down and when the wind isn't blowing," Duncan said. "Building more transmission also raises utility costs for American ratepayers, even if those ratepayers may not directly benefit from the added transmission."

California and New England have adopted similar policies driving their grids to zero out emissions, but both rely on imports from other areas, and both have some of the highest electricity prices in the country, Duncan added.

Georgia Public Service Commissioner Tricia Pridemore touted the reliability of her state's vertically integrated structure.

"Georgia is in need of more power than ever before," she said. "Our market structure makes us more energy-secure than other regions; we have the authority to instruct utilities to construct generation and build transmission. The state of Georgia holds a compact with a vertically integrated utility, and they must generate what our state consumes."

While the Vogtle nuclear plant's cost overruns might have made a lot of headlines and increased her consumers' bills, she said that the Peach State still has rates 10% below the national average.

Peters asked Pridemore whether Georgia would exclusively rely on its own power plants, given that it is connected to five other regions of the Eastern Interconnection.

While Georgia is connected, the regulatory compact the state has with Southern Co.'s Georgia Power requires it to produce all of the power the state needs, she said.

"You mentioned blackouts and forced outages earlier," Pridemore said. "You can look at the last three winter storm incidents, and the number of blackouts and outages that we had were so minimal. They were just those that were caused by downed trees and localized events."

Pridemore called for easing regulation of pipelines, and Peters asked whether she thought that effort should be extended to transmission. Pridemore answered that she is "satisfied" with how Georgia manages electric transmission.

Colorado, the only state with a carbon policy at the hearing, was represented by Keith Hay, senior director of policy in the state Energy Office, who said the state's goals are not too difficult to achieve with the resources it can access.

"Our modeling shows that under the business-as-usual approach, which is the lowest-cost scenario that meets a 2040 load growth of 40%, the Colorado grid can achieve a roughly 94% reduction in greenhouse gas pollution," Hay said. "It does this by adding significant amounts of wind, solar and batteries while retaining a gas generation fleet that is approximately the size of today's."

While the gas plants will still be there, their capacity factors would drop significantly over time according to the model: By 2030, only one natural gas unit approaches a 20% capacity factor, and by 2040, natural gas will produce just 2% of the state's electricity, he added.

"The analysis strongly indicates that expanded transmission capacity, both in-state and interregional, which will enable reaching regions of high renewable potential and allowing access to energy from across diverse geographic areas, will be important to reliably meeting Colorado's electric needs," Hay said.

Indiana has seen coal fall from 90 to 95% of its electricity 20 years ago to about 45% today, with the rest coming from natural gas, nuclear, wind, solar and other fuels, said Utility Regulatory Commission Chair Jim Huston. While Colorado has found no major issues in moving to a net zero future, Indiana has said it would face difficulty meeting the requirements of EPA's power plant rule.

"Our concerns included a focus on the proposed rules' unrealistic timing, particularly in the context of the utilities' state-sanctioned and regulator-reviewed integrated resource plans," Huston said. "It is not obvious that the proposed environmental benefits outweigh the other pillar considerations that state regulators must consider to ensure safe, reliable service at affordable rates."

Arizona also has seen cost issues from shutting down fossil fuel-fired plants early, said Corporation Commissioner Nick Myers.

"Many of the challenges we face moving forward with regard to reliable generation center around early forced retirement of coal plants without adequate replacement," Myers said. "Personally, it pains me to have to approve accelerated cost recovery for early shutdown of coal plants, while at the same time authorizing recovery on new purchase power agreements."

The replacement generation usually has to come with backup natural gas and transmission, which Myers said makes its all-in costs higher. The transmission also presents its own roadblocks, as Arizona had to deal with multiple iterations of the SunZia Transmission project and its 16-year development journey, marred by lawsuits and red tape. (See *SunZia Project Wins Final Approval, Signs Offtakers*.) ■

FERC/Federal News

Engineering Firm Finds Quality Problems in BESS Manufacturing

CEA Report Gathers Six Years of Factory Inspection Data

By John Cropley

Quality-control problems affect a sizable number of new energy storage systems, creating potential safety and performance risks, *a new report* indicates.

Clean Energy Associates (CEA) based its conclusions on an extensive series of audits over six years.

CEA found 18% of inspected lithium-ion battery energy storage systems (BESS) had quality issues related to their thermal management system and 26% had issues related to their fire detection and suppression system.

CEA suggested the industry is focusing too closely on cell selection and said it should not overlook system integration as a potential source of problems. Nearly 50% of the defects CEA found were at the system level.

The report, "BESS Quality Risks," comes amid an extensive buildout of BESS and a lingering public uneasiness about the safety of these systems. Fires are hard to extinguish and can emit toxic fumes.

The advisory and engineering services firm conducted more than 320 quality audits at over 52 BESS factories on systems that comprise more than 30 GWh of capacity. It found more than 1,300 problems.

CEA said the defects it found were split nearly equally between components — cells or modules — and systems. The integration of components into a system is subject to less stringent quality-control procedures, it said, even though it is a highly manual and labor-intensive process.

Meanwhile, the systems themselves are highly complex and vulnerable to component defects missed in earlier quality checks.

Other system-level findings in the report broke down as follows:

Firefighters pour water on a large fire at a solar and battery facility in northern New York in July 2023. | *Kyle Cheeseman/Three Mile Bay Fire Company*

- 8% were performance-related, due to manufacturing defects and/or integration errors. This led to problems such as diminished capacity and round-trip efficiency results due to large temperature and voltage variations among cells within a module, thanks to poorly welded wiring connections.
- 34% were enclosure-related, due to manufacturing defects or damage sustained in transportation. These included poor rigidity, weakness, deformation, grounding defects, water ingress, cosmetic problems, and poor wiring or cabling.
- 58% were related to the balance of system — various defects in components or errors in their integration. These included coolant leakage from a variety of causes; malfunctioning sensors and alarms due to miswiring; and exposure of a live conductor within the AC/DC distribution.
- Common fire suppression system defects included nonfunctioning release actuators for the fire-extinguishing agent due to a faulty diode; nonfunctional fire alarm abort buttons due to miswiring; and nonresponsive smoke and temperature sensors, also due to miswiring. These defects pose a risk of fire and explosion, or of serious equipment damage due to unnecessary activation of the fire control system.
- Common thermal management system defects included circulation system component failures due to fasteners being not tightened enough, leaving a loose connection, or over-tightened and deforming flange plates; and compressor mainboard short circuiting due to a burned metal oxide semiconductor tube. These defects pose a risk of thermal runaway or accelerated battery degradation.
- Battery cell defects were attributed fairly evenly among electrode manufacturing, cell assembly and cell finishing.
- Module defects were heavily attributed to sorting and installation (45%) and interconnection welding (41%); enclosing and end-of-line testing issues were less common. ■

FERC/Federal News

FERC Approves Vistra Purchase of Energy Harbor, Requires Divestment

By James Downing

FERC on Feb. 16 approved Vistra Energy's deal to buy Energy Harbor, which it wants largely for its four nuclear plants and retail business, for $3 billion plus paying off $430 million of debt (*EC23-74*). The commission required divestment of two of Vistra's fossil plants in PJM.

Vistra *plans* to launch a new subsidiary combining its clean energy generation and retail business called "Vistra Vision," of which 15% will be owned by Energy Harbor shareholders, while spinning off its natural gas and coal units into a separate subsidiary called "Vistra Tradition."

Energy Harbor is the competitive generation and retail business spun off from FirstEnergy several years ago. It owns three nuclear plants: Beaver Valley Power Station at 1,969 MW, the Davis-Besse Plant at 962 MW and the Perry Nuclear Power Plant at 1,302 MW.

Energy Harbor also owns some fossil plants, and Vistra already owns generation in PJM. The merging firms argued their impact on competition should be measured against the whole RTO, while PJM's Independent Market Monitor, the U.S. Department of Justice's Antitrust Division and the Ohio Consumers Counsel all argued FERC needed to consider smaller submarkets.

Both Energy Harbor and Vistra own generation in the American Transmission System Inc. (ATSI) zone, so Vistra agreed to sell off its 369-MW Richland natural gas peaking plant and its 16-MW Stryker oil plant to end concerns over an excess of power in that submarket of PJM.

The sale of those plants "obviates the need" for FERC to determine any submarkets relevant to the transaction so it focused on its impact on PJM as a whole, the order said.

"After the proposed transaction closes and after completing the divestiture of Richland-Stryker, the Davis-Besse and Perry generating units, currently owned by Energy Harbor, will comprise the only units owned by Vistra in the ATSI transmission zone," FERC said. "Furthermore, as discussed below, Vistra must sell Richland-Stryker to a buyer that will not fail the horizontal competitive analysis screens, including the delivered price test, for the PJM market or any relevant submarket, post-transaction."

Beaver Valley Power Station in western Pennsylvania | *Energy Harbor*

FERC was not convinced the deal would impact any other submarkets, saying they failed to show any consistent price separation caused by transmission constraints that would indicate a submarket under commission precedent. The commission found the deal would not impact the whole of PJM either, and declined to adopt behavioral requirements suggested by the Monitor.

"The PJM IMM relies on perceived existing limitations in PJM's market power mitigation as the basis for proposing additional behavioral mitigation," the order said. "These arguments are directed at the effectiveness of the PJM markets and mitigation measures as a general matter."

FERC declined to deal with such general issues in this merger case, saying it is not the appropriate venue for that.

The IMM also used a different analysis than what FERC employs in merger reviews to argue the combined firm would have market power in PJM, especially in local markets. DOJ's Antitrust Division also wanted FERC to use a "supply curve" analysis to review the deal.

"The commission's regulations do not require a supply curve analysis, and applicants have provided a horizontal market power analysis, including three delivered price tests, consistent with our requirements," FERC said. "Moreover, the divestiture commitment appears to alleviate DOJ Antitrust Division's specific concern about the proposed transaction given that the divestiture of Richland-Stryker eliminates Vistra's 'ability' to engage in strategic withholding using that facility."

The OCC and the Northeast Ohio Energy Council argued FERC should examine the deal's impact on Ohio's retail energy market as it will combine two of its largest firms. While FERC lacks explicit authority over the retail power market, the Ohio PUC is unable to review the merger and its impacts on the market, the two said.

The federal regulator's policy is to review the impact on retail competition whenever a state regulator asks it to. Because the PUC made no such request, FERC declined to examine the deal's retail market impacts.

The Ohio Energy Advocate, which was set up to represent the interest of the state's energy consumers at FERC and before other federal regulators, did file a request to review the impact on retail markets, but the commission said it does not count as a state regulator. ■

FERC Rejects Pump Storage Projects Over Navajo Objections

New Policy: No Permits on Indian Lands over Tribe's Opposition

By Rich Heidorn Jr.

FERC on Feb. 15 rejected preliminary permits for seven pump storage projects on *Navajo Nation* land, saying it will no longer will consider projects that are opposed by host tribes.

Preliminary permits give the permit holder priority for filing a development application while it conducts feasibility studies. It does not authorize access to project lands or any construction.

The commission previously granted preliminary permits routinely, saying concerns about potential impacts could be addressed in subsequent licensing proceedings. Recently, however, it denied permits at federal facilities where the agency that operates the facility opposed the project.

"We believe that our trust responsibility to tribes counsels a similar policy in cases involving tribal lands and accordingly, we are establishing a new policy that the commission will not issue preliminary permits for projects proposing to use tribal lands if the tribe on whose lands the project is to be located opposes the permit," FERC said. "To avoid permit denials, potential applicants should work closely with tribal stakeholders prior to filing applications to ensure that tribes are fully informed about proposed projects on their lands and to determine whether they are willing to consider the project development."

Denied were five preliminary permit applications filed by Nature and People First Arizona PHS LLC (NPFA):

- the 2,250-MW Black Mesa Pumped Storage Project North; the 1,500-MW Black Mesa Pumped Storage Project East; and the 2,250-MW Black Mesa Pumped Storage Project South, all closed-loop systems on Navajo Nation land in Navajo and Apache counties, Ariz. (*P-15233, P-15234, P-15235*);
- the Chuska Mountain Pumped Storage Project, proposed for San Juan and McKinley counties, N.M. (*P-15293-001*); and
- the Chuska Mountain North Pumped Storage Project in Apache County, Ariz. (*P-15309*).

FERC also rejected Western Navajo Pumped Storage's proposed Western Pumped Storage 1 and Western Pumped Storage 2 in Coconino County, Ariz. (*P-15314, P-15315*)

In contrast, the commission awarded preliminary permits Feb. 15 to Neptune Pumped Storage for feasibility studies of the 318-MW Elephant Rock Pumped Storage Project near Sixes River (*P-15310*) and the 550-MW Soldier Camp Pumped Storage Project on Lobster Creek (*P-15311*), both in Curry County, Ore.

The commission approved the permits, which are good for 48 months, despite protests from environmental groups that cited concerns over the projects' impact on water quality and quantity, aquatic resources, wildlife and habitats, and tribal resources. Some opponents said it was doubtful the state of Oregon would issue water quality certifications for the projects.

But FERC ruled that because a preliminary permit does not authorize access to project lands or project construction, "addressing the commenters' concerns at the permit stage is premature."

FERC said it sent 12 tribes identified by Neptune Pumped Storage as having a potential interest in the Soldier Camp project a copy of the notice accepting the application but none of the tribes filed comments.

The Navajo Nation raised numerous objections to the projects proposed on its lands, including that developers had not sought its consent for use of the land or procured required clearances for preliminary biological investigations. The Nation also cited concerns over its water rights and potential impacts on rare and culturally important plants and wildlife and said the developers had failed to engage in "meaningful consultation."

The Navajo Tribal Utility Authority, a unit of the nation that provides electric generation, transmission and distribution, did not take a position on NPFA's Black Mesa projects but said it "looks forward to robust cooperation, communication and transparency" as the developer pursued its application.

"Despite substantial progress in recent years, thousands of homes on the Navajo Nation still lack access to electricity and other basic services," the authority told FERC in January 2023. "Accordingly, NTUA recognizes the wide range of benefits that can flow from environmentally, economically and culturally responsible energy development on and around Navajo land, including the creation of well-paying, local jobs for Navajo residents."

In addition to its new policy, FERC's acknowledgment of tribal concerns was reflected in the Office of Public Participation's *annual report*, issued Feb. 15, which noted its participation in the Tribal Energy Equity Summit, "Just Transmission for a Just Transition" in Saint Paul, Minn., in May 2023. (See related story, *FERC Meets at Howard Law School and Gets Update on OPP Activity*.) ■

Black Mesa area near Kayenta, Ariz. | *Ken Lund, CC BY-SA 2.0*

CAISO/West News

LADWP Poised to Join CAISO Day-ahead Market After Board OK

Largest Municipal Utility in US Would be 3rd Entity to Commit to EDAM

By Robert Mullin

CAISO notched another victory in the competition to bring organized markets to the West on Feb. 13 when the Los Angeles Department of Water and Power's oversight board authorized the utility to prepare to join the ISO's Extended Day-Ahead Market.

LADWP has yet to issue a formal announcement on a market decision and did not respond to a request for comment in time for publication of this article. But the *resolution* advanced by utility officials and approved by the Board of Water and Power Commissioners on Feb. 13 allows LADWP "to proceed with necessary activities, agreement preparations, and other related EDAM work that will be brought back to the board in the future for approval."

"We think this is a good move forward," Fred Pickel, LADWP's ratepayer advocate, said ahead of the vote. "While the benefits exceed costs, it won't have as big of an impact as participating in [CAISO's] EIM, probably, but the information that all parties will get by participating in a formal market of this type will likely enhance everybody's understanding of both short-run and long-run impacts and needs."

LADWP would be the third entity to commit to the EDAM following commitments by six-state utility PacifiCorp and the Balancing Authority of Northern California, a joint powers authority that manages system operations for the Sacramento Municipal Utility District and five other publicly owned utilities. (See *BANC Moving to Join CAISO's EDAM*.)

The largest municipal utility in the U.S., LADWP has been participating in CAISO's real-time Western Energy Imbalance Market (WEIM) since April 2021. EDAM will expand the capability of the WEIM by including trading of day-ahead energy, which requires increased coordination among participants. As it works to attract members, the ISO faces strong competition from SPP's Markets+ day-ahead offering, which has generated especially strong interest in the Northwest.

The commissioners offered no comments before approving the request, which LADWP officials, including General Manager Martin Adams, submitted in a Feb. 5 *letter* and accompanying resolution.

"EDAM builds on the success of WEIM, providing additional benefits to its participants while increasing regional coordination, supporting policy goals of the state of California and meeting demand more efficiently," the letter said.

LADWP estimates EDAM will increase its net revenues by $20 million to $59 million a year, with most gains "expected to result from savings in adjusted production costs and enhanced EDAM transmission-related congestion transfers," the officials said in the letter. LADWP realized nearly $149 million gross benefits from its participation in WEIM in 2023, according to CAISO.

The utility expects to incur about $14.7 million in setup costs to join EDAM, including system upgrades, training and ISO onboarding fees. It also estimates $21.1 million in annual costs for ongoing participation in the market, mostly stemming from administrative fees.

