ISSN 2377-8016 : Volume 2024/Issue 33 ▪ August 20, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

MISO

Some MISO Regulators Signal Early Discontent with New MISO-PJM Interregional Study (p.13)

Members Want More Features in New MISO Load Tracking (p.14)

2023 Queue Cycle Delayed into 2025 as MISO Seeks Software Help on Studies (p.15)

CAISO/West

Pathways Initiative Committee Floats Ideas to Protect Public Interest (p.5)

CAISO, WEM Boards Approve Pathways 'Step 1' Plan (p.6)

CAISO/West SPP

Markets+ Backers Highlight Reliability in 2nd 'Issue Alert' (p.7)

SPP Dispels Concerns over Markets+ Deficiency Letter (p.27)

PJM

Maryland Report Details PJM Cost Increases for Ratepayers (p.21)

ERCOT

CenterPoint Energy Still in Eye of the Storm (p.9)

COVER: *(Page 13)* |

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

Editor & Publisher
Rich Heidorn Jr.

Editorial

Senior Vice President
Ken Sands

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Mid-Atlantic Bureau Chief
K Kaufmann

Associate Editor
Shawn McFarland

Copy Editor / Production Editor
Patrick Hopkins

CAISO/West Correspondent
Ayla Burnett

D.C. Correspondent
James Downing

ERCOT/SPP Correspondent
Tom Kleckner

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Vincent Gabrielle

PJM Correspondent
Devin Leith-Yessian

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Senior Vice President
Adam Schaffer

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Holly Rogers

Director, Sales and Customer Engagement
Dan Ingold

Sales Coordinator
Tri Bui

Sales Development Representative
Nicole Hopson

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Stakeholder Soapbox

PJM Resists Battery Storage Reforms Given to Data Centers 3

FERC/Federal

Renew Home Foresees Bright Future for Residential VPPs 4

CAISO/West

Pathways Initiative Committee Floats Ideas to Protect Public Interest 5
CAISO, WEM Boards Approve Pathways 'Step 1' Plan 6
Markets+ Backers Highlight Reliability in 2nd 'Issue Alert' 7

ERCOT

CenterPoint Energy Still in Eye of the Storm.................................. 9

ISO-NE

NEPOOL Reliability/Transmission Committee Briefs 11
FERC Establishes Settlement Procedures for ISO-NE IEP Exit Request 12

MISO

Some MISO Regulators Signal Early Discontent with New MISO-PJM Interregional Study 13
Members Want More Features in New MISO Load Tracking 14
2023 Queue Cycle Delayed into 2025 as MISO Seeks Software Help on Studies 15
FERC OKs $116M Settlement for New Orleans over Grand Gulf Nuclear Mismanagement 16

NYISO

NY Orders Utilities to Join in Proactive Grid Planning........................17
NYISO Operating Committee Briefs 18
NYISO Tariff Revisions Include Uncertainty Reserve.........................19
NYISO Presents Initial 2025 Project Budget Recommendation.............20

PJM

Maryland Report Details PJM Cost Increases for Ratepayers................21
PJM MRC/MC Preview..23
Fate of Appalachian Power's Coal Plants Debated in RPS Proceeding 24
FirstEnergy Pays Ohio $20M to End Bribery Scandal Litigation 25

Southeast

SEEM Members Respond to FERC Briefing Request 26

SPP

SPP Dispels Concerns over Markets+ Deficiency Letter 27
FERC Accepts Changes to SPP's WEIS Market 28

Briefs

Company Briefs..29
Federal Briefs..29
State Briefs 29

Stakeholder Soapbox

PJM Resists Battery Storage Reforms Given to Data Centers

By Mike Jacobs

Mike Jacobs

Battery storage facilities and data centers added to existing generator locations have a lot in common, with both supply and demand on a single interconnection. Yet despite the similarities, PJM is refusing FERC Order 2023 requirements regarding flexibility on charging battery storage while offering data center co-location projects those same provisions.

Kahuku battery storage facility in Hawaii | Mike Jacobs

PJM treats storage interconnection requests as an unavoidable driver of peak demand, while Order 2023 provides the option to assume the opposite. The PJM framing of interconnection causes batteries to appear to exacerbate transmission problems from plant retirement and require additional transmission upgrades, rather than meeting the system need caused by retirement.

(PJM's claims of unsolved problems with providing storage developers the ability to define operational limits are on Page 27 of *Answer to Protests* filed in July 2024.)

This is in direct opposition to the *Order 2023 directive* (starting at paragraph 1,448) that allows energy storage projects to define their interconnection operational limits on charging.

PJM claims that storage asset owner commitments, real-time monitoring equipment and system protection controls are all insufficient and incapable of limiting battery charging operations throughout its interconnection rulemaking comments and initial Order 2023 compliance filing.

Simultaneously, PJM developed guidelines and interconnection agreements for data centers co-located with generation, allowing those asset owner commitments, real-time monitoring equipment and system protection controls to limit data centers from creating transmission system demand.

In March, PJM published guidelines for co-located load with a new or existing generation facility. PJM includes data center loads as an example of a more sophisticated and flexible treatment of both a supply and a demand at a single point of interconnection. PJM now provides an interconnection agreement for such co-located facilities after study of their proposal.

Meanwhile, PJM simultaneously argues it cannot modify interconnection manuals' treatment of energy storage facilities as inflexible loads. This accommodation of co-located load illustrates PJM's ability to establish sensible requirements through interconnection agreements that could allow both data centers and energy storage assets to contribute to the economy without undue obstacles.

Neither the co-location guidelines nor the interconnection manuals have been filed at FERC, but the efforts by PJM to continue discriminating against storage interconnection were expressly rejected by FERC in Order 2023.

PJM's effort seeking reconsideration of this practice also was rejected by FERC. A third attempt by PJM to avoid compliance with the provision that storage be able to request to be limited from charging on peak, which is recognized elsewhere in the U.S., is included in FERC's current refusal to accept PJM's compliance filing for Order 2023.

FERC has given PJM until late October to once again explain why its noncompliant load deliverability tests for storage interconnection requests, which also disqualify storage from surplus interconnection and CIR transfer opportunities, should be permitted.

PJM's refusal to comply with Order 2023 is a disservice to the millions of people who rely on the interconnection process to address supply needs and provide just and reasonable rates.

FERC's directive more accurately reflects a wholesale market where storage assets can arbitrage between charging in low-price, off-peak hours and selling only in peak periods. PJM's disparate treatment of energy storage load is not based on science or engineering.

