ISSN 2377-8016 : Volume 2024/Issue 6 ▪ February 13, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: FERC Commissioner Willie Phillips | © *RTO Insider LLC*

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

Biden Drops 'Acting' from Phillips' Title; Clements to Leave at End of Term

By James Downing

President Joe Biden on Friday removed "acting" before FERC Chair Willie Phillips' title, as Commissioner Allison Clements announced she would not seek a second term.

Phillips had been serving as "acting" chair since the start of 2023 after Sen. Joe Manchin (D-W.Va.) refused to hold hearings for the renomination of former Chair Richard Glick, who had to step down at the end of 2022.

"I'm honored to continue to lead FERC as chairman and thank [the president] for his faith in my leadership," Phillips *posted* on X. "I'm laser focused on securing a reliable, affordable and sustainable energy future for our nation."

The "acting" title did not functionally change Phillips' job at the commission; it signaled that the White House had intended to replace him with a new commissioner. (See *Phillips Addresses Acting Status as FERC Awaits Nominees*.)

The announcement came the same day that POLITICO reported that Clements would not seek another term, which her office confirmed to *RTO Insider*. But it would not comment on what she intended to do after her term expires June 30; commissioners whose terms have expired without a replacement can stay at their posts until Congress adjourns at the end of the year.

The opening means the White House and Senate will have up to three new nominees to process. Glick's seat has been open since his departure, and former Commissioner James Danly's has been since the end of last year,

FERC Commissioner Willie Phillips | © RTO Insider LLC

as he also stayed past his own June 30 term expiration. (See *Secretary Bose and Commissioner Danly Honored at Their Final FERC Meeting*.)

Failing to move any nominees before Clements departs would leave FERC short of a quorum and unable to vote out orders, which happened early in former President Donald Trump's term.

Before joining FERC in late 2021, Phillips was chair of the D.C. Public Service Commission. He previously worked as assistant general counsel at NERC. He earned his law degree from Howard University School of Law and his bachelor's from the University of Montevallo.

Clements came to FERC in December 2020 after a range of experience in energy law in both the public and private sectors with stints at Energy Foundation, Good Grid and the Natural Resources Defense Council. She earned her law degree from the George Washington University Law School and her bachelor's from the University of Michigan.

The news about Phillips' title was applauded by many, with Manchin, the Senate Energy and Natural Resources Committee chair, saying he looked forward to working with him on an "all-of-the-above energy policy."

"Throughout the last year overseeing a very productive and bipartisan FERC, Chairman Willie Phillips has proven time and time again that he was the right person to lead this ever-important agency from the start," Manchin said. "Amid the ongoing need to bolster our energy infrastructure, I have no doubt that Chairman Phillips will continue to lead FERC with his wealth of experience and consensus-building skills to the benefit of our country."

Advanced Energy United Managing Director Caitlin Marquis also welcomed the news, noting it will allow Phillips to continue working on key issues like transmission planning.

"As FERC continues work on these issues and takes up additional priorities, Advanced Energy United asks that the Biden administration quickly nominate new commissioners eager to tackle the challenges and opportunities facing the electricity system, ensuring that FERC is wholly staffed and equipped to take on critical energy sector issues," Marquis said. ■

FERC/Federal News

DOE Opens 2nd Solicitation in Transmission Offtake Program

Will Spend up to $1.2B to Reduce Project Risks

The U.S. Department of Energy opened the second solicitation in its program to prime the pump for new transmission needed to meet the Biden administration's climate goals.

Initial proposals for the $1.2 billion to be offered in Round 2 of the *Transmission Facilitation Program* will be due March 11, DOE's Grid Deployment Office said in its Feb. 6 *announcement*.

Authorized by the Infrastructure Investment and Jobs Act, the program allows DOE to borrow up to $2.5 billion to assist in the construction of high-capacity transmission lines that otherwise would not be built or to increase the capacity of already planned lines.

On Oct. 30, DOE announced it would spend $1.3 billion to purchase up to 50% of the capacity on three projects totaling 3.5 GW: the 500-kV Cross-Tie Transmission Line (Nevada and Utah), the Southline Transmission Project (Arizona and New Mexico) and the Twin States Clean Energy Link (New Hampshire and Vermont). (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

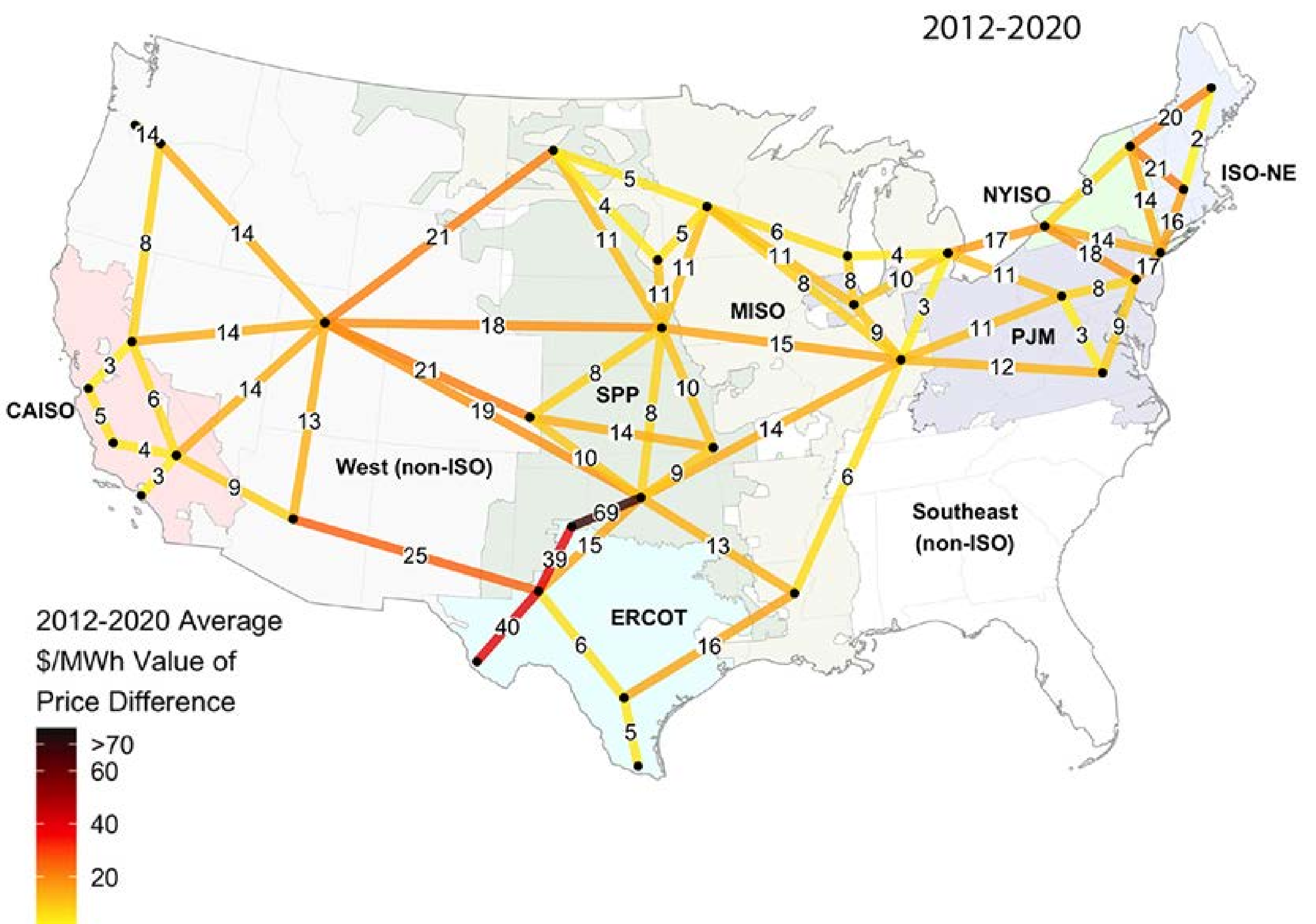
The program offers capacity contracts to late-stage projects to increase investors' and potential customers' confidence and reduce the risk of developers undersizing projects. DOE will seek to recover its costs by selling its capacity rights, allowing it to make offers to additional projects.

DOE's *National Transmission Needs Study*, also released in October, estimated the U.S. must more than double its regional transmission and expand interregional capacity more than fivefold by 2035 to ensure reliability, resilience to extreme weather and access to renewables.

Responding to industry feedback, DOE broke its second *solicitation* into two parts, with an initial submission of a "project paper and virtual presentation" to be followed by a detailed application and in-person interview.

DOE will hold a *public webinar* to provide additional information on the solicitation Feb. 21 at 3 p.m. ET. ■

— Rich Heidorn Jr.



The final National Transmission Needs Study found that interregional transmission will have the highest value between ERCOT and non-ISO regions in the Mountain West and Southwest. | *DOE*

FERC/Federal News

DOE Official Defends LNG Approval Pause at Senate Hearing

By James Downing

A Department of Energy official defended the Biden administration's pause on processing LNG export facilities at a Senate hearing Feb. 8.

Energy and Natural Resources Committee Chair Joe Manchin (D-W.Va.) and the committee's Republicans told Deputy Energy Secretary David Turk the administration should reverse course and start processing applications again.

"Simply put: Politicizing LNG exports is reckless and dangerous, and it could empower and enrich Russia, Qatar and Iran," Manchin said. "Deputy Secretary Turk, if I'm correct, DOE is just now beginning its new analysis of the economic impacts of our growing export levels. If this is the case, I strongly urge that this pause should be reversed immediately."

Ranking Member John Barrasso (R-Wyo.) said the pause was all about the upcoming presidential election, with Biden trying to win votes from environmentalists.

"Critics have claimed that American natural gas exports would raise natural gas prices here at home," Barrasso said. "The data shows otherwise. In the eight years since we began exporting LNG, the domestic spot price of gas is, on average, much lower than the domestic spot price on gas during the eight years before we were able to start exporting LNG."

Turk said DOE is supposed to approve LNG export facilities to countries without free trade agreements when that is in the public interest, which is made up of economic, market, national security and environmental considerations. The last time the department reviewed how it analyzes new projects' impacts was 2018, and much has changed since.

"First, the amount of U.S. natural gas that is being exported has dramatically increased, and we need to answer how authorizing exports beyond these unprecedented volumes could impact affordability for U.S. consumers

Deputy Energy Secretary David Turk testifies before the Senate Energy and Natural Resources Committee on Feb. 8. | *Senate Energy and Natural Resources Committee*

and competitiveness of U.S. manufacturing," Turk said in written testimony. "Second, our understanding of CO_2 and methane's effect on climate change have only become sharper, and we need to further improve our analytical tools

Continued on page 6

President Biden's LNG Pause Fuels Partisan Debate at House Hearing

By James Downing

Republicans teed off on President Biden's pause on processing new applications for liquified natural gas (LNG) exports at a congressional hearing Feb. 6. (See *Report: Biden Admin to Evaluate LNG Terminals' Impact on Climate*.)

"In addition to undercutting our domestic energy industry, President Biden's decision is a gift to Vladimir Putin," said Jeff Duncan (R-S.C.), chair of the House Energy, Climate & Grid Security Subcommittee. "Global demand for natural gas is expected to increase 46% by 2050. And our European and Asian allies who want to do business with the United States will now look to Qatar, Russia and Iran to meet their growing energy needs."

Duncan said committee leaders had invited a speaker from the Department of Energy, but nobody from the administration came. Undersecretary of Energy David Turk is scheduled to testify on the subject at a Senate Energy & Natural Resources Committee hearing Feb. 8.

The pause comes after the industry already has built enough capacity to export 14 billion cubic feet per day, with enough under construction to double that capacity, said Subcommittee Ranking Member Diana DeGette (D-Colo.). Additional projects with full approvals from FERC and DOE, but yet to start construction, would triple that capacity, DeGette said.

None of those facilities under development will be affected by the pause in reviews, she added. The last time the review process for new export facilities was updated was 2018, when export capacity was just one-third of today's level.

"The fact that our nation's production has ramped up so quickly must be considered, especially since the U.S. currently has enough approved capacity to fulfill the world's energy needs in the short and medium terms," DeGette said. "Continuously increasing LNG exports, without updating guidelines to account for new information, is a fundamentally unserious proposal."

EQT calls itself the largest producer of natural gas in the country, with its drilling focused around the Marcellus and Utica shales in Pennsylvania, Ohio and West Virginia. EQT CEO Toby Rice blasted the decision to pause approvals for new export facilities.

"The Biden administration's decision was pure politics," Rice said. "The moratorium was made under the guise of updated research and a claim that we needed updated studies on the environmental and economic impact of U.S. LNG. But we all know what it really is, and that's an election-year stall designed to garner votes."

Europe has had to rely on importing LNG from the U.S. since its countries were cut off from Russia following its invasion of Ukraine, said Brigham McCown, senior fellow at the Hudson Institute. Last month, spot prices there averaged \$9.56/MMBtu (million British thermal units), while Henry Hub gas was at just \$2.26/MMBtu this week, McCown said.

"Europe should not be allowed to recede into the background," McCown said. "Energy security highlights the need for a comprehensive approach and a stable policy environment coupled with innovation, technology and international cooperation. Our allies would like to be able to have energy security as well."

Gillian Giannetti is a former high school teacher along the part of Louisiana's coast called

FERC/Federal News

"cancer alley" because of the concentration of industrial facilities and their pollution's impact on locals. Now senior attorney for the Natural Resources Defense Council's Sustainable FERC Project, Giannetti said she's witnessed the effects on her former students, who had high rates of asthma and other respiratory conditions.

The pause impacts only LNG facilities being built to serve countries that do not have a free-trade agreement with the U.S., she noted. DOE must find that a facility shipping gas to non-free trade countries is in the "public interest" to approve it, and so far, it has yet to deny an application for any facility, Giannetti said.

"Put simply, DOE's tools for assessing whether future gas exports are consistent with the public interest are both obsolete and inapplicable," she added. "First, DOE has never published guidelines for evaluating the public interest for LNG exports. Never."

The closest it came was a 1984 effort that sought to come up with rules for LNG imports, which do not work well for licensing export facilities four decades later, Giannetti said. DOE did do some studies on the economic impact of LNG exports in 2018, but they need to be updated too, she added.

Constellation's Everett LNG Facility is the longest-operating LNG import facility of its kind in the U.S | *Constellation Energy*

The Industrial Energy Consumers of America (IECA) was not invited to testify, but it released comments saying LNG exports affect domestic prices, especially when storage is low. That coincides with demand peaks, which the IECA claims contributed to $84 billion and $53 billion in higher natural gas and electricity prices in 2022 compared to a year earlier.

"Accelerating volumes of LNG exports do have increasing impacts to reliability and prices of natural gas and electricity that are accentuated when inventories are low and during peak winter and summer demand," said IECA President Paul Cicio. "The relationship is fundamental to the law of supply and demand. Low inventories result in high prices and high inventories result in low prices." ■

DOE Official Defends LNG Approval Pause at Senate Hearing

Continued from page 5

to answer a range of questions about LNG exports' climate and environmental consequences, both near and longer term."

The country has 14 Bcfd of export capacity up and running now, with an additional 12 Bcf under construction and expected to be online by 2030. A total of 48 Bcfd has already been approved, which is nearly half of the total domestic production of 104.4 Bcfd.

The pause will not impact the ability to fuel allies, with Turk noting that European demand for LNG is falling, demand has peaked in Japan and South Korea will peak by the end of the decade, Turk said.

While domestic prices have not converged with the higher costs of global LNG's yet, Turk said the Energy Information Administration has said that will happen eventually as exports grow.

The other side of the aisle of the committee defended DOE's review, with Sen. Angus King (I-Maine), who caucuses with the Democrats, saying the department is trying to make sure the economic impact of continued growth in export capacity is worth it and to understand the lifecycle emissions of LNG exports.

"I don't understand how you would take 50% of the production of a commodity and that won't affect the price," King said, referencing the total number of facilities that have already been approved.

Australia has ramped up its export capacity, and it has seen prices increase by a factor of five as it reached equilibrium with global markets.

Addressing Turk, King said, "My understanding is all you are trying to do is be sure before we add additional commitments that we know what the effect will be on a manufacturer in Michigan or a family in New England trying to heat their house."

The analysis hopes to answer those kinds of questions, Turk said, and he expects the department will take "months, not years," to get it done.

"If we were talking about considering a pause, this is a great, great panel for this," Manchin said. "You have an executive order doing a pause, that's the difference. That's the difference I have with the administration."

It would have made more sense to do the analysis first and then pause applications if it found additional capacity goes against the public interest, he added.

King pushed back, saying that the department is only doing its job, and it would not make any sense to keep approving projects only to find out "five years from now, it's a complete disaster."

"I'm just saying that the pause was ill advised from a political standpoint of sending out to the world right now that we might not be in the market," Manchin said. ■

CAISO/West News

WEIM Ends 2023 Exceeding $5B in Benefits

Expanded Footprint Continues to Deliver Lower Costs, Increased Reliability, CAISO Says

By Ayla Burnett

CAISO's Western Energy Imbalance Market has yielded $5.05 billion in benefits for its members since its inception in 2014, continuing the positive trend of growth tied to an expanding Western footprint, according to the ISO's *fourth-quarter benefits report* released Jan. 31.

"This level of economic benefits are a very good representation of the value and effectiveness of the WEIM market to meet supply and demand across the wide footprint," Guillermo Bautista Alderete, director of market performance and advanced analytics for the ISO's Department of Market Monitoring, said at a Feb. 6 WEIM Governing Body meeting.

Q4 2023 produced a total of $391.82 million in cost savings for WEIM participants, accrued from having additional entities join the market in 2023, which now stands at 22 balancing areas representing nearly 80% of the demand for electricity in the Western Interconnection.

The Balancing of Authority of Northern California saw the largest share of benefits last quarter at $73.24 million, with PacifiCorp second at $50.46.