"Overall, EDAM presents a strong net annual financial opportunity while helping LADWP better integrate additional renewable generation, thereby minimizing curtailments and greenhouse gas emissions in its service territory and the Western region," the letter said.

LADWP headquarters | *LADWP*

Extensive Reach

While LADWP's service territory is limited to the city of Los Angeles, its reach extends far into other parts of the West. The utility owns and operates more than 3,600 miles of transmission lines spanning five states, including half the capacity on the 3,100-MW Pacific DC Intertie linking the L.A. metro area with the Bonneville Power Administration's area in the Pacific Northwest.

LADWP's other interstate transmission assets include 60% of the contract capacity rights on the Southern Transmission System line connecting Southern California with the Intermountain Power Project (IPP) in Utah, a 36% ownership stake in the Mead-Adelanto Transmission Project connected to Nevada, and co-ownership of the Navajo-McCullough Transmission Line between the now-retired Navajo Generating Station in Arizona and the McCullough substation in Nevada.

The utility also controls about 8,000 MW of generating capacity, including the 1,900-MW coal-fired IPP, 15% of the output from the 2,080-MW Hoover Dam in Nevada, and 5.7% of output from the 3,300-MW Palo Verde nuclear generating station in Arizona.

IPP is slated for conversion to an 840-MW natural gas-fired plant in 2025, including turbines capable of burning a fuel mixture containing 30% hydrogen. Last year, LADWP was authorized to convert its Scattergood Generating Station, the largest gas-fired plant in Los Angeles, to hydrogen. ■

Western RTO Effort Makes Gains on Funding, Legal Analysis

Pathways Initiative Plugs Away at CAISO Legal Questions, Secures $300K in Pledges

By Robert Mullin

The West-Wide Governance Pathways Initiative is advancing on its $570,000 funding target.

And its members also are wading deeper into one of the key subjects it was conceived to address: how to work around CAISO's state-run governance model to create the framework for an independent Western RTO that pointedly includes the ISO and builds on its Extended Day-Ahead Market (EDAM).

Members of the initiative's Launch Committee addressed both topics during a virtual monthly update Feb. 16.

"We are making really good progress [and] want to acknowledge and thank all of those entities who have pledged funding or committed funding in one way to support the launch framework," committee Co-chair Kathleen Staks, executive director of Western Freedom, said during the update.

The Pathways Initiative has reached around "$300,000-ish" in pledges and is "still in fundraising mode," Staks said.

"So, if you have not yet been hit up, or you have not asked, consider yourselves solicited for funding," she told meeting participants.

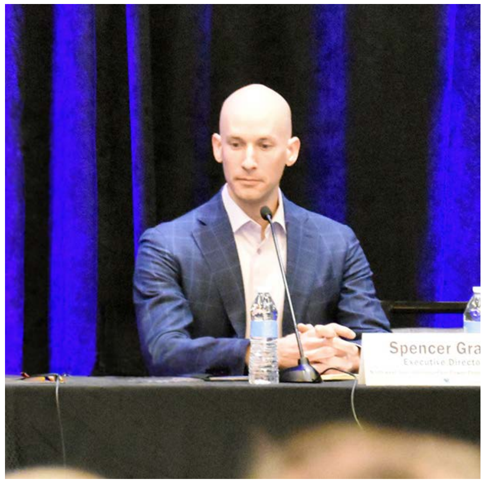
The initiative in January applied with the U.S. Department of Energy for grants totaling $800,000 to support its operations over two years. (See *Western Pathways Initiative Sets Budget, Seeks Funders*.)

Staks also noted the Pathways Initiative had hired Seattle-based energy consulting company Utilicast to provide project management and meeting coordination, relieving the Regulatory Assistance Project of some of its initial responsibilities as a facilitator of the effort.

Utilicast's Sarah Davis and independent consultant Jessica Singh will become the Pathways Initiative's key points of contact for stakeholders, as noted on the group's *landing page* on the Western Interstate Energy Board website, Staks said.

'Stepwise' Governance Approach

Pathways Initiative stakeholders have signaled "general support" for a "stepwise" approach to addressing the issue of CAISO's state-run governance, Northwest & Intermountain



Spencer Gray, Northwest & Intermountain Power Producers Coalition | © *RTO Insider LLC*

Power Producers Coalition Executive Director Spencer Gray said during the call.

Gray is co-chair of the Launch Committee's Priority Functions and Scope Working Group, which is driving the legal analysis around ISO governance.

Under the stepwise approach, the committee would take the first step of exploring how far "a more autonomous [CAISO] governance option could be pushed" under existing California law. (See *Western RTO Initiative Outlines Governance Options*.)

"We're still working with [legal] counsel to figure out where that boundary is, where it seems obvious that state law precludes a more autonomous option, or the litigation risk of a more autonomous option becomes unreasonably high," Gray said.

The next step would seek to determine what legislation would be needed to provide the ISO with more autonomy.

"The overall feedback on a stepwise approach is it would be helpful to push the ball further, without having the assumption that legislation would pass in California, and then also envision what is a durable governance structure that could be put into place with some continuity from what we would scope from step one," Gray said.

Gray said his group also is examining the processes used by different RTOs in the U.S. to identify potential models for the Western effort.

Research has focused specifically on governance structures that allow for dual filings with FERC under Section 205 of the Federal Power Act. He said the "strongest precedent" for that model is in New England, where ISO-NE and the NEPOOL stakeholder group operate under a "jump ball" provision that gives both organizations equal rights to file competing ISO-NE tariff provisions with FERC when the two organizations fail to agree on rule changes.

"A fruitful area for us to explore: How did that get designed in the beginning in New England, and what should we think about ways to structure dual-filing opportunities in this context that would be consistent with what FERC's found in New England?" Gray said.

Gray pointed out that the objective of having a dual-filing option to resolve disputes is to avoid triggering it and instead compel both parties to reach a compromise ahead of a FERC filing.

Gray's group is additionally working to address the issue of identifying when Pathways Initiative backers would seek to trigger any governance changes outlined in the first part of the stepwise process.

Gray said the group is trying to avoid making changes to the joint authority structure shared between CAISO's Board of Governors and the WEIM's Governing Body "without any indication that there's actually a critical mass of entities interested in EDAM."

The Launch Committee's incremental approach to building a governance framework is rooted in the fact that Western transmission owners are not yet clamoring for deeper cooperation than a day-ahead market, Gray said.

"There are some utilities who have publicly expressed interest in doing so; there are a couple state mandates in the West about utilities joining RTOs of some form," he said. "But the reality we're facing is a really heterogeneous interest and public expression of interest in steps beyond EDAM, and that fundamentally affects the design of the ladder steps of what we're imagining."

Gray said his group plans to offer "public-facing" legal analysis by the end of March, followed by a substantive report back to stakeholders by mid-April, in time to report findings at the spring joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body to be held in Denver April 24-26. ■

CAISO CEO Emphasizes Power of Partnership in West

Mainzer Touts Importance of Interregional Coordination to Meet Policy, RA Goals

By Ayla Burnett

FOLSOM, Calif. — CAISO CEO Elliot Mainzer thinks interregional coordination is key to Western states meeting their goals around climate policy and grid reliability in the face of a changing resource mix and increasingly volatile weather conditions.

And getting to that level of cooperation will be most efficient inside the footprint of a single electricity market to serve the broad region, Mainzer said in a Feb. 13 interview with *RTO Insider*.

"How do you bring different parts of the West together, respect their differences and their desires, interests, policies, preferences, etc., but link them together to really harness the physics and the economics so that everybody can save money and do this reliably and efficiently?" Mainzer said.

The Western Energy Imbalance Market's (WEIM) role in helping the West respond to extreme weather events provides proof that having just one regional wholesale electricity market would be crucial to meeting decarbonization goals reliably and economically, Mainzer said. The transmission connectivity enabled by the WEIM has allowed entities across the West to share energy in times of need.

"It's a basic principle of portfolio diversification that the broader the footprint and the deeper the pool of diversity and transmission connectivity … your chances of an economically efficient and reliable solution are better," he said.

Mainzer and CAISO are pushing to further expand WEIM's footprint and capabilities by rolling out the Extended Day-Ahead Market (EDAM), which FERC approved in December. (See *CAISO Wins (Nearly) Sweeping FERC Approval for EDAM*.)

"Our hope would be to try to make sure that everybody that's currently in EIM would also join our Extended Day-Ahead Market," he said. "A market footprint that does not optimize that natural transmission connectivity and resource diversity across the West is going to be less optimal for consumers at large in terms of both economics and reliability."

Mainzer said the ISO is less focused on the markets debate among Western stakeholders than on getting the first tranche of new EDAM members into the market, ensuring that market rules and stakeholder processes are as solid as possible. EDAM so far has commitments from six-state utility PacifiCorp and the Balancing Authority of Northern California, with an announcement from the Los Angeles Department of Water and Power likely pending. (See *LADWP Poised to Join CAISO Day-ahead Market After Board OK*.)

CAISO CEO Elliot Mainzer emphasized the importance of interregional coordination in meeting California's decarbonization goals. | *CAISO*

CAISO/West News

Long-Term, Interregional Transmission Planning Crucial

CAISO is also looking to improve long-term, interregional transmission planning, Mainzer said.

The ISO faces the challenge of onboarding roughly 7,000 MW of capacity a year for the next two decades to meet the climate goals set out by California's Senate Bill 100, he said. To do so, it is prioritizing long-term transmission planning via partnerships with regulatory agencies, utilities and other entities throughout the Western Interconnection to expand transmission interconnectivity.

"We certainly think that both the economic value proposition and the reliability benefits of the Extended-Day Ahead Market will be significantly enhanced by bringing even greater transmission connectivity to the Western system," he said.

CAISO's *2022-2023 Transmission Plan* provides a 10-year blueprint, and its *20-Year Transmission Outlook*, released in May 2022, looks further into the future, forecasting the connectivity needed to meet increasing demand over the next two decades.

The ISO is also developing several interregional transmission lines, including the Ten West Project, which will enable delivery from 1,000 MW of renewables into California from the Southwest while also increasing CAISO's export capability in the opposite direction. The line is under construction and is expected to be in service by this May.

CAISO last year approved the Southwest Intertie Project-North (SWIP-N), a 285-mile, 500-kV line in Nevada that will allow access to 2,000 MW of Idaho wind resources. The line is expected to be in service by the end of 2026. (See *CAISO Board Approves Nevada Transmission Line to Access Idaho Wind*.)

Three other interregional transmission lines are in the works as well.

Looking to the Future

While transitioning the grid to non-emitting resources is no easy feat, Mainzer is optimistic about the direction the industry is headed.

"When I think back to where things were when I was first coming in in the late '90s and I think about where things are now today in terms of just the sheer amount of renewable resources on the grid and the new technology and the level of market sophistication that we have — we could have never imagined it," he said.

Mainzer came to CAISO in 2020 when the ISO's fleet contained only 250 MW of battery storage. The current figure is 7,000 MW and climbing. The grid operator is also integrating more long-duration energy storage, including rapidly evolving batteries that can hold up to 100 hours of storage.

And Mainzer expects to see much more innovation around clean, dispatchable generation in the next 10 to 15 years. He considers himself "energy agnostic," believing portfolio diversity is key to the energy transition.

"The growth curves are amazing," he said. "That will bring additional capabilities and allow us to be even less and less dependent on the gas fleet, but certainly for the next few years … we'll continue to rely on those resources under the most extreme conditions."

Load flexibility will be important in responding to volatile weather, Mainzer said, particularly with demand response, virtual power plants and other types of adjustable capabilities.

"When we get into these crazy-hot days in the summer and we're 5 to 10% away from problems, just having 5 to 10% load reduction capability that would be automated and embedded into people's thermostats to be able to back off that super-peak consumption would be a huge difference maker," he said.

'Fabulous Success Story'

Historical tensions between California and the rest of the West, including around the 2000/01 energy crisis, largely stemmed from "immature" resource adequacy programs, Mainzer said, and so CAISO is also focusing on strengthening RA in partnership with other state entities.

"When we don't take care of business in terms of resource adequacy, our markets go sideways and it becomes very divisive," Mainzer said. "RA success is the foundation of healthy partnership."

Mainzer hopes industry participants can look beyond historical friction to enable stronger collaboration in the energy transition.

"I think we tend to focus far too much on the small number, literally handful, of issues that we've run into together over many, many years of partnering," Mainzer said. "I believe that when you look at the facts, when you look at the economic value that's been created from the partnership between California and its neighbors through transmission optimization, bilateral and market trade, and supporting each other through reliability events, it's been a fabulous success story." ■

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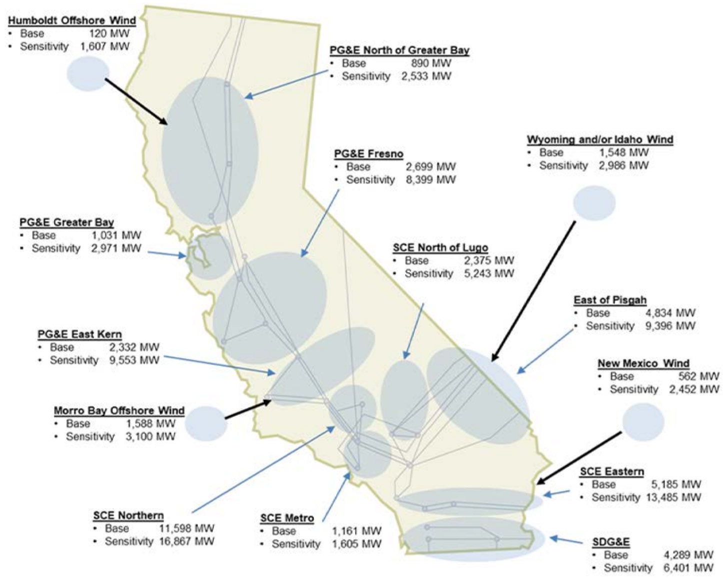
CAISO/West News

CAISO Releases Draft Interconnection Process Enhancements Proposal

Changes Address Clogged Queues, Comply with FERC Order 2023

By Ayla Burnett



CAISO is moving forward with the zonal approach as a method of addressing clogged interconnection queues. | *CAISO*

CAISO on Feb. 8 released its *final draft proposal* out of its Interconnection Process Enhancements (IPE), its initiative to address the "unprecedented and unsustainable interconnection request volumes" submitted in the current and prior study windows.

The draft refines the initial IPE *straw proposal* released Sept. 21, 2023. Among the changes are the development of a generic timeline expected to align with *FERC Order 2023* requirements, tweaks to the implementation of the zonal approach and more detail on how to fulfill the 150% planned transmission capacity within each zone.

"I just want to emphasize [that] the process we have right now is not working and will not get us to a reliable system," Danielle Mills, principal of infrastructure policy development at CAISO, said at an IPE working group meeting Feb. 15. "So, we need fundamental change, and I know it's a little scary, but we need to just all link arms and jump in together."

Mills emphasized that the IPE initiative is part of a broader set of changes designed to onboard new resources quickly and cost-effectively to meet California's decarbonization goals. As part of the process, the ISO signed a joint *memorandum of understanding* with the California Public Utilities Commission and Energy Commission in December 2022 to establish a general direction.

The goal of the initiative is to prioritize interconnection requests aligned with priority zones, called the "zonal approach," where transmission capacity exists or is approved for development. Entities seeking to interconnect must go through a process in which they will receive a score based on project readiness that determines if they can enter the queue.

Because of such high rates of interconnection requests (in 2023, Cluster 15 set a record at 541 requests), the ISO also asked for FERC approval to cancel the 2024 interconnection window to give it more time to study current requests, as well as to continue to refine the draft proposal. (See *CAISO Seeks FERC's OK to Shut 2024 Interconnection Window*.)

Data Transparency

In previous working group meetings, stakeholders emphasized the need for more information about where priority zones are located.

In the draft proposal, the ISO identified that it would consolidate relevant information into a single document that provides line diagrams of interconnection areas and points of interconnection, identifies transmission constraints, and gives a list of substations within each zone and the transmission plan deliverability allocated for each constraint.

Per Order 2023, heat maps will be available 30 days after a cluster study and 30 days after the restudy. The ISO is developing a heat map for Cluster 14, though it likely won't be available 30 days after the cluster's phase 2 reports are issued because Order 2023 applies to only Cluster 15 and beyond.

Timeline Concerns

CAISO is seeking to implement its interconnection reforms — both its IPE proposal and Order 2023 compliance filing — at once.

ISO staff plan to file the compliance proposal in April, though they are not sure when FERC will act upon it. Jeff Billinton, director of transmission infrastructure planning at the ISO, said because of that uncertainty, staff don't expect to re-engage with Cluster 15 until the first half of 2025. Order 2023 compliance will have a negligible impact on clusters prior to 15, the IPE draft states.

Stakeholders expressed concern over the intent to move forward with IPE changes while waiting on FERC's approval, especially regarding site-control requirements.

"There's uncertainty about ... your idea that there's a certain timeline for re-engagement with Cluster 15," said Jason Burwen, vice president of policy and strategy at GridStor. "Folks are going out to get site control, sign lease options and whatnot. As the timeline of uncertainty moves forward ... folks are hanging on to land for even longer than they anticipated." He asked if the ISO could make a definitive statement about site-control requirement timelines.