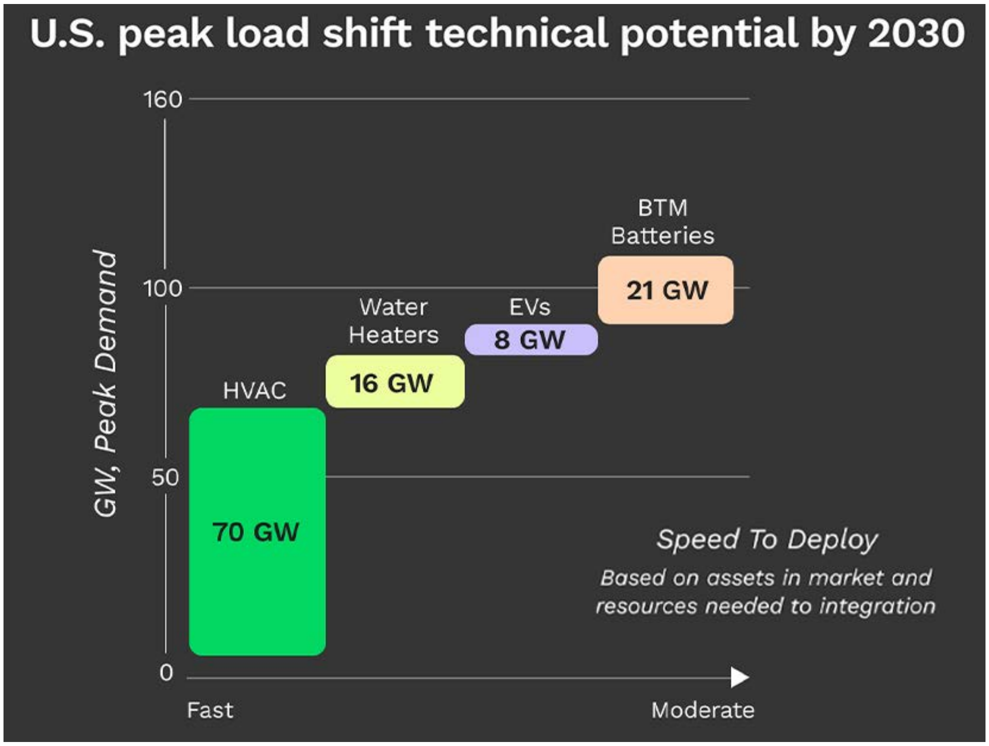
Just as they negotiated provisions for data centers, they must do the same for storage. PJM's next Order 2023 compliance filing is the time to make this change. ■

Mike Jacobs advocates at PJM, FERC and state commissions for the reliable expansion of the grid for renewable resources.

FERC/Federal News

Renew Home Foresees Bright Future for Residential VPPs

By James Downing



| *Renew Home*

Home energy management company Renew Home released a *position paper* last week arguing that the virtual power plants it creates with aggregations of residential customers can quickly be stood up to help meet growing demand.

As the generation mix shifts ever more toward intermittent renewable resources, the grid needs to be balanced at specific times, which VPPs can help with, Renew Home Executive Vice President Cisco DeVries said in an interview.

"We need to find hundreds of gigawatts of additional capacity in order to meet the challenges faced by the growth in demand for electricity and the management of more intermittent renewables," DeVries said.

VPPs are going to be key to meeting that demand because they can be stood up around the country much more cost effectively and quickly than other options, including building new natural gas plants, he argued.

"A lot of entities are taking an all-of-the-above approach: looking at natural gas, looking at batteries and looking at VPPs," DeVries said. "And fundamentally, from an economic perspective, it's really hard to get there with gas alone, right? Even if you set aside the climate and greenhouse gas impacts, which are significant, you still have an issue of building hundreds of gigawatts of new generation capacity, much of which is only needed for small portions of time in the year."

Renew Home is a member of Sidewalk Infrastructure Partners, which was formed as an independent entity out of Alphabet, Google's parent company. The company was created earlier this year by the merger of Google's Nest Renew service and OhmConnect, and is the largest residential VPP provider in the country, with almost 3 GW under control and plans to expand up to 50 GW by 2030.

Core to that expansion will be growing the number of smart thermostats to cover more of the 82 million homes that have central HVAC systems. Pairing every single HVAC system with a smart thermostat and linking them to a VPP could create 70 GW of load-shifting potential, the company argues in the paper.

Smart thermostats are the quickest way to set up residential VPPs, it says, but electric vehicles and distributed batteries are also part of the plants. The paper forecasts 8 GW worth of EVs and 21 GW of batteries charging by 2030.

VPPs come out of traditional demand response and can still provide that emergency service to the grid when needed, DeVries said, but they are meant to operate more often with less of an impact on the individual customers in an aggregation. They are "designed to run 3 to 5% of the time [and to] have predictable, reliable dispatch in a way that can be just as good as, if not better than, fossil fuel plants."

They can also do the same work as peaker plants, but even more cheaply without factoring any of the environmental externalities of their competitors, he said.

While most customers are not interested in being a resource that has to respond to changing grid conditions, spreading VPPs out among many customers with smart thermostats can get around and aggregate capacity without too much aggravation.

"We have millions of customers using Nest thermostats who have already given permission to flex their load," DeVries said. "To say, 'go ahead, make some modest adjustments in the temperature; pre-cool a little here; let it drift a little there; whatever you want to do. I'm comfortable with it.'"

Renew Home manages their thermostats every day to help customers manage time-of-use rates, save money on their bills and even to use power when the carbon intensity of the grid is lower.

"We have got not only an enormous stranded asset now, as far as gigawatts of existing load that is ready to be controlled today, but there is a near-term pathway to get that into the 50W to 70 GW over the coming few years, and that could transform the reliability of the U.S. grid and also help people actually reduce their energy bills pretty dramatically," DeVries said.

Electric water heaters could provide another 16 GW in load shifting if connected to smart controllers.

"There are millions and millions of hot water heaters that are put into people's homes every year, and with a small additional effort, those are all controllable and can be navigated in the same way we do thermostats," DeVries said. "Customers won't even notice it's happening, but their hot water heater will participate, essentially as a thermal battery shifting load around. The capabilities of that are dramatic." ■

CAISO/West News

Pathways Initiative Committee Floats Ideas to Protect Public Interest

Launch Committee Considers a States Committee, Consumer Advocate Organization for New RO

By Ayla Burnett

Protecting the public interest while implementing the Extended Day-Ahead Market (EDAM) and expanding the Western footprint was central to the discussion in a West-Wide Governance Pathways Initiative workshop Aug. 15.

"How are we going to continue to serve the public interest with an expanded footprint and with alternative, different governance?" Alice Reynolds, president of the California Public Utilities Commission, asked.

Members of the launch committee sought feedback on a combination of tools that could protect the public interest across the footprint of the regional organization (RO) the Pathways Initiative seeks to establish.

Beyond regulation by FERC, members discussed five main components that could be integrated into the structure of a new RO, including a stakeholder process, an independent market monitor, consumer advocate engagement, a states committee and an RO board.

In the implementation of an RO board, members emphasized public interest protection language in the articles of incorporation and the charter provisions. Also deemed important: a commitment to expand public benefits by attracting new participants, protecting individual state and local generation preferences and climate policies, holding open meetings and adhering to open records requirements.

Board members should have a history of protecting the public interest in their official roles, said Ben Otto, consultant with NW Energy Coalition and a launch committee member.