CAISO said economic transfers within the WEIM were "substantial" in Q4. The ISO itself had the highest volume of net exports, at 1,403,521 MWh, followed by the Salt River Project (629,470 MWh) and PacifiCorp East (538,108 MWh). Powerex was the largest net importer at 1,266,745 MWh, followed by CAISO with 735,579 MWh.

CAISO also led in the volume of wheel-through transfers, at 1,140,739 MWh, followed by Arizona Power at 379,452 MWh.

WEIM also continued to provide emissions benefits due to its ability to enable transfers that prevent renewable output from being curtailed. According to the report, the total avoided renewable curtailment by volume reached 49,880 MWh, displacing an estimated 21,349 metric tons of CO_2 in Q4. Avoided curtailment since 2015 yielded a reduction of 925,568 equivalent tons of CO_2.

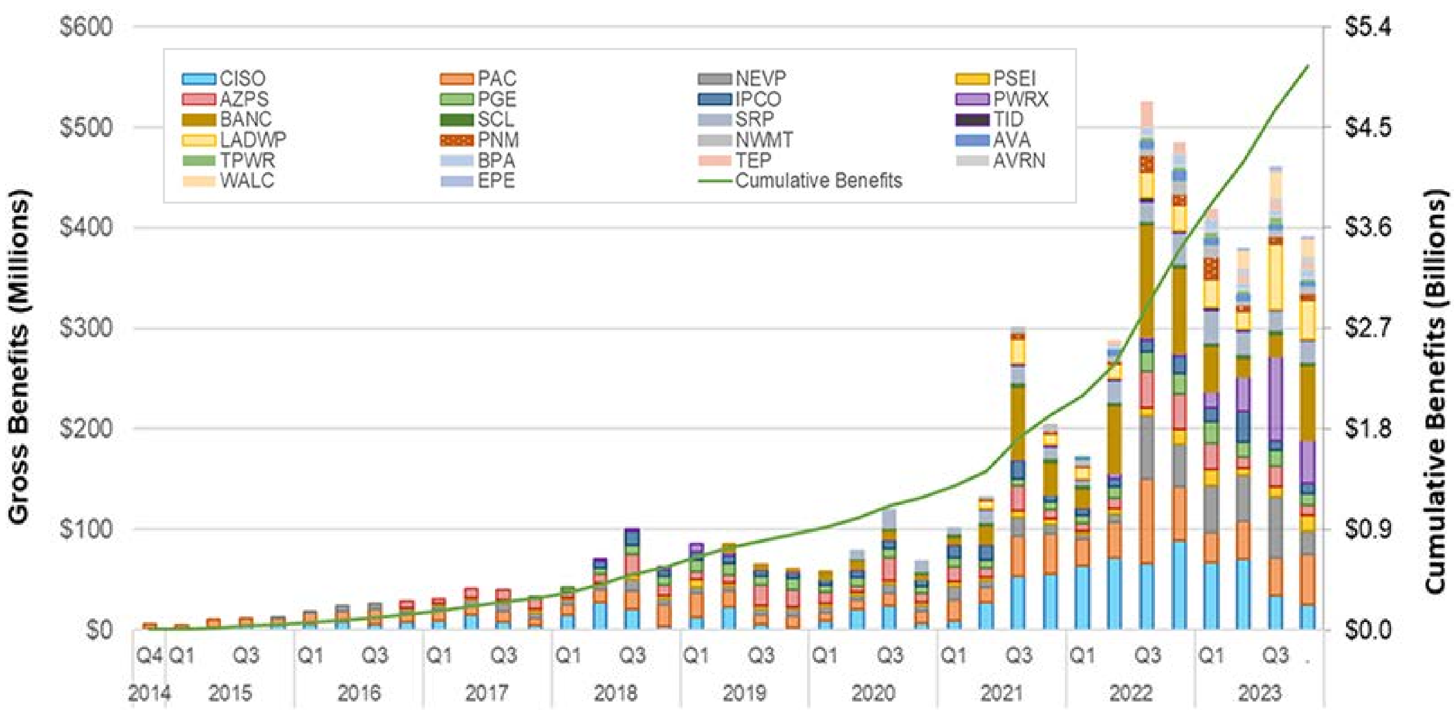
"The environmental benefits of the WEIM are very compelling, really helping to bend the cost curve for many," CAISO CEO Elliot Mainzer said during the Feb. 6 meeting. "We see an increasingly volatile system that's impacted by extreme weather and new resource development. That wide-area capability of the WEIM will continue to produce these tangible economic and environmental benefits."

Extreme Weather at Play

January's extreme cold snap in the Pacific Northwest demonstrated the WEIM's ability to deliver reliability, CAISO officials said at the meeting. During that weather event, California balancing authority areas were able to transfer energy to Northwest areas struggling to meet demand.

"The market's performance in 2023 shows how widespread cooperation among entities in the Western Interconnection reduces consumer costs and quickly sends energy where it's most needed during stressed weather conditions," Mainzer said. "The value of that broad transmission connectivity and resource diversity across the West as a reliability support mechanism continues to come into sharper focus."

A report analyzing how CAISO responded to extreme weather conditions in the Northwest in January is slated for the week of Feb. 19, Mainzer said. ■



WEIM benefits have been increasing quarterly, exceeding $5 billion through Q4. | *CAISO*

CAISO/West News

CEC Reduces Calif. Electricity Forecast on Lower Population Growth

But Agency Report Shows Electrification Driving Demand After 2033

By Elaine Goodman

Slower anticipated growth in California's population has prompted state regulators to downwardly revise the electricity demand forecast used for grid planning.

The reduced demand relative to a 2022 forecast is projected to continue to about 2033. But after that, the latest forecast shows a surge in demand compared to previous predictions, as the state's potential new requirements for zero-emission appliances are expected to kick in.

The forecast is part of the California Energy Commission's 2023 Integrated Energy Policy Report (IEPR). The proposed *final IEPR* will go to the commission for approval Feb. 14.

The CEC calls its California energy demand forecast "foundational" to state energy planning. The California Public Utilities Commission uses the forecast in overseeing energy procurement, while CAISO uses it in transmission planning.

Like previous forecasts, the CEC's new projections show a steep growth in statewide electricity demand due to California's rapid shift toward electrification of transportation and buildings.

Climate change is also expected to increase load, as heat waves are projected to become longer, hotter and more frequent, CEC said.

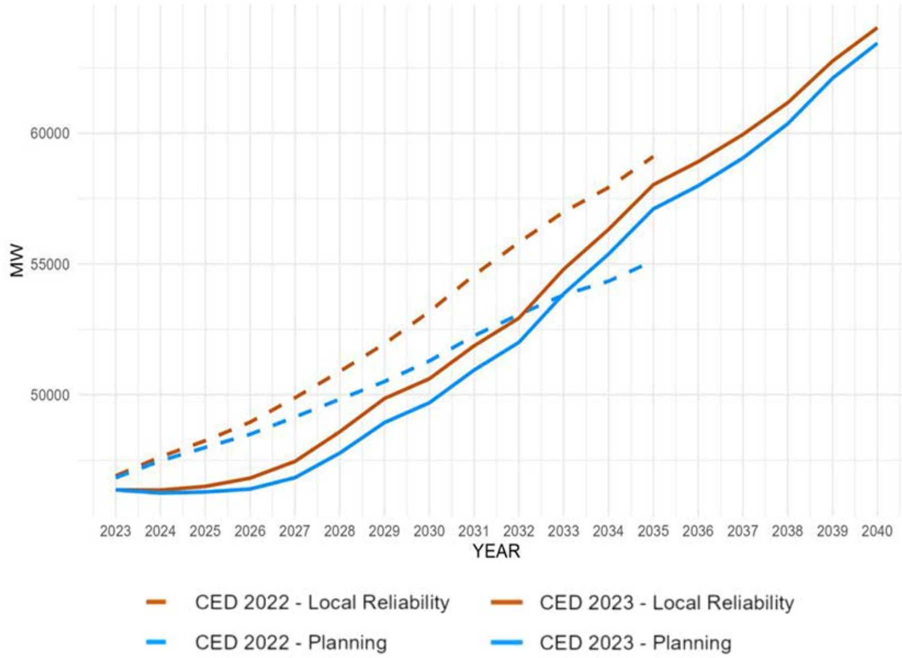
From the 2018 forecast to the 2022 forecast, the expected peak demand in 2030 increased by more than 5 GW.

Population Trends

In contrast, the latest forecast has revised energy demand downward compared with previous predictions — at least through about 2033.

The change is based on a statewide population growth of 0.2% a year, which is less than the previous projections of 0.4% annual growth. The slower expected population growth follows a state population decrease of about 0.5% in 2022. The population data come from the California Department of Finance.

"The slowdown in population growth can be attributed to slow in-migration and steady out-migration on top of an aging baby boomer population and declining fertility," the report said.



The CEC has reduced California's peak managed-system energy demand in its latest planning forecast through 2033, partly because of slower population growth expected in the state. | *CEC*

Other factors that contributed to a lower load forecast are anticipated electric rates that are higher than previously predicted, and projections of greater growth in rooftop solar generation.

But after 2033, projected load starts to rise above previously predicted levels. That's partly due to the expected impacts of zero-emission appliance rules that the California Air Resources Board (CARB) is considering.

Last year, CARB started holding workshops on the potential rules, which would apply to new natural gas-powered space and water heaters for residential and commercial buildings. If approved, the regulations are expected to become effective in 2030. (See *California Considers Zero-emission Appliance Rules*.)

2040 Peak Demand

The IEPR forecast shows CAISO peak demand growing by 1.8% a year and hitting 63,442 MW by 2040. CAISO's record peak demand is 52,061 MW, set on Sept. 6, 2022. Peak demand in 2023 was 44,534 MW on Aug. 16, the ISO *reported*.

The energy forecast also includes projections for managed electricity sales, in which customer generation is deducted from consumption.

The figures also factor in the projected impacts of energy efficiency, building electrification and transportation electrification.

Managed electricity sales are expected to grow from about 245,000 GWh in 2023 to 352,563 GWh in 2040. Solar generation is expected to hit 64,460 GWh by 2040.

CEC continually works to improve its energy demand modeling. For the 2023 forecast, CEC moved away from relying on historical data for its weather forecasts. The agency worked with Lumen Energy Strategy to incorporate global climate models into its projections.

CEC considers the impacts of regulations, policies and programs through an "additional achievable scenario" framework. Additional achievable load modifiers are applied for energy efficiency, transportation electrification and the fuel substitution that occurs with the shift to electric appliances.

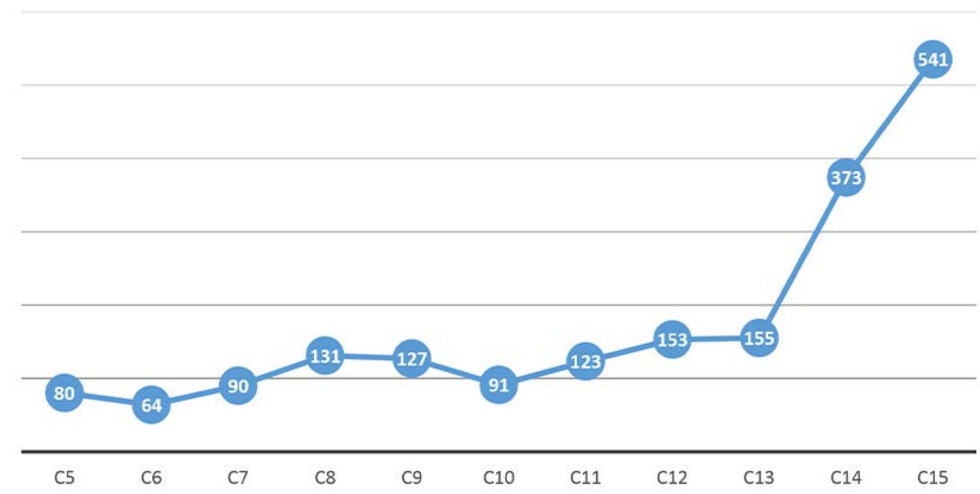
The forecast includes estimates of the impacts from planned data centers, as well as load growth from increased cannabis consumption.

Port electrification is "partially accounted for," CEC said. But electricity needed for hydrogen production is not included "because of the high uncertainty around the future of hydrogen," the report said. ■

CAISO/West News

CAISO Seeks FERC's OK to Shut 2024 Interconnection Window

By Robert Mullin



CAISO has seen a sharp increase in interconnection requests over its past two study periods, with cluster 15 representing over 350 GW of new capacity. | *CAISO*

CAISO is seeking FERC approval to scrap its process for taking on new interconnection applications this year as it works through the "unprecedented volume" of requests submitted for the previous interconnection study period.

CAISO's tariff requires it to open a new window for interconnection requests each year on April 1. But in a Feb. 8 *filing* with the commission, the ISO asked permission to forgo the process for 2024 to give it more time to study existing requests representing more than 350 GW of capacity — about seven times greater than CAISO's peak load.

"Adding new interconnection requests at this time would exacerbate current challenges and delay studies further," the filing stated. "Forgoing the 2024 window is a just and reasonable solution to prioritize the huge volume of existing interconnection requests on time."

Like other RTOs and ISOs, CAISO uses a "cluster" approach to dealing with interconnection requests whereby multiple resources are studied together to assess their impact on the existing grid and determine the need for transmission upgrades.

For each cluster of resources, the two-year process consists of a Phase I interconnection study that determines what interconnection facilities and reliability and delivery upgrades will be needed by each potential interconnection customer. A Phase II study refines the cost estimates in the first study "based upon changes in queue and deliverability allocation results," according to CAISO.

"Because the most common change in queue is an interconnection customer's withdrawal, both the Phase II interconnection study and the annual reassessment typically remove no longer needed upgrades from interconnection customers' studies and cost responsibilities, reducing costs," the ISO noted in its filing.

In the Cluster 14 window of 2021, the number of CAISO interconnection requests skyrocketed to 373, up 241% over the previous — record-setting — cluster. To manage the volume, the ISO was forced to cancel its 2022 interconnection window.

And on top of the sheer growth in volume, the ISO also saw that just 40% of resources dropped out of the queue after completion of the Phase I study, compared with a typical drop-out rate of 60%, which the ISO attributed to financial strength in the industry.

In 2023, Cluster 15 set yet another record, reaching 541 interconnection requests.

"Even accounting for the year without a cluster application window, Cluster 15's extreme volume represents the low bar to submit an interconnection request and the high level of financial opportunity in generation development," CAISO wrote in its filing. "Developers submitted these interconnection requests understanding they would face an extended study process and longer construction timelines. In [an] accurate but self-fulfilling prophecy, developers also submitted multiple interconnection requests because the CAISO would be unlikely to be able to open another interconnection request window in 2024."

CAISO last year proposed to forgo the 2024 interconnection window when it began its Interconnection Process Enhancements stakeholder initiative, but deferred to stakeholder wishes to hold off on that move.

"Since then, stakeholders and the CAISO have focused their efforts on necessary reforms to enable meaningful study of cluster 15. The CAISO subsequently reproposed deferring the 2024 interconnection request window. No developer, transmission owner or other stakeholder opposed the proposal," the ISO noted in its filing.

CAISO has asked FERC to approve the change effective March 31. ■

National/Federal news from our other channels

9 States Agree to Accelerate Home Heat Pump Installations

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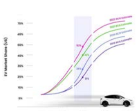

NERC Addresses Growing EV Risks in White Paper

ERO Insider

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CAISO/West News

WPP: Cold Snap Showed 'Tipping Point' for Northwest Reliability

Imports from Desert Southwest and Rockies Supported Northwest During Extreme Conditions

By Ayla Burnett

High imports from the Desert Southwest and Rocky Mountain balancing areas (BAs) helped the Northwest survive extreme weather from Jan. 12 to Jan. 16, showing the region's reliability is at a "tipping point," the Western Power Pool said.

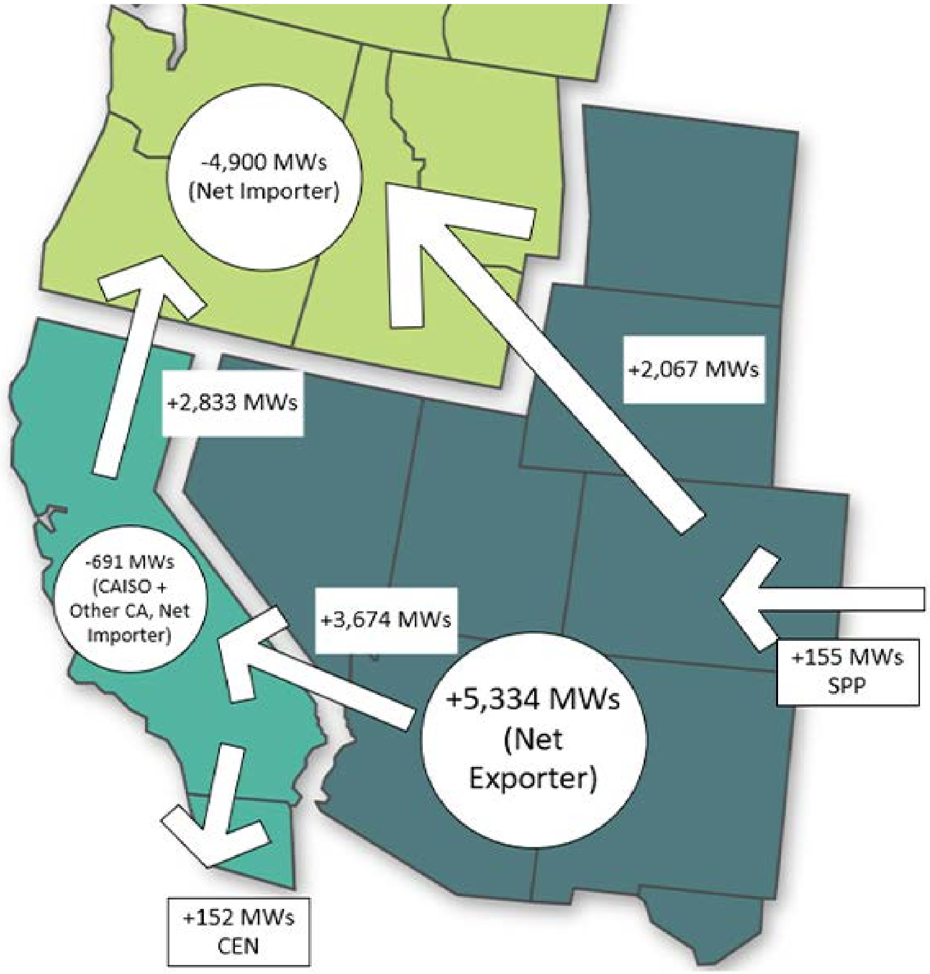
A *report* released by WPP on Feb. 8 outlined the actions taken by the RC West Reliability Coordinator and quantified the interchanges that allowed the Northwest to avoid outages.