Billinton responded that the timeline shouldn't be too troublesome for entities seeking site control and interconnection in the Cluster 15 window.

"The outermost deadline for having site control really is the commencement of the cluster study, which would be only, I don't know, a few months after we re-engage with Cluster 15 and go through the validation process," Billinton said.

Chris Devon, director of energy market policy with Terra-Gen, asked if there was any chance FERC could move fast enough to expedite the timeline.

"It is our intent to beg FERC for an order as fast as possible," Billinton said. ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

IBR Ride-through Rule Change Remains Tabled

ERCOT stakeholders last week agreed with staff's position to continue tabling a rule change that would address reliability concerns with inverter-based resources (IBRs) while both sides work on settlement discussions in an attempt to compromise.

The Technical Advisory Committee had agreed to move up its February meeting by a week to send a timely endorsement to ERCOT's Board of Directors before the latter's Feb. 27 meeting.

That the rescheduled meeting fell on Valentine's Day was not lost on its participants. A bowl of "metaphorical" candy, printed with acronyms specific to the discussion, was set out for members.

"My only question is, [who] do I send the bill to for the bouquet of flowers I had to buy my wife for being here today?" Engie North America's Bob Helton jokingly asked.

Eric Goff, speaking for the joint commentators negotiating with ERCOT staff, said those he represented were not opposed to keeping the nodal operating guide revision request (*NOGRR245*) on the table.

"We believe that we're getting through productive dialogue with ERCOT," he said. "There are some outstanding issues that will take some time to resolve, but I'm feeling cautiously hopeful … that we will be able to give something for the March TAC [meeting]."

ERCOT's Stephen Solis agreed and apologized for not meeting the timeline.

"We're not quite there yet," he said. "We cleared up some misunderstanding, I think, and there are some core issues that we're still working on where we stand apart and trying to find perhaps more creative ways of addressing that."

The grid operator says the prevalence of IBRs on ERCOT's system has increased the likelihood of potential instability issues, such as the recent Odessa disturbances. They say the issues are only going to increase along with the continued growth of solar and wind resources. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

ERCOT says the NOGRR would improve the clarity and specificity of IBRs' voltage ride-through requirements. The measure would

TAC member Eric Goff (left), with Luminant's Ned Bonskowski, shares the joint commentators' view on NOGRR245. | *ERCOT*

align the grid operator's rules with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers *standard* for IBRs interconnecting with the grid. (See *ERCOT Technical Advisory Committee Briefs: Jan. 24, 2024*.)

Vistra's Katie Rich is serving as an independent arbiter during the settlement discussions, which Goff said could take either of two directions.

"One, we have a common agreement on language, which would be great. The other is ERCOT would file comments, we would file responsive comments, and Katie would tell us the difference between the two," he said. "We'll see which one we get to."

TAC will meet twice before the board's April 23 meeting.

NPRR1186 Goes to Board

TAC did not take up a protocol change (*NPRR1186*) regulating energy storage resources (ESRs) that was remanded back to ERCOT last month by the Public Utility Commission. (See *Texas PUC Sends ESR Change back to ERCOT*.)

The grid operator's staff *said* that as the PUC's directive "seems straightforward," they recommended the Board of Directors adopt the commission's recommendations "without formally requesting additional input from the [TAC] or other stakeholder bodies."

"The board's authority to decide this question without soliciting stakeholder feedback is consistent with the governing statute," staff said, noting stakeholders always can submit a comment on the NPRR for the board's consideration.

The rule change sets a one-hour state of charge (SOC) for ESRs participating in two ancillary services (ERCOT contingency reserve service and non-spinning reserve). It also includes penalties of up to $25,000 per violation.

The PUC's remand included "suggested modifications" to remove the SOC compliance requirements and other minor clarifications.

ERCOT also is asking the board to provide direction on *NPRR1209*, a directive from the directors, as NPRR1186 ran into trouble and has been tabled. The change would consider an SOC insufficiency by any ESR carrying an ancillary service resource responsibility to be a "failed quantity" that would result in a clawback of AS revenues.

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

The ISO had 3.3 GW of ESRs on its system in

ERCOT News

June. It expects to have 9.5 GW of ESRs energized by October.

TAC: More Info on Budget

Staff's two-slide presentation on the budgeted system administration fee's forecasted adequacy for 2025 — "currently forecast to be adequate" and requiring no changes — led to a request from TAC for more background.

"It wouldn't hurt to have maybe a few slides that actually show us the actual budget itself and kind of where we're trending and what we're spending the money on," Reliant Energy Retail Services' Bill Barnes said. "Some background: 'Well, why is it adequate?'"

At TAC's request during the 2016-2017 budget process, ERCOT provides stakeholders advance notice of any future administrative fee rate increases. The board in December approved the fee and the ISO's budget for 2024-25 after the PUC trimmed both; the admin fee was cut from 71 cents/MWh to 63 cents/MWh, up from the previous 55.5 cents/MWh. (See "Revised Budget Passes," *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

Controller Richard Schaal promised "a couple" of extra slides to provide more information.

8 Revisions on Combined Ballot

TAC's unanimously approved combined ballot of voting items endorsed Rich as chair of the Reliability and Operations Subcommittee. Rich stepped aside temporarily in January after a job change.

The combo ballot also included four NPRRs, a NOGRR and a load planning guide revision request (LPGRR), and two changes to the settlement metering operating guide (SMOGRRs) that, if approved by the board, would:

- *NPRR1193*: Change the ERCOT-polled settlement (EPS) design-proposal form's referenced location when it moves from the other binding document (OBD) list into the SMOG.
- *NPRR1199*: Revise the protocols to add definitions related to the Lone Star Infrastructure Protection Act (LIPA), a 2021 law that prohibits Texas businesses and governments from contracting with entities owned or controlled by individuals from China, Russia, North Korea or Iran if the contracting relates to "critical infrastructure." The measure also adds language reflecting ERCOT's statutory authorization to immediately suspend or terminate a market participant's registration or access if the ISO has a reasonable suspicion that the entity meets any of the LIPA's criteria, among other revisions.
- *NPRR1210*: Change the frequency of the next-start resource and the load-carrying tests from every five years to every four calendar years.
- *NPRR1213*: Amend requirements for distribution generation resources (DGRs) and distribution energy storage resources (DESRs) seeking qualification to provide ERCOT Contingency Reserve Service (ECRS). The NPRR also modifies requirements for ancillary service self-arrangement and ancillary service trades for DGRs and DESRs that provide non-spinning reserve on circuits subject to load shed.
- *LPGRR074*: Align specific term language in the profile decision tree "definitions" worksheet with profile segment language that was added to the "segment assignment" worksheet with the Public Utility Commission's 2022 approval of *LPGRR069*.
- *NOGRR261*: Incorporate the OBD "Procedure for Calculating Responsive Reserve (RRS) Limits for Individual Resources" into the nodal operating guide.
- *SMOGRR027*: Move the EPS metering design proposal from the OBD list into the SMOG, standardizing the approval process, and amend the design proposal form to require more information identifying any and all distribution service providers that have the right to serve a project.
- *SMOGRR030*: Move the EPS metering facility temporary exemption request application form from the OBD list into the SMOG to standardize the approval process. ■

— Tom Kleckner

ISO-NE News

FERC Rejects Rehearing Request for Mystic Agreement Disclosures

By Jon Lamson

The Mystic Generating Station in Everett, Mass. | *Shutterstock*

FERC has rejected a rehearing request from a group of New England public power utilities seeking the disclosure of additional information related to the Mystic cost-of-service agreement between Constellation and ISO-NE (*ER18-1639-026*).

In October, FERC initially *ruled against* the public power groups' request for additional disclosures of information, focused on the agreement's supply arrangement with the nearby Everett LNG import facility. (See *FERC Rules Against Additional Mystic Agreement Disclosures*.)

The public power organizations argued in their November rehearing request that FERC improperly denied outside entities the ability to review and challenge data related to the Mystic Generating Station's revenues and the management of Everett as a part of the Mystic agreement. Both Everett and Mystic are owned by Constellation.

The coalition wrote that FERC's denial of the request for more transparency "pulls an impenetrable veil over information that the ISO-NE customers … require in order to verify the justness and reasonableness of the charges imposed on them and their customers."

In its Feb. 15 response to the rehearing request, FERC stood by its decision to deny additional public disclosures.

"We continue to find the Mystic Agreement's arrangement is just and reasonable and appropriately provides sufficient assurance that the inputs to the Mystic Agreement filed rate are accurate," FERC wrote.

The commission emphasized its prior finding that ISO-NE's auditing rights in the agreement "are sufficient to ensure accuracy and transparency while preserving the confidentiality of commercially sensitive information and avoiding security risk."

ISO-NE and Constellation signed the Mystic agreement in 2018 over concerns that Mystic's impending retirement would introduce significant resource adequacy risks to the regions. The cost-of-service agreement to retain Mystic began in June 2022 and will expire at the end of May 2024.

As Mystic is the main customer of LNG from Everett, its looming retirement has triggered an ongoing effort to retain Everett after Mystic's retirement. The two largest gas utilities in Massachusetts recently announced agreements with Everett to keep the LNG import facility operating for six more years, subject to the approval of the Massachusetts Department of Public Utilities. (See *Constellation Reaches Agreements to Keep Everett LNG Terminal Open*.)

ISO-NE has not been involved in the negotiations to keep Everett open beyond the end of the Mystic agreement. The station is on track to retire at the end of the agreement in the spring.

The costs associated with the cost-of-service agreement have been substantial; ISO-NE *estimated* that it cost ratepayers more than $600 million in the first 18 months of the agreement. More than $200 million of this cost came solely from January and February of 2023, driven by the spike in global LNG prices.

Everett's primary operational conditions for these months were listed as tank management, which includes self-scheduling to run and burning off excess fuel to make room for prescheduled LNG shipments.

"While we remain sympathetic to customers' concerns regarding the high costs of the provision of fuel security by the Mystic units, we believe we have struck the right balance," FERC wrote in its rehearing response. "We are not persuaded that providing the additional information … is necessary to verify Mystic's costs and ensure that the Mystic Agreement's filed rate is accurately implemented."

The public power entities also *challenged* FERC's ruling with the D.C. Circuit Court of Appeals in early February, writing that "the commission's decision to prevent customers from verifying the justness and reasonableness of the charges imposed on them through the cost-of-service agreement is not supported by substantial evidence or reasoned decision making, as required by the Federal Power Act." ■

ISO-NE News

NEPOOL Reliability Committee Briefs

By Jon Lamson

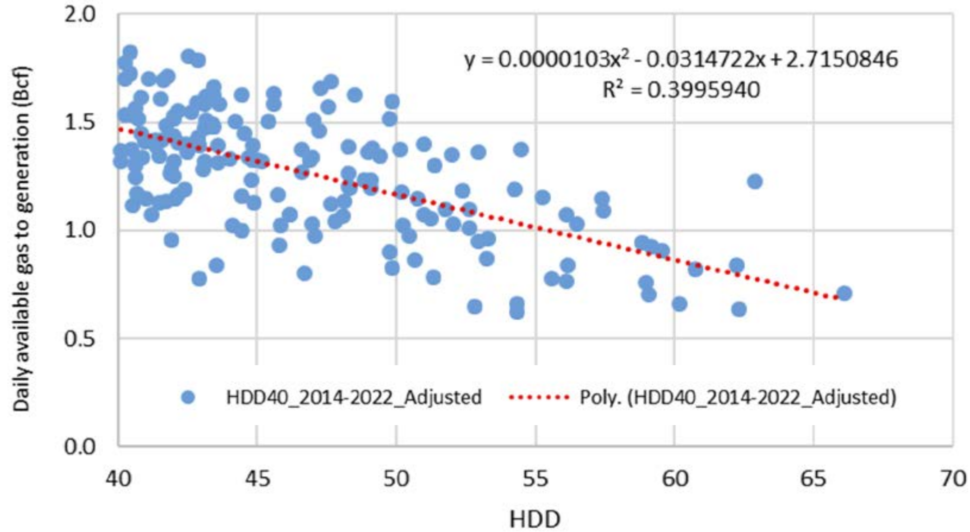
ISO-NE provided *additional detail* in response to stakeholder questions about how the RTO plans to model oil and gas resources as part of its ongoing Resource Capacity Accreditation (RCA) project at the NEPOOL Reliability Committee (RC) on Feb. 14.

The RTO explained the Resource Adequacy Assessment (RAA) modeling approach to the RC in January. (See *ISO-NE Details Resource Modeling Plans for Capacity Accreditation*.) Stakeholders followed up with feedback related to the modeling of imports from Saint John LNG, the uncertain future of the Everett Marine Terminal (EMT) and variability in the amount of gas available to generators.

Fei Zeng of ISO-NE said the current modeling approach "accounts for the EMT impact in a balanced way, given its uncertain future status. The adjustments made to historical availability to generation do not contemplate a single scenario of EMT either continuing operation or retired; therefore, fewer additional adjustments will be needed when EMT status becomes known."

If EMT is not retained, ISO-NE will adjust its modeling to consider how the loss would impact local gas distribution companies, and the knock-on effects this would have on gas available for generators, Zeng said. If EMT is retained, ISO-NE will assess how much "additional available gas to generation EMT can provide through the remaining capacity headroom" on the region's major gas pipelines.

Massachusetts' two largest gas utilities recently announced agreements with Constellation, the owner of EMT, to keep the facility open through May of 2030, pending approval of the Massachusetts Department of Public Utilities.



Gas available for generation based on heating degree day (HDD) | *ISO-NE*

(See *Constellation Reaches Agreements to Keep Everett LNG Terminal Open*.)

In response to feedback that the modeling approach "assumes higher LNG imports from Saint John than have been observed historically," Zeng said the modeling approach is intended to calculate how much nonfirm gas is available when gas utility demand is accounted for, and modeling "unavailability due to economic reasons for the future is very difficult to predict and is generally not considered in the resource modeling."

Regarding concerns about whether the modeling will adequately capture variability associated with extreme temperatures, Zeng said ISO-NE thinks the approach "reasonably reflects the gas fleet availability under different temperature conditions," adding that the RTO "is open to further evaluating the inclusion of variability in the gas profile modeling as a future enhancement."

Zeng also *discussed* how the RCA changes will affect how ISO-NE models the load profile in RAA. The load shape is currently built "by scaling the 2002 hourly load shape to reflect the forecasted seasonal 'gross' peaks."

ISO-NE is planning to switch to "a composite seasonal load shape that is based on the 2021 annual net load characteristics and reflecting 2021 hourly weather for [April through September] and the 2013/14 hourly weather" for October through March.

Zeng noted that the 2002 load shape does not capture recent changes stemming from energy efficiency gains and behind-the-meter solar. He said the updates would better align ISO-NE with the methodology used in NPCC seasonal assessments. ■

ISO-NE News

Eversource Finds OSW Buyer, Takes $1.95B Hit for 2023

Utility to Refocus on Gas, Electric Transmission and Distribution

By John Cropley

Eversource Energy has finalized its long-running attempt to sell off its offshore wind assets, but not soon enough to avoid a $1.95 billion impairment for 2023.

If the moving pieces come together as planned, the New England utility will be done with the struggling offshore wind sector, though it will continue to lead onshore transmission infrastructure work for the projects underway in its joint venture with Ørsted.

Eversource announced the sale to Global Infrastructure Partners (GIP) after the financial markets closed Feb. 13, along with its fourth-quarter and full-year financials. Its stock, which has been trading near a five-year low, closed 4.7% higher in heavier-than-average trading Feb. 14.

Eversource also said it will begin to evaluate market interest for Aquarion Water, the sale of which would bring an infusion of cash without resorting to the equity market.

The sale of the offshore wind interests and the water utility would refocus the company on natural gas and electric transmission and distribution, which now provide the vast majority of its earnings.

The Ørsted-Eversource venture has not been a failure: The partners expect to finish the nation's first utility-scale offshore wind farm — South Fork Wind — next month, have begun construction of Revolution Wind and are far along in planning for Sunrise Wind. But the effort has been much more costly than expected, causing billions in losses for both.

Ørsted, the world's leading offshore developer, is pushing forward with some cutbacks. (See *Ørsted Exits Offshore Wind Markets, Remains Committed to US*.) But Eversource, New England's largest electric utility, decided over a year ago to jettison what was becoming an albatross around its neck.

Piece by piece, it has made progress. Ørsted bought Eversource's share of their as-yet-undeveloped seabed leases, and it agreed to buy Eversource's share of Sunrise if New York state awards Sunrise a new, more lucrative offtake contract to replace the one initially awarded to the partners.

In the latest development, GIP will buy Eversource's share of South Fork and Revolution. Eversource expects to realize approximately $1.1 billion in cash proceeds from the deal but said that could be higher or lower because of factors including construction costs, tax credit eligibility and project delays.

An *8-K filing* by Eversource on Feb. 14 indicates that GIP is guaranteed a pretax equity internal rate of return of 13% for Revolution and South Fork upon the start of commercial operations; if it is less, Eversource will pay GIP the difference, and if it is more, GIP will pay Eversource.