"There can be standards of duty for the board that are incorporated, like they have to act to protect public interest, and that is then their obligation when they're acting as a board member, to follow those requirements and not their own wishes," Otto said.

The RO also could establish a states committee that would maintain the current Western Energy Imbalance Market Body of State Regulators structure with a charter requiring protection of the public interest. Under this structure, states individually or through the committee could continue to submit 206 pleadings at FERC.

Other aspects of the committee would be

A transmission tower in Mountain View, Calif. | *Balise42, CC BY-SA-4.0, via Wikimedia Commons*

having access to market monitor data, having the power to originate a stakeholder initiative with support from half of the participating states or half the load, having a seat on the RO board, and having veto rights over RO board nominations with a two-thirds vote of states and load. A subset of the committee representing one-quarter of states or load could vote to trigger a requirement for a supermajority vote on a particular topic.

Consumer advocates also could play a role by participating in stakeholder processes, having access to market monitor data and obtaining a seat on the RO board.

"This is absolutely necessary to ensure that the board is well informed on consumer issues. Being informed on consumer issues, we think, is key to fulfilling the public interest mission that we've laid out here in Pathways," said Michele Beck, director at the Utah Office of Consumer Services and a member of the launch committee.

Individual consumer advocate offices aren't resourced enough to participate in these processes, Beck said, creating the need for a central consumer advocate organization that could maintain interaction with RO processes. Launch committee members suggested the creation of a 501(c)(3) organization that could facilitate consumer advocate participation. Beck highlighted the Consumer Advocates of the PJM States (CAPS) program as an example worth replicating.

Launch committee members also highlighted other existing structures within the CAISO model that could be carried forth in the new RO, including the ISO's Department of Market Monitoring and Market Surveillance Committee.

Additional 'Tools in the Toolbox'

Stakeholders provided additional ideas for protecting the public interest.

"One other tool that we should have in the toolbox for protecting the public interest is really allowing and enabling the public to participate in our decision making to the extent that it's appropriate," said Mark Specht, Western states energy manager at the Union of Concerned Scientists and a member of the launch committee. "Things we might consider would be creating some sort of office of public engagement that would really serve as a resource for folks who are interested in participating and having their voices heard in our decision making."

Preserving state and local autonomy within regions also was a primary point of conversation given the different laws, policies and preferences within each state.

"We've really been thinking about, how do we create a system that explicitly acknowledges and protects the ability for states to keep that authority in place and enables states to really develop their own vision of what the public interest is?" said Kathleen Staks, executive director of Western Freedom and co-chair of the Pathways Initiative. "What tools holistically across the entire regional organization ensure that the regional organization protects the public interest in lieu of a single state statutory requirement like we have with the CAISO today?"

Commissioner John Hammond of the Idaho Public Utilities Commission echoed concern over the challenge of defining the public interest given the array of different players.

"There are obviously common interests in keeping costs low and in reliability, but I worry about when we start getting into policy areas and what impacts that might have on the individual states that have different policies," Hammond said. "My fear is you start incorporating too many things in the toolbox, you might get a reaction legislatively from particular states … so I think it's very important that we define exactly what public interest we are trying to protect." ■

CAISO/West News

CAISO, WEM Boards Approve Pathways 'Step 1' Plan

Officials, Stakeholders Applaud Vote, Acknowledge Challenges Ahead

By Ayla Burnett

A proposal to elevate the Western Energy Markets (WEM) Governing Body's authority over CAISO energy markets was unanimously approved by the Governing Body and ISO Board of Governors Aug. 13.

The *proposal* by the West-Wide Governance Pathways Initiative is "Step 1" in a two-step effort to establish an independent regional organization to govern CAISO's Extended Day-Ahead Market (EDAM) and Western Energy Imbalance Market. (See *CAISO Advances Pathways Initiative 'Step 1' Proposal to Board Vote.*)

"In a little over a year, we've moved from the regulator letter to a full proposal that is before us today that will enhance and reinforce the capabilities of the Western energy markets," Scott Ranzal, director of portfolio management at Pacific Gas and Electric, said during the meeting.

"A celebration of today's vote and hope for the approval is certainly warranted, but it should quickly follow with additional action and effort to address the growing needs of the Western Energy Markets and that continued need for regional collaboration," Ranzal said.

The proposal received wide support, with 22 entities participating in the Step 1 stakeholder process expressing approval, six remaining neutral and one member of the public opposing.

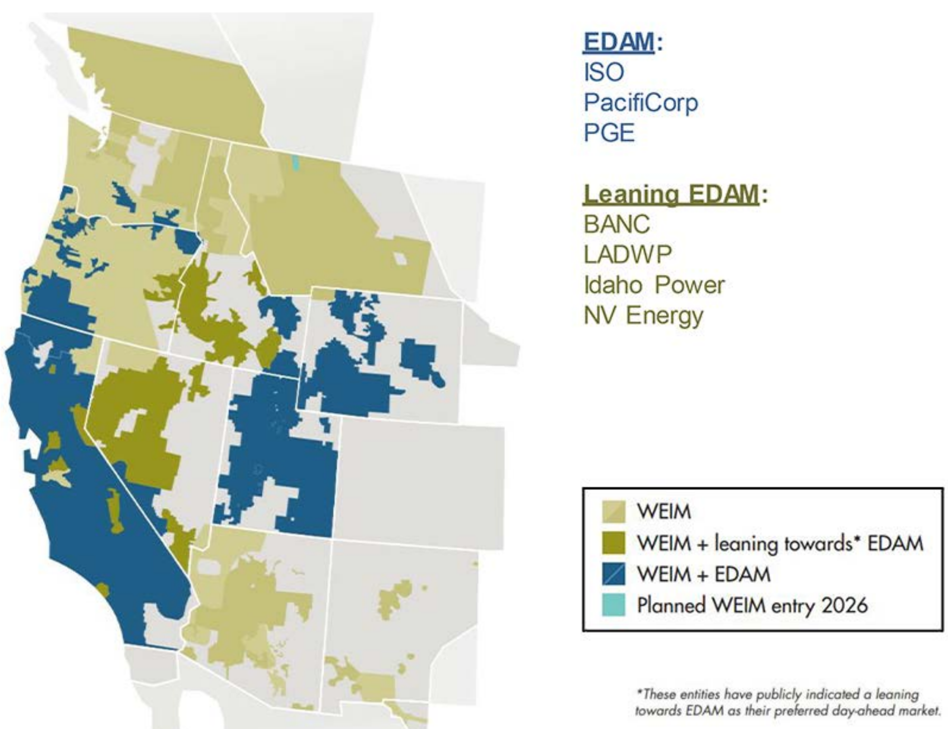
Before the proposal went up for a vote, Adam Schultz, manager of regional coordination at CAISO, provided an overview of stakeholder comments received in the process, placing them in two primary categories.

The first category included stakeholders' desire for more clarification of "exigent circumstances" that the straw proposal states are necessary if dispute resolution between the ISO board and the Governing Body is exhausted before a FERC filing.