BAs in the Northwest reported lower-than-normal temperatures for a sustained period, contributing to high loads and the need for imported energy. Starting the morning of Jan. 13 and lasting through the evening of Jan. 15, the reliability coordinator placed four entities in either an Energy Emergency Alert Watch (EEA), EEA 1 or EEA 3. The report said the Northwest imported an average of 4,900 MWh of energy per hour over five days, underscoring the continued call for an interregional resource adequacy program that can provide support across BAs during extreme conditions.

By summing and averaging interchanges between Northwest BAs and Nevada Power Co., PacifiCorp East and Western Area Power Administration, and Upper Great Plains West, the report found that 2,067 MW of power that was delivered to the Northwest originated from the Eastern/Rockies AC system.

Using the same interchange data, the report also demonstrated that while CAISO was exporting to the Northwest during this time, the ISO and other BAs were net importers, receiving more energy from the Desert Southwest than they were exporting to the North.

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



High net imports from the Desert Southwest and the Rockies supported the Northwest during January's cold snap. | *WPP*

Call to Action

WPP emphasized the need for initiatives like the Western Resource Adequacy Program to strengthen reliability during extreme weather events.

During the cold snap, "temperatures and loads were at or near historic peaks, BAs were managing through energy emergencies in real time and there was a significant amount of support required from BAs outside of the Northwest Region, particularly from the Desert Southwest and Rockies regions," the report reads. "All these factors point to the need to act quickly to address potential capacity challenges in the Northwest and realize the benefits afforded by full, binding implementation of a nearly WECC-wide resource adequacy program like WPP's WRAP."

CAISO is expected to release a report the week of Feb. 19 analyzing the response to January's extreme weather. ■

West news from our other channels

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ISO-NE News

ISO-NE Moving Forward with Prompt, Seasonal Capacity Market Design

FCA 19 Would be Delayed 2 Additional Years if New Capacity Market Design not Approved

By Jon Lamson

ISO-NE told the NEPOOL Markets Committee on Feb. 7 that it is *proposing* a major redesign to its capacity market, moving from a three-years-ahead schedule to a prompt and seasonal design.

To accommodate the change, the RTO is also proposing an additional two-year delay of Forward Capacity Auction 19 for the 2028/29 capacity commitment period (CCP).

FCAs are currently held more than three years prior to each CCP. ISO-NE is proposing to break up the CCP into distinct seasons and hold the capacity auction just several months before its start.

ISO-NE has been contemplating the move with NEPOOL stakeholders for several months and commissioned Analysis Group to study the proposed changes. The consulting firm recommended that the RTO make the move, writing that it would "support the transition toward a grid of the future." (See *Analysis Group Recommends Prompt, Seasonal Capacity Market for ISO-NE*.)

To provide time to complete the changes, ISO-NE is also proposing a "backstop" two-year delay of FCA 19 if the redesign is not approved by the time it is to be held in February 2026. FERC had approved a one-year delay of the auction to allow the RTO to implement its resource capacity accreditation (RCA) changes and contemplate the move to a prompt and seasonal market. (See *FERC Approves ISO-NE's One-Year Delay of FCA 19*.)

ISO-NE expects the MC to vote on the delay of FCA 19 in March. The RTO did not comment on when it would put the redesign before stakeholders.

Chris Geissler of ISO-NE said the changes would better prepare the region for the changing resource mix and demand profile. A prompt market would better reflect "demand and resource capabilities used to determine capacity awards, thereby producing more cost-effective outcomes," he said.

While New England's grid reliability risks have historically been concentrated in the summer, ISO-NE anticipates that winter will surpass it in the coming years with the increase in heating and transportation electrification. Geissler said a seasonal market would help the region prepare for this shift because it "more accurately accounts for seasonal differences in resources' supply capabilities and forecast energy demand."

Geissler also highlighted some design components that have yet to be determined. These include when exactly the prompt auction would be held, the number and length of the seasons, and whether seasonal auctions would be held separately or all at the same time.

A prompt and seasonal market would also mean significant changes to the resource retirement process, which is currently connected to the FCM, Geissler said. While ISO-NE could decouple the retirement process from the capacity market to maintain the current retirement notice timeline, a shorter timeline could provide some benefits, he said.

"ISO plans to prioritize evaluating retirement process reforms, including tradeoffs between shorter and longer time frames, and to discuss its recommendations with stakeholders early in the prompt/seasonal design discussions," Geissler said.

Geissler noted that the proposal "includes language allowing resources with early in-service dates to submit qualification materials in 2025 and 2026" to allow them to quantify for earlier reconfiguration auctions.

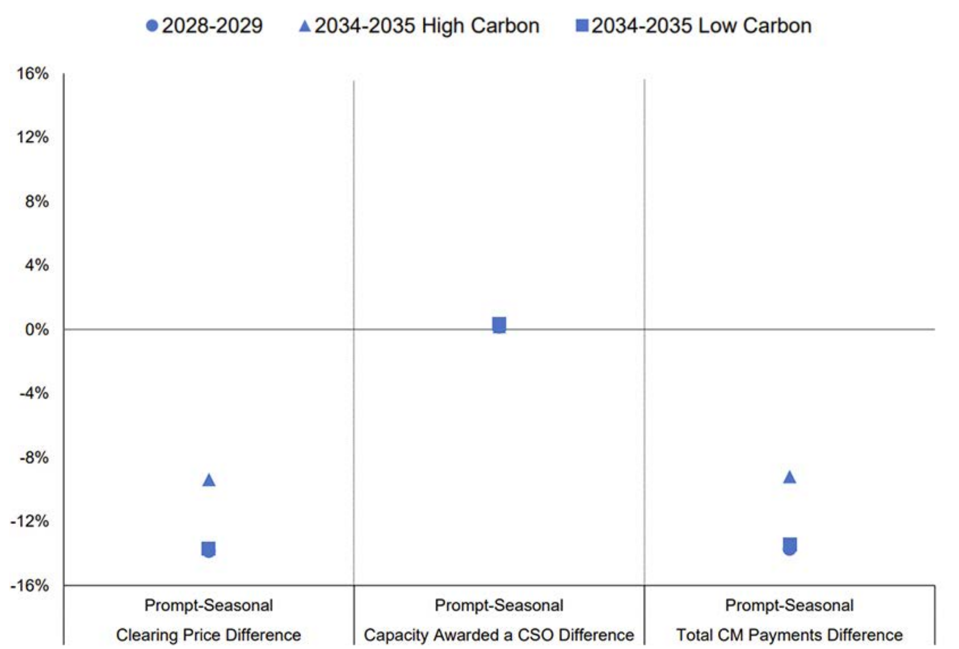
In a public *letter* to ISO-NE issued in mid-January, Jamie Donovan, an analyst in the Energy and Environment Bureau of the Massachusetts Attorney General's Office, expressed support for a seasonal market but said the AGO is "still weighing the tradeoffs of a prompt market."

Donovan added that the AGO is concerned "that the expanding scope of capacity reforms could increase project implementation risk and [about] the difficult situation that could arise if FCA 19 is further delayed for the development of a prompt/seasonal market design that is not completed in time or rejected by FERC."

Once stakeholders have voted on the additional delay, "we encourage the ISO to release as much of its impending market design as quickly as possible for stakeholder review and feedback," Donovan said.

Alex Lawton of Advanced Energy United said the organization is "concerned that this change is moving forward without sufficient stakeholder discussion."

"There are several important concerns that will not be addressed until after stakeholders are asked to vote on the issue," Lawton said. He added that the organization would like to see more analysis on how the transition would impact price formation and "whether a prompt market can adequately incentivize new resource entry without the three-year forward price lock under the status quo." ■



Projected cost savings of a prompt, seasonal market compared to the current FCA | *Analysis Group*

ISO-NE News

NEPOOL Markets Committee Briefs

Resource Capacity Accreditation Impact Analysis

ISO-NE on Feb. 6 presented the NEPOOL Markets Committee with the *initial results* of the RTO's Resource Capacity Accreditation (RCA) impact analysis modeling, providing a preliminary look at how the changes will affect the accreditation values and capacity market revenues of different resource classes.

The initial results showed that the accredited capacity value of the entire resource mix decreased by about 17%. The resource classes generally boosted by the RCA updates include wind, energy efficiency and hydro. Accreditation values also increased slightly for dual-fuel gas and oil resources, as well as for a broad category of nonintermittent resources including nuclear, coal, wood, municipal solid waste and landfill gas.

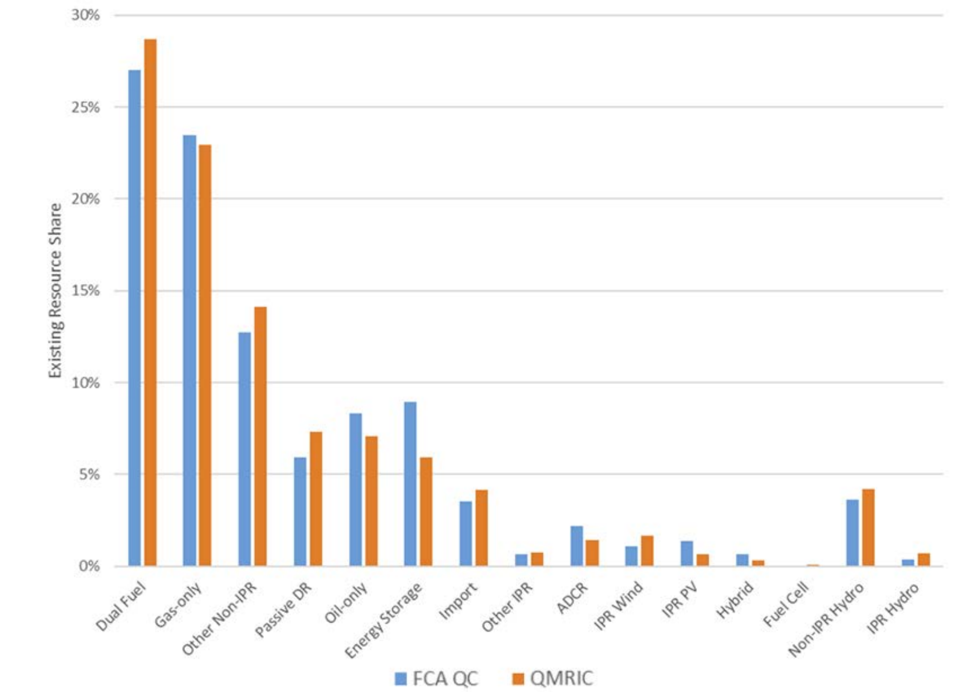
In contrast, the RCA changes would significantly decrease the accredited capacity of oil-only, battery storage, active demand response and solar resources. Gas-only resources would also take a modest hit.

ISO-NE's Dane Schiro noted that the resource class impacts are aggregations. He highlighted some of the main factors that could impact an individual resource's accredited capacity.

For thermal resources, having a high rate of historical forced outages was generally a significant factor in the loss of accreditation. Resource size also plays a role: Smaller thermal resources typically have higher accreditation values, because a forced outage of a smaller resource is less likely to cause shortfalls.

The accredited capacity of storage resources depends largely on duration, Schiro said. For intermittent resources like solar and wind, higher accreditation values will go to resources that typically produce energy during the times it is most needed.

As the resource mix and the timing of reliability concerns continue to shift, the capacity values and revenues for different resource classes will also shift. While ISO-NE assessed that about 80% of the loss-of-load risk occurs in the summer, the shift in risk toward winter will likely increase the annual accreditation values of resources that perform better in that season.



Projected effects of the RCA project on resource share of accredited capacity | *ISO-NE*

In March, ISO-NE is planning to present to the MC the results of modeling sensitivities related to the resource mix and load profile and will detail how these factors affect accreditation values.

Nonfirm Gas Modeling Concerns

Pallas LeeVanSchaick of Potomac Economics, ISO-NE's External Market Monitor, *outlined* for the MC some concerns about the RTO's proposed approach to accrediting non-firm gas capacity.

ISO-NE said at the previous MC meeting that a "market constraint approach" that would limit the total amount of capacity available to gas resources would be its preferred method, but it said this method "is not implementable" for Forward Capacity Auction 19. (See *NEPOOL Markets Committee Briefs: Jan. 11, 2024*.)

LeeVanSchaick said ISO-NE's proposed interim "derating approach" will likely overaccredit nonfirm gas resources, reducing the incentives for firm fuel contracts that would increase winter reliability.

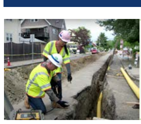
He proposed that ISO-NE should instead "estimate the marginal reliability impact (rMRI) of nonfirm gas-fired units in the same manner as other resource types," and accredit capacity using an rMRI floor "that would be sufficiently high to ensure available nonfirm gas is fully utilized in periods of reliability risk."

The Massachusetts Attorney General's Office expressed concerns in a January letter to the RTO that its proposal would overaccredit nonfirm gas resources while showing interest in expediting work on a market constraint approach.

"The opportunity to bypass ISO's transitional derating approach would be a substantial benefit to the development of a seasonal capacity market proposal for FCA 19," the AGO wrote. ■

— Jon Lamson

Northeast news from our other channels



Mass. Gas Working Group Finalizes Recommendations to Legislature

NetZero Insider

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Early MTEP 24 Designates $5.5B in Transmission Spending

By Amanda Durish Cook

MISO revealed last week that its draft 2024 Transmission Expansion Plan calls for $5.5 billion in projects, with the South region again accounting for some of this year's most expensive projects.

MISO has a $5.5 billion, 453-project portfolio in its hands thus far under MTEP 24, stakeholders learned over a series of subregional planning meetings last week. The draft MTEP 24 represents a more typical investment amount for MISO's annual transmission cycle on the heels of the record-breaking, $9 billion MTEP 23.

However, MISO South transmission owners are continuing last year's trend of recommending costly local projects.

MTEP 24 contains $793 million in generator interconnection projects, $904 million in baseline reliability projects needed to meet NERC criteria and almost $3.8 billion in "other" projects, or projects needed to address load growth, the age and condition of existing facilities and transmission owners' self-imposed reliability criteria.

MISO said the 10 most expensive projects account for 26% of the total proposed MTEP 24 costs, with seven located in MISO South.

MTEP 24's costliest baseline reliability projects either rebuild or construct lines and substations in the South. The portfolio also includes projects to meet load growth in central Mississippi. The central part of the state is positioned for even more load growth, with Entergy *announcing* it will power two data centers totaling $10 billion for Amazon Web Services, Amazon's cloud technology subsidiary.

"Again, we have a big year in the South," Trevor Armstrong, manager of MISO South's expansion planning, said during a Feb. 8 South Subregional Planning meeting.

Armstrong said most of the generator interconnection upgrades in the South region are intended to connect new solar farms.

Amanda Schiro, MISO senior manager of expansion planning, attributed some of the continued uptick in MISO South projects to load growth while working around the South's webbing of load pockets.

Schiro said MISO will select some projects for project alternatives study, though it hasn't decided which projects warrant further analysis. She said MISO will keep stakeholders informed on which projects are getting a second look.

"We are looking for more efficient solutions, potentially larger solutions to replace some local projects," Schiro said during a Feb. 5 Central Subregional Planning meeting.

A future Amazon data center megasite on the campus in Madison County, Mississippi | *Entergy*

However, at a Feb. 6 West Subregional Planning meeting, Expansion Planning Manager Zheng Zhou said there are "limited opportunities" to devise alternatives for some project categories, such as load growth, age and condition replacements, and smaller projects, such as breaker replacements.

Some stakeholders urged members to upgrade to advanced conductors when completing age and condition projects. They said using state-of-the-art conductors on replacement projects will save money in the long run.

MISO will continue to evaluate part of a project Entergy submitted last year to meet load growth in the Amite South load pocket in southeast Louisiana under MTEP 24. MISO made a substitution on the first section of Entergy Louisiana's nearly $2 billion, three-part Amite South reliability project during MTEP 23 and delayed approval of the third portion of the project until it can vet project substitutes. (See *MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects*.)

So far, MISO hasn't landed on a satisfactory alternative to part three of Amite South project, but it's still searching.

"At this point, we're performing longer-term studies to see how it fits in with the phase one and two portions of the project," Armstrong said.

Schiro said last year's MTEP represented the largest investment in the South region since its integration 11 years ago. She also said MTEP 23 saw a record-breaking number of generator interconnection queue applications.

Over 2023, MISO developers struck generator interconnection agreements for 69 projects and withdrew 145 projects.

More withdrawals are all but certain. For the 2021 cycle of generation projects wishing to connect in MISO South, MISO's studies show $14.5 billion in network upgrade costs is needed. MISO said South region generation projects currently face around $100 million apiece in interconnection costs.

MISO's current generator interconnection queue consists of 1,379 projects totaling 237.1 GW. Those figures don't yet include the 2023 class of project submittals. MISO has put those entries on hold until March while it implements new, stricter queue rules meant to discourage speculative generation projects. (See *MISO to Try Again for Interconnection Queue MW Cap, Open Window for 2023 Requests*.) ■

MISO News

MISO Asks Court for Injunction Reversal on Iowa LRTP Projects

RTO Says FERC Should Oversee Any Change in Developers

By Amanda Durish Cook

MISO has waded into the battle over who will build the Iowa portions of its long-range transmission projects two months after a court found the state's right-of-first-refusal law unconstitutional.