The transaction cannot close without federal and state approvals.

In a call with financial analysts the morning of Feb. 14, Eversource CEO Joe Nolan immediately launched into discussion of the proposed sale.

"When we started down this path in 2016, we were very excited for the opportunity to bring much needed renewable energy to our region," he said. "Unfortunately, our offshore wind investment experienced difficulties as early-stage projects."

These problems — inflation, interest rates, shortage of material and dearth of specialized vessels — came to the fore in late 2022, after several projects off the Northeast coast already had locked in offtake contracts at fixed rates, thus rendering the projects financially untenable.

Developers in Massachusetts, Connecticut, New York, New Jersey and Maryland canceled projects or put them on hiatus; canceled offtake contracts; and dissolved partnerships. Ørsted took over Public Service Enterprise Group's share of a now defunct New Jersey project, while Equinor and BP have agreed to divvy up their proposed wind farms off New York and New England.

If all the pieces come together for Eversource, it will be a chance to exit offshore wind and refocus on gas and electricity with its feet firmly on land.

"Our core business is well positioned to deliver solid operational and financial results as we move forward in supporting the region's transition to a cleaner energy environment," Nolan said. "Moving forward, Eversource will focus on the delivery of clean, safe, reliable energy to our customers."

In another *8-K filing* Feb. 13, Eversource reported a net loss of $442 million for 2023, which compares with net income of $1.4 billion in 2022. That breaks down to a 2023 loss of $1.26/share and 2022 earnings of $4.05/share.

As Nolan indicated, the onshore businesses performed well: Electric, gas and water distribution, and electric transmission generated earnings of $4.34/share, compared with $4.09 in 2022.

But impairments totaled a loss of $5.60/share for 2023, all but two cents of it attributable to offshore wind.

The pretax impairment for 2023 was $2.17 billion: $400 million for Sunrise and South Fork in the second quarter, $545 million for Revolution in the fourth quarter and $1.22 billion for Sunrise in the fourth quarter.

A $215 million tax benefit brought the after-tax impairment down to $1.95 billion for 2023. ■

Construction work continues on South Fork Wind. Eversource has reached a deal to divest its interest in South Fork and other offshore wind projects. | *South Fork Wind*

MISO News

Entergy States Debut Long-range Tx Cost Allocation Proposal; MISO Members Unconvinced

By Amanda Durish Cook

| Entergy

Entergy regulatory staff have revealed their vision for cost allocation on future long-range transmission projects, with multiple clean energy groups deeming the proposal incompatible with building a grid that's ready for the future.

The Entergy Regional State Committee (ERSC) Working Group debuted a preferred cost allocation for the upcoming long-range transmission plan (LRTP) portfolio of projects that will focus on MISO South. At a Feb. 9 teleconference, the ERSC said it prefers a 90% allocation based largely on adjusted production cost savings and avoided reliability projects, with the other 10% assigned to new generation in MISO South using a flow-based methodology.

The draft allocation proposal doesn't include a postage stamp to load components. The ERSC said it wants costs allocated as specifically as possible based on cost causation and beneficiaries' pay principles. It also said other benefit metrics should be "accurate, objective, measurable, quantifiable, nonduplicative, forward-looking and replicable."

The ERSC also said LRTP projects that are proposed "solely to meet" state or local clean energy policies should be paid for in full by those jurisdictions.

Last year, MISO proposed using a blend of a 50% postage-stamp allocation to load and a 50% allocation to the local transmission zone for MISO South LRTP projects. The new allocation is meant for the third LRTP portfolio and will be used in place of the 100% postage stamp to load allocation MISO is using for the first two LRTP portfolios aimed at the Midwest.

The ERSC has said it won't support any postage-stamp aspect in MISO's LRTP allocation and therefore opposes the 50/50 allocation split. (See *Entergy Regulators Mount Challenge to MISO South Cost Allocation*.)

MISO Members Doubt Projects Under Allocation

Members of MISO's environmental and consumer advocates sectors seemed skeptical the allocation would foster any meaningful transmission expansion in the South.

Sustainable FERC Project attorney Lauren Azar said MISO's LRTP is "decidedly not" a local planning exercise and that regional projects deserve a regional allocation. She urged the ERSC Working Group to get advice from experts and involve state commissioners in allocation design decisions.

Azar said the MISO community should "beware of a wolf in sheep's clothing," referring to cost allocation designs "under which no projects would actually qualify for funding" because they are too prescriptive and convoluted.

Yvonne Cappel-Vickery, the clean energy organizer for the Alliance for Affordable Energy, said she was especially concerned about the South's provision that transmission furthering decarbonization be billed to states or cities with targets.

Cappel-Vickery said the ERSC's draft allocation is hostile to known clean energy benefits. She cautioned the ERSC against pushing an allocation style that considers "too few benefits."

"There is an ever-growing body of evidence pointing to the need for new transmission," Cappel-Vickery said.

Attendees pointed to the U.S. Department of Energy's *National Transmission Needs Study*, which found the Delta region requires more transfer capability, and a *working paper* released by the National Bureau of Economic Research that concluded that Entergy Arkansas and Entergy Louisiana brought in about $930 million in profit in 2022 because of transmission constraints in their territories.

Multiple attendees questioned how the ERSC envisions realistically handling the 10% allocation to new MISO South generation.

Southern Renewable Energy Association's Andy Kowalczyk asked whether MISO South's proposal will create a bifurcated generator interconnection queue, where MISO South generation projects receive different treatment to work in extra transmission costs.

Organization of MISO States Executive Director Marcus Hawkins asked if there was the potential for allocation "leakage" among the queue, where generation projects that aren't located in the South benefit from the lines and are assigned costs for South LRTP lines.

Hawkins also asked how MISO South envisions handling "blended" transmission projects that further both reliability and decarbonization goals.

Sustainable FERC Project's Natalie McIntire asked how it's possible for the South to tease out when exactly an LRTP line is intended only for clean energy targets when, by design, LRTP lines are designed to deliver multiple benefits simultaneously.

MISO News

The ERSC Working Group didn't provide justifications for their proposal during the teleconference. ERSC Working Group representative and Public Utility Commission of Texas economist Werner Roth explained the proposal and said he collected stakeholders' questions during the teleconference and will take them back to the Entergy Regional State Committee board so they can "make an informed decision on how to proceed."

Southern Renewable Energy Association's Simon Mahan said MISO South should be proffering a cost allocation method that not only works for the third LRTP portfolio, but also the fourth LRTP portfolio, which will zero in on how MISO can expand the transfer capability between its Midwest and South regions. He said working out an allocation that could serve both would save MISO South time, energy and money.

Mahan said he didn't think the ERSC's proposed cost allocation would result in the projects that would best position the South to serve future energy needs.

"We've been experiencing constraints in MISO South currently and for quite some time," Mahan said. He added his fear is that South region members advance a futile cost allocation that deters transmission projects.

Kowalczyk said there have been longstanding issues with energy delivery in MISO South that need to be addressed with regional transmission projects.

"Load pockets are not making this any better. There have been load pockets that have been persistent for decades," he said, adding that MISO South needs to proactively become the grid of the future and not rely on interconnection customers to build out the grid in a "piecemeal" fashion.

Kowalczyk also questioned if it was fair to place more cost burdens on interconnection customers, pointing out that for the 2021 class of MISO South generation projects, developers already face network upgrade costs of about $100 million per project.

Entergy's Matt Brown said there are "serious data errors" in DOE's Transmission Needs Study that seriously undercount Entergy's transmission work in the Delta region. Brown said combined Entergy transmission investment represented in its FERC Form 1 is six to 12 times higher than what was represented in DOE's investment data. He said DOE used project data from MAPSearch, which missed about $700 million worth of Entergy projects in the Delta region.

Brown also said there will be "enormous complexity" in addressing MISO's Midwest-South transfer constraint.

"It's important to underscore that it's not a simple issue," Brown said, emphasizing that the constraint isn't physical, but contractual and agreed upon more than 10 years ago by SPP, Southern Co., TVA and other parties.

Brown said MISO and the joint parties to the contract could renegotiate the contract to be able to flow more power because the system is capable of greater flows than currently allowed. The agreement with seven joint parties — including SPP — limits transfers between MISO Midwest and South to 3,000 MW southbound and 2,500 MW northbound.

Brown didn't address MISO members' other concerns with the cost allocation proposal.

MISO said it has reviewed ERSC's draft proposal and listened to stakeholders' opinions during the Feb. 9 teleconference. Spokesperson Brandon Morris said MISO could weigh in on the allocation plan during a Feb. 26 meeting of the ERSC board of directors.

MISO did not address *RTO Insider's* other questions on whether it might consider eliminating the postage-stamp piece of its own allocation proposal, where its allocation proposal stands today or whether it believes it can cleanly isolate clean energy policy projects for allocation purposes.

Suspicion from Watchdog Organization

Daniel Tait, research and communications manager at the renewables watchdog organization Energy and Policy Institute, agreed the ERSC's proposal won't result in regional projects that can pass muster.

In an interview with *RTO Insider*, Tait said the ERSC's allocation proposal seems counterintuitive because Entergy's own service territory includes New Orleans, which has an ambitious 100% clean energy standard by 2035 and a goal for complete carbon neutrality by 2050.

Tait said there are "clear financial incentives" to Entergy continuing to advance "local, emergency projects that are basically exempt from any type of scrutiny except for state approval."

"The results speak for themselves," he said, noting the lack of regional South projects to prevail in MISO's planning process.

Tait said Entergy sometimes can pull in "hundreds of millions of dollars" more in a gas plant's return on equity than when compared to a new transmission line's ROE.

"Whether they want to admit it or not, shareholders are forcing the C-suite to make these kinds of decisions every time. This isn't pennies we're talking about," Tait said. "Somebody has to check that. I understand why they're doing that, but where are the other parties that are supposed to rein this in?"

Tait said he would argue the existing system in MISO South was broken before the ERSC introduced the proposal. The MISO South grid is "severely debilitated" today, Tait said, and unable to host meaningful new generation, as evidenced by expensive network upgrade costs for developers wishing to interconnect in MISO South.

"So, by definition, nothing is ever going to get built unless Entergy goes to its regulators and says, 'We need this,'" Tait said.

Tait likened the slim interconnection opportunity and sky-high network upgrade costs in the South to a neighborhood Walmart at full capacity with a line out the door. When a new shopper is allowed in, they're charged something like $100 per tomato, he said.

"That's a crazy assertion that we would never see in any other marketplace. Now, that messiness coupled with this plan ensures [Entergy] can continue to do whatever they want," Tait said.

Tait said while the future MISO South grid is uncertain, if Entergy is allowed to have its way, MISO South won't reach its full potential for solar installment. He predicted that when solar capacity is built, it will be owned and controlled by Entergy "because it, and only it, will have the ability to navigate all these roadblocks that it's thrown up."

Tait also said DOE's Transmission Needs Study represents a snapshot in time and that it's not incumbent on DOE to track down every utility's recently approved transmission. He said DOE is correct that transmission planning in the Delta has been paltry, even accounting for the additional $700 million in projects that Entergy has planned from its "white castle" and has claimed the department omitted from the study.

Tait said the main takeaway from DOE's study is that the Delta region's transmission planning has been badly neglected in the past decade.

"Entergy and Southern Co. cannot deny that number is awful," he said. "MISO South is going to get left behind, and what I mean by that most directly is that as an Entergy customer in MISO South, you're losing access to a whole host of affordable clean energy. … That should be a big deal to customers right now." ■

SPP, MISO Clash over Crypto-strained M2M Flowgate

By Amanda Durish Cook

SPP, MISO and its Independent Market Monitor are at odds over how congestion should be managed on a market-to-market flowgate taxed by a cryptocurrency mining operation within SPP's borders.

The three filed comments with FERC last week over whether the 230-kV Charlie Creek-Watford line in North Dakota should remain under M2M coordination, when congestion stemming from the 200-MW Atlas Power Data Center is costing MISO members millions. (See *Crypto Load on MISO-SPP M2M Constraint Draws Complaint from Montana-Dakota Utilities*.)

Montana-Dakota Utilities filed a complaint on the ongoing controversy in late January, arguing SPP should be found in breach of the grid operators' joint operating agreement for unjustly taking M2M payments from MISO to manage local congestion. MISO and its IMM agreed the line's M2M status should be lifted; SPP argued for the status quo (EL 24-61).

SPP contends there is no basis for Montana-Dakota Utilities' complaint because the more than 3-year-old M2M flowgate is "clearly authorized" by the MISO-SPP joint operating agreement and other arrangements between it and MISO. It said an order for refunds would be illegal in this case, and it asked the commission to deny the complaint.

"Moreover, SPP and MISO are already discussing prospective enhancements to the removal provisions under the JOA's dispute resolution process. SPP hopes that these discussions will successfully address the future operation of Flowgate 5717, while also avoiding near-term reliability risks and ensuring that similarly situated M2M-coordinated flowgates are treated comparably," SPP said.

SPP said there's no need for FERC to initiate hearing and settlement procedures or an alternative dispute resolution and that doing so could be "needlessly disruptive."

SPP pushed back against Montana-Dakota's claim that the flowgate is a local constraint, not a regional one. It said the constraint passed multiple eligibility studies before it was designated for M2M coordination.

"To the best of SPP's knowledge, MISO has never objected to the results of the flowgate studies," SPP said. The RTO also said it continues to believe M2M coordination on the flowgate is an "effective mechanism to manage congestion."

The Atlas Power Data Center in Williston | *KFYR TV*

SPP also said nothing in MISO and SPP's agreements prohibits constraints from becoming M2M-coordinated flowgates just because they're situated in a load pocket.

However, MISO Independent Market Monitor David Patton said the nature of the load addition means Charlie Creek shouldn't be designated as an M2M flowgate.

Patton said while Charlie Creek technically passed the tests laid out in MISO and SPP's congestion management process, the flowgate's congestion now is local and is "not a regional issue that M2M coordination was intended to address." He added that MISO, SPP and PJM in the past have agreed to remove flowgates from M2M procedures on a case-by-case basis when impacts are found to be local.

"[I]t is understood that this congestion is almost entirely managed by generation inside the [Williston load pocket (WLP)], almost none of which is operated by MISO. Likewise, MISO has no meaningful resources that can be used outside the WLP to provide relief on the Charlie Creek flowgate. These characteristics clearly indicate that the congestion on the Charlie Creek flowgate is local in nature and, as such, was never intended to be the type of flowgate that should be coordinated," the Monitor argued.

MISO itself said negotiations with SPP over the flowgate effectively are at a stalemate. It said it is seeking immediate removal of Charlie Creek from joint congestion management and for SPP to return all associated M2M payments it made to SPP starting April 1, 2023. MISO said the "only practical result of the M2M coordination on that flowgate is an unjustified financial subsidy to SPP from MISO customers."

MISO told FERC it objects to "SPP's improper application of the M2M coordination protocol" on the Charlie Creek line. But it said it remains unable to remove Charlie Creek from M2M coordination, even after engaging in negotiations with SPP pursuant to their formal dispute resolution rules.

The MISO-SPP JOA allows the RTOs to cease M2M congestion management on flowgates when the process isn't effective at curbing congestion. However, both MISO and SPP must consent to striking the flowgate from congestion coordination before it can be terminated.

MISO said it has repeatedly requested that SPP agree to eliminate the M2M designation on the line, but SPP "steadfastly refused, turning the consent requirement into a veto."

MISO asked FERC to take swift action to "stop the unjustified flow of M2M payments" and direct it and SPP to draft revisions to their M2M coordination procedures to avoid similar situations in the future. It asked that FERC fast track Montana-Dakota Utilities' complaint, given that its M2M payments to SPP are likely to rise when lower, summer ratings are applied to the line beginning in April.

MISO said it was well known that the Williston load pocket had longstanding congestion issues and said the recent load addition means its resources can offer near-zero relief.

"When SPP added a significant new load, the Atlas Power Data Center, to the WLP in early 2023, it exacerbated the existing constraints while neither SPP nor MISO have sufficient generation in the area to relieve those constraints. In other words, there is no economic M2M coordination solution that the RTOs may provide through redispatch to alleviate congestion," MISO explained.

MISO argued that SPP acknowledged the load pocket's issues in its 2021 Integrated Transmission Planning Report prior to the cryptocurrency mining facility's operation. In the 2021 report, SPP said "the root of the issues in the [Williston load pocket] is the lack of transmission to accommodate the level of transfers required to serve the forecasted load in the future, contributing to a weak system unable to maintain acceptable voltage levels." ■

MISO News

We Energies Secures FERC Permission to Switch Coal Interconnection with Gas Plant

By Amanda Durish Cook

Oak Creek Power Plant | *We Energies*

FERC on Feb. 15 allowed We Energies a MISO tariff waiver, making it simpler for the utility to trade gas for coal at its Oak Creek campus in Wisconsin.

The commission granted We Energies a one-time waiver of MISO's generator interconnection procedure requirements so it can link up a new gas-fired generator at a different voltage to replace its Oak Creek coal plant under a replacement generating facility request (*ER24-646ER24-646*).