The second concerns the trigger mechanism requiring that the FERC tariff filing needed to establish the Governing Body's primary authority over EDAM/WEIM issues wait until the EDAM obtains implementation agreements from a "set of geographically diverse" EDAM participants representing load equal to or greater than 70% of CAISO's balancing authority area annual load in 2022. The category also included concerns related to the scope of "primary authority" and with public interest language in the charter.

Schultz reiterated that issues in the first category were "exhaustively considered" by the Pathways Launch Committee. Topics in the second category included ensuring continuing collaboration between the board and the Governing Body, logistical details for the dual filing mechanism and the process for implementing Step 1.

Schultz said the second category of comments represented issues at a level of implementation detail not considered in depth by the Launch Committee and that will be considered later in a different stakeholder process.



| CAISO

'Hang in There'

Several officials spoke in support of the proposal and applauded the quick work it took to develop it.

"I believe the best governance is created by stakeholders through a broadly representative process," WEM Governing Body member Andrew Campbell said. "The universe of stakeholders needs to include the market participants, as well as the state government representatives and nongovernmental organizations that represent the public interest. Today's proposal is consistent with that principle."

Other CAISO officials saw the success of implementing Step 1 as a boost of confidence for the challenge ahead.

"Step 2 is going to be a heavier lift and a challenge, and I just want to encourage everyone to hang in there," said ISO board Vice Chair Severin Borenstein. "This showed a lot of cooperation and willingness to work together. We're going to need that for Step 2, which I think is where the real value will be unlocked." ■

CAISO/West News

Markets+ Backers Highlight Reliability in 2nd 'Issue Alert'

Funding Parties Laud Market's Integration with Western Resource Adequacy Program

By Robert Mullin

Arizona Public Service is among the group of Western utilities contributing to the '"issue alerts" supporting SPP's Markets+. | *Arizona Public Service*

The integration of Markets+ with the Western Resource Adequacy Program (WRAP) would be among a handful of key reliability benefits of SPP's Western day-ahead offering, according to an "issue alert" published Aug. 13 by 10 entities that backed development of the market.

The *alert*, sent to the Markets+ States Committee (MSC) on Aug. 13, is the second in a series of seven such notices intended to highlight the purported advantages of Markets+ over CAISO's Extended Day-Ahead Market (EDAM) and Western Energy Imbalance Market (WEIM). The first covered differences between how the two markets would be governed. (See *Governance is 'Key Consideration' for West, Markets+ Backers Say*.)

The Markets+ Phase 1 Funding Parties include Arizona Public Service, Powerex, Public Service Company of Colorado, Salt River Project, Tacoma Power, Tri-State Generation and Transmission Association, Tucson Electric Power, and the Chelan, Grant and Snohomish public utility districts of Washington state. The alerts aren't vetted by the MSC and don't represent the positions of the committee or of the staff for the Western Interstate Energy Board, which hosts both the MSC and the WEIM's Body of State Regulators.

"Market design elements that support electric system reliability must be considered prior to joining a market, as reliable service is not only expected by consumers; it is also essential to the safety and wellbeing of the general public," the alert said. "As evidenced by the impact of extreme weather events over the past several years, reliability risk is elevated."

The alert contends that Markets+ will address that risk because its "robust, stakeholder-driven governance framework" produced a market design with a "strong focus" on reliability. The parties to the notice also point out that SPP has a "long track record" as a reliability coordinator in both the Eastern and Western interconnections and through operation of the SPP RTO and Western Energy Imbalance Service (WEIS).

But the integration of Markets+ with the Western Power Pool's (WPP) WRAP, which SPP operates on behalf of the WPP, gets top billing in the alert. Under the Markets+ tariff, market participants must join the program "because a common and rigorous resource adequacy structure is foundational to reliability and critical to achieving equitable outcomes within a market footprint," according to the alert.

"WRAP applies a common approach for calculating resource capacity values and determining each participant's minimum obligation for resource adequacy, which, in the context of Markets+, will prevent market participants from being over-reliant on others' resources," the parties wrote, adding that the arrangement will ensure that capacity obligations — and the benefits of regional diversity — are "distributed equitably."

The parties contend also that the WRAP component of Markets+ will provide visibility into how various resources perform during critical hours "in a way that does not currently exist" and enforce resource deliverability requirements that will incentivize development of new transmission, "supporting reliable service to customers and the efficient integration of clean energy resources."

The alert further said that Markets+ "builds upon" WRAP's forward resource procurement requirement — an explicit commitment to make resources available during a specific time frame — that ensures the market has sufficient generation on hand during real-time intervals through use of a must-offer requirement that can only be satisfied by WRAP supply or other "specified resources."

"This approach improves reliability in the West by addressing those instances where historically some energy commitments have not been backed by reliable physical supply (and ultimately did not deliver to load)," the alert said.

The WRAP was originally scheduled to begin its "binding" penalty phase in summer 2026,

CAISO/West News

but this spring program stakeholders requested that step be delayed until summer 2027, saying that supply chain delays, rapid growth in regional peak load and extreme weather events are affecting participants' ability to procure enough capacity to meet RA requirements. (See *WRAP 'Binding' Phase Delay Finds Stakeholder Support*.)

'Fundamentally Different'

Non-California participants in CAISO's WEIM and EDAM are not required to participate in a resource adequacy program, but California utilities are subject to one overseen by the state's Public Utilities Commission. To prevent participants from leaning too heavily on the WEIM/EDAM to meet forecasted demand, CAISO instead administers a resource sufficiency evaluation ahead of each market interval to gauge whether each member is prepared to cover expectations for that interval.

The alert singles out that practice for particular criticism.

"Resource sufficiency tests applied in the operating time frame without the underpinning of a common resource adequacy program are inherently challenging for several reasons," the alert contended. "These reasons include challenges in accurately applying such a test, insufficient failure consequences to prevent deliberate leaning and insufficient notice of a deficiency due to the late timing of the test."

The alert called the tests "flawed," saying there have been "numerous examples of inaccurate outcomes" stemming from differing treatment between WEIM balancing authority areas and the CAISO BAA, although no specific examples were cited.

"This experience has reduced some stakeholders' confidence that an accurate resource sufficiency test will be applied in the day-ahead time frame for the Extended Day-Ahead Market," the parties to the alert wrote.

The alert additionally criticizes the WEIM/EDAM approach for resulting in "inadequate consequences."

"Regardless of whether a resource sufficiency test is applied accurately, a standalone resource sufficiency test does not provide adequate time to resolve supply deficiencies that may be identified," it said. "As a consequence, such a test necessarily relies on failure consequences that are known ahead of time to create incentives for participants to procure sufficient supply in advance to avoid failing."

The alert also argues that the lack of a common RA framework in the WEIM/EDAM could reduce liquidity in the day-ahead market because participants might hold back supply "in order to manage unforeseen risks in their individual areas through real-time operations."

"Such voluntary holdback actions for local reliability further diminish available resources in the market, diminishing the market's overall reliability and efficiency," it said.