The RTO filed an amicus brief in the case, asking the Polk County District Court to lift an injunction that halted regulatory permitting for long-range transmission plan (LRTP) lines that incumbent developers ITC Midwest, MidAmerican Energy and Cedar Falls Utilities elected to build under the ROFR law (*CVCV060840*).

The District Court in December struck down Iowa's ROFR law and prohibited regulatory permitting on Iowa's portion of five of MISO's LRTP projects in which incumbent developers had benefited from the law. The ruling cast doubt on $2.6 billion in already approved LRTP projects located at least partly in Iowa. (See *Iowa ROFR Law Overturned, Throwing Multiple MISO LRTP Projects into Uncertainty*.)

Since then, competitive developer LS Power has asked the court to reverse MISO's assignment of the Iowa projects to the incumbent developers after the ROFR was deemed unconstitutional. LS Power challenged the ROFR's validity in the first place, arguing it was shut out of the bidding process.

MISO said while it doesn't take a position on the legitimacy of the ROFR, it is asking the court to reconsider the injunction against permitting, given that the planned lines are needed for the sake of grid reliability. The grid operator also argued the District Court's interference with the line development is improper because FERC is best situated to handle who is allowed to build the lines pursuant to the MISO tariff.

MISO said it has a "strong and substantial interest" in making sure the LRTP projects in Iowa are built by the 2028-2030 time frame. The RTO said while the four- to six-year span seems like a long time, 345-kV line construction is a lengthy process that requires "timely permitting" to achieve targeted in-service dates. It emphasized that benefits stemming from its $10 billion LRTP portfolio will cover costs and save billions more in reliability advantages and access to new generation across the Midwest. MISO added that the LRTP lines' benefits are premised on the lines operating as a whole.

A 345-kV MISO multivalue project ITC Midwest completed near the Iowa-Minnesota border in 2017 | *ITC Midwest*

"The injunction in question in this case, if sustained, would stand as an obstacle to timely completion of much-needed transmission to serve not only Iowa but the region as a whole," MISO wrote to the court in its Feb. 6 brief. "MISO strongly urges this court to revisit its prior decision regarding the subject injunction in light of these factors and circumstances to avoid potentially ruinous practical public policy consequences."

MISO said if the injunction is allowed to stand, current and future long-range transmission planning will be put at risk.

'Impermissibly Intrudes'

The grid operator also said the court's December injunction "impermissibly intrudes on the FERC's exclusive authority over the transmission of electric energy in interstate commerce under the Federal Power Act." It said the court "should not disrupt the timely completion of these projects in pursuit of a remedy that only FERC may grant" and added that only FERC has the authority to interpret the MISO tariff.

MISO said while LS Power can argue that it was deprived of the opportunity to bid on the lines' construction and suffered economic harm due to the ROFR law, "whatever harm LS Power may potentially suffer is not as severe, concrete and particularized as the harm energy users, energy providers, MISO and its affiliates may suffer."

FERC, MISO argued, is in the best position to assess competing claims to the lines' construction, weigh how changes and delays to the lines will impact all parties, and order remedies. The RTO said LS Power already has "an effective federal remedy" through FERC and is free to argue before the commission that MISO's assignment of the Iowa LRTP projects to the incumbents violated its tariff in light of the unconstitutionality holding.

"The public policy interests at stake, the balance of the harms as between the parties involved (and as to MISO), in the context of the nature and gravity of the vital regional utility grid issues at stake, make this matter ideal for judicial reconsideration as requested," MISO wrote.

At a Feb. 7 MISO Advisory Committee meeting, Clean Grid Alliance's Beth Soholt said she believed the Iowa ROFR ruling affects more than just the Iowa line segments in the first LRTP portfolio.

Soholt said the delays and uncertainty could bleed over to impede progress on MISO's second LRTP portfolio, which is in the works.

"I think it's very important for MISO to be [as] transparent as possible about the impacts and what that does to the study process of follow-on lines. … It's a really major thing if we start having cascading timing issues. A lot of states are counting on these transmission buildouts," Soholt said.

MISO Deputy General Counsel Kristina Tridico said the RTO will contemplate the most appropriate venue to share new information on the status of the Iowa projects with stakeholders.

Tridico said MISO will defer to the court's decisions on the matter and understands the court's actions stand to affect the planning and timely completion of LRTP lines. She said the RTO hopes to convey the importance of the LRTP lines in its brief. ■

MISO News

OMS, OPSI Urge MISO, PJM to Invigorate Interregional Planning

By Amanda Durish Cook

The state regulatory organizations for both MISO and PJM have sent a letter to the RTOs asking them to redouble efforts around interregional transmission planning.

The Organization of MISO States (OMS) and the Organization of PJM States, Inc. (OPSI) penned a joint letter to MISO and PJM, telling them the time is right to initiate long-term interregional transmission planning. The letter was signed by the presidents of OMS and OPSI and addressed to the RTOs' Interregional Planning Stakeholder Advisory Committee. MISO South state agencies didn't participate in the letter.

"The transition from dispatchable thermal generators to intermittent, clean energy resources, and a surge in electric demand raise challenges to PJM, MISO and their interconnected neighbors' ability to reliably and cost-effectively support one another when called upon," OMS and OPSI wrote.

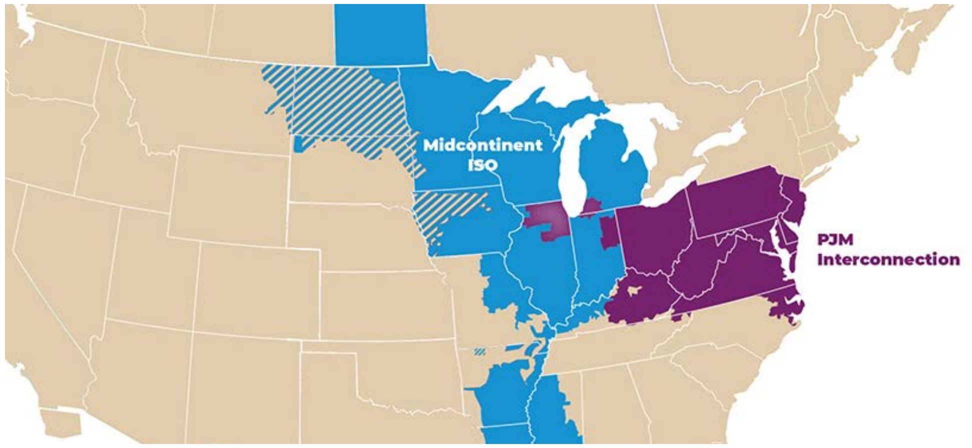
The organizations said their concerns are heightened by increasingly common severe weather. They said MISO and PJM were "heavily dependent" on one another's resources while importing and exporting to other neighboring regions during the December 2022 arctic blast. They also said last August's heatwave forced MISO to import roughly 8.5 GW from PJM and Manitoba.

"While these events were managed, the growing frequency of these events and shrinking capacity reserves in each footprint [have] the potential to disrupt electricity supplies, which in turn disrupts the economy and may put public health and safety at risk. Expanding transfer capacity between regions can help to improve grid resilience and minimize the negative impacts of extreme weather events,"

OMS and OPSI pointed to the U.S. Department of Energy's recent National Transmission Needs study, FERC considering a rule to establish a minimum transfer capability between regions and Congress tasking NERC with studying interregional transmission capacity.

"With these factors in mind, OPSI and the OMS urge PJM and MISO to begin to explore joint long-term interregional transmission planning between their footprints while maintaining a focus on affordability and identifying optimal solutions," the organizations wrote.

The two said MISO and PJM should jointly



MISO and PJM's borders | *ISO/RTO Council*

model their systems, work with state regulators to agree on reliability and policy objectives, and borrow from their existing long-term planning to devise an interregional process.

"Both of our organizations have a renewed focus on interregional planning," OMS Executive Director Marcus Hawkins said during a Feb. 7 MISO Advisory Committee teleconference.

RTOs Respond

MISO responded that it's always looking to improve its planning processes, including interregional planning.

"MISO has a long history of performing coordinated interregional transmission planning with its neighboring grid operators. Interregional planning helps us identify projects that improve the system's ability to mitigate constraints, respond to extreme weather and increase interregional transfer capability," spokesperson Brandon Morris said in an emailed statement to *RTO Insider*.

Morris said MISO appreciates the regulators' input and looks forward to "enhancing our work with our neighboring transmission planning partners while balancing our staffing needs to identify and move forward the regional and interregional solutions needed to respond to the evolving resource mix."

PJM spokesperson Jeffrey Shields said PJM already engages in healthy collaboration with its neighbors to identify congestion-relieving and reliability-boosting projects, as outlined in the MISO-PJM joint operating agreement.

In an emailed statement to *RTO Insider*, Shields said PJM has significant export capability, as evidenced by the 12 GW in exports PJM flowed to neighbors at the height of the mid-January arctic blast.

"At the same time, PJM is committed to working with MISO and others to determine if more should be done with interregional transmission. That discussion is ongoing," Shields said. "PJM believes that the best way forward is with analysis on how best to define whether and what level of transmission solutions are needed to ensure sufficient interregional transfer capability. We need to understand very clearly what the problem is that we're solving for before committing significant investments that will be borne by customers."

Shields said while a minimum transfer capability is "sensible," interregional planning should not become a substitute for RTOs maintaining adequate reserve margins.

"If all of our regions are hit with the same winter storm, the results could be very harmful to consumers," he said.

The grid operators will address the regulatory organizations' request again at the March 1 *teleconference* of their Interregional Planning Stakeholder Advisory Committee.

MISO and PJM have approved one large *interregional market efficiency project* in 2020 and four sets of *smaller* transmission projects aimed at relieving congestion since 2017. The two haven't completed an interregional transmission planning study since 2022.

In a report last year, the American Council on Renewable Energy concluded MISO and PJM could save their ratepayers $15 billion over a little more than a decade if they dedicated more resources to planning interregional transmission. (See *New Report Finds MISO, PJM Could Save Billions Through Interregional Tx Expansion*.) ■

MISO's MSC to Debate Multiday Gas Requirements

By Amanda Durish Cook

| MidAmerican Energy Co., Berkshire Hathaway Energy

MISO's Market Subcommittee likely will devote some time this year to discussing either a multiday gas purchase requirement or a multiday gas unit commitment process for use during extreme cold.

The RTO's Steering Committee tasked the Market Subcommittee with consideration of the topic during a Feb. 6 teleconference. The issue was originally brought to the Steering Committee by member MidAmerican Energy.

In a written request, MidAmerican Energy's Dennis Kimm said MISO should either introduce a multiday unit commitment process or adopt a requirement that natural gas generators buy fuel when weather is forecast that will send gas and electricity demand soaring. Kimm said the multiday commitments or natural gas procurements should not be used during normal operations.

Kimm said generators "undertake a significant economic risk in executing purchases for fuel and capacity without a guarantee that the generator will be dispatched." He wrote that uncertainty regarding MISO dispatch "can act to discourage participation in the natural gas marketplace during times of greatest liquidity."

MISO reported experiencing gas supply challenges, resulting in reduced generator availability, during the mid-January cold front that played out over a holiday weekend.

Kimm said some advance notice from MISO on what it plans to call up would "increase flexibility for natural gas-fired generators to obtain fuel and better situate the electric industry to adequately plan and prepare to deliver reliable service" during extreme cold.

But Executive Director of Market Operations J.T. Smith seemed unconvinced multiday commitments would improve natural gas generators' performance issues during cold spells. He said a more successful approach would include better offers that reflect true capabilities, take into account lead times and consider temperatures and fuel procurement.

Smith said he understands generation owners want certainty, but there's a "hesitancy from the membership" to provide true startup times and realistic availability of their generation in the market because it would harm their capacity accreditation values.

Smith said during cold snaps — including the latest widespread mid-January deep freeze — "we don't get offers from our generators that reflect true availability."

Smith said the optimization in MISO's day-ahead market already gives owners and operators the signals to make commitment decisions days ahead of a weather event.

"In my mind, the multiday market already exists," Smith said, adding he was "not so sure the problem" could be solved through MISO developing a new commitment model or fuel purchase requirement.

"Give me a valid offer of your true availability capabilities first," he said.

Smith also said the topic likely contains resource adequacy implications that may need to be hashed out at the Resource Adequacy Subcommittee, in addition to the Market Subcommittee. ■

NYISO News

NYISO to Pause New Interconnection Requests for 3 Months in Order 2023 Transition

By John Norris

RENSSELAER, N.Y. — NYISO on Feb. 6 *presented* the Interconnection Issues Task Force (IITF) with its plan for transitioning to its new generator interconnection procedures under FERC Order 2023, including a nearly three-month pause on accepting new interconnection requests.

The pause would begin April 4, one day after NYISO's deadline to file its full Order 2023 compliance proposal with FERC. The commission last month approved a partial compliance filing that allows developers to opt in to certain studies that will be eliminated under the new rules. (See *FERC Approves NYISO Waiver on Interconnection Study Requirements*.)

The ISO would then begin accepting applications into a transitional cluster July 1, until Oct. 15; work on processing the projects would begin Jan. 15, 2025, with a goal of finishing by April 20, 2026.

The "first official study" under Order 2023 would then begin on May 1, said Sara Keegan, NYISO's assistant general counsel, "but we're still looking at this start date and how to actually tie it into the end of the [transitional study], so this is still a bit of an unknown."

Keegan highlighted the possibility of changes to the proposed transition timeline because of the "inherent risks" associated with any FERC filing. She said FERC "does not have a deadline by which they have to act," so should the commission not issue a timely ruling or require additional compliance requirements, "things could unravel" and necessitate adjustments to the proposed dates.

Inverter-based resource with electronic power converter | *Claus Ableiter, CC BY-SA 3.0, via Wikimedia Commons*

NYISO is "approaching this filing carefully," Keegan said, and it "appreciates the frustration" from developers who are apprehensive about the transition, especially those either with projects already in the interconnection queue as part of class year 2023 or considering having their projects participate in the transitional cluster.

Keegan discussed other adjustments to NYISO's interconnection procedures during the IITF meeting, which will eventually be in tariff *Attachment HH*. This proposed attachment will consolidate existing interconnection requirements from *Attachment S* (rules to allocate responsibility for the cost of new interconnection facilities), *Attachment X* (standard large facility interconnection procedures) and *Attachment Z* (small generator interconnection procedures), along with the new processes. The attachments will remain in NYISO's tariff for the limited purpose of completing CY23 projects and facilitating the transition.

The ISO also posted a *redline* of Attachment HH, incorporating stakeholder feedback since the last IITF meeting.

NYISO will return to IITF stakeholders multiple times before the April 3 filing deadline to review and finalize the proposed tariff language. ■

PJM News

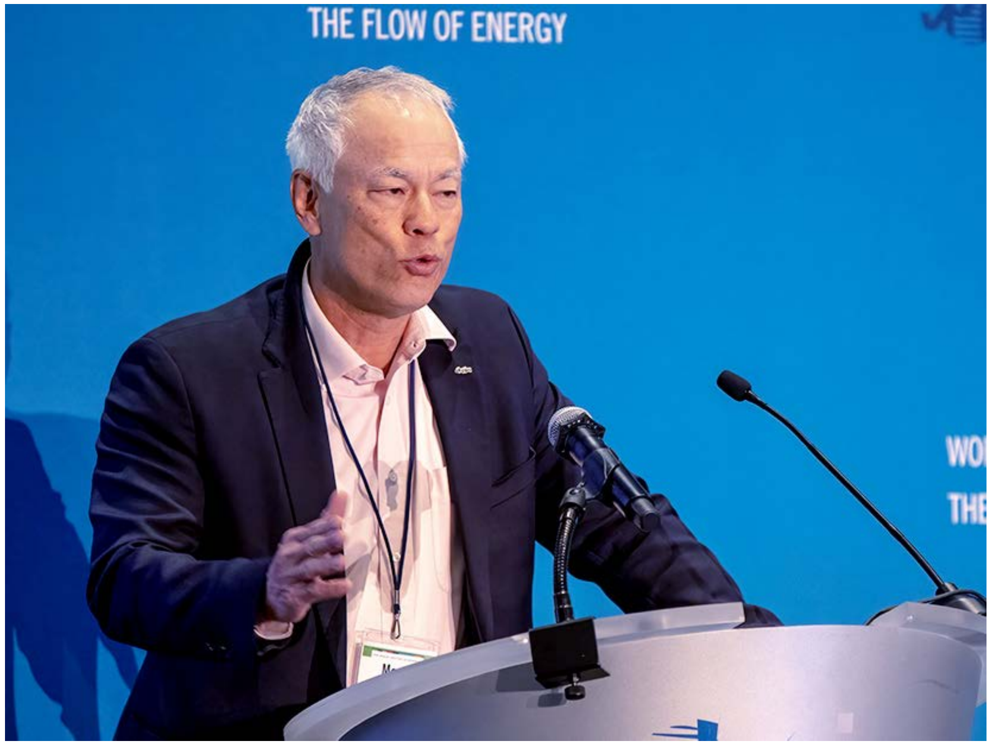
FERC Rejects Changes to PJM Capacity Performance Penalties

By Devin Leith-Yessian

FERC on Feb. 6 rejected a PJM proposal to rework the role of performance penalties in its capacity market and how the associated risks can be reflected in seller offers (*ER24-98*).

The filing was one of two the RTO made in October after the conclusion of the Critical Issue Fast Path (CIFP) process, largely focused on market issues highlighted by December 2022's Winter Storm Elliott and PJM's February 2023 "*4R's Report*." The commission approved the second filing last week, greenlighting changes to how PJM measures reliabilities risks, accredits capacity resources and verifies generators' ability to operate throughout the delivery year (*ER24-99*). (See *FERC Approves 1st PJM Proposal out of CIFP*.)