We Energies plans to retire two of its 60-year-old Oak Creek coal units in May and the remaining two units by December 2025. It intends to replace the capacity with a $1.4 billion, 1.1-GW natural gas power plant and LNG storage facility to be completed in 2028.

Oak Creek is connected to ATC's 230-kV transmission facilities. ATC plans to transition its system surrounding Oak Creek to 345-kV and 138-kV only and eliminate its 230-kV facilities by 2027, hence the new gas plant requiring an interconnection at a different voltage than the existing coal plant. We Energies said it had to request the waiver due to factors outside of its control.

ATC supported We Energies' waiver request and said it would be the most cost-effective and efficient means of dealing with the issue. We Energies said if it wasn't granted the waiver, it would have been forced to either install facilities to interconnect with ATC's current 230-kV facilities and then replace them soon after with 138-kV- or 345-kV-compatible facilities, or "submit a new interconnection request for a project that would otherwise qualify for MISO's generating facility replacement process due to no fault of its own."

Oak Creek's generator interconnection agreement struck in 2000 did not specify a voltage level for the coal plant's interconnection service.

FERC said We Energies acted in good faith and that the waiver addresses a concrete problem with no detrimental consequences.

We Energies executives have said the Oak Creek gas plant would serve as a backup power source when renewable energy output dwindles. Nonprofit Clean Wisconsin has *argued* any new natural gas additions go against We Energies' goal of achieving an 80% reduction in carbon emissions from 2005 levels by 2030 and 100% carbon-neutral energy by 2050. ■

MISO News

Enviros, Consumer Advocates Join Regulators Urging PJM-MISO Interregional Planning

By Amanda Durish Cook

A bevy of consumer, clean energy and environmental advocates have joined state regulators in appealing to MISO and PJM to undertake more comprehensive interregional transmission planning.

Clean energy groups and consumer advocates have banded together to send separate letters to MISO and PJM's Interregional Planning Stakeholder Advisory Committee (IPSAC) to request a new approach to interregional planning.

A collection of 13 environmental groups said there's an urgent need for more transmission bridging MISO and PJM "from a reliability, economic and public policy perspective." The letter was penned by the Rocky Mountain Institute and signed by the Union of Concerned Scientists, Advanced Energy United, Clean Grid Alliance, Sierra Club, Environmental Law and Policy Center, Natural Resources Defense Council, Americans for a Clean Energy Grid and Earthjustice, among others.

"Despite the continued demonstration of need for enhanced interregional transmission between PJM and MISO, total buildout of interregional transmission continues to lag this demonstrated need," the organizations said.

Consumer advocates, including Michigan's and Illinois' attorneys general; the Citizens Utility Boards of Michigan, Illinois and Minnesota; the Indiana Office of Utility Consumer Counselor; and the New Jersey Division of Rate Counsel struck a similar tone in their letter.

"Transmission planning is more cost effective and results in better outcomes for consumers when it is done comprehensively, transparently, and using multivalue drivers. The current siloed process forces ratepayers to pay more

NIPSCO construction on the Reynolds substation in 2017 | *NiSource*

MISO News

for less beneficial outcomes," the offices wrote. They said MISO and PJM don't have a process to "proactively plan and build large-scale transmission" across their seams.

"The processes that do exist are reactive, difficult to navigate and small scale," the offices added.

The groups' appeal to the RTOs' IPSAC coincides with a similar letter from the Organization of MISO States (OMS) and the Organization of PJM States Inc. (OPSI), which also asked MISO and PJM to redouble efforts around interregional planning. (See *OMS, OPSI Urge MISO, PJM to Invigorate Interregional Planning*.) MISO and PJM are conducting an annual issues review to determine the need for a joint transmission study this year.

Both the consumer and clean energy advocates said the RTOs could use a proactive, forward-looking approach to plan interregional projects, rather than the historical view of their system that they have relied on to pinpoint needs. The clean energy organizations said MISO and PJM would benefit from a standardized set of benefit metrics, shared system modeling and a more comprehensive view of project needs that merges reliability, economics and public policy instead of considering them one at a time in studies.

Today, MISO's and PJM's planning limitations "result in minimal transmission buildout, higher costs for consumers, and a less reliable and resilient grid," the clean energy groups said. They recommended MISO and PJM incorporate their members' plans and generation expansion predictions into a long-range-style planning process that looks ahead about 20 years.

"Given the demonstrated, and accelerating, need for more interregional transmission between PJM and MISO, we request that the IPSAC initiate a more proactive, comprehensive interregional transmission planning process than what is currently done today," they wrote to MISO and PJM. They asked the IPSAC to host a series of stakeholder discussions or create a working group to design a revamped planning process that can be kicked off with a study within one or two years.

"Failure to do so will continue to commit ratepayers in PJM and MISO to overpaying for inefficient, balkanized regional solutions that do not take into consideration the billions of dollars in benefits from enhancing interregional transmission between the two RTOs," they stated.

Rocky Mountain Institute's Claire Wayner said while MISO and SPP have been actively planning for their seam through the Joint Targeted Interconnection Queue, MISO's and PJM's seam has been overlooked.

"There hasn't been much, really nothing at the scale we need to enhance grid reliability and reduce costs for customers and further clean energy," Wayner said in an interview with *RTO Insider*.

Wayner said she suspects there aren't enough resources dedicated to MISO-PJM interregional planning and that the grid operators are employing a "wait and see mentality" on FERC's potential minimum requirement for interregional transfer capability. She said she was "thrilled" to see OMS and OPSI's nudge by way of their joint letter. Wayner said she thinks MISO and PJM members are missing an opportunity to secure federal money for new interregional linkages through the Infrastructure Investment and Jobs Act.

Wayner said new MISO-PJM lines could bring not only new generation onto the grid and relieve interconnection queues but also aid progress toward clean energy goals in states like Michigan and Illinois, which straddle MISO and PJM and have aggressive clean energy goals.

"I think there's a disconnect between what planning MISO and PJM are doing by way of their coordinated system plan and the IPSAC and what all of these least-cost decarbonization models are showing us we need," she said.

Beyond decarbonization, Wayner said stronger connections will help maintain reliability during increasingly severe weather events. She said there's growing research showing that the nation will need "major, lateral transfers of power."

Wayner said she thinks MISO and PJM should reassess their existing coordinated system plan and Targeted Market Efficiency Project process and put in place a planning process that looks 20 years ahead and simultaneously considers multiple benefits. She said she's "not impressed by the scope or scale of planning that's happened between MISO and PJM to date" and said much of that planning appears to be motivated by Northern Indiana Public Service Co.'s 2013 complaint against MISO and PJM's interregional efforts. She said MISO's and PJM's sole interregional market efficiency project and four batches of small TMEPs are "not the type of transmission that we need to build the grid of the future."

"We're telling them, you need to reinvent your framework because it's siloed and it's not working," she said.

MISO and PJM are set to address regulators, consumer advocates and clean energy groups' ask for better interregional planning at the March 1 IPSAC *teleconference*. ■

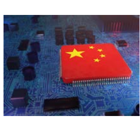
National/Federal news from our other channels

DOE to Fund Enhanced Geothermal Demo on Oregon Volcano

NetZero Insider

NERC Board of Trustees/MRC Briefs: Feb. 14-15, 2024

ERO Insider



CISA Highlights China Threat in 2024 Priorities Report

ERO Insider

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

MISO News

Consumer Collective Again Asks FERC to Strike ROFR Laws from MISO Planning

By Amanda Durish Cook

An alliance of consumer groups has asked FERC to address its 2022 joint complaint against MISO's practice of deferring to state right of first refusal (ROFR) laws in its regional transmission planning.

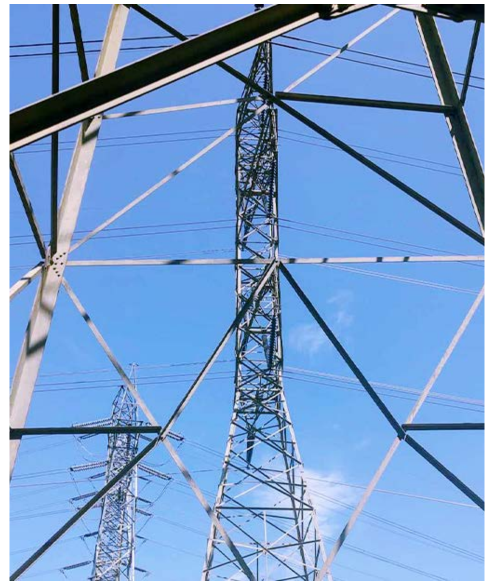
The alliance — which includes the Industrial Energy Consumers of America, the Coalition of MISO Transmission Customers and others — said "despite the significant rate impact on consumers, the commission has not ruled on the complaint" (EL22-78).

In the summer of 2022, the consumer alliance *asked* FERC to block MISO and other RTOs from applying "anticompetitive" state ROFR laws to their regional transmission planning and cost allocation processes. The group said MISO shouldn't hamstring itself by maintaining tariff provisions that prohibit it from holding a competitive solicitation for regionally cost allocated projects. It also argued that state-level ROFRs interfere with FERC's "exclusive jurisdiction to set just and reasonable rates for transmission in interstate commerce." (See *Consumer Groups File FERC Complaint Against MISO*.)

Now the alliance has said FERC's inaction has allowed uncertainty to fester, as evidenced by MISO asking an Iowa court to lift an injunction against some of its long-range transmission plan (LRTP) after Iowa's ROFR was deemed unconstitutional. (See *MISO Asks Court for Injunction Reversal on Iowa LRTP Projects*.) The group said MISO's argument that FERC alone has the power to oversee any change in developers coincides with its complaint that FERC should be able to override state-level ROFRs in transmission planning.

The consumer alliance said the litigation and delay among the Iowa LRTP projects are a "concrete example" that it's unreasonable for MISO to continue to yield to state ROFRs.

"The ROFR law exception in MISO's tariff — as played out in the state of Iowa — has hampered MISO's ability to select the more efficient or cost-effective developer in a timely manner or to effectively facilitate transmission development subject to the commission's exclusive jurisdiction. And now MISO asserts that its determination to skip competition cannot be undone by a state court ruling that the law was unconstitutional from the inception," the alliance argued. ■



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NYISO News

ConEd to Invest $20B in Tx and Climate Resiliency Through 2028

By John Norris

Consolidated Edison last week *reported* its plan to invest nearly $20 billion over the next four years in transmission infrastructure as part of its *Reliable Clean City* initiative and to mitigate climate vulnerabilities.

The New York-based utility, which serves parts of New Jersey via Orange & Rockland (O&R) Utilities, made significant strides in the past year with the Clean City project, completing several sections and receiving state authorization for further upgrades to the six-mile-long Queens-based underground transmission line. It also was approved to start its $810 million Brooklyn-based interconnection hub for offshore wind power. (See *$1.2B Con Edison Clean Energy Upgrade Approved*.)

"Clean energy is the future of our industry, and we are making strategic investments to build a grid capable of carrying that clean energy and protecting our infrastructure from climate change while maintaining our world-class reliability," said ConEd CEO Tim Cawley in a *statement*.

ConEd's subsidiaries, Consolidated Edison Co. of New York (CECONY) and O&R, submitted plans to the state's Public Service Commission (PSC) to invest $1.3 billion over five years to prepare for climate change (*22-E-0222*). They also proposed investments of about $2.82 billion in heat pump programs (*18-M-0084*) and obtained approval to increase their electric vehicle implementation budgets to nearly $450 million (*18-E-0138*).

The subsidiaries submitted utility thermal energy network pilot proposals totaling $289 million but await PSC approval (*22-M-0429*).

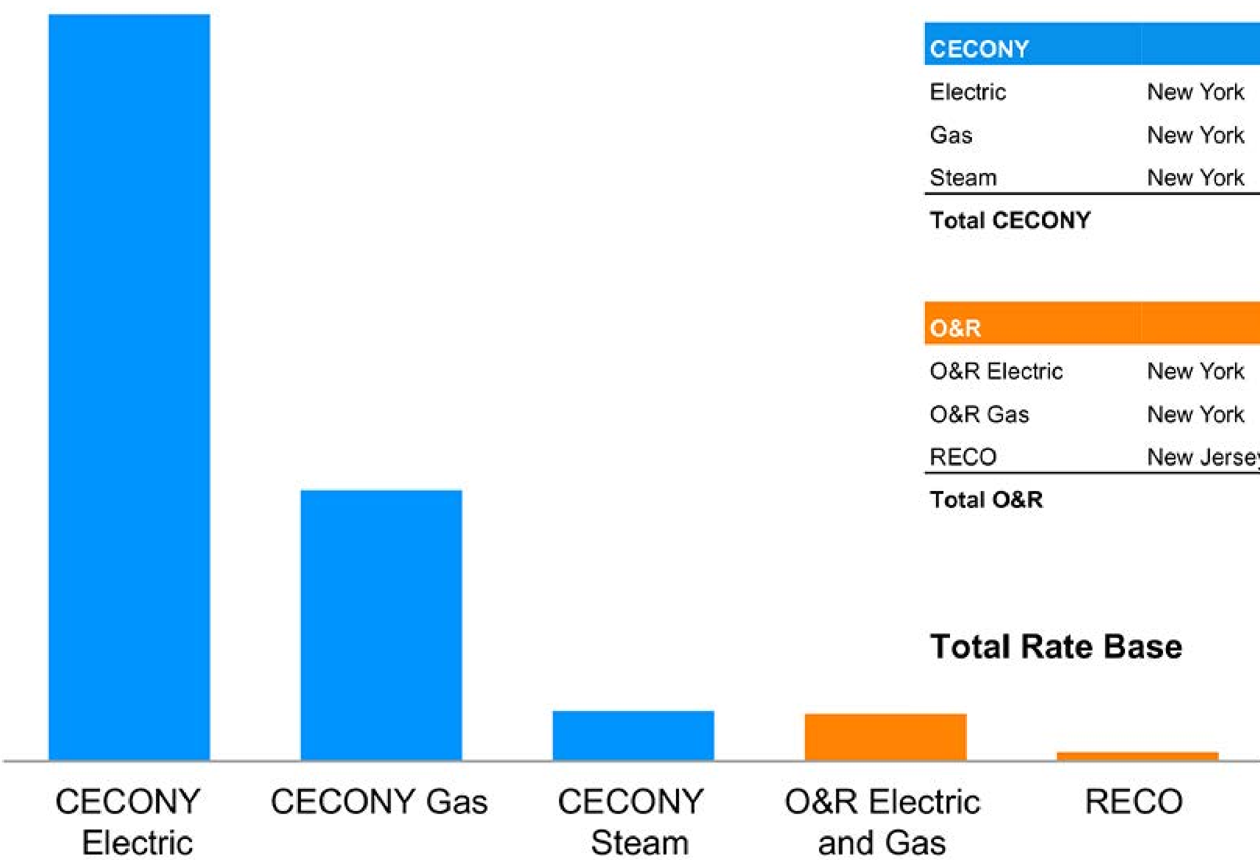
ConEd plans to fund these investments by issuing $3.25 billion of long-term debt in 2024 and an additional $1 billion in 2025, with $6 billion more in long-term debt expected through 2026 and 2028 at CECONY and O&R.

"Con Edison closed the year with no long-term debt at the parent company, due to the strategic sale of our former subsidiary, the Clean Energy Businesses," said ConEd CFO Robert Hoglund.

ConEd sold off CEB, consisting of 3,300 MW of renewable energy projects, to RWE Renewables America in 2022 for $6.8 billion and continues to realize financial benefits. In its *10-K filing*, the utility reported a nearly 41% increase in annual net income, which rose to just under $2.52 billion ($7.25/share) in 2023 from $1.66 billion ($4.68) in 2022. (See *Con Ed Yearly Earnings Continue to Rise*.)

Adjusting for the CEB sale, and other financial hypotheticals, ConEd's annual earnings saw a more modest 9.6% increase, rising to $1.76 billion ($5.07/share) in 2023 from $1.62 billion ($4.57/share) in 2022.

ConEd forecasts its 2024 adjusted earnings per share to be between $5.20 and $5.40 and expects an average annual increase in peak demand for electricity and gas over the next five years to be 2.7% and 1%, respectively. It also anticipates a 6.4% annual rate base growth through 2028. ■



CECONY		($ in millions)
Electric	New York	$26,680
Gas	New York	9,692
Steam	New York	1,820
Total CECONY		**$38,192**

O&R		($ in millions)
O&R Electric	New York	$1,083
O&R Gas	New York	626
RECO	New Jersey	340
Total O&R		**$2,049**

Total Rate Base **$40,241**

Composition of Con Edison's regulatory rate base as of Dec. 31 | *Con Edison*

NYISO Operating Committee Briefs

Expedited Deliverability Study 2023-1

NYISO's Operating Committee on Feb. 15 voted to approve the results from the Expedited Deliverability Study (EDS) 2023-01 report that *included* 16 projects, two of which were found to be undeliverable.

The 14 projects found to be deliverable have until Feb. 22 to accept or reject their deliverable megawatts as determined by the EDS report. Developers who fail to notify NYISO about their decision will be deemed nonacceptances.