The alert also cautions that utilities participating in both the WRAP and WEIM/EDAM could incur additional costs for having to meet two "unlinked" requirements: the WRAP's forward-showing obligation and WEIM's sufficiency test.

"Ensuring reliability is an essential priority that Markets+ and EDAM seek to address in fundamentally different ways, resulting in material differences in the reliability risk that will prevail in each market," the alert said. ■

ERCOT News

CenterPoint Energy Still in Eye of the Storm

Texas AG Latest to Open Probe into Beleaguered Utility

By Tom Kleckner

It's been six weeks since Hurricane Beryl, a Category 1 storm, blasted through the heavily wooded Houston area, toppling trees into distribution lines and knocking out power to nearly 3 million residents.

Electricity has been restored after weeks of recovery efforts, but lawmakers and regulators still are trying to figure out how a puny Cat 1 storm could have caused the devastation that led to long-term outages.

Houston utility CenterPoint Energy has borne the brunt of the scrutiny. Entergy lost several hundred thousand of its own customers in its Texas footprint; however, it had better communications with its customers and an *outage tracker that worked*.

Texas Attorney General Ken Paxton (R) became just the latest to probe the beleaguered company when he *launched an investigation* on Aug. 12 over allegations of CenterPoint fraud, waste and "improper use of taxpayer-provided funds" following Beryl. He said any unlawful activity his office uncovers will be met "with the full force of the law."

Texas Gov. Greg Abbott (R), who said in 2021 just four months after the disastrous winter storm that ERCOT's grid "is better today than it's ever been," has taken a hands-on approach with CenterPoint. He ordered the utility to file a plan outlining its preparation and response practices for the next storm, threatening to cut rates if the response was insufficient. After meeting with CenterPoint executives at the July 31 deadline, he *called* the plan "inadequate" and said "more must be done [and] faster."

Abbott also has *directed* the Public Utility Commission, whose members he appoints, to conduct a "rigorous" study to determine why severe weather events lead to "repeated ... power failures" in the Houston area. The PUC brought first-year CEO Jason Wells and other CenterPoint executives in for one hearing and is receiving regular updates from the utility. It plans to report its findings to the legislature by Dec. 1 (*56822*).

Both of Texas' legislative houses have joined in the fun and conducted public floggings of the utility's executives, with most of the ire coming from Houston senators. Wells was asked by Sen. Paul Bettencourt (R) whether he would heed calls for his resignation during a special Senate committee's July 29 hearing. Noting CenterPoint has laid out *40 actions* to immediately begin regaining community trust, Wells said, "I think if I resign today, we lose momentum on the things that are going to have the best possible impact for the greater Houston region."

The special Senate committee on severe storm preparedness. | *Texas Senate*

Some lawmakers were shocked — *shocked* — to learn during the hearing that CenterPoint's regulated business model allows it to recover storm-restoration, vegetation management, line maintenance and other costs in its rate cases, while earning a 9.4% return on capital investments. They called for more accountability from the utility, threatening it with clawing back profits, trimming rates, shrinking its service territory and implementing performance-based ratemaking.

"It's a pretty amazing business model," Sen. Lois Kolkhorst (R) told CenterPoint execs. "Most of us that run a business, we don't get reimbursements for our expenses."

However, it's CenterPoint's $800 million lease agreement for 15 large (32 MW) mobile generators and several smaller ones in 2021 that has attracted much of the politicians' focus. The utility said the larger generators could support restoration efforts after power outages. However, they sat unused after Beryl, as they have since being leased. The large units are so heavy they need permits to be transported and take days to set up.

Senators derided the generators as "quasi-mobile." Wells defended the lease agreement, which may have relied on *personal relationships*, saying the generators are necessary when there is another load shed event as occurred during the 2021 winter storm.

"I find it troubling that you've been using the rate of return on something that you're not using," said Sen. Charles Schwertner (R), the committee's chair. "It doesn't smell good at all."

"That's fraud!" Bettencourt charged, threatening to claw back rates related to the lease agreement.

As the senators piled on Wells, Jason Ryan, CenterPoint's executive vice president of regulatory services and government affairs, took to social media to say the large generators are a necessary tool in the toolbox to avoid a repeat of Winter Storm Uri.

"Like our own toolboxes at home, not every tool is used in every situation, and not every emergency generation asset in our fleet is likely to be used in any one event," he wrote on X, formerly known as Twitter. Ryan's account no longer exists.

Sen. Phil King (R), who wrote the legislation that cleared the way for regulated wires

ERCOT News

provider CenterPoint to acquire generation, apologized to the committee after Wells' testimony.

"The intent was to simply allow there to be very mobile storm response generation," he said. "It was never intended, at least by me, to allow it to be used for large generation of the nature we've talked about today. I feel like I've been taken advantage of, to be honest. We will fix that going forward."

Following the hearing, Lt. Gov. Dan Patrick (R), who essentially runs the Senate, sent a letter to the PUC urging it to claw back the $800 million to ensure ratepayers do not pay for CenterPoint's "mismanagement." Schwertner promised lawmakers "will hold CenterPoint accountable for lining its pockets at the expense of its customers" in the coming months.

Apparently, renegotiating the generators' contract is not an option. Ryan told the PUC during its Aug. 15 open meeting that CenterPoint can't break the contract unless the vendor, Life Cycle Power, fails to meet its obligations. That left the commissioners incredulous.

"You entered into a contract you can't terminate unless there's vendor non-performance," Commissioner Lori Cobos told Ryan. "It just seems like we're in this circular place where you all are coming across like your hands are tied to this contract."

Energy consultant Alison Silverstein, a former PUC and FERC adviser, said the easiest way for Texas regulators to punish CenterPoint would be to reopen the mobile generation case and assess whether CenterPoint provided "accurate or misleading" information about the generation assets and their intended purpose.

"This could be a pretty fast proceeding and could look like enough of a spanking to make customers and politicians happy," Silverstein told *RTO Insider*.

She dispelled the notion that a new wires provider could be handed the franchise for the nation's fourth-largest city.

"Outside of Florida, no utilities are doing a competent job dealing with hurricane-heavy service geographies," Silverstein said.

Performance-based ratemaking could be one option, she said, by aligning all utility incentives

CenterPoint CEO Jason Wells gathers his thoughts during a pause in the Senate hearing after a technical glitch. | *Texas Senate*

(profits, cost recovery, executive compensation) with reliability, resilience and affordability. At the same time, Silverstein doubted the PUC would revise the state's ratemaking rules on its own.

"This would be a long and boring process that won't have the speed, bloodletting and circus elements or assured outcome that would make local and state politicians happy," she said.

"I think we need a comprehensive look at how we fund utilities, how they prepare for storms," PUC Chair Thomas Gleeson said during the Senate hearing.

The day after that hearing, CenterPoint held its quarterly earnings call with financial analysts and reported a 93.2% increase in earnings. It said it planned to ask the PUC to recover between $1.5 billion and $1.7 billion in Beryl storm costs.

"That dog won't hunt," Sen. Carol Alvarado (D) said on X.