In splitting the changes the Board of Managers sought to make after the CIFP process into two filings, PJM Senior Counsel Chen Lu said staff sought to ensure that components that relied on each other were accepted or rejected as a package and to avoid potentially riskier elements from sinking the entire proposal.



PJM Board Chair Mark Takahashi | © *RTO Insider LLC*

At the heart of the filing was how market sellers can represent the risks they face in taking on a capacity obligation through the Capacity Performance quantified risk (CPQR) component of their capacity offers; how those values are reviewed by Independent Market Monitor and PJM; and under what circumstances generators can be assigned penalties for underperforming or receive bonuses for overperforming.

During the Market Implementation Committee's meeting Feb. 7, PJM's Skyler Marzewski said the RTO does not plan to seek a delay of the 2025/26 Base Residual Auction scheduled to be conducted in June. Both CIFP filings were intended to be effective for the auction, and Marzewksi laid out a *timeline* for when PJM plans to seek endorsement of several manual changes to implement the proposal approved in ER24-99.

FERC's Order

FERC said that PJM had not provided enough detail around how it planned to implement the changes and sought to give the RTO guidance on changes that might be beneficial if it sought to refile the proposal.

In rejecting PJM's plan to largely redefine the market seller offer cap (MSOC) based on CPQR and costs incurred to avoid those risks, FERC said that the proposal failed to define what qualifies as the sort of incremental cost that a generator could include in its offer versus actions that generation owners would have taken in the absence of a capacity commitment.

"PJM does not include in its pleadings or proposed tariff provisions a defining principle to identify and differentiate costs incurred only in the absence of a capacity obligation compared to costs incurred in whole or in part for some other purpose, such as to enhance EAS [energy and ancillary services] revenues," the commission wrote. "PJM's proposal seems to require PJM to employ a subjective assessment as to the intentions underlying complex investment decisions of sellers participating in a variety of markets, i.e., the capacity, energy and ancillary services markets, and bilateral transactions."

The commission also said it saw merit in PJM's proposal to create a standardized calculation for CPQR that incorporates unit-specific parameters that market sellers could accept or substitute with their own determination. But without FERC, the Independent Market Monitor and stakeholders having access to the proprietary model it sought to utilize, it would not be possible to understand what a valid CPQR value would be, it said.

"Though we have found that PJM has not provided sufficient detail to understand how the model components would be implemented in its proposed standardized CPQR formula, using a probabilistic model with unit-specific data would ensure a CPQR value that is specific to that resource and its risk profile," FERC said.

PJM sought to provide more certainty of the costs that market participants could include in their CPQR submissions by introducing a third-party review process where sellers could include a review by a qualified, independent party and include that as documentation in support of their submissions. The commission found that the existing tariff language already supports that process and that the proposal would create a requirement that PJM and the Monitor accept the results of that outside review. FERC also raised questions of how PJM would define the qualifications that the third party must possess and how to ensure independence from the market seller whose offer it is reviewing.

"In other words, it would require PJM to automatically accept any third-party consultant justification regardless of reasonableness. We find that such a requirement would not be just and reasonable because it would delegate responsibility that belongs to PJM and the

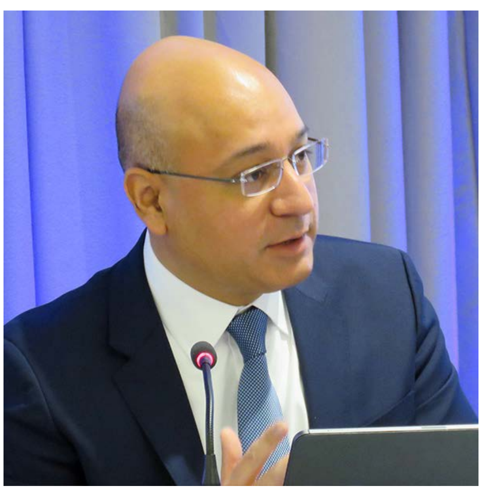
PJM News

Market Monitor to third parties. The commission has found it is inconsistent with the principles of mitigation to allow sellers with market power to determine their own costs without review."

FERC rejected PJM's proposal to allow it to calculate an alternative MSOC using the information submitted by the market seller if the RTO determined that the one submitted after the review process conducted by the Monitor did not conform to the tariff. The tariff only empowers PJM to accept or reject the offer cap submitted by market sellers, which the RTO argued leaves its hands tied when it agrees with parts of an offer, but not the entirety.

The Monitor argued that granting PJM the ability to calculate its own offer cap would impinge on its prerogative in reviewing offers for market power, a position the commission cited in denying the filing. FERC pointed to Order 719 in finding that external monitors have the expertise and means to identify and mitigate market power and provides them with the sole authority to make market power determinations.

"We share commenters' concerns that under PJM's proposal, the Market Monitor would not be able to provide meaningful feedback because PJM would replace the Market Monitor's role in calculating offer caps, which could undermine the Market Monitor's duty to ensure competitive markets," it said.



PJM CEO Manu Asthana | © *RTO Insider LLC*

The proposal would have also created a new exception generation owners could claim to avoid being assigned Capacity Performance (CP) penalties by exempting generators not dispatched during a performance assessment interval (PAI) on a market-based offer that exceeded their cost-based offer. PJM argued that resources following dispatch instructions should not be penalized, but the commission sided with protests arguing that the change would allow generators to avoid being subject to CP by submitting offers that are unlikely to be committed.

"We agree with the Market Monitor that, with respect to nonperformance charges, there is no meaningful difference between resources that choose to submit market-based offers using relatively less flexible parameters than their cost-based offer or market-based parameter-limited offer, and those that choose to submit market-based offers using relatively higher economic parameters than their cost-based offers. Both strategies would constitute a capacity resource failing to meet its obligation to perform during an emergency and, therefore, require appropriate penalties," the commission wrote.

FERC also rejected PJM's proposal to limit eligibility for CP bonus payments, which are paid out from the pool of penalties collected following PAIs, to committed capacity resources. It pointed to comments from the PJM Industrial Customer Coalition, which said that about 40% of the overperformance seen during Winter Storm Elliott came from market sellers lacking a capacity commitment. Making such resources ineligible would remove an incentive for all resources to be prepared to operate during emergencies and limit the solutions available to maintain reliability during stressed system conditions.

FERC Commissioner Allison Clements | © *RTO Insider LLC*

Clements Partially Dissents

In a partial dissent, Commissioner Allison Clements said she agreed with the bulk of the order but disputed the majority's reading of Order 719 in relation to PJM's proposal.

Rather than making market power determinations, she said that the changes would have given PJM flexibility in considering whether an offer complies with the tariff, arguing that the "Monitor plays an important but circumscribed and advisory role under PJM's offer cap rules."

Clements also disagreed with the majority in rejecting PJM's request to eliminate the physical replacement option for fixed resource requirement (FRR) entities who underperform. Instead of incurring financial penalties, such entities can choose to procure additional capacity for one year. PJM argued the option lacks the teeth of immediate financial penalties by deferring the costs and results in a smaller economic impact.

Clements wrote that PJM's difficulty incentivizing resources to perform during extreme weather makes it reasonable to create FRR penalties that are more in line with those used in the Reliability Pricing Model. ■

PJM News

Ex-PUCO Chair, Ex-FirstEnergy Execs Indicted in Ohio

State Fraud, Bribery Charges are Latest Fallout from H.B. 6 Scandal

By John Cropley

Three former Ohio utility and regulatory officials face dozens of new charges in the House Bill 6 scandal.

The Ohio Attorney General's Office on Feb. 12 announced the latest developments in the long-running fallout over H.B. 6, which granted subsidies for the operation of two FirstEnergy Corp. nuclear power plants and locked in profits for the utility.

Charles Jones, former CEO of FirstEnergy | *FirstEnergy*

Indicted on charges ranging from theft to bribery to telecommunications fraud were Samuel Randazzo, former chair of the Public Utilities Commission of Ohio; Charles Jones, former CEO of FirstEnergy; and Michael Dowling, FirstEnergy's former senior vice president of external affairs.

The new state *indictment* brings the first criminal charges against Jones and Dowling, who were fired by the company in 2020 after allegations of wrongdoing surfaced. (See *FirstEnergy Fires Jones over Bribe Probe*.)

A federal indictment announced in December brought bribery, fraud and other charges against Randazzo, who resigned as PUCO chair in late 2020. (See *Former Ohio PUC Chair Charged with Bribery*.)

The indictment runs 50 pages. It alleges that from 2010 to 2021, the three men "were literally as thick as thieves. Together, they would steal money from FirstEnergy, write legislative provisions worth unearned millions of dollars to FirstEnergy, legally guarantee … FirstEnergy's [continued] profitability and take over the state government in a way that allowed FirstEnergy to regulate itself."

Ohio Attorney General Dave Yost said a multiagency task force formed under the framework of the Ohio Organized Crime Investigations Commission prepared the case against the trio.

"This indictment is about more than one piece of legislation," Yost said in a *news release* Feb. 12. "It is about the hostile capture of a significant portion of Ohio's state government by deception, betrayal and dishonesty."

Michael Dowling, FirstEnergy's former senior vice president of external affairs | *University of Akron*

These are not the first charges brought in connection with the H.B. 6 scandal.

A federal jury convicted former Ohio House Speaker Larry Householder (R) of racketeering conspiracy in March 2023. He was sentenced in June to 20 years in prison but appealed his conviction. (See *Former Ohio House Speaker Householder Sentenced to 20 Years in Prison*.)

There have been numerous civil actions as well. Yost said his office has averted nearly $2 billion in charges to FirstEnergy customers over the period covered by H.B. 6.

FirstEnergy itself agreed to pay a $230 million federal fine for its role in H.B. 6. (See *DOJ Orders $230 Million Fine for FirstEnergy*.)

The Allegations

FirstEnergy was alleged to have spent $61 million in bribes, campaign contributions and advertising to advance Householder to the speakership. He then supported H.B. 6, which provided more than $1 billion in subsidies for the nuclear plants the company owned at the time.

The indictment paints a picture of a decade-long scheme that "all began with a well-lawyered theft in 2010." The paperwork states and alleges that:

- Randazzo was simultaneously a consultant for FirstEnergy; a representative of a group of large commercial electric users who thought they were paying too much for electricity; and the operator of two shell companies, Sustainability Funding Alliance of Ohio and IEU-Ohio Administration Co.
- Randazzo subsequently skimmed $5.4 million of the $13.2 million he obtained for his commercial clients from FirstEnergy.
- FirstEnergy paid out Randazzo's consulting fees in full shortly before he was nominated to head the PUCO; Randazzo lied about the relationship in his testimony to the General Assembly and failed to disclose the millions of dollars he had received from the company he soon would regulate and would continue to work for as an unregistered lobbyist.

Samuel Randazzo, former chairman of the Public Utility Commission of Ohio | *WKRC*

- Randazzo wrote portions of H.B. 6 that subsidized the nuclear plants, which FirstEnergy said were losing money.
- Also in H.B. 6, Randazzo scuttled a 2024 rate case that likely would have resulted in a PUCO order to lower FirstEnergy's rates; this maintained FirstEnergy's profits at the levels of 2018, a very good year for the company.
- All the while, Jones and Dowling directed and funded Randazzo and other lobbyists. They profited personally as First Energy stock rose from $28.83 in May 2017 to $50.47 in January 2020.
- Jones texted Randazzo a screen shot of the stock price in November 2019 with a two-word message: "Thank you!!"

The Charges

Randazzo was indicted on 22 felony counts: one count each of engaging in a pattern of corrupt activity, grand theft and bribery; two counts of aggravated theft; three counts of telecommunications fraud; six counts of tampering with records; and eight counts of money laundering.

Jones was indicted on 10 felony counts: one count each of engaging in a pattern of corrupt activity and bribery; two counts each of aggravated theft of $1.5 million or more and telecommunications fraud; and four counts of money laundering.

Dowling was indicted on 12 felony counts: one count each of engaging in a pattern of corrupt activity and bribery; two counts each of aggravated theft of $1.5 million or more, telecommunications fraud and tampering with records; and four counts of money laundering.

Sustainability Funding Alliance of Ohio is included in 11 of the criminal charges; IEU-Ohio Administration is included in five. ■

5 PJM States Considering Bills to Require Utilities to File Stakeholder Votes

By James Downing

Legislators in five states in PJM have filed similar bills that would require regulated utilities to submit all of their stakeholder votes publicly with state regulators.

Illinois, Maryland, Pennsylvania, Virginia and West Virginia have all introduced bills in the effort, which is supported by the National Caucus of Environmental Legislators (NCEL) and the Citizens Utility Board (CUB) of Illinois.

Maryland Del. Lorig Charkoudian (D) introduced a similar bill, *HB 505*, last year that cleared the House; she has reintroduced it this year. (See *Maryland Bill Would Require Utilities to Report Votes at PJM*.)

"My colleagues and I, across the PJM region, know that decisions made at PJM affect our ratepayers, the reliability of our electric grid and our transition to clean energy," Charkoudian said. "These are all issues we are working on at the state level, and PJM's rules have the ability to either support or hamper our ability to address these issues. This bill will go a long way to establishing transparency to support our ability to engage with PJM on these crucial issues."

While PJM's meetings are open to the public, so many are held that state regulators and consumer groups cannot track all of them, Clara Summers, manager of CUB's *Consumers for a Better Grid* campaign, said in an interview.

"When utilities vote at PJM, the outcome of those votes impact our clean energy transition; they impact our reliability and the cost of electricity," Summers said. "So, these bills are about introducing better transparency and better accountability for how those utilities are voting on these issues that affect our electric markets and transmission."

With hundreds of meetings a year that can last hours and do not always produce records of how individual firms voted, making sure utilities are open about how they are voting will ensure states that their policies are being respected, she added.

PJM itself did not weigh in on the substance of the bills, but it said its stakeholder process is transparent.

"The PJM stakeholder process and the various stakeholder meetings, approximately 450 meetings, are open to the media and the public, with agendas and minutes posted on our website," the RTO said in a statement.

Unlike the major committees — the Markets and Reliability Committee and the Members Committee — the lower committees allow firms' individual affiliates to vote. Some firms, like American Electric Power and FirstEnergy, have so many affiliates that on their own, their votes can outweigh the combined votes of the participating consumer advocates, Summers said. "That increases their potential for impacting which proposals get voted on to advance."

To win approval, rule changes need a majority in the lower committees and a two-thirds sector-weighted majority at the MRC and MC. PJM provides summaries of votes by sector at the major committees, but not any individual votes. Only the results, without any voting summaries, are provided for the lower committees.

Both Summers and Ava Gallo, NCEL's climate and energy manager, said one reason states have become more interested in the PJM process is the drama around the now-defunct extended minimum offer price rule (MOPR-Ex). During the Trump administration in 2018, FERC controversially ordered the RTO to expand its bidding floor in the capacity market to all new state-subsidized resources; the rule had previously only applied to new gas-fired resources. (See *FERC Extends PJM MOPR to State Subsidies*.)

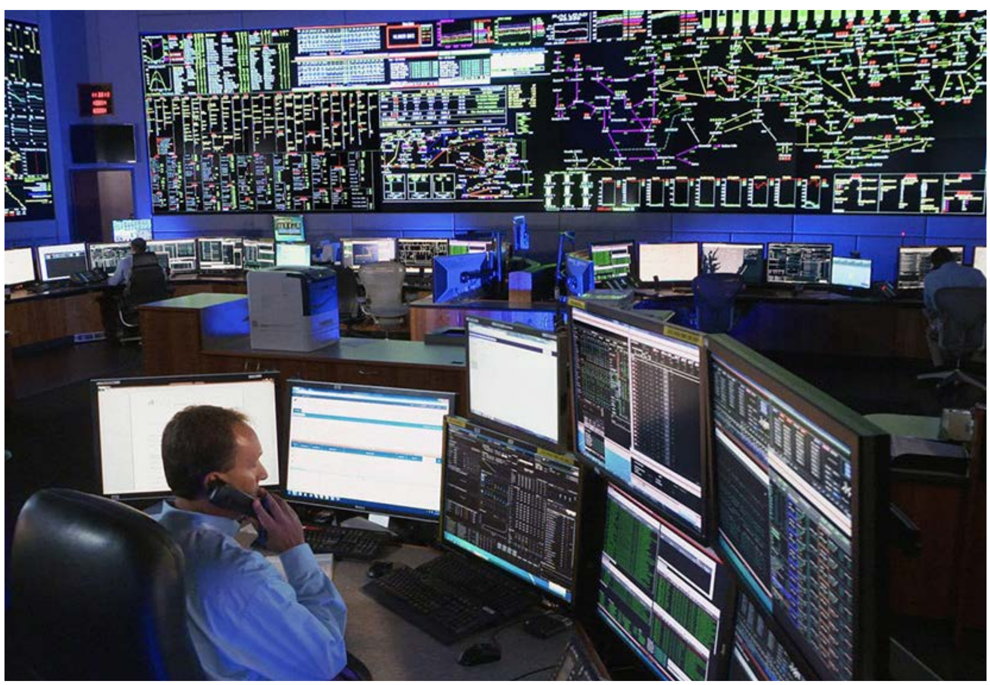
Politics among the PJM states is diverse, but Gallo said that while West Virginia and Illinois might differ sharply on energy policy, they both value transparency.

"NCEL is proud to help organize these state legislators across the PJM region," Gallo said. "We know that legislators work tirelessly to ensure their constituents have affordable, reliable and clean electricity. States are stronger together, and this legislation can help ensure that utilities across the region are also working towards these same goals."

The West Virginia legislation comes almost a year after its Public Service Commission filed a *complaint* at FERC alleging it had been improperly blocked from the PJM Liaison Committee, whose meetings are limited to members and the RTO's Board of Managers. (See *W.Va. PSC Files Complaint over PJM Meeting Policy*.)

In the still-pending complaint proceeding (*EL23-45*), PJM *responded* that the committee was created so stakeholders could have direct communication with its board outside of the normal stakeholder process and that the board has closed-door meetings with state regulators under a deal it signed with the Organization of PJM States Inc.