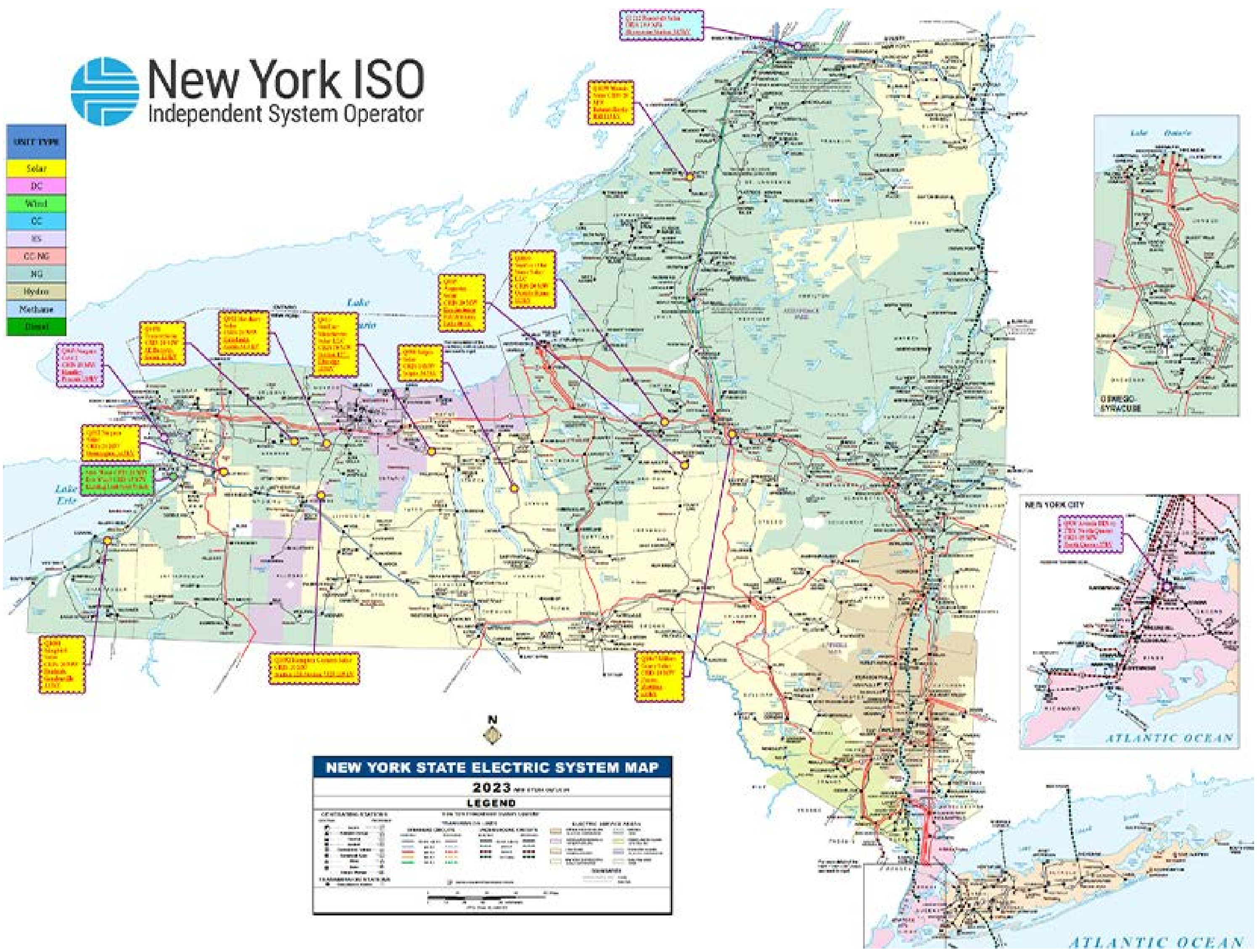
"Should every developer accept their deliverable megawatts, then EDS 2023-01 will be deemed complete," said NYISO Manager of Facility Studies Wenjin Yan.

The EDS process fast-tracks projects seeking capacity resource interconnection service (CRIS) rights by assessing whether the project is deliverable as proposed, without the need for system deliverability upgrades. (See "Class Year & Expedited Deliverability Study Update," *NYISO to Ask FERC for Order 2023 Compliance Extension*.)

The two projects deemed not fully deliverable, Q1039 Morris Solar (20 MW) and Q1212 Roosevelt Solar (19.9 MW), must now decide whether to either await the next EDS cycle or join the upcoming transitional cluster study as a CRIS-only request to identify what upgrades are required to become deliverable. Projects looking to participate in the cluster study, however, must complete a small generator facility study.

NYISO will report to the developers about each other's decisions, sharing whether projects chose to not proceed. Should one or more developers provide a nonacceptance notice after the initial decision period, then the ISO will issue updated study results for the EDS projects remaining that reflect the impact of any projects withdrawn.

The study is expected to be completed Feb. 22, but if a non-acceptance is issued, a revised EDS report will be issued on March 7.



| NYISO

NYISO News

NYC PPTN

NYISO *told* the committee the New York City Public Policy Transmission Needs (PPTN) solicitation window will open April 4.

Major Steps	Process Steps	Estimated Timeline
Solicitation of Solutions	Prepare baseline assessment	Q3 - Q4 2023
	Hold technical conference	Q4 2023
	System Data and Information Sharing	Q4 2023
	Issue solicitation for solutions	April 4, 2024 (Q2)*
	Solutions due in 60 days	June 4, 2024 (Q2)*
Viability & Sufficiency Assessment	Perform Viability & Sufficiency Assessment	Q2 – Q4 2024*
	Project information release, facility characterization, and stakeholder review	Q2 – Q3 2024*
	Final Viability & Sufficiency Assessment filed with PSC	Q4 2024*
Evaluation & Selection	Evaluate viable and sufficient transmission solutions	Q4 2024 – Q1 2025*
	Identify top-tier projects	Q1 2025*
	Evaluate top-tier projects and issue draft report	Q1 - Q2 2025
	Board review and action	Q2 - Q3 2025

*Denotes change to schedule presented at January 23, 2024 ESPWG meeting

NYC PPTN schedule with solicitation window opening April 4 | *NYISO*

Developers' proposed solutions are due by June 4, with NYISO committing to provide technical documents to developers prior to issuing the solicitation.

The New York Public Service Commission *initiated* the PPTN in June 2023, with the aim to both facilitate the delivery of 6,000 MW of offshore wind power generated off the Long Island coast to New York City and help meet the state's Climate Leadership and Community Protection Act *mandate* to develop at least 9,000 MW of OSW by 2035 (*22-E-0633*).

Doreen Saia, an attorney with Greenberg Traurig, asked if NYISO was aware of the two Feb. 14 filings from the state's Department of Public Service, which *requested* that the ISO clarify how recent contract terminations from two OSW projects, Beacon Wind and Empire Wind 2, would be reflected in the PPTN and shared *questions* the department has already received from stakeholders concerned about the terminations. (See *Empire Wind 2 Cancels OSW Agreement with New York*.)

Saia also wanted to know if the cancellations would result in NYISO adjusting the PPTN's base case, power flow cases, modeling results, timeline or technical guidance documents.

Supriya Tawde, manager of transmission integration at NYISO, responded that the ISO will be "sharing updates to the power flow cases" next week and then reviewing "our procedures to make a determination if any other changes need to be made" based on these developments.

January Operations

Aaron Markham, NYISO vice president of operations, shared the January operations *report* with the OC, saying, "the above-average temperatures we've been experiencing came to an end" and resulted in a winter season peak load of 22,754 MW, which was roughly 94% of the baseline forecast for winter.

The cold snap led to increased natural gas prices, which in turn drove up wholesale energy market prices and contributed to slightly higher local reliability costs.

External ICAP Rights

NYISO's Business Issues Committee on Feb. 14 voted to approve *revisions* to the Installed Capacity *Manual* that update the maximum amount of import capacity allowed from neighboring control areas for the 2024/25 capability year.

The ISO can import 214 MW above grandfathered rights from its neighboring control areas this coming capability year, with 97 MW available from PJM, 68 MW from ISO-NE, 37 MW from Ontario and 12 MW from Quebec.

Four-Control-Area-Participation	PJM	ISO-NE	Quebec	Ontario	Totals
Initial Values (TTC Summer Ratings)	1450	1400	1770	1950	6570
Grandfathered Rights*	1080	0	1110	0	2190
Individal Limits (above GF)	285	200	36	110	631
Simultaneous Limits (above GF)	97	68	12	37	214
Final Values **	1177	68	1122	37	2404

2024/25 import rights for NYISO's neighboring control areas | *NYISO*

The revised figures represent a 10-MW decrease from the 2023/24 capability year, with PJM's and Quebec's limits increasing by 39 MW and 1 MW, respectively, and Ontario's and ISO-NE's decreasing by 43 MW and 7 MW, respectively.

Including existing transmission capacity for native load, and other grandfathered rights, the ISO's biggest import sources are PJM (1,177 MW) and Quebec (1,122 MW).

The summer capability period auction will be held no later than 30 days prior to the start of the period on May 1. ■

— John Norris

Mid-Atlantic news from our other channels

NJ Closes Nuclear Subsidy Process as PSEG Looks to Feds

NetZero Insider

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

NYISO Defends 10-kW Minimum for DER Aggregation Participation

By John Norris

| Shutterstock

NYISO on Feb. 13 defended its proposal to set a 10-kW minimum requirement for distributed energy resources to participate in an aggregation in response to a deficiency letter from FERC, which asked it to justify the figure (*ER23-2040*).

The ISO has argued that the rule will prevent staff from being overwhelmed by initial program participation requests. Renewable energy advocates have protested, arguing that the rule would discriminate against smaller aggregations. (See *Clean Energy Groups Protest NYISO DER Proposal*.)

NYISO explained that the 10-kW threshold "is based on its two decades of experience administering" the existing special-case resource (SCR) and emergency demand response programs (EDRP), which it views to be the "participation models closet in kind to the DER and aggregation model."

The ISO said it settled on the 10-kW requirement because it believes that, like the SCR program and EDRP, managing DER aggregations will include "a significant amount of manual work" and want staff to become accustomed to it.

It also reasoned that the rule would mostly impact residential facilities employing demand-reduction technologies, such as energy storage resources or smart home products, and the 172,434 rooftop solar installations in New York with capacities under 10 kW.

These smaller resources, NYISO claimed, are minor contributors to the ISO's markets and might not even opt to participate in the DER aggregation model, favoring other programs meant for small facilities, such as the SCR.

"The question is whether the delayed implementation and costs associated with building the infrastructure to enable sub-10-kW resource participation in the DER and aggregation participation model is justifiable in light of their expected contribution to the Bulk Electric System," it said.

This is the second time NYISO has responded to a deficiency notice to its DER participation model proposed in June; much of its response reiterated arguments it made the first time, in October. FERC had requested more details about how the ISO settled on the 10-kW figure.

The ISO argued that any further delays, such as FERC rejecting its proposal, would mean it would need to "undertake a significant multiyear process to develop new market rules" addressing the commission's concerns and potentially "delay the transition of over 400 MW" of demand-side resources capable of participating in the DER aggregation model.

NYISO said it "is ready to implement the model immediately upon commission acceptance of the tariff revisions proposed," adding that "seven entities" already "submitted aggregator registration materials" and three have completed their registration.

The ISO urged FERC to act on the proposed revisions by April 15, as it is prepared to roll out its DER aggregation participation model April 16. ■

PJM News

PJM MRC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee meeting Feb. 22. 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)

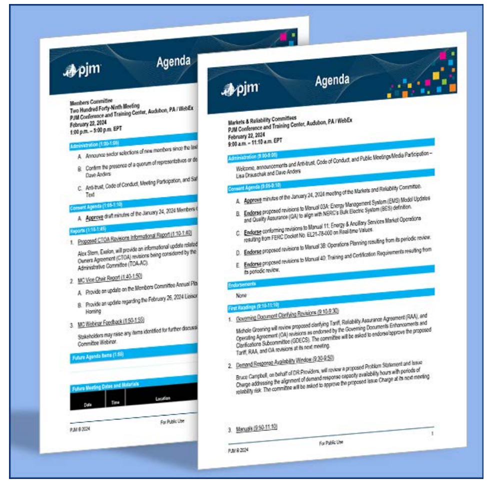
B. Endorse proposed revisions to Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance with the goal of aligning with NERC's Bulk Electric System (BES) definition. (See "Other Committee Business," *PJM OC Briefs: Feb. 8, 2024*.)

C. Endorse conforming revisions to Manual 11: Energy and Ancillary Services Market Operations to implement the real-time temporary exception process FERC approved in EL21-78. (See "Real-time Temporary Exceptions Manual Revisions Proposed," *PJM MIC Briefs: Jan. 10, 2024*.)

D. Endorse proposed revisions to Manual 38: Operations Planning resulting from its periodic review. (See "Other Committee Business," *PJM OC Briefs: Feb. 8, 2024*.)

E. Endorse proposed revisions to Manual 40: Training and Certification Requirements resulting from its periodic review. ■

— Devin Leith-Yessian



| PJM

PJM News

GSA, DOD to Power Federal Facilities with 2.7M MWh of Clean Energy

Contracts Could be Awarded in September, First Power Delivered by Year's End

By K Kaufmann

The Biden administration wants to buy more than 2.7 million MWh of carbon-free electricity (CFE) per year to power hundreds of federal and military facilities across the 13 states served by PJM, according to a *request for information* jointly issued by the General Services Administration and Department of Defense on Feb. 9.

The RFI also sets out an ambitious timetable for the procurement, which it describes as "one of the federal government's largest-ever clean electricity purchases." The official request for proposals could go out in May, with awardees announced in September and the first clean electrons going online by the end of the year.

In line with President Joe Biden's 2021 *executive order* establishing a 100% clean energy goal for federal facilities by 2030, GSA and DOD are looking to make half of the CFE procurement matched hour for hour with demand on a 24/7 basis.

With over 300,000 buildings, the U.S. government is the nation's largest energy consumer and "a steady customer prepared to make long-term investments," GSA Administrator Robin Carnahan said in the RFI *press announcement*. "We're using the government's buying power to spur demand for clean, carbon pollution-free electricity, and we're partnering with industry to drive toward the triple win of good jobs, lower costs for taxpayers and a healthier planet for future generations."

Brendan Owens, assistant secretary of defense for energy, installations and environment, stressed the link between clean energy and national security, and DOD's leadership in "greening federal government operations."

"Today's announcement will help facilitate grid transformation to address the climate crisis and to provide clean, reliable and affordable electricity that ensures mission resilience for DOD operations," Owens said.

The RFI specifies that the government is looking to procure the CFE through retail electricity contracts rather than traditional power purchase agreements. Contracts could be for up to 10 years, with fixed per-kWh prices.

Critically, the government is only interested in retail contracts for "bundled CFE," which means "the original associated energy attributes have not been separately sold, transferred or retired," according to the RFI. Renewable energy certificates (RECs) are the most used measure of clean energy attributes, with each REC certifying that 1 MWh of new wind or solar energy has been put on the grid.

"Unbundled" RECs or similar energy attribute certificates (EACs) can be sold separately from the power that produced them. Solar installers may sell them to bring down the costs of an installation, and utilities or other companies often buy them to meet state-level clean energy mandates, passing on the cost to customers through increased rates.

In other words, the Biden administration wants to make sure that the EACs for any clean electricity used to power federal facilities will not be sold for profit or used as a substitute for putting additional, clean energy on the grid.

The RFI specifically asks that retail electricity suppliers be able to track and document that that any bundled CFE does not include EACs that have previously been counted for a state renewable portfolio standard. Companies are also expected to be able to track and report how much of the CFE provided is matched hour for hour with demand.

1 million MWh for BGE

The RFI does not list the federal or military facilities to be powered with CFE or their locations, but it does provide some hints.

GSA intends to include 650 accounts in the solicitation, with contracts possibly awarded in phases.

The RFI also provides a list of the megawatt-hours the government will need in the service territories of each of the investor-owned utilities in the PJM states. Baltimore Gas and Electric leads the list with 1,031,740 MWh. The massive military base at Fort Meade is part of the utility's service territory.

Commonwealth Edison comes second, with 403,774 MWh, while 201,297 MWh will be needed for Pepco's service territory, which includes the high concentration of federal buildings in Washington, D.C.

All three utilities are owned by Exelon Corp., which also owns Delmarva Power (1,381 MWh) and Atlantic City Electric (2,273 MWh). How will Exelon and other utilities handle the additional clean power this procurement could produce?

In a statement emailed to RTO Insider, Exelon said it has been "modernizing our [transmission and distribution] assets over the last decade, allowing us to continue delivering safe, reliable, affordable energy to our customers even with a growing share of renewable and distributed energy resources."

Exelon's long-range plan calls for $31 billion in investments "to strengthen our infrastructure — both physical and IT — to prepare our assets for an influx of renewable energy sources. … When these sources are built — we will be ready to deliver the energy."