Two days later, CenterPoint withdrew both its $2.3 billion resiliency plan filed in April (56548) and its rate-increase request to recover $6 billion of investments made since its last rate proceeding in 2019 and expand its return-on-equity (56211). The utility had been negotiating settlements in both dockets.

However, on Aug. 16, the state Office of Administrative Hearings rejected the rate case's withdrawal. The court said the withdrawal would conflict with state law requiring investor-owned utilities in the ERCOT region to file a comprehensive rate review within 48 months of their most recent rate proceeding.

Consumer groups opposed CenterPoint's request, saying it would prevent them from clawing back certain expenditures.

Since then, CenterPoint has continued to try to make amends. The utility rolled out its Greater Houston Resilience Initiative that tracks its progress in substituting composite poles for wood structures and its vegetation management program; unveiling a new cloud-based outage map to replace its locally hosted version that crashed during a derecho in May; fired its senior vice president of electric business; beefed up its social media presence, with more than a dozen posts on *X* on Aug. 17-18 alone; and held the first of 16 community open houses through September.

PUC staff is attending each of the open houses and will lead a public work session in Houston Oct. 5. The commission also created a web tool to gather feedback from Houston residents.

"What was good enough 15 years ago is not good enough anymore," Gleeson told the Senate committee. "We have not held them to a standard that is sufficient. I think we need a comprehensive look at how we fund utilities and how they prepare for storms." ■

National/Federal news from our other channels

The IRA at 2: A Mixed Record of Achievement and Uncertainty

NetZero Insider

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

ISO-NE News

NEPOOL Reliability/Transmission Committee Briefs

Regional Network Service Rate Increase

New England transmission owners have *presented* a regional network service (RNS) rate increase to $185 per kW-year for 2025, an increase over the $154 per kW-year rate in 2024.

The increase was explained by Jim Augelli of the Participating Transmission Owners Administrative Committee at a joint meeting of the NEPOOL Reliability and Transmission Committees (RC and TC) on Aug. 13. The rate stems largely from incremental revenue requirements and a true-up to account for under-collection in 2024, Augelli said.

David Burnham of Eversource Energy presented the RNS rate *forecast* for 2026/29, estimating the rate will increase from $185 per kW-year in 2025 to $217 per kW-year in 2029.

Asset condition projects are projected to account for nearly half of forecasted regional investments in 2024 at $814 million and are projected to increase to $965 million in 2025. Regional system plan projects are projected to cost $622 million in 2024 and $254 million in 2025.

Regional Energy Shortfall Threshold

On Aug. 14, ISO-NE provided an *update* on its work to develop a regional energy shortfall threshold (REST), which is intended to determine an acceptable level of load shed risk during extreme weather events, serving as a complement to the traditional one-day-in-10-years standard. (See *ISO-NE Provides Update on Potential New Resource Adequacy Metric*.)

The effort to improve upon traditional approaches based on one-in-10 loss of load expectations is part of a broader trend toward more advanced methods of evaluating shortfall risk.

In July, a working group convened by NERC and the National Academy of Engineering issued a *report* recommending NERC develop a "multi-metric approach" to supplement traditional loss-of-load expectation with expected unserved energy and loss-of-load hours, with a long-term eye at developing additional metrics.

"LOLE does not adequately account for the growing risk, over all hours, arising from increased variability and uncertainty caused by the evolving resource mix and increasing demand levels," the report stated. (See *Report Says New Energy Metrics Needed*.)

Jinye Zhao of ISO-NE said the RTO still is assessing which extreme weather events should be used to evaluate shortfall risks.

Zhao said ISO-NE is ranking "all possible 21-day events based on average system risk" to identify those with the highest risk and will further evaluate event candidates by considering key system factors such as fuel inventories, prices and generator outages.

Mike Knowland of ISO-NE said there have been "no notable changes in ISO's current thinking with regard to REST periodicity or REST metrics and thresholds" since the RTO's update in May.

Votes

The RC voted to support *conforming changes* to ISO-NE planning procedure 5-6 associated with Order 2023 and Order 2023-A compliance.


ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

Alex Rost of ISO-NE said additional changes may be needed to the planning procedures after the start of the transitional cluster study but prior to the start of the first cluster study.

The RC also voted to support *revisions* to Operating Procedure (OP) 12, which relates to voltage and reactive control. The revisions stemmed from the periodic review process and would affect voltage control options and voltage scheduling.

The committee also supported *changes* to OP-23 related to generator form submission rules for resource auditing. ■

— Jon Lamson

ISO-NE News

FERC Establishes Settlement Procedures for ISO-NE IEP Exit Request

By Jon Lamson

FERC established on Aug. 12 settlement judge procedures in response to a waiver request from a generator seeking to exit ISO-NE's inventoried energy program (IEP) and refund the net revenues received from the program (*ER24-1407*).

The IEP compensates generators for maintaining fuel inventories in the winter and applies to the winters of 2023/24 and 2024/25.

In March, Canal Marketing asked FERC to allow the company to withdraw from the program for the 2023/24 winter period and return the net revenues, plus interest, that it received from its participation in the program.

The company operates a 333-MW gas and oil generator that has been out of service due to a mechanical issue since early 2023. Canal said it initially anticipated the generator would return to service in time for most of the 2023/24 winter, but delays extended the outage through the entire winter.

Canal alerted ISO-NE of the delay in December 2023 and determined ISO-NE's tariff does not include provisions that enable "the return of net revenues by a market participant in this particular situation or for a participant to withdraw from the program once its election submission has been accepted by ISO-NE."

In its request to FERC, Canal said granting the waiver "would not harm any third parties" and that the returned revenues would be "allocated to the market participants that are responsible for the costs of the program."

Following the request, ISO-NE offered its support for the proposal to return the net revenues. The ISO-NE internal market monitor (IMM) also supported the return of revenues in comments to FERC, while emphasizing the importance of sticking to a "narrow remedy" to the issue.

A winter storm in Boston | *© RTO Insider LLC*

"Any remedy should be narrowly tailored to preserve the incentives and the design of the program," the IMM wrote. The market monitor cautioned that any solution must not enable IEP participants in the upcoming winter period to retroactively exit the program if they experience net losses.

"This could create a 'heads I win, tails you lose' situation for the upcoming 2024-2025 winter program: a participant that erroneously (or even wrongfully) qualifies for the IEP, could wait-and-see the outcome, and then at the end of the program file for a waiver and return of money if it is in its favor, or not," the IMM added.

In response comments filed with FERC, Canal disagreed with the IMM's concerns about broader implications of a waiver, arguing the company communicated to ISO-NE its intention to withdraw from the program and return its net revenues in mid-December 2023, and that it took time to determine the best course of action to remedy the issue.

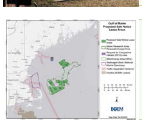
FERC ordered settlement judge procedures "to permit the parties to seek a settlement to resolve whether and how Canal Marketing should return to ISO-NE the revenues or net revenues."