"In West Virginia, people's electric rates have gone up faster than any other state," state Del. Evan Hansen (D) said. "We need our electric utilities to explain how their secret votes at PJM are in the public interest." ■



PJM control room | *PJM*

N.J. Opens 2nd State Agreement Approach to Connect OSW with PJM

By Devin Leith-Yessian

The New Jersey Board of Public Utilities (BPU) has initiated a second state agreement approach (SAA) process with PJM to build the transmission needed to connect 3,500 MW of offshore wind with the RTO's grid.

In a Feb. 5 *announcement* of the SAA, BPU President Christine Guhl-Sadovy said the first agreement in 2022 — also the first for PJM — made the state a national leader in developing offshore wind, putting it on track to construct 4,890 MW.

In addition to resources being developed through PJM's traditional generation interconnection queue, the second SAA will allow the state to meet Gov. Phil Murphy's goal of installing 11 GW of offshore wind by 2040. PJM and the BPU jointly filed the SAA with FERC on Feb. 2 (*ER24-1187*).

"We believe that a coordinated and planned approach could result in more efficient and cost-effective transmission solutions, significantly reducing the risks of permitting and construction delays and protecting ratepayers with cost containment options," Guhl-Sadovy said in a statement. "This approach helps minimize environmental impacts associated with onshore and potentially offshore upgrades. We look forward to further evaluation and planning, as a result of SAA 2.0."

PJM CEO Manu Asthana said New Jersey's use of the SAA process shows the promise it holds for states with policy goals that required developing new generation.

"The continued collaboration between PJM and New Jersey through the State Agreement

NJ BPU President Christine Guhl-Sadovy | *NJ BPU*

Approach underscores PJM's commitment to reliably and cost-effectively facilitating states' renewable energy policy goals," Asthana said in the announcement. "PJM's competitive planning process allows for creative solutions to complex infrastructure challenges. New Jersey has been a leader in this approach and can be a template for other states pursuing their individual energy policies."

New Jersey has pushed ahead with solicitations for offshore wind infrastructure since approving the $1.1 billion in transmission projects PJM recommended through the first SAA round, but hit a snag when developer Ørsted canceled its two Ocean Wind projects in November. (See *New Jersey Launches OSW Infrastructure Solicitation.*)

Speaking at a Feb. 6 PJM Transmission Expansion Advisory Committee meeting, PJM's Susan McGill said the RTO *plans* to run the SAA planning process parallel to the 2024 Regional Transmission Expansion Plan (RTEP), with the goal of opening competitive solicitation windows for both in July. Doing so would allow PJM to select project components that meet both future reliability needs and New Jersey's interconnection request in the most cost-effective manner and on a timeline that allows the BPU to consider project approval in the second quarter of next year.

McGill encouraged developers to draft proposals that address needs identified in both windows and submit them to each window, which would allow PJM to ensure it is selecting the best match of components.

"We will look at it from every angle to make sure we are only building what's needed," she said.

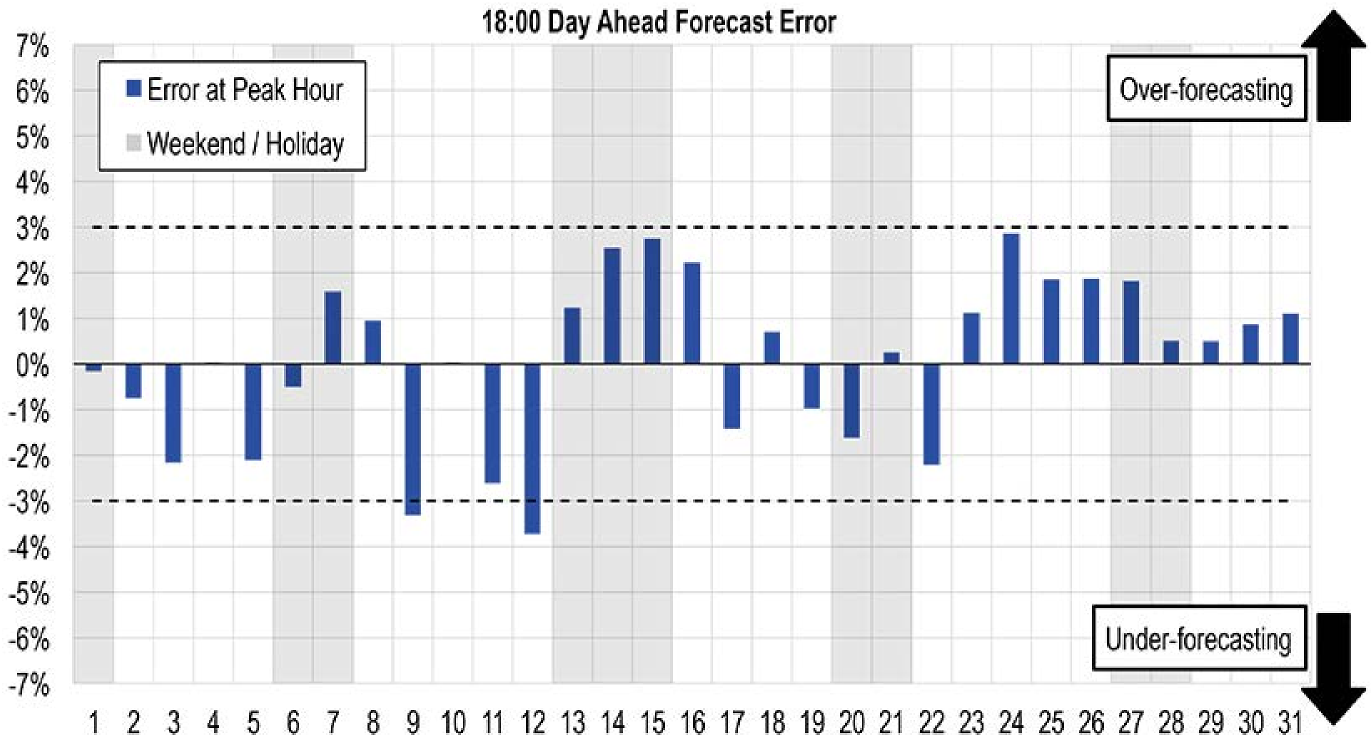
McGill said PJM will also give further thought to a stakeholder question about whether this approach could result in transmission owners who submit projects having to pay twice the fees to have a proposal considered for both windows.

Several stakeholders raised concerns that having two competitive windows open at once could strain the resources of PJM and transmission owners. They suggested that better ideas might be submitted if the RTO conducted the processes on a staggered timeline.

PJM's Sami Abdulsalam said the RTO considered delaying one of the windows but said there are time constraints on when each needs to be finished. Completing one without knowing what proposals will be made for the other could result in overlap and projects having to be canceled, he said. ■

PJM News

PJM OC Briefs



PJM experienced two days where the daily peak forecast error exceeded the RTO's 3% target. | *PJM*

Stakeholders Endorse TO/TOP Matrix Revisions

The Operating Committee endorsed revisions to the Transmission Owner/Transmission Operator (TO/TOP) Matrix, which defines the tasks TOs and PJM are accountable for to comply with NERC reliability standards. Gizella Mali, TO/TOP Matrix Subcommittee chair, said the changes reflect several new NERC reliability standards including *EOP-011-4* (Emergency operations), *FAC-014-3* (Establish and communicate system operating limits), *IRO-017-1* (Outage coordination) and *TOP-001-6* (Transmission operations). (See *NERC Board Approves Cold Weather Standards*.)

Operating Metrics

PJM's daily peak forecast error exceeded its targeted 3% two days last month, with actual loads Jan. 9 and Jan. 12 being between 3% and 4% higher than forecast, according to Markets Coordination Manager Stephanie Schwarz. The RTO experienced one shared reserve event and three spin events in January, and the winter storm that spread across the region in the middle of the month led to one conservative operations alert, two cold weather alerts and 22 post-contingency local load relief warnings.

Security Update

PJM Director of Enterprise Information Security Jim Gluck *urged* members to keep computers and networked devices, particularly home routes for out-of-office employees, updated to reduce the risk that attackers can use old vulnerabilities to gain access to critical infrastructure and remain dormant. He said attacks from the Volt Typhoon group have targeted critical infrastructure software and attempted to fly under the radar by not installing malicious software to instead take advantage of any existing vulnerabilities. One of the group's tactics has been using unsecured routers of employees working from home.

A separate recent attack he highlighted used a company's software development sandbox environment to gain access to a wider range of internal systems, including a portion of the company's email accounts. He also gave the perennial advice that members be wary of suspicious communications that may be attempting to gain sensitive information or designed to trick employees into opening malicious files.

Other Committee Business

- Stakeholders endorsed *revisions* to Manual 38, which pertains to operations planning identified by PJM during the document's periodic review. The new language would specify that the studies conducted by the Operations Assessment Task Force will use generation outage data selected from three previous seasons rather than comparable seasons. The changes are scheduled to be voted on by the Markets and Reliability Committee on Feb. 22.
- The committee endorsed *revisions* to Manual 40, which defines training and certification requirements, to update the titles of programs that have changed, clarify the responsibilities of different PJM positions and add detail to how rollover hours are calculated. The MRC is set to consider endorsing the changes Feb. 22.
- Stakeholders endorsed a PJM quick fix *proposal* to remove the Compliance Bulletin 14 in Manual 3A and add language pointing to NERC's bulk electric system (BES) element definitions. The compliance bulletin details how PJM members are to notify the RTO of any changes to BES elements resulting from NERC's BES definition. The proposal is set for an endorsement vote at the MRC on Feb. 22 and at the System Operations Committee on March 1. ■

— Devin Leith-Yessian

PJM MIC Briefs

Stakeholders Endorse Real-time Temporary Exception Manual Revisions

VALLEY FORGE, Pa. — The Market Implementation Committee endorsed *revisions* to Manual 11 to codify the real-time temporary exception paradigm approved by FERC on Nov. 30. This replaces PJM's real-time values process for generators to submit any change in their ability to perform to their unit-specific parameters. (See "Real-time Temporary Exceptions Manual Revisions Proposed," *PJM MIC Briefs: Jan. 10, 2024*.)

The temporary exceptions process is designed for short-term events and repeat or long-term constraints over 30 days that should be reported to PJM and the Independent Market Monitor as period exception requests, PJM's Lauren Strella Wahba said. Generation owners should notify PJM and the Monitor when the resource has returned to being able to operate at full capability.

During the Feb. 8 Operating Committee meeting, PJM's Chris Pilong said temporary exceptions led to an uptick in outages being reported at least a day in advance of the unit being scheduled. However, only 22% of gas generators reported outages despite all pipelines seeing constraints that warranted notifying PJM.

PJM Discontinues Market Certification Exam

Citing low participation and difficulties keeping exam materials up to date with the rate of market design change, PJM has retired its market certification exam with the aim of replacing it with a certification of training completion which signals that an individual is competent with the procedures in place at that time.

PJM's Don Kujawski said it typically takes two to three years to develop new exams, introducing the possibility that questions may be outdated by the time trainees are in the classroom. Enrollment also has been significantly lower than the other certification programs PJM administers. About 60 people have taken the markets exam since its inception, whereas around 1,000 have taken the generation and transmission exams.

The new paradigm will be put into practice with the market optimization workshop scheduled for the third quarter of 2024.

PJM's Lauren Strella Wahba presents to the Market Implementation Committee on Feb. 7. | *© RTO Insider LLC*

Other Committee Business:

- PJM provided additional detail on its quick fix *proposal* to revise Manual 11 to reflect its approach to interface pricing points, a mechanism that groups buses together when calculating LMPs for energy transfers between external areas. Delivering the second first read, PJM's Zhenyu Fan said the proposal is a response to a recommendation from the Independent Market Monitor that PJM adjust the weighting of the component interfaces to maintain congruity between prices and system conditions and also conduct annual reviews of the mapping of neighboring balancing authorities to individual interface pricing points. The manual revisions would add a definition for interface pricing points and establish an annual review looking at power flow impacts on each interface. Fan said similar language already included in the governing documents and the manual changes, which are set to be considered for MIC endorsement March 6, would memorialize existing practices. (See "Quick Fix Proposal on Interface Pricing Points," *PJM MIC Briefs: Jan. 10, 2024*.)
- PJM's Pete Langbein told the committee that an increase in load forecasting will prompt demand for about 3,000 MW of additional capacity in the third Incremental Auction, which is set to open Feb. 27. ■

— Devin Leith-Yessian

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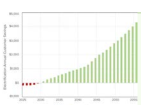

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PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse Revised RRS Values

The Planning Committee endorsed a PJM *proposal* to reset the installed reserve margin (IRM) and forecast pool requirement (FPR) values for the 2025/26 delivery year to reflect the shift to marginal ELCC accreditation approved by FERC last month (*ER24-99*). The changes were approved with 57% support.

Driven by several resource classes seeing reduced average accreditation, the FPR would decline 15% from the 1.1171 endorsed by stakeholders last year to 0.9440, while the IRM would remain static at 1.17%. The FPR formula was changed in the filing approved last month to multiply the IRM by the pool-wide average accredited unforced capacity factor, rather than the equivalent forced outage rates previously used, to determine the capacity required to meet forecast peak load. (See "Stakeholders Endorse Reserve Requirement Study Values," *PJM PC/TEAC Briefs: Oct. 3, 2023*.)

PJM's Pat Bruno said the RTO continues to review the unit-specific performance adjustment before it can release generator's accreditation values, which are calculated using the adjustment and class ratings presented to the PC. Those values are to be considered by the Markets and Reliability Committee and Members Committee for endorsement Feb. 22. The PJM Board of Managers is expected to establish the values by the end of the month.

PJM's Patricio Rocha Garrido said the FPR values PJM proposed Feb. 6 differed from preliminary estimates because of increased winter risk being identified because of the resource portfolio including a higher concentration of solar resources and fewer wind generators. Bruno said there also was a smaller number of generators that attested to their ability to provide dual-fuel capability than expected and those that did seek that classification had a wide range of historical performance, resulting in some being disqualified.

Multiple stakeholders said there was too little information to understand how the new figures were being calculated and the effect they could have on unit-specific accreditation, raising a concern that the new values were being moved to a vote too quickly.

"I am concerned about PJM pushing us to vote. Clearly there was very little transparency into the numbers that PJM has published. They have extraordinary commercial implications for all of your stakeholders. To try and cut off conversation is really inappropriate," LS Power's Marji Philips said. After the meeting, Philips said she appreciated PJM allowing more voices to be heard before moving to a vote.

PJM Corrects Electric Vehicle Load Forecast

PJM updated its *forecast* for electric vehicle load growth with corrected figures from S&P Global, which PJM contracted to provide estimates for the first time for the 2024 Load Forecast. (See "PJM 2024 Load Forecast Sees Jump from EVs, Data Centers, Heat Pumps," *PJM PC/TEAC Briefs: Dec. 5, 2023*.)

The projected numbers were incorrectly offset to increase one year in advance, PJM's Andrew Gledhill said, resulting in the EV forecast being inflated by 10% for 2030. The revised forecast resulted in varying outcomes across transmission zones, with the MedEd region seeing the largest difference with a summer peak forecast over 2% smaller in 2030.

Vistra's Erik Heinle questioned if PJM plans to continue using contractors for this portion of its forecast or if multiple vendors could be used to receive estimates that could be analyzed or averaged together. Gledhill said PJM sees value in getting an outside expert opinion on EV load growth and there has not been any decision to change course.

Transmission Expansion Advisory Committee

Supplemental Needs and Project Proposals

- Exelon *presented* a $175 million project to build a new Keslinger Substation and several lines in its ComEd zone to serve a new customer with an ultimate load of 210 MW. Keslinger would include four new six-mile lines cutting into the Waterman-Crego Road and Crego Road-Glidden 138-kV lines, as well as two new 345-kV lines spanning 0.7 miles to cut into the Nelson-Electric Junction lines. The project is in the conceptual phase with an envisioned in-service date of Dec. 31, 2027.
- Exelon revised the scope of a prior *project* to build a new Navy Yard 230-kV substation to serve growing load in Philadelphia, bringing the cost from $71 million to $82 million. The original design would have configured the facility as a breaker-and-a-half. Limited space led the utility to shift to a ring configuration. The project is in the conceptual phase with a projected in-service in 2029.

Pat Bruno, PJM | © *RTO Insider LLC*

- Public Service Enterprise Group revised a *project* to upgrade communications equipment on 500-kV lines running between its Deans, East Windsor and New Freedom substations, increasing the cost from $20 million to $39 million. The new proposal would replace 68 miles of static wire with fiber lines and upgrade line relay equipment. The original proposal would have replaced the static wire with optical guide wire. The project, which is in the conceptual phase, would complete work on the Deans-East Windsor line in December 2025 and finish the East Windsor-New Freedom line in June 2027.
- PPL *presented* a customer service need to add 1,275 MW served by a 138-kV source in New Kingston, Pa. The load is expected to come online in the summer of 2026 starting at 40 MW and grow to 1,275 MW in 2032.
- Dominion Energy *presented* several distribution requests to serve data center loads in Northern Virginia. ■

— Devin Leith-Yessian

PJM News

PJM: 'Conservative Operations' Maintained Reliability During Jan. 2024 Storm

Multiday Commitments to Ensure Generators' Availability Cost $53.5M

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM last week presented two deep dives into how the grid performed during the January 2024 Winter Storm Gerri, highlighting changes to how it committed generators to reduce risk. The RTO's out-of-market actions cost $53.5 million. (See *PJM: Grid Performed Well During January Winter Storm*.)

Much of the discussion during a Feb. 7 *presentation* to the Market Implementation Committee centered on PJM's use of conservative operations to commit generators to operate throughout the storm. PJM's Joe Ciabattoni said conservative operations were used to maintain transmission security that could not be accomplished with the resources committed through the day-ahead market alone.

A subset of those resources whose start-up parameters would have prevented dispatchers from ramping them up and down throughout the storm as needed were given multiday commitments, as were gas-fired generators that might have difficulty procuring fuel without certainty regarding how long they would be expected to run.