GSA does recognize that the size and scope of the procurement may mean it will have to be rolled out in phases, and the agency may not be able to get all the clean energy it wants at the time contracts are awarded. The RFI notes that "GSA is considering including minimum CFE requirements describing how much bundled CFE can be delivered and when."

In such cases, "it is anticipated that contractors will be required to provide traditional retail electricity supply to meet [GSA's] requirements," the RFI says.

A key question is how much new clean electric power will be needed to meet the government's procurement targets. The RFI specifically says any clean power that has come online since Oct. 1, 2021, could be awarded a contract.

In addition, beginning in July, PJM began its new "first-ready, first-served" interconnection process aimed at clearing a backlog of 260,000 MW from its interconnection queue.

According to a *year-end post* on the RTO's website, it estimates it will be able to clear 300 projects totaling 26,000 MW for interconnection this year. However, the overlap between the PJM queue and the federal procurement could be minimal as the RFI differentiates the bundled CFE it wants to purchase from "grid-supplied" CFE.

The comment period on the RFI will run through March 18. GSA is holding an "industry day" Feb. 20 to talk about the RFI with retail electricity suppliers and other stakeholders. For more information, email *CFESupport@GSA.gov*. ■

FERC Approves Rate Incentives for NJ OSW Transmission

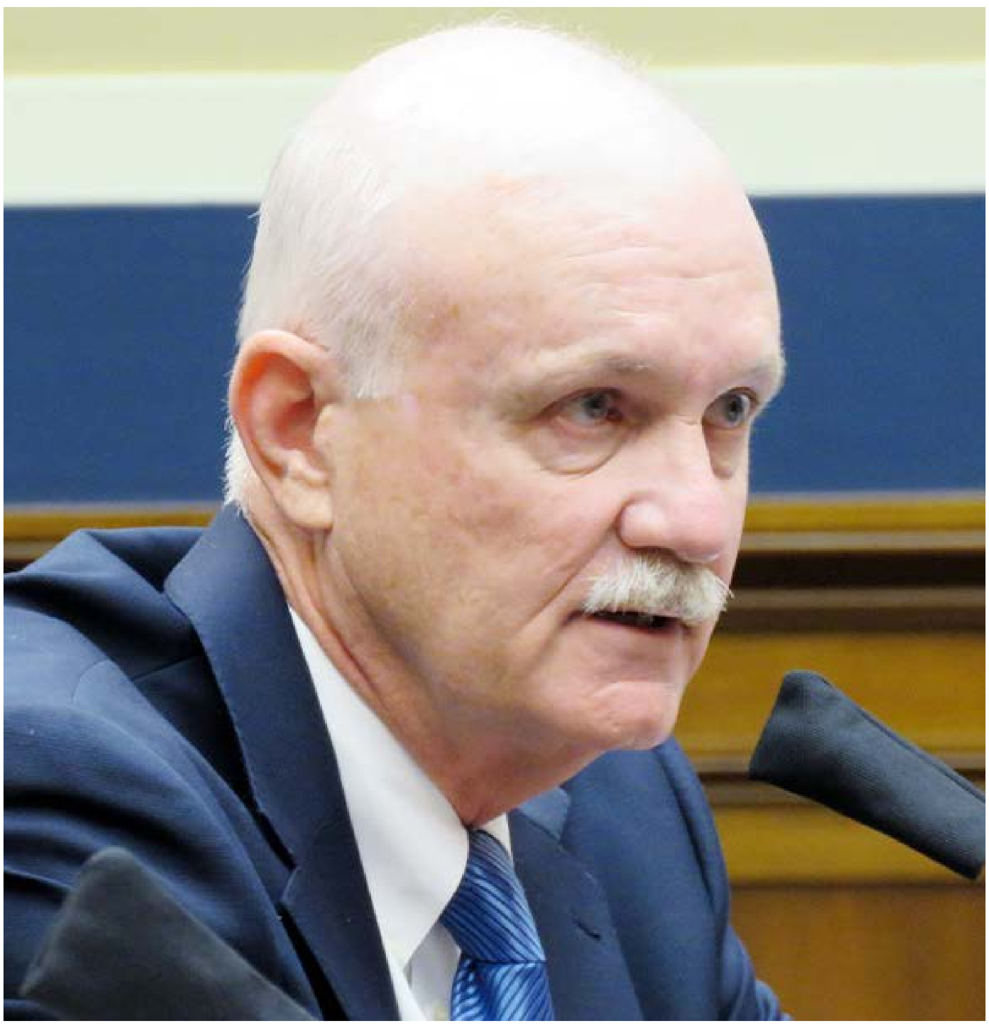
By Devin Leith-Yessian

FERC on Feb. 15 approved four rate incentives to Mid-Atlantic Offshore Development (MAOD) for its component of the approximately $1 billion in transmission to serve offshore wind in New Jersey under the State Agreement Approach (SAA) with PJM (*EL23-101*).

The company, a joint venture between Shell New Energies US and EDF-RE Offshore Development, received approval to receive the RTO participation, regulatory asset, abandoned plant and hypothetical capital structure incentives. MAOD is tasked with constructing the new 230-kV Larrabee Collector substation and HVDC converter stations for $193.6 million, nearly a fifth of the total SAA project cost. (See *New Jersey Launches OSW Infrastructure Solicitation*.)

The company's request was protested by the Long Island Commercial Fishing Association and New Jersey ratepayers, who argued that it did not meet the Order 679 requirement that there be a connection between the incentives sought and the investments being made. They posited that Ørsted's cancellation of the Ocean Wind 1 and 2 projects and economic assistance requested by Atlantic Shores Offshore Wind signal that the generation that the transmission is designed to serve may not be built.

The commission rejected the protests, stating that the SAA projects are meant to support New Jersey's offshore wind development goals, not any three of the planned projects, and therefore may move forward even if those projects are not built.



FERC Commissioner Mark Christie | © *RTO Insider LLC*

"Denying incentives because of the actions of third-party developers that may negatively impact the project would be inconsistent with the commission's interpretation and implementation of Section 219," the commission wrote, citing the Federal Power Act section requiring transmission incentives supporting capital investment.

The company sought the regulatory asset and hypothetical capital structure incentives because of its status as a first-time, nonincumbent transmission developer without existing rates that can offset development costs. Establishing a regulatory asset would allow startup and development costs not capitalized to be recovered once rates are initiated after the project's completion; the commission said that approving a 50% debt and 50% equity capital structure would establish financial principles that nonincumbents lack.

Approval of the 50-point RTO participation adder was conditioned on it being applied to a base return on equity that is later shown to be just and reasonable.

The order also greenlit the abandoned plant incentive to provide 100% recovery of costs if the project is abandoned for reasons outside of the developer's control. MAOD cited environmental, policy, siting and land acquisition risks the project faces, as well as risks inherent in it being one component of the larger SAA project involving numerous other developers.

Commissioner Mark Christie concurred with the majority's order, reiterating his concern that in many cases, the commission has a "check the box" approach to approving incentives; in this case, however, he said they are warranted on the basis that they are in support of New Jersey's policy goals and the associated costs would be allocated to the state's ratepayers.

But Christie also disputed the order's wording in finding that MAOD's request met the Order 679 requirement that projects seeking incentives undergo "a fair and open regional planning process that considers and evaluates reliability and/or congestion." He argued that PJM did not review whether the project would improve reliability or economics and that the project was instead evaluated by the New Jersey Board of Public Utilities using its own criteria. Nonetheless, he agreed that the incentives are appropriate given that the costs and benefits are allocated to one state. ■

PJM Seeks Waiver to Postpone 2025/26 Capacity Auction

PJM on Feb. 12 submitted a *waiver request* asking FERC to delay the 2025/26 Base Residual Auction by 35 days, which would bump the commencement to July 17.

The RTO argued the delay would allow a more "orderly administration" of the auction and additional stakeholder education on how effective load-carrying capability (ELCC) values will be calculated under the process FERC approved last month. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

"Such education would provide market participants with greater confidence that their respective accredited UCAP [unforced capacity] values are accurate and consistent with the approved marginal ELCC methodology," the request states.

During the Jan. 16 meeting of the Planning Committee, Adam Keech, PJM vice president of market design and economics, told stakeholders the RTO plans to release class average accreditation values in the coming weeks.

Keech also said PJM has shifted the pre-auction activities schedule by 10 days in support of stakeholder education, with an additional special session of the PC scheduled for Feb. 21 for that purpose.

The auction was originally scheduled to commence June 12.

Adam Keech, PJM | © *RTO Insider LLC*

PJM requested expedited commission action by Feb. 26, one day before the pre-auction deadline for market participants to submit unit-specific offer caps and inform the RTO of whether they intend to use the fixed resource requirement alternative to the Reliability Pricing Model. ■

— Devin Leith-Yessian

SPP MSC Approves 'Duty of Candor' Tariff Language

By Tom Kleckner

State regulators in SPP's Markets+ footprint have approved tariff language designed to address a "gap" in the accuracy of information to be shared with the Market Monitor under FERC's duty-of-candor requirements.

Weeks of discussion between regulators, SPP's Market Monitoring Unit, and SPP and western utility legal staff resulted in the Markets+ State Commission's endorsement of a paragraph during its regular monthly conference call Feb. 16.

Nebraska abstained from the vote.

The proposed tariff language would require market participants to "exercise due diligence and good utility practice" in providing material information when responding to the MMU's written request for data and information. The MMU would provide a "reasonable amount of time" for utilities to deliver the requested information, depending on the amount of information.

If the market participant determines there is an error in its response, it would have to "promptly" notify the MMU and work to correct the mistake.

Questioned as to why the language is necessary, Keith Collins, vice president of market monitoring at SPP, said the MMU has encountered several instances within the RTO's current footprint of entities either ignoring the monitor's request or submitting incorrect action.

"This does happen, unfortunately," he said, noting the MMU based several hypothetical examples shared during deliberations over the language on those circumstances.

"We feel that this particular language will solve that gap that we've identified with those examples," Collins added.

"Given what we've seen in the West, I just think there's some real scar tissue about market manipulation," said MSC Chair Eric Blank, who also chairs the Colorado Public Utilities Commission. "This is just common-sense protection that it seems the lawyers for SPP and for the market participants have agreed to."

Western commissioners brought the issue up during the Markets+ Participant Executive Committee meeting in January, requesting a clear definition of the participant obligation gap. (See "MMU, MSC to Collaborate," *SPP Markets+ Participants Executive Committee Briefs: Jan. 23-24, 2024*.)

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

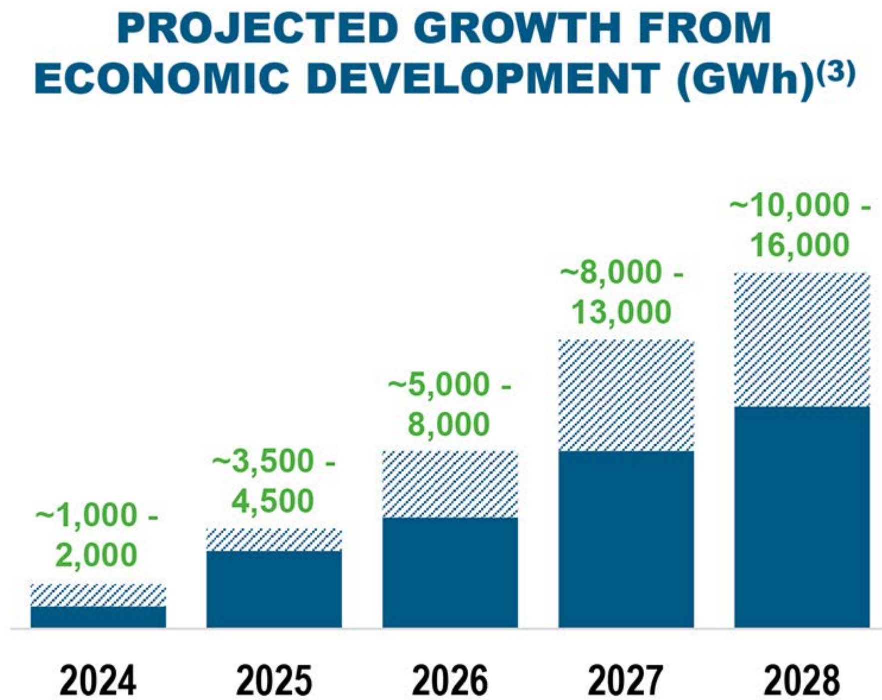
The language will be brought forward for stakeholder approval during MPEC's virtual meeting Feb. 20. ■

SPP Market Monitoring Unit's Keith Collins.| *© RTO Insider LLC*

Company News

Duke Energy Projects Higher Earnings, Load Growth in 2024

By Jack Bingham



Duke Energy in its earnings call projected long-term load growth of 1.5-2%, driven in part by economic development. | *Duke Energy*

Duke Energy has upped its forecast for growth across its territories, driven by migration, economic development and government funds, the company said during a Feb. 8 call to report its *year-end earnings*.

The company is entering the year with "significant momentum," CEO Lynn Good said. For the first time in decades, Duke is beginning the year as a fully regulated utility following the July sale of its last renewables business. (See *Duke Energy Sells Distributed Renewable Business to ArcLight*.)

With this regulatory "transformation," Good said, the company is "poised to deliver on [its] simplified, 100% regulated growth plan."

Duke's long-term load growth projections increased to 1.5-2%, CFO Brian Savoy said. This growth is underpinned by economic development projects coming online, strong residential growth and a post-COVID trend of customers returning to their offices. "Those three factors give us confidence that 2% load growth in '24 is definitely in our sights," Savoy said.

Duke Energy's third-quarter earnings call projected load growth of 0.5-1%. (See *Duke Earnings Slip on Low Demand, but Long-term Growth Expected*.)

To keep up, Good said a "record infrastructure build" is ongoing across Duke's fastest-growing jurisdictions.

In Florida, where the number of customers grew 2% from 2022 to 2023, 300 MW of solar additions are under construction, with expectations of 1.5 GW of in-service solar in the state by 2025.

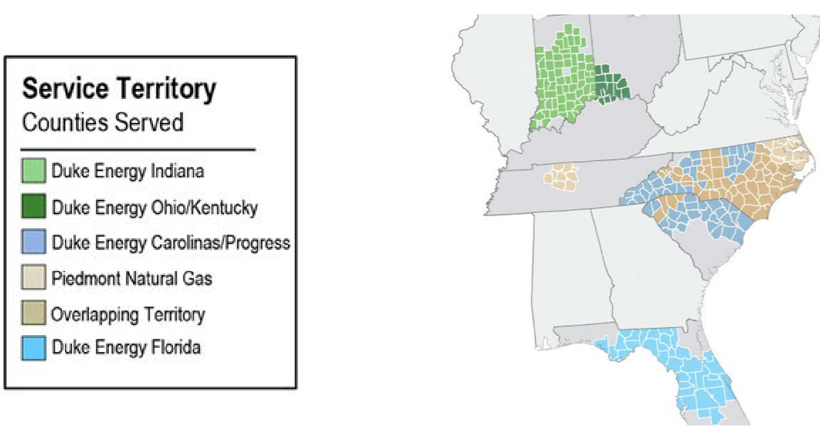
In the Carolinas, which grew by 2.1%, annual solar procurement targets of over 1 GW are in place. Duke plans to file Certificates of Public Convenience and Necessity for 2 GW of natural gas generation in North Carolina this year as well. Growth in the Carolinas is outpacing the forecast from August's resource plan, Good said, leading the utility to file supplemental plans in January.

Duke added 195,000 customers in 2023 across all jurisdictions, Savoy said.

Nuclear PTCs

2024 marks the first year Duke can claim the nuclear production tax credits (PTCs) implemented under the Inflation Reduction Act. Savoy said the utility expects to claim several hundred million dollars of the credits.

These benefits will be amortized over four years, reducing customers' electric bills during that time, Savoy added.



Duke Energy's Service Territory | *Duke Energy*

Financials

Adjusted earnings per share were $5.56, compared with $5.27 at the end of 2022, a growth rate of about 6%. This growth came primarily from rate case outcomes, multiyear rate plans and rider growth across the utility's territory.

The utility projected yearly growth of another 6-7%, to a range of $5.85-$6.10. This is expected to be driven primarily by electric utilities and infrastructure, particularly North Carolina's "historic" base case, Savoy said. Updated rates in Kentucky and expected updated rates in South Carolina also will drive this growth, he added.

This growth will be offset by the utility's average tax rate, which sits at 10% but is expected to increase to 12-14%, as well as "depreciation and property taxes on a growing asset base," Savoy said. ■

Company News

DTE Highlights Improved Infrastructure in Year-end Earnings Call

By John Norris

DTE Energy *touted* its investment of more than $3.8 billion in Michigan's electric and gas infrastructure last year for investors and analysts during its fourth-quarter earnings call Feb. 8.

The company said it put $3.1 billion into improving electric reliability and increasing clean energy, with the rest going into upgrading its gas distribution lines. The electric work included trimming more than 5,200 miles of trees, installing more than 200 automated reclosers and replacing more than 3,500 utility poles. That led to 33% less outages in the second half of the year, the company said.