The Commission added that "with regard to the IMM's concerns about future erroneous qualifications for, and late withdrawals from, the IEP, we note that we are establishing settlement judge procedures here based on the unique circumstances and the various arguments raised by parties to this proceeding." ■

Northeast news from our other channels

Mass. Breaks Ground on Salem Offshore Wind Terminal

NetZero Insider



Maine Approved for Floating Wind Research Lease

NetZero Insider

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

MISO News

Some MISO Regulators Signal Early Discontent with New MISO-PJM Interregional Study

By Amanda Durish Cook

Some members of the Organization of MISO States are implying that MISO's new interregional study with PJM is falling short of their hopes for a rigorous search for seams transmission projects.

At an Aug. 14 MISO Advisory Committee meeting, OMS Executive Director Tricia DeBleeckere said OMS is exploring next steps regarding whether the requests contained in its joint letter with the Organization of PJM States Inc. (OPSI) line up with the aims of MISO and PJM's new transfer capability study. She also said OMS wants more visibility from MISO into the inaugural study.

OMS and MISO will continue to meet to discuss the scope of the study, regulatory staff said at an Aug. 15 OMS Board of Directors meeting.

MISO and PJM have said they will pursue only smaller, near-term projects at the seams for the inaugural study, not the more complex, interregional construction that requires greenfield development. (See *Smaller Projects Expected from Maiden MISO-PJM Joint Tx Study*.)

At a late July OMS meeting, Michigan Public Service Commission Chairman Dan Scripps said representatives from the Organization of MISO States approached MISO officials about the limits of the study scope.

| © RTO Insider LLC

Scripps said while MISO may envision potential projects as a simple reconductoring of lines, that's not exactly what OMS and the OPSI meant when they requested more meaningful interregional planning.

"I think there are some additional conversations needed, and I hope we can go further than what's been put on the table," Scripps said.

At the time, Scripps said regulators would meet with MISO planners again on "whether this hits the mark."

"We kind of got cut out of the conversation on the scoping of this study," Wisconsin Public Service Commissioner Marcus Hawkins said.

Responding to regulators' observations, MISO Vice President of System Planning Aubrey Johnson said MISO and PJM "have a long history of working together to address operational and planning challenges in our regions."

"We will continue working with our regulators and other grid operators to explore interregional planning solutions with a focus on both addressing near-term needs and building a framework for future studies," Johnson said in a statement to *RTO Insider*.

At the August Advisory Committee, MISO members said OMS and OPSI's letter urging more dynamic joint planning should be featured during the MISO Board Week meeting Sept. 18, where MISO members and board members are set to hold a discussion *titled* "Seams: Reliability and Market Efficiency Across Borders."

WEC Energy Group's Chris Plante said MISO and PJM also should consider improving coordination on larger projects that are near the seams but aren't interregional projects. He cited ComEd's expansion of its 765-kV Wilton Center substation to accommodate more renewable energy and its potential impact on the MISO footprint. ■

Members Want More Features in New MISO Load Tracking

By Amanda Durish Cook

MISO continues to try to get a bead on load growth and took stakeholder suggestions this week on how best to monitor sizable future load additions across the footprint.

MISO since late June has maintained a list of large load *announcements* in its footprint.

At an Aug. 14 Advisory Committee teleconference, Stakeholder Services Executive Director Suzie Jaworowski said MISO envisions the list becoming a dashboard-style feature on its website to track significant new load announcements.

MISO members asked that the list contain features to make it easier to interpret.

The Coalition of Midwest Power Producers' Travis Stewart asked MISO to include a baseline load forecast alongside the load additions list. He said it would be helpful to compare forecasts made before large load announcements.

"There isn't a reference point for load forecasts one year, five years and 10 years down the line and how these incremental increases are going to affect [them]," Stewart said.

However, Jaworowski said the load catalog isn't meant to serve as a forecasting document or be used for planning purposes.

"This is just one more channel ... that opens our eyes to the potential. It doesn't mean all of these are going to be built," Jaworowski said.

Clean Grid Alliance's Beth Soholt said the list is "confusing" because it's not clear which projects load-serving entities already have included in the load projections they submit to MISO.

"I think the key question is, 'Are we planning for these?'" Soholt said.

The Union of Concerned Scientists' Sam Gomberg also requested that MISO indicate which load entries are planned to host onsite generation.

Jaworowski said MISO would consider both suggestions.

"I think as we move forward, this will evolve into something very helpful for everyone," she said.

Minnesota Public Utilities Commissioner Joe Sullivan said MISO neglected to add Microsoft's intentions for the vacant manufacturing space at Foxconn's facility between Milwaukee and Chicago, as well as Google's plan for a data center in rural Minnesota.

Jaworowski said MISO compiled the list after researching publicly announced plans for new or expanded facilities. She said MISO planners will search again for missing plans.

MISO has said it plans to update its load addition list periodically as more announcements are made. In June, MISO executives said announced load additions in the footprint from manufacturing projects and data centers totaled more than 8 GW. (See *MISO Leadership Issues Urgent Call for In-Service Dates*, *MISO Members Stress Need for Speed to Manage Load Growth, EPA Carbon Rule*.)

The Advisory Committee will have a daylong meeting Sept. 18 in Indianapolis during MISO Board Week. There, members plan to hold a *discussion* on how to keep costs affordable as the demand for electricity rises and aging infrastructure is traded for new grid technologies. ■

MISO's Advisory Committee in front of the board of directors in June | *© RTO Insider LLC*

MISO News

2023 Queue Cycle Delayed into 2025 as MISO Seeks Software Help on Studies

By Amanda Durish Cook


Construction of Entergy Arkansas' Searcy Solar Energy Center | *Entergy*

MISO said its 123-GW collection of projects in the 2023 queue cycle will be subject to another delay into early 2025 as it pauses to see if a tech startup can help it better scale interconnection studies.

In an email to stakeholders Aug. 13, MISO announced it will hold off on starting the definitive planning phase for the 2023 interconnection until February. The RTO said the extra time will allow it to enlist the help of Pittsburgh-based Pearl Street Technologies to better manage interconnection studies.

MISO previously said it solicited help from Pearl Street Technologies to see if the company's *SUGAR* (Suite of Unified Grid Analyses with Renewables) software can speed up interconnection studies. Pearl Street has claimed its software can model more generation projects for transmission operators and drastically cut back time spent on engineering analysis.

MISO said the delay in conducting studies ultimately will help it "process more interconnection applications in a timely manner." It also said it would expand Pearl Street's assistance from model development to power flow analysis and network upgrade identification.

"MISO would like to take this opportunity to reassure customers that we are committed to processing interconnection requests in a timely manner," the RTO said to its stakeholders.

In a statement to *RTO Insider*, MISO said it's working with Pearl Street to establish some automation in the queue study process that will allow it to complete the first phase of studies more quickly. The RTO said it would begin studies on the 2023 cycle after it can implement automation and after the 2022 cycle of projects clears the first study phase of the three-part interconnection queue.

If it deems all the 2023 applications valid, MISO has said its queue could grow to nearly 350 GW.