Around 98,000 MW of resources were identified for conservative operation commitment Jan. 12, of which 58,000 MW received multiday commitments. Two-thirds of the committed resources were gas-fired, while just over a quarter were coal. Conservative operations peaked at 15,189 MW of resources committed Jan. 16.

Senior Dispatch Manager Donnie Bielak said fuel type was not a major focus in which resources were selected under conservative operations. PJM started by looking at which units were needed for reliability, and analysis of fuel security followed, he said.

Uplift payments between Jan. 12 and 22 totaled over $53.5 million, with over half of that concentrated on the 15th and 16th. PJM's Lisa Morelli said there is a correlation between the number of resources operating on multiday commitments and the amount of uplift paid, but there were other contributors to the amount of uplift as well.

During an Operating Committee *presentation* Feb. 8, Bielak said committing resources for multiple days proved valuable to dispatchers in mitigating the risks associated with fuel insecure resources.

PJM's Joe Ciabattoni presents data about grid performance during the January 2024 winter storm to the Market Implementation Committee on Feb. 7. | *© RTO Insider LLC*

Bielak said PJM also modified its practice around committing gas resources to treat flexible combustion turbines as if they were inflexible. The RTO normally commits inflexible combustion turbines earlier in the day than other resources to provide additional time for them to procure fuel, which also has the added benefit of giving dispatchers more reaction time if that generator is unable to obtain gas. Bielak said PJM is considering standardizing the procedure going forward by adding triggers for when it may be initiated and transparency around how it will be used.

Senior Vice President of Operations Mike Bryson said the storm presented unique challenges, including the worst weather manifesting at the end of a holiday weekend. Instead of buying one day's worth of gas on a weekday, generators must buy for an entire weekend — a full three days if it's a holiday.

Gas must be purchased as a package over weekends, with the commitments largest during holiday weekends.

Michelle Bloodworth, president of coal lobby America's Power, questioned whether using a special dispatch process for inflexible resources undermines PJM's incentives for generator investments in fuel security and winterization. Committing them early could also suppress prices for generators that have made those investments, which she said may further weaken the incentive to perform.

Reviewing the load forecast performance, PJM's Stephanie Schwarz said some of the underforecasting in valley periods was due to lower-than-forecast temperatures and snow cover suppressing behind-the-meter solar generation.

The number of forced outages during Gerri was significantly lower than the December 2022 Winter Storm Elliott, peaking at 16,119 MW on Jan 16. Elliott peaked at 46,124 on Dec. 24, 2022.

PJM's Ray Lee said most outages experienced during Gerri were due to plant equipment failures, followed by gas procurement problems and freezing, which each contributed to a lesser extent than during Elliott.

More generation owners submitted real-time temporary exceptions at least 24 hours in advance of being dispatched during Gerri than during Elliott. However, PJM's Chris Pilong said generators are still underreporting constraints. He said that throughout the storm, all pipelines reported constraints to PJM, while only 22% of generators subsequently submitted temporary exceptions. ■

SPP Regulators Settle Their Leadership Structure

By Tom Kleckner

SPP state regulators last week filled a leadership vacancy within the Regional State Committee by approving the Nomination Committee's selection of Oklahoma Corporation Commission Chair Todd Hiett as its vice president.

He replaces Minnesota Commissioner John Tuma, who was to serve as the commission's vice president this year until incoming President Will McAdams resigned from the Texas agency and the RSC last year. McAdams was elected as president during the state regulators' October meeting, but Tuma said McAdams called him three hours after the meeting and told him he was planning to resign.

"I was elected vice president but immediately became president," Tuma mused during the committee's Feb. 5 meeting.

The Nebraska Power Review Board's (NPRB) Chuck Hutchison remains the RSC's treasurer and secretary, with Texas Commissioner Lori Cobos replacing McAdams.

McAdams officially resigned from the Texas commission in December and has since joined an Austin, Texas-based lobbying firm. He also agreed to consult with the RSC, focusing on the Resource and Energy Adequacy Real Leadership (REAL) Team under its chair, South Dakota Public Utilities Commissioner Kristie Fiegen. If time allows, McAdams also will work on interregional planning issues.

"He's rolled up his sleeves and dived right into work already," Tuma said. "I know that for a fact, because I've already approved the first invoice a couple of days ago."

"I sincerely appreciate the work of the RSC leadership and of the REAL Team to allow me to continue to work on these important issues for the [load-resource entities], those utilities and stakeholders," McAdams said. "I look forward to being able to work with you and members of the REAL Team to continue to address our large and important calendar."

Revised RCAR Endorsed

The RSC approved the lessons learned from SPP's third regional cost allocation review (RCAR), long a bone of contention by Missouri utilities that have felt the review's methodology results in their benefit-to-cost ratio being unreasonably high.

Minnesota's John Tuma (left), RSC chair, with Missouri's Scott Rupp | © *RTO Insider LLC*

The most recent RCAR, completed in 2022, left City Utilities of Springfield and Empire District Electric with B/C ratios of 14.87 and 7.99, respectively. Post-review adjustments lowered those ratios to 3.82 and 3.82, respectively.

Fiegen, who chaired the Regional Allocation Review Task Force, said after the first two reviews used "future theoretical models," RCAR III used actual market data and compared it to the market without highway/byway projects.

"It had some unique opportunities to probably get more precise, but it also created some challenges," she said.

Fiegen said the task force dug into years of daily market data to analyze the issue. Eventually, it determined the production cost runs in the base case and change case were accurate, but those liable for the costs were not as accurate as they were in the actual market.

The task force adjusted some of the benefits for the two utilities that "felt their benefits were overstated in our original report ... to be more realistic," Fiegen said. "Both of those entities have acknowledged these changes and found that they meet their needs."

Commissioners unanimously approved seven recommended changes to the RCAR's methodology and the updated RCAR 3.1.

JTIQ Backstop Funding OK'd

The committee unanimously agreed to a policy that the Department of Energy's *Grid Resilience and Innovation Partnerships* (GRIP) funds be applied to offset capital costs' allocation to load for SPP's Joint Targeted Interconnection Queue (JTIQ) transmission portfolio with MISO. Using the DOE funds to cover the 10% allocation to load, with the balance going to generator interconnectors, the RTOs' interregional load share will be eliminated.

NPRB's John Krajewski, speaking for the RSC's Cost Allocation Working Group, said subscriptions to fully fund the JTIQ projects are inadequate. He said conversations he's had with transmission owners reveal a risk — and who bears it — if there's not enough JTIQ participation.

"If the subscriptions don't materialize, it's the region that will be the backstop for any shortfalls that may occur," he said. "For the first time, this would be a situation where we're building projects without a guarantee of funding. The way that the tariff is currently written, the risk ends up falling back on the customers of this transmission owners who are building the projects."

The DOE in October awarded $464.5 million in GRIP funds to MISO and SPP for their JTIQ portfolio. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

Last January, the RSC approved proposed cost allocations for the five projects in the portfolio. (See "Commissioners Approve 90-10 Split on JTIQ Cost Allocation," *SPP Regional State Committee Briefs: Jan. 30, 2023.)*

The RSC also endorsed a pair of policy proposals related to availability and outage policies to avoid "paper resources," Tuma said.

"We're trying to ... make sure that units that are in the workbooks, or outages that are done, are done in a way that we know what's happening," he said, "and that we have actual resources we know that we can count on when we're doing our planning."

SPP staff and the CAWG are collaborating on an "availability" definition (*RR605*) requiring load-responsible entities submitting deliverable or firm capacity to meet their resource adequacy requirement to certify the resource will be available and ready to perform at the accredited capacity level for the applicable season.

The REAL Team recommended prioritizing an outage policy for the winter planning resource margin while delaying additional components. The proposed policy will require any outage that is either taken or extended into the resource adequacy season without SPP's approval to harm the LRE's performance-based accreditation. ■

SPP News

Cupparo Replaces Certoma as SPP Board Chair

By Tom Kleckner

SPP's Board of Directors has elected independent director John Cupparo to be its chair, the RTO said Feb. 6.


Susan Certoma | © *RTO Insider LLC*

Cupparo, who will assume the role Feb. 7, will fill out the remainder of Susan Certoma's term, which expires at year's end. Certoma told stakeholders Feb. 6 she is stepping down as chair but will remain a board member.

"It's an honor and a privilege to have the opportunity to follow in the footsteps of the SPP board chairs that have come before me," Cupparo said during a Feb. 6 board meeting, which featured several discussions on resource adequacy and the grid's transformation.

"As we saw in the conversation today, SPP is faced with a series of opportunities and challenges," he said. "I believe SPP is well positioned to capture those opportunities and to meet those challenges, given the strength of this board, [SPP CEO] Barbara [Sugg] and her team, [and] the members in the broader SPP community."

Cupparo was elected to the board in 2022. He will continue to chair the Strategic Planning Committee and serve on the Interim Markets+ Independent Panel and the Finance and Human Resources committees. He was previously an officer with PacifiCorp, a senior executive at Berkshire Hathaway Energy leading a transmission investment program in the West and a board member for WECC.

Certoma opened the board's quarterly meeting Feb. 6 by announcing she was giving up her position as board chair, a position she has held since 2023. She will continue to serve on SPP's Finance and HR committees.

"At this time, there are other matters that require my attention," Certoma said.

Sugg lamented that the meeting's virtual format prevented a standing ovation for Certoma. Still, members were able to use the webinar application to send virtual hand claps to Certoma.

"I don't think that the membership realizes the load of work that the chair takes on, and it is significant," Sugg said. "Susan has been with me at every step of the way over the last year."


John Cupparo (foreground) has been selected to chair SPP's Board of Directors, replacing Susan Certoma. | © *RTO Insider LLC*

The three-year board terms for both Certoma and Cupparo expire at the end of the year, along with that of Ben Trowbridge. All three have expressed a desire to remain on the board. The Corporate Governance Committee will consider their interest when it meets next week.

Liz Moore will remain as the board's vice chair. ■

SPP Board of Directors/Members Committee Briefs

Resource Adequacy, Preparing for Extreme Weather Top 2024 Goals

SPP senior management rolled out its top 2024 corporate goals for its Board of Directors and stakeholders, cautioning they don't reflect all the important work the grid operator will take on this year.

"While we believe that every one of these goals [either is] ... mission critical or [provides] significant strategic value, we'll also strive to be as affordable as we can be as we undertake these efforts," COO Lanny Nickell told the board and Members Committee Feb. 6 during their virtual meeting.

Topping the list, of course, is resource adequacy — "one of our greatest risks," Nickell said —and mitigating those risks. "We're continuing to see increasing amounts of intermittent generation," he said. "At the same time, we're seeing thermal generation being retired, [and] we're experiencing extreme load growth, and also an increasing threat of extreme weather."

SPP has listed 15 initiatives that reflect the priorities the Resource and Energy Adequacy Leadership (REAL) Team established in 2023. They include a winter resource adequacy requirement, value-of-lost-load metrics and usage policy, an improved outage policy, and winter and summer planning reserve margin (PRM) revision requests. (See *'Therapy Session': SPP REAL Team Reviews Draft LOLE Study*.)

Nickell noted the three severe storms that swept across the SPP footprint during the past four winters and said it should not be a surprise the grid operator wants to "continue to enhance our readiness for extreme weather" as its second goal.

He said reports filed after winter storms Uri and Elliott contain 33 recommendations for improvements. Staff plans to close out the remaining open items from the reviews and bring back a final report to the board next January.

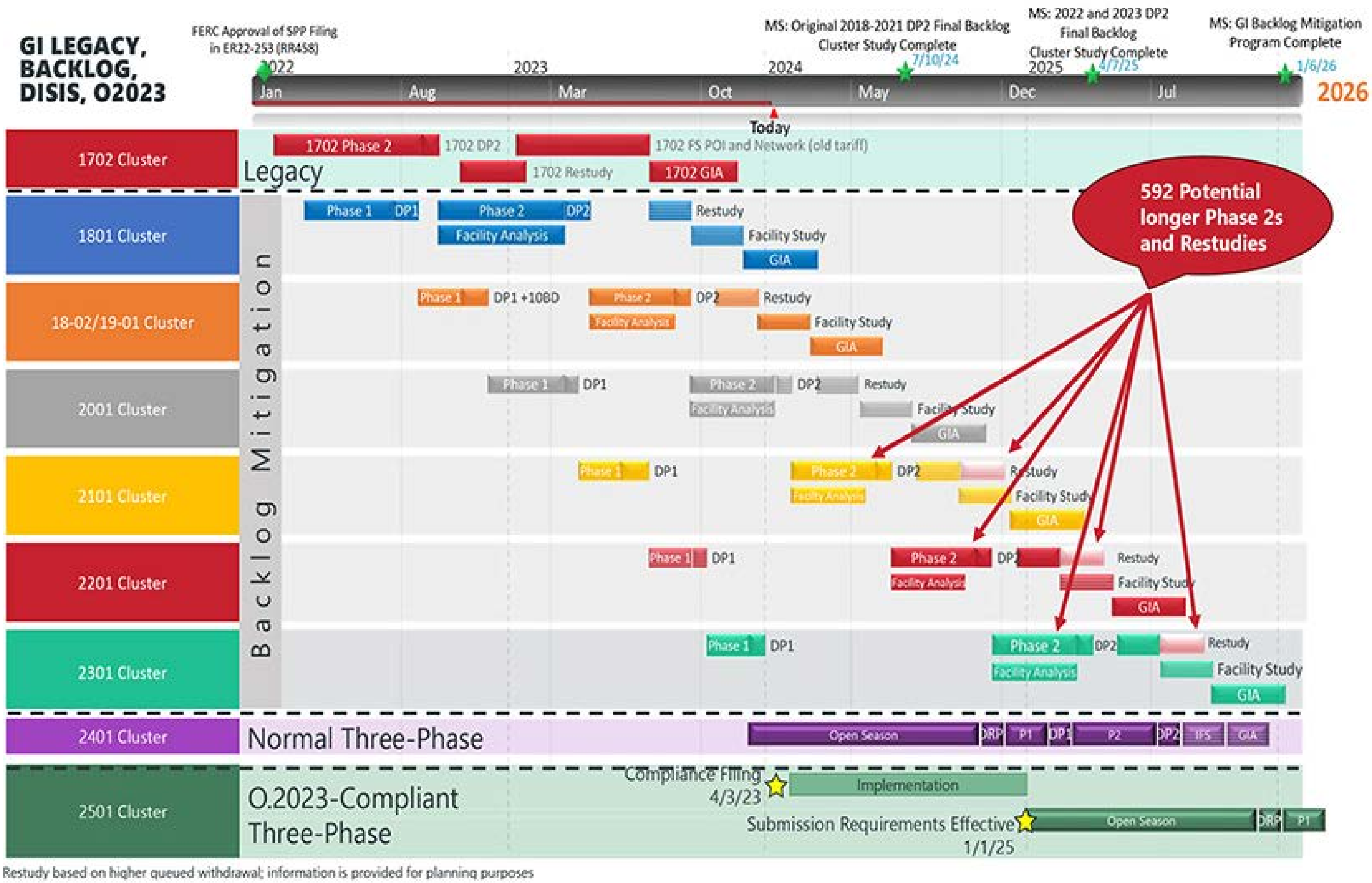
"We expect that will complete development of our market policies and will enhance our transmission planning processes to address extreme weather scenarios," Nickell said.

The other three goals are:

- optimizing the generator interconnection (GI) queue's processing;
- advancing innovative transmission policies; and
- continuing the western expansion's progress.

All five goals come with specific milestones designed to chart progress and gauge success at year's end.

"We know priorities will likely change throughout the year. ... These could very well get



SPP and stakeholders are working to keep the RTO's effort to clear the GI queue backlog on track. | *SPP*

SPP News

rearranged as we go through the year," Nickell said. "We know that some of these are going to take years in order to fully effectuate and realize the benefits of the policies and requirements that are being proposed."

To drive the message home to staff, CEO Barbara Sugg said SPP has, for the first time she could remember, developed a theme for the year: EMBRACE 2024. It's an acronym for Expansion, Mission, Branding, Reliability, Affordability, Community and Engagement.

"EMBRACE is an acronym, because it's the world we live in," she said. "We're going to see the word 'EMBRACE 2024' plastered throughout the [SPP headquarters] building. We really want the employees at every level of the organization to come together under this particular theme as we work on addressing the challenges and the opportunities that we face in 2024."

Congestion-hedging Policies' Implementation

SPP's board and regulators approved the implementation of a package of eight congestion-hedging policies they signed off on in July 2023. The proposals are designed to increase equity, fairness and financial transmission rights awards among market participants. (See *SPP Board/Members Committee Briefs: July 24-25, 2023*.)

Stakeholders have since added language for the annual long-term congestion rights (LTCRs) analysis performed during each round of the auction revenue right (ARR) nomination process. This ensures nominated candidate ARRs do not violate any transmission-line thermal ratings under normal system conditions.

They also revised the policies to distribute ARR surplus. This includes an iterative approach to the ARR allocation's first round and the distribution of excess auction revenues. Once approved by FERC, SPP would allocate 50% of the excess revenue in one year under the old method and 50% under the new method. After that, the new process would take over.

Board votes are not disclosed, but the Regional State Committee approved *RR591* by a 10-2 vote, with South Dakota's and North Dakota's commissioners both casting dissenting votes.

North Dakota's Randy Christmann said some members have invested the time to make the policies work for them, while others "maybe did less of that."

"So now we're just going to socialize it, and I just don't find that right," he said.

The board also approved without discussion *RR583*, which allows SPP to nominate LTCRs for federal service exemption and grandfathered agreement carveouts to further mitigate the load's exposure to the day-ahead market's congestion costs.

The rule change became necessary when SPP added the northern portion of the Western Area Power Administration, a federal power marketing agency. WAPA brought with it grandfathered transmission rights that caused some loss of congestion opportunities for other market participants.

"This is certainly not a fix to congestion-hedging issues, but it's a good small step forward," said Minnesota Commissioner John Tuma, the RSC's chair.