DTE also "replaced more than 200 miles of cast iron pipes with more durable materials" and "moved more than 22,000 natural gas meters to the outside of homes and businesses" to improve safety, it said.

"By making strategic investments in our infrastructure at levels significantly higher than our earnings, we accelerated our long-term plans for transforming our electric generation and distribution," CEO Jerry Norcia said in a press *release*. "We will continue to increase our infrastructure investments in each of the next five years to keep getting better, faster."

Operating earnings for the year were down by just 1%, at $1.184 billion ($5.73/share). A loss of $170 million on the year in the company's electric business was offset by profits in DTE Vantage — its direct-to-business energy solutions subsidiary that owns renewable natural gas and carbon-capture facilities — and in its energy trading subsidiary. It reported operating earnings of $406 million ($1.97/share) for the fourth quarter, a nearly 53% increase over the same period in 2022.

The loss in electric earnings was mostly attributed to weather: a warmer winter, a cooler summer and higher storm-related expenses.

"2023 was a challenging year for DTE as we faced significant headwinds from an unprecedented combination of weather and storm activity," Norcia said during the earnings call. "The fact that we were able to offset most of the challenges we faced while maintaining service excellence is a clear indication of our highly engaged team and our commitment to operating excellence."

Norcia also said that clean energy legislation recently signed by Michigan Gov. Gretchen Whitmer (D) "creates a very clear roadmap for the development of additional solar, wind and storage assets" and aligns with DTE's 20-year *Integrated Resource Plan*, which was approved by the PSC in July with the goal of reducing the company's carbon emissions by 85% and ending coal usage by 2032. (See *Whitmer Signs Climate Bills, Including 100% 'Clean Energy' Goal* and *DTE Earnings Focus on Faster Clean Energy Transition*.) ■

Wind turbines at DTE Energy's Meridian Wind park | *DTE Energy*

Company News

PPL CEO Talks Energy Transition on Q4 Earnings Call

By James Downing

PPL headquarters in Allentown, Pa. | *PPL*

PPL Corp. CEO Vincent Sorgi on Feb. 16 touted his company's plans to prepare its utility subsidiaries for a changing grid.

"Looking ahead, we remain laser focused on creating the utilities of the future to advance the clean energy transition reliably, affordably and sustainably for our customers," Sorgi said during an earnings call. "And throughout PPL, we're driven to create long-term value for both our customers and shareowners.

The company reported annual earnings of $740 million, which were down slightly from 2022 in the face of milder temperatures, more storms and a more challenging economy in 2023.

PPL owns utilities in Pennsylvania, Kentucky and Rhode Island, and Sorgi reported "constructive regulatory outcomes" in the latter two. Kentucky regulators approved $2 billion in spending on generation, while the Rhode Island Public Utilities Commission approved PPL's first infrastructure safety and reliability plan since the company purchased Rhode Island Energy from National Grid in 2022.

"In addition, we received the green light to deploy advanced metering functionality across Rhode Island as we lay a foundation for a smarter, more resilient, more reliable and more dynamic electric grid capable of supporting the state's leading climate goals," Sorgi said.

PPL is planning to invest $14.3 billion in capital spending from 2024 to 2027, which will strengthen reliability and resiliency while enabling more clean energy and keeping a lid on costs for customers, Sorgi said. That will translate into rate-base growth of 6.3% annually, compared with 5.7% last year.

The company does not plan to file any rate cases this year, though it might go to the Pennsylvania Public Utility Commission for a waiver request "in the near future" to accelerate the replacement of aging infrastructure at PPL Electric Utilities, Sorgi said.

PPL's long-term plans are to continue hardening its transmission and distribution systems against climate change, improving its cybersecurity and rolling out advanced grid technology.

"It means expanding our industry-leading use of technology, including smart grids, automation, data analytics, AI and technologies that haven't even been invented yet to build a self-healing grid," Sorgi said. "It means investing in R&D to drive innovation to advanced technologies that can be scaled safely, reliably and affordably to meet our customers evolving energy needs."

The company plans to expand its transmission system and add grid-enhancing technologies (GETS) to existing lines to connect more renewables and improve reliability. It also expects to invest in its distribution system to manage two-way power flows as more distributed energy resources are connected.

The broader energy transition is going to require significant investments from the entire sector, Sorgi said.

"The industry and others are projecting a 200 to 300% increase in electricity demand, which will require additions of reliable generation unless we see unprecedented amounts of energy conservation," he said. "At the same time, aging fossil fuel plants in this country are being retired very rapidly, without replacements of reliable dispatchable generation capacity."

Sorgi said the math does not add up, with fossil fuel plants representing 50% of the total generation capacity in the country and some of the needed replacement technologies not ready. The power industry tends to take 40 years to commercialize new technology, but that is not good enough now, he said.

"We need to cut that time frame in half, at least, to meet net zero-by-2050 targets, especially as we think about the big four new potential technologies: nuclear [small modular reactors], carbon capture and sequestration, long-duration energy storage and hydrogen," Sorgi said. "In the meantime, we need to leverage commercially viable resources that exist today to reduce our carbon footprint while maintaining reliability."

For now, the industry will need to continue using natural gas plants to balance renewables and keep the lights on, he added. ■

Company News

Southern Looks Beyond Vogtle After Challenging 2023

Mild Weather Blamed for Declining Electric Revenue

By Holden Mann

After a year in which unusually mild weather depressed electric use, Southern Co. is forecasting 5 to 7% annual earnings growth thanks to a robust economy in Georgia.

The company faced "unprecedented headwinds" in 2023 but achieved numerous milestones during "an exceptional year," CEO Chris Womack said in announcing the company's fourth-quarter and full-year *earnings* Feb. 15.

Among the accomplishments Womack highlighted in his presentation was the long-delayed completion of Unit 3 at the Vogtle nuclear power plant near Waynesboro, Ga., which *entered commercial operation* on July 31 more than seven years late and $17 billion over budget.

The CEO pointed out that Southern subsidiary Georgia Power reached an *agreement* with the state's Public Service Commission last August to resolve all remaining prudency issues at Unit 3 and Unit 4. Under the agreement, the recovery of capital construction costs from ratepayers for both units is capped at $7.6 billion, leaving the remaining costs — estimated at around $2.6 billion — to be paid by Georgia Power. The PSC *approved* the agreement in December.

Womack said Southern is making "meaningful progress" toward completion on Unit 4, with initial criticality achieved Feb. 14, marking the start of the nuclear chain reaction inside the reactor. The company expects the final unit to be in service by April.

Along with the progress on Vogtle, Womack mentioned the completion of Unit 8 at Alabama Power's Plant Barry, a 727-MW combined cycle unit that began operating Nov. 1, and the acquisition of two solar projects that will provide 350 MW when finished.

The company's operating revenue for the three months ending in December came to $6 billion, compared to $7 billion for the same period in 2022. Net income for the period — excluding losses on plants under construction, losses on capital investments and tax impacts — stood at $700 million, compared to $285 million for the same period the year before.

The turbine generator at Unit 4 of the Vogtle nuclear power plant in Georgia, which achieved initial criticality on Feb. 14. | *Georgia Power*

Operating revenue for the full year was $25.3 billion, down from $29.3 billion in 2022; however, net income for the full year — excluding the same elements — was $4 billion, up from $3.9 billion the previous year.

Southern reported adjusted earnings per share of 64 cents for the quarter, up from 26 cents for the same period in 2022, with adjusted earnings per share for the whole year rising from $3.60 to $3.65, which CFO Dan Tucker noted was "at the very top of our 2023 guidance range." He cited "higher utility revenues and lower nonfuel O&M [operations and maintenance] costs and income taxes."

Tucker said the company's electric revenue was reduced because 2023 was "the mildest year in our history for our electric service territories." Electric retail sales, adjusted for weather, were down 0.4% from 2022, with reduced residential and industrial usage (down 0.5% and 1.9% respectively) balanced by strong commercial sales growth of 1.3%.

The decline in industrial sales was primarily due to "continued slowing in [the] housing and construction-related sectors, as well as lower sales to chemical companies due to outages and long-planned plant closures," Tucker said. However, he pointed out that the population in Southern's electric territories grew by 0.8% between July 2022 and July 2023, with Georgia adding more than 26,500 new jobs last year. In 2022, the state added 45,600 jobs, more than 15,000 of them from auto *factories* being built by Hyundai and EV truck maker Rivian.

Based on these trends, Southern is setting an adjusted earnings per share guidance range for 2024 of $3.95 to $4.05, with long-term adjusted EPS growth rate of 5-7%, Tucker said. These figures assume Vogtle Unit 4 is completed on schedule.

Despite the challenges, Womack said Southern's electric and gas businesses "continued to excel at the fundamentals and started this year strong," noting that the company operated reliably during January's winter storm even as "electricity demands reached all-time winter peaks." ■

Company Briefs

Qcells, Solarcycle Aim to Jointly Recover 95% of Solar Panel Value

Solar module manufacturer Qcells has entered a partnership with recycling company Solarcycle to recycle solar panels after decommissioning.

Solarcycle said its recovery process retains 95% of the value of materials in the panels.

The National Renewable Energy Laboratory projects that by 2040, recycled panels and materials could help meet 25% to 30% of U.S. domestic solar manufacturing needs.

More: *pv magazine*

Constellation Seeks License Renewal of Clinton Clean Energy Center

Constellation on Feb. 15 announced it has filed a license renewal application with the Nuclear Regulatory Commission for its Clinton Clean Energy Center in Clinton, Ill.

Clinton is currently licensed to operate through April of 2027. The renewal seeks to add another 20 years.

Renewing the license of Clinton would provide Illinois an estimated 179 TWh of carbon-free electricity over the extended lifespan of the license, Constellation said.

More: *Constellation*

Ameren to Build Natural Gas-fired Plant in St. Louis County

Ameren on Feb. 16 said it plans to build a natural gas-fired power plant in south St. Louis County on the site of the retired coal-fired Meramec Energy Center.

The utility said the $800 million Castle Bluff Energy Center would be used as a peaker plant to bolster power reliability when demand is greatest.

Ameren aims to begin construction sometime next summer, although regulatory review processes before the Public Service Commission can often take a year.

More: *St. Louis Post-Dispatch*

FERC OKs Solar Project Interconnection with Arizona Co-op

FERC approved agreements providing developer THSI BN LLC interconnection service via Arizona Electric Power Cooperative (AEPCO) for its *Three Sisters Solar ProjectThree Sisters Solar Project*, a 300-MW solar array with 300 MW/1,200 MWh of battery storage planned in southeast Arizona.

The commission's Feb. 15 order followed its Oct. 19 proposed order directing the interconnection service and giving THSI and AEPCO 30 days to negotiate terms, rates and conditions. (See *FERC Directs Ariz. Utility to Allow Solar Project to Interconnect*.)

AEPCO initially questioned whether allowing THSI to hold an interconnection queue position for more than five years served the public interest, and asked FERC to dismiss the request. FERC responded saying it found the public interest would be served because precedent holds that transmission availability enhances competition in power markets, which should result in lower prices for consumers.

More: *TX23-5*

Federal Briefs

US Appeals Court Rejects Renewed MVP Challenge

The U.S. Court of Appeals for the D.C. Circuit on Feb. 13 rejected a second challenge by property owners to the Mountain Valley Pipeline's use of eminent domain.

In a unanimous, unsigned opinion, the three-judge panel agreed with a district court's ruling that it could not hear the owners' lawsuit against FERC and the developers because it was brought after the D.C. Circuit had taken up an appeal from a separate administrative challenge over the same issue.

Mia Yugo, a lawyer for the landowners, said her clients would ask the Supreme Court to review the case.

More: *Reuters*

US Issues Clean Air Permit to New York's Empire OSW Project

EPA on Feb. 15 granted a Clean Air Act permit to New York's Empire Offshore Wind project.

The permit was given after an air quality analysis showed federal air quality standards would not be compromised during construction and operation of the project, the agency said.

The Empire Wind project will include two offshore wind farms, the 816-MW Empire Wind 1 and the 1,260-MW Empire Wind 2, that will produce 2,000 MW.

More: *Reuters*

House Approves Bill to Block Biden's Pause on New Gas Export Projects

The House of Representatives on Feb. 15 voted 224-200 to approve a bill that would block the Biden administration's pause on new natural gas export projects by removing its ability to reject export projects altogether.

The legislation would remove the Energy Department's authority to reject projects that would export natural gas, instead giving the power to approve or reject a project solely to FERC. Currently, projects need approval from both FERC and DOE to begin construction.

While the bill won majority support in the House, it is unlikely to advance through the Democratic-controlled Senate or the White House.

More: *The Hill*

FERC, NERC to Review Grid Performance During Recent Winters

FERC, NERC and NERC's regional entities on Feb. 13 announced the launching of a joint review of the performance of the bulk power system during recent winter storms from Jan. 10 through Jan. 16.

The review will look at progress made since FERC and NERC completed joint inquiries into two recent winter storms, Uri in 2021 and Elliott in 2022. The team plans to deliver the results of the review no later than June 2024.

More: *NERC*

State Briefs

CONNECTICUT

Eversource Seeks Rate Hike for CL&P Customers

Eversource Energy filed a request Feb. 15 with the Public Utilities Regulatory Authority seeking a $784 million rate adjustment that would bump its Connecticut Light & Power electric rates by nearly 19%.

Eversource claimed a directive that they purchase electricity at a favorable rate from Millstone, the state's last nuclear plant, caused $605 million of the $784 million in unrecovered costs. It blamed another $160 million on mandated benefits for the poor and medical hardship cases.

More: *CT Mirror*

MARYLAND

Gov. Moore Unveils EmPOWER Plan to Boost Energy Efficiency

Gov. **Wes Moore** (D) on Feb. 13 announced that the state Department of Housing and Community Development will increase the number of households served by its EmPOWER Maryland energy efficiency program over the next three years.

The program supports repairs and upgrades to limited-income households that help reduce energy use and lower utility costs. The plan is in response to new statewide household electric savings goals for limited-income households, established by the passage of HB169 during the 2023 General Assembly.

More: *WBFF*

MINNESOTA

Meeker, Chippewa Counties Approve Renewables Moratoriums

The Meeker County and Chippewa County boards of commissioners on Feb. 6 adopted one-year moratoriums on the permitting or zoning of wind or solar energy projects to provide time to study ordinances.

The moratoriums were spurred by Xcel Energy's intent to build a high-voltage transmission line in the region.

More: *Inforum*

NEVADA

PUC: NV Energy Customers to Pay for Employee Bonuses

The Public Utilities Commission on Feb. 13 voted 2-0 with one dissention to require customers to pay for NV Energy employee bonuses.

Chair Hayley Williamson voted with Commissioner Randy Brown, while Commissioner Tammy Cordova dissented. Cordova supported two motions for reconsideration of the PUC's December ruling allowing NV Energy to recoup the $5.7 million cost of the bonuses from customers.

The average compensation among NV Energy employees is $130,812, 1.3% less than the national benchmark of $132,509, according to testimony submitted to the PUC last year as part of the utility's general rate case.

More: *Nevada Current*

NORTH CAROLINA

Attorney General Appeals Duke Energy's Approved Rate Hike

Attorney General Josh Stein on Feb. 14 filed an appeal against Duke Energy Carolinas' recently approved rate hikes and asked the state Supreme Court to reject it.

The Utilities Commission in December approved the 15% rate hike, to be spread out over the next three years.

More: *WCNC*

SOUTH DAKOTA

House Committee Kills Bill Aiming to Stop Eminent Domain

The House Commerce and Energy Committee on Feb. 12 voted 7-6 to kill a bill that would have stopped carbon sequestration pipelines from using eminent domain.

The legislation, if passed, would have prohibited the use of eminent domain by carbon dioxide pipelines if more than half of the transported carbon dioxide is intended for sequestration rather than commercial uses. Opponents said the bill would negatively impact the state's ethanol industry and corn farmers if a proposed Summit Carbon Solutions pipeline isn't built.

More: *South Dakota Searchlight*

VIRGINIA

Lawmakers Delay Decision on Dominion Energy's OSW Monopoly

The Senate Commerce and Labor Committee on Jan. 29 unanimously tabled a proposal to let private developers compete with Dominion Energy on offshore wind procurement. The decision to push the proposal onto the 2025 agenda followed intense lobbying from Dominion to protect its monopoly.

As drafted, the bill would have required the state's next 2,600 MW to be competitively bid among private developers.

Sen. Creigh Deeds (D), the bill's sponsor, joined advocates in claiming that such competition would provide a swifter, cheaper, more transparent and less risky path to meet or exceed the target of 5,200 MW of offshore wind by 2032 outlined in the Virginia Clean Economy Act.

More: *Energy News Network*

Tazewell Board Approves Siting Agreement for Solar Farm

The Tazewell County Board of Supervisors on Feb. 6 unanimously approved a siting agreement with Energix for a proposed solar farm.

The agreement provides for setbacks from property boundaries, vegetative barriers and fencing to shield the project from view, and a bond to be posted to pay for removing the panels once the farm is no longer in service, among other requirements.

Construction is expected to begin in late 2025.

More: *Bluefield Daily Telegraph*