Sarah Martz, a member of the Iowa Utilities Board, cast the lone opposing vote against the change during the RSC meeting over concerns it will create more scarcity of LTCRs should congestion-hedging rights be reset.

Compliance Deadline Met

The board and directors approved urgent proposed tariff changes (*RR606*) setting the PRM to meet a FERC compliance deadline. The change includes explanations of the loss-of-load expectation study methods, assumptions and approval process, and the timeline for the PRM's approval and implementation process.

Staff met the deadline with a Feb. 9 *filing*, asking for an effective date of April 10.

The proceeding stems from FERC's rejection in 2023 of several members' attempt to overturn SPP's 2022 tariff change raising the PRM from 12% to 15%. The commission in September 2023 *denied* a rehearing request, modified the discussion and directed the grid operator to make a compliance filing (EL23-40). (See *FERC Rejects Protest of SPP PRM Increase*.)

American Electric Power, Oklahoma Gas & Electric and Xcel Energy are the SPP members that protested the original order. Stacey Burbure, an AEP vice president, said AEP doesn't believe the tariff change goes "quite far enough" and is not certain it "fully complies with a directed revisions directed by FERC and its order."

"Our concern has always been, and remains, having an appropriate level of detail and the tariff to ensure that the process is transparent," she said. "We fully support the need for flexibility and increasing the planning reserve margin to meet reliability needs, but we also recognize that there needs to be an appropriate balance with respect to the level of the detail and the tariff."

AEP and Arkansas Electric Cooperative Corp. opposed the measure, which passed the Members Committee's advisory vote 16-2, with three abstentions. AECC's Andrew Lachowsky said the cooperative already is adding a 900-MW generating resource but is worried the PRM will be increased again before the unit goes online.

During the RSC's discussion of RR606, Oklahoma Corporation Commission Chair Todd Hiett offered an amendment that, should the PRM need to be increased by more than a percentage point, the new value would not be effective until at least a year after the regulators' and directors' approval.

"Just to ensure we don't do too much too fast," Oklahoma Municipal Power Authority's Dave Osburn said.

The amendment failed, 2-10. The RSC then unanimously approved the measure.

Board Approves Appeal

The board approved renewable interests' appeal of a revision request (*RR592*) approved in January by the Markets and Operations Policy Committee, siding with their request to endorse an amendment that failed during that meeting.

The Advanced Power Alliance and nine other members asked directors in a letter to reduce the risk of further GI study delays by adopting the amendment or adding a later cluster study. The amendment would have approved RR592, effective with 2022 and 2023 Phase 2 studies. Instead, MOPC endorsed a fuel-based dispatch adjustment beginning with a 2021 Phase 2 study.

Transmission Working Group Chair Derek Brown, with Evergy, told the board MOPC's decision could add six to 18 months to the GI backlog mitigation effort. As passed by MOPC, RR592 includes nonfirm, nonlegacy Integrated Transmission Planning generators as prior-queued in steady-state analysis dispatch tables.

David Kelley, SPP's engineering vice president, said staff supported implementing the measure with the 2022 study.

"It gives us more time to work on any issues that we may see and allows us to complete [the 2021 study], and it wouldn't prevent us from hopefully completing the goal that we've set for completing 2022 [studies] this year," he said. "I think that sufficiently buys us enough time that we would be comfortable as staff if the board were to adopt the amendment."

The Members Committee's advisory vote to the board endorsed the appeal, 10-8, with three abstentions.

Western Expansion 'Ramping Up'

Bruce Rew, SPP's senior vice president of operations, said during the quarterly joint stakeholder briefing that the *RTO's western expansion* is "ramping up" and "continuing to move forward."

He said staff has completed drafting tariff changes for RTO West and created 15 revision requests. The first six tariff changes were approved unanimously by the Markets and Operations Policy Committee during January's meeting, and the full package, including membership agreements and bylaw changes, will be brought to the board's April quarterly meeting.

Several of the seven utilities in the Rocky Mountains region that are interested in joining the RTO have embedded entities within their balancing areas. SPP is working with the entities to determine how they would participate in the market or pseudo-tie out of the system to join another BA. Staff are preparing the entities to declare their intent by April 1, Rew said.

SPP plans to file its tariff changes May 31, even as systems development begins in April. Go-live is targeted for April 2026.

"We're pleased with the progress so far," Rew said.

SPP RTO West could add four states to SPP's footprint: Arizona, Colorado, Utah and Wyoming.

3rd 100-year Storm in 4 Years

"What would the new year be if we hadn't already had some kind of an extreme weather event?" Sugg asked rhetorically. "We all know that they're no longer called 100-year storms when you have three of them in four winters. We might start calling them holiday storms, though, because they all are tied to some national holiday."

Sugg said SPP experienced its highest 24-hour winter load during the January winter storm and its sixth-highest overall, just missing a seasonal peak by about 400 MW. The grid operator was able to import 6.7 GW from its neighbors at one point, exceeding the 6 GW of imports during the February 2021 storm.

"We were certainly thankful for our interconnections and our interregional transfer capacity," Sugg said, thanking the RTO's neighbors. "There is no way that we could have been successful with that winter event if not for our member companies and your system operators."

Consent Agenda Passes

The board's consent agenda approval included the Corporate Governance Committee's review of stakeholder group rosters to ensure members' expertise and geographic locations yield a "widespread and effective representation of the membership"; modification of a notification to construct (NTC) issued to Western Farmers Electric Cooperative for a 20-MVAR capacitor bank; withdrawal of an NTC issued to Southwestern Public Service Co. for a $1.1 million, 115-kV line upgrade; an out-of-cycle re-evaluation of a Northwestern Energy 115-kV project after a new power plant was added to models; the *2024 Transmission Expansion plan*; and the 2023 Integrated Transmission Plan's (ITP) *short-term reliability project report*.

The consent agenda also included three RRs that:

- *RR560*: move operating criteria language to the system operating limits (SOLs) methodology.
- *RR597*: document the day-ahead market's high-level process used for effective limit application.
- *RR598*: remove planning criteria portions outlining the methodology to develop SOLs and interconnection reliability operating limits in the planning horizon. This aligns with NERC's retirement of *Mandatory Reliability Standard FAC-010-3*. ■

— Tom Kleckner

Company Briefs

FirstEnergy Scraps 2030 Climate Goal

FirstEnergy on Feb. 9 said it has abandoned its 2030 target for slashing greenhouse gas emissions because its coal plants can't be replaced in time.

FirstEnergy said it can't meaningfully cut emissions because the coal-fired Fort Martin and Harrison power plants in West Virginia are crucial to ensuring adequate regional electricity supplies.

The company's longer-term goal of becoming carbon neutral by 2050 remains in effect. The two West Virginian coal plants are to be shut down in 2035 and 2040.

More: *Bloomberg*

Duke Energy Removes CCP-tied Batteries from Project at Marine Base

Duke Energy on Feb. 9 said it will decommission industrial batteries manufactured by Chinese company CATL that are connected to a renewable project at Marine Corps Base Camp Lejeune in North Carolina.

The company also plans to phase out CATL products in its civilian projects after U.S. lawmakers raised national security concerns about CATL's ties to the Chinese government and hackers targeting critical infrastructure.

More: *Fox Business*

Piedmont Lithium Cuts Workforce as Prices Plunge

Piedmont Lithium on Feb. 6 said it had laid off 27% of its workforce as a sharp downturn in the lithium market is forcing miners to cut production and look for cost-cutting measures.

The battery metal producer said it expects to complete most of its cost-saving initiatives by the end of the first quarter as it aims to achieve about $10 million in annual savings.

Lithium prices have plunged more than 80% from a late-2022 record high.

More: *Mining.com*

Federal Briefs

EPA Reports 'Widespread Noncompliance' with Coal Ash Regs

EPA recently said it found "widespread noncompliance" with the nation's first regulations on coal ash.

In an enforcement alert issued in December, EPA said its conclusion is based on "numerous facility assessments and inspections to determine compliance with regulatory requirements such as groundwater monitoring, corrective action implementation and disposal unit closure." The agency did not identify the facilities where the contamination occurred.

EPA said it had detected several kinds of noncompliance, including a failure to assess whether all waste had been removed and whether the environment had been affected. It also said it had documented a failure to implement measures to prevent future contamination and establish an adequate groundwater monitoring network.

More: *Inside Climate News*

EPA Tightens Soot Rule

EPA on Feb. 7 said it is tightening air pollution restrictions on small particles.

The rule would set the standard for annual average air pollution at a level of 9 micrograms per cubic meter, down from the annual average of 12 set under former President Barack Obama.

States will be required to meet the standard in 2032.

More: *The Hill*

BOEM: Calif. OSW Development Could Take 15 Years

The Bureau of Ocean Energy Management last week said it could take 12 to 15 years to fully develop the planned wind projects off the coast of Morro Bay, Calif.

"This will be a phased approach with four phases and each phase can last between one and five years," BOEM Renewable Energy Specialist Matthew Blazek said during a Feb. 6 scoping meeting on the project.

In May 2022, the U.S. Department of the Interior auctioned off the first California wind energy leasing areas off the coast of Humboldt and Morro Bay. The areas were divided into five lease areas and auctioned off for $757.1 million. The areas are roughly 20 miles offshore.

More: *New Times San Luis Obispo*

Cryptocurrency Companies Must Report Energy Use to the Government

The Biden administration is requiring some cryptocurrency producers to report their energy use following rising concerns that the industry could pose a threat to the nation's grids and exacerbate climate change.

The Energy Information Administration announced Jan. 31 that it would start collecting energy use data from more than 130 "identified commercial cryptocurrency miners" operating in the U.S. The survey, which started the week of Feb. 5, aims to get a sense of how the industry's energy demand is evolving and where in the country operations are growing fastest.

An EIA report released Feb. 1 found that the world's crypto miners used as much electricity in 2023 as the entire country of Australia, accounting for up to 1% of global demand. In the U.S., 137 mining facilities were responsible for up to 2.3% of the nation's total demand last year.

More: *Inside Climate News*

FWS Revises Permit Process to Benefit Bald, Golden Eagles

The U.S. Fish and Wildlife Service on Feb. 8 announced its final revised regulations for how it processes permits related to the incidental take of bald and golden eagles.

The revised regulations include a new system of general permits and the specific-permit system FWS has used in the past. The general permits allow applicants to receive immediate authorization by certifying that they meet requirements and commit to preidentified conservation measures. They are designed for situations that pose low risks to eagle populations and are an alternative approach to authorize wind energy projects, transmission infrastructure, disturbance of breeding eagles and eagle nest take. FWS will continue to review specific permits for situations that have high or uncertain risks to eagles.

The final rule was published in the *Federal Register* on Feb. 12, and will go into effect April 12.

More: *U.S. Fish & Wildlife Service*

State Briefs

REGIONAL

NARUC Adds New Members to Board of Directors

The National Association of Regulatory Utility Commissioners last week appointed nine new members to the association's Board of Directors.

The new appointments include: Katherine Peretick (Mich.), Kent Chandler (Ky.), Mary Throne (Wyo.), John Hammond (Idaho), Carlton Simpson (N.H.), Leo Asunsion (Hawaii), Emile Thompson (D.C.), Ron Gerwatowski (R.I.) and Jennifer French (Ohio).

More: *NARUC*

CALIFORNIA

Storms Knock Out Power to Record Number of Residents

A storm that dumped more than a foot of rain in some parts of Los Angeles County from Feb. 4-8 also damaged electrical equipment, resulting in the highest number of outages of Pacific Gas & Electric customers from a single storm in at least 30 years, the utility said.

About 1.4 million PG&E customers statewide lost power during the storm. At their peak, the outages affected around 875,000 people.

The storm damaged more than 2,500 spans of powerlines, as well as 866 power poles and 327 transformers, according to PG&E.

More: *Los Angeles Times*

CONNECTICUT

Green Bank Approves $110M in Large-scale Financing

The Connecticut Green Bank last week announced it has more than doubled its funding to $110 million for commercial-scale solar projects.

Originally approved in 2020 at $49.5 million, the allocation was increased due to ongoing demand.

To date, the facility has been used for $30 million for more than 100 projects totaling 25 MW across the state.

More: *Solar Industry Magazine*

MICHIGAN

PSC Considers Charge to Fund Incentive Program for Utilities

The Public Service Commission is considering a proposal that would reward utilities with more money from a $10 yearly charge to consumers for improved performance.

That extra charge would equal incentive funds of about $23 million for DTE Energy and $19 million for Consumers Energy.

The PSC will hold an engagement session on its proposals Feb. 12.

More: *WWJ-TV*

MINNESOTA

Xcel Plans Higher Rates During Peak Evening Hours

Xcel Energy on Feb. 5 filed a plan with the Public Utilities Commission to switch state electric customers to variable rates, which on summer weekdays would be seven times more expensive from 3-8 p.m. than between midnight and 6 a.m., and nearly twice as expensive as all other hours.

The company said the shift is meant to ease pressure on the grid when demand is highest, help the utility better use wind power generated at night and give customers more control over their power bill. It predicts the average residential customer would see a 17.8% jump in bills during the four summer months and a 10.6% decrease for the rest of the year. The average bill would be about the same as flat rates over the course of a year.

Customers would be able to opt out of the variable rates for the current flat rate.

More: *Star Tribune*

MISSOURI

Evergy Seeks Rate Increase

Evergy on Feb. 6 filed for a rate increase with the Public Service Commission.

The company is requesting an increase of $104 million (13.42%), excluding fuel for its Missouri West customers. The request also includes a 0.57% increase for increased fuel costs. Evergy said the increase is needed to recover investments related to two natural gas plants and to reduce Missouri West's exposure to market price volatility.

If approved, the new rates will become effective Jan. 1.

More: *OK Energy Today*

NEW HAMPSHIRE

Officials Share Draft Climate Priorities

The Department of Environmental Services on Feb. 5 released a draft of issues they'll include in the Priority Climate Action Plan.

The state's priorities focus on reducing emissions in transportation and residential buildings. Officials are using funding from the Inflation Reduction Act to create the plan.

The Priority Climate Action Plan is due March 1, and applications for funding to implement the measures are due April 1.

More: *NHPR*

NEW MEXICO

Senate Committee Tables Carbon Sequestration Bill

The Senate Conservation Committee on Feb. 6 voted 8-1 to table a bill that would have created a regulatory framework for carbon sequestration.

The decision comes after the largest carbon capture proposal in the state — retrofitting the coal-fired San Juan Generating Station — failed when the City of Farmington chose to end its bid to take over the power that it partially owned.

More: *New Mexico Political Report*

OHIO

Montgomery County Approves Solar Project

The Montgomery County Commission on Feb. 6 approved a payment-in-lieu-of-taxes agreement for the Gem City Solar project.

TED Renewables will develop the 49.9-MW project on more than 250 acres.

Construction is expected to start next year.

More: *Springfield News-Sun*

TEXAS

Lt. Gov. Patrick: State Will Build Gas Plants if Private Sector Doesn't

If the state's effort to encourage the private sector to build more natural gas plants fails, the state would seek to build them itself and contract private operators to run them, Lt. Gov. Dan Patrick (R) said at a press conference Feb. 6.

Patrick said the goal is to attract 10 GW of natural gas power plants. State officials believe the Texas Energy Fund, a $10 billion package mostly for low-interest loans to developers of natural gas power plants, will deliver the results they seek. And if it doesn't, state-built power plants could be on the table.

"If we can't get an incentive program to attract investors to build, then the state would have to build [gas power plants] ourselves and then subcontract out for someone else to run it. We can't sit and do nothing," Patrick said.

More: *Houston Chronicle*

VERMONT

House Committee Supports Bill Increasing Renewable Purchases

The House Environment and Energy Committee on Feb. 6 voted 9-1 to support a bill that would increase the amount of renewable energy that utilities are required to purchase.

Utilities are recurrently required to purchase 75% of their power from renewable sources by 2032. The bill would increase that to 100% by 2030. It would also require utilities to purchase an increasing amount of energy from new renewable sources that came online after 2010.

The bill now heads to the House Ways and Means Committee.

More: *VT Digger*

VIRGINIA

Judge Allows GHG Lawsuit to Proceed

Circuit Judge Mike Fleenor on Feb. 5 denied a motion from an energy conservation group to dismiss a case filed by Attorney General Jason Miyares, which argued that the Association of Energy Conservation Professionals lacked standing to challenge a decision to pull the state out of the Regional Greenhouse Gas Initiative.

The association contended that the withdrawal deprived it of funds from the initiative that supported its work weatherizing low-income homes to make them more energy efficient. In arguing that the association lacked standing to sue, the state said it is a trade group representing about 15 nonprofit organizations, which receive the funding.

Fleenor did not rule on the association's request to stay Virginia's withdrawal from RGGI, which took effect Jan. 1, while the case is pending. The judge gave the parties 10 days to file briefs on that issue.

More: *The Roanoke Times*

Senate Committee Passes Bill to Ban Political Donations from Utilities

The Senate Committee on Privileges & Elections on Feb. 6 voted to advance a bill to ban public utility companies from donating to political campaigns.

The bill would prevent 73 companies from donating to campaigns. Dominion Energy made over $10 million in campaign contributions in 2023 to both sides of the aisle, according to the Virginia Public Access Project.

The bill will now move to the Finance Committee.

More: *WTKR*

WISCONSIN

We Energies to Replace Coal Plant with Gas Plant

We Energies on Feb. 7 filed a plan with the Public Service Commission to end the use of its coal-fired Oak Creek plant and construct a $1.2 billion natural gas plant.

The new 1,125-MW gas plant is planned to serve as a "peaker" plant but is not intended to replace the coal-generated power from Oak Creek when it goes offline over the next two years. The company also will build a $200 million liquefied natural gas storage system on site.

We Energies also plans to install seven gas-fired reciprocating internal combustion engines (128 MW combined) near its Paris Generating Station in Kenosha County. That project is estimated at $211 million.

More: *Milwaukee Journal Sentinel*