MISO told stakeholders more discussion on the 2023 queue class will take place at upcoming meetings of the Planning Advisory Committee and Interconnection Process Working Group.

The 2023 queue cycle already was delayed last year, as MISO sought permission from FERC for steeper penalties, higher fees and more binding proof of land use as a means to get a handle on the sheer number of projects lining up annually for grid treatment. The grid operator ultimately didn't begin certifying the 2023 class until spring of 2024.

The 2024 cycle also is destined for delays. While it's unclear if the current software delay will affect when MISO begins processing 2024 entrants, MISO already planned to postpone this year's cycle while it tries again to win FERC approval of an annual megawatt cap on projects that may enter. (See *MISO Sets Sights on 50% Peak MW Cap in Annual Interconnection Queue Cycles*.)

MISO said it doesn't "anticipate closing the window for the next queue cycle until after a cap filing is submitted and accepted by FERC, which is currently on track for 2025." MISO pointed out it's currently accepting online applications for the next cycle of interconnection requests, though it's waiting to kick off any studies.

Meanwhile, clean energy developers' interest in queueing up appears full steam ahead. Last week, developers Ørsted and Mission Clean Energy *announced* their intent to join forces to build 1 GW of battery storage in MISO Midwest. Mission Clean Energy plans to submit applications for four projects across MISO's North and Central regions and give Ørsted the option to buy an ownership stake later in the process.

Ørsted said the storage plans are its first-ever standalone battery storage partnership, in the U.S. or globally.

"Continuing to invest in and build out storage solutions is critical for ensuring a resilient and reliable grid, and this partnership with Mission advances this important goal," Ørsted Chief Commercial Officer James Giamarino said in a release. ■

MISO News

FERC OKs $116M Settlement for New Orleans over Grand Gulf Nuclear Mismanagement

By Amanda Durish Cook

Students tour the Grand Gulf Nuclear Station's simulator in 2023. | *Entergy*

FERC sanctioned a partial settlement to resolve many of the New Orleans City Council's longstanding complaints over management of the Grand Gulf Nuclear Station.

The commission in an Aug. 14 order said Grand Gulf operator and Entergy subsidiary System Energy Resources, Inc.'s (SERI) $116 million partial offer seemed fair and in the public interest (*ER18-1182-008*).

The settlement resolves numerous grievances New Orleans officials made in 20 FERC dockets related to subpar Grand Gulf operations, ratemaking and tax violations that shifted costs to customers, an unreasonable capital structure and return on equity and excessive costs of the Grand Gulf sale-leaseback renewal. The earliest docket involved in the settlement stretches back to 2017.

The New Orleans City Council *settled* with Entergy unofficially last spring in a three-part agreement: $116 million to settle allegations around misconduct within SERI; $138 million more to resolve allegations of dubious tax accounting; and lastly, $500,000 to put concerns over reliability to bed. (See *Entergy Earnings Call Focuses on La. Resilience Plan, Nuclear Outage and Settlements*.)

The partial settlement provides a return on equity moratorium: SERI will use a fixed, 9.65% ROE in monthly sales to Entergy New Orleans that began in June and will continue through June 30, 2026. The agreement also stipulates SERI's equity ratio in its capital structure won't exceed 52% in bills to Entergy New Orleans.

Entergy's operating companies in Arkansas, Mississippi, Louisiana and New Orleans purchase Grand Gulf's power through SERI. The state public service commissions from the trio of states all have or are on the verge of agreeing to their own settlements with SERI over mismanagement of the southwest Mississippi nuclear plant, with Louisiana the latest to agree to an offer. (See *Entergy Touts Louisiana Settlements, Beryl Response in Q2 Earnings*.) ■

NYISO News

NY Orders Utilities to Join in Proactive Grid Planning

Electricity Demand Growing Faster Than Traditional Planning Processes Can Respond

By John Cropley

New York is *ordering electric utilities* to plan for expected future demand from the clean energy transition and identify urgent infrastructure needs that already exist.

The Public Service Commission on Aug. 15 ordered "proactive planning for upgraded electric grid infrastructure" (Case *24-E-0364*) with hopes of meeting the increasing loads created by electrified buildings and battery-powered transportation.

New York and its electric utilities have anticipated and planned for much higher electric use for most of a decade. But it often has been a top-down process that can move much more slowly than load grows. So, a bottom-up approach that is more granular — and hopefully much faster — is being added.

The state's six major investor-owned electric utilities are directed to collaborate to develop two filings: a proposal for proactively planning to meet the future needs of transportation and building electrification and a proposal identifying urgent needs that may need to be met before the process detailed in the first proposal can be put into motion.

Heat pumps and electric vehicle chargers can be ordered and installed in a matter of weeks or months, but an upgrade to the utility infrastructure supporting them can take more than seven years to move from concept to completion.

The order seeks to narrow this gap, and also to create a unified planning process across the utilities to reduce the chance of infrastructure upgrades being redundant, insufficient or misaligned across utility territories.

This new bottom-up process is intended to complement the Coordinated Grid Planning Process (CGPP) *created in August 2023* (Case *20-E-0197*), which involves the same utilities but is more suited to a top-down focus on high-voltage transmission, the order explains.

The utilities are directed to recommend whether this new proactive process can formally integrate with the CGPP and, if so, how.

When Schuyler Matteson, clean energy planning lead at the Department of Public Service, completed his presentation on the proposed order, PSC Chairperson Rory Christian said, "I want to clarify something in case some are left with the impression we just figured this out. We did not. In fact, this particular proceeding has been quite some time in development."

An Orange and Rockland Utilities substation is shown in Airmont, N.Y. | *Shutterstock*

Some of the PSC cases on which this new process is built date back almost a decade, Christian added. "We've known this problem was coming."

Commissioner John Maggiore asked, "Why haven't we done this already?"

Matteson explained how it took so long, rather than why: Some groundwork already was in place, but the PSC's July 2020 electric vehicle make-ready order really began the process by which staff "identified some significant differences between planning for transportation loads versus traditional electric system planning and how there was some conflicts there in the ways the loads show up and how to plan for those loads."

Commissioner Uchenna Bright asked if the rate of electrification of buildings and vehicles had accelerated and if the state is trying to be more strategic about infrastructure investments in response.

"I think that's exactly right," Matteson said. "We had fairly stable both peak and average load growth over the last five or 10 years. But as we see fleets responding to both our policies and national policies, we see large, very chunky popcorn-type loads popping up around the state that might be 5, 10, 20 megawatts at a time, which is a very significantly sized load." Sales of individual electric vehicles and heat pumps add to the load, he said.

Commissioner Denise Sheehan said she thought coordinating the new proactive process with the existing CGPP would be essential. She asked about the economic development potential.

"I would say there's a couple of ways it's implicated," Matteson replied, noting the number and variety of new load requests coming in and the different approaches to meeting them.

"So, a lot of the largest types of loads, the 50-, 100-MW-plus loads that might be coming into the system, they're likely to be captured under the Coordinated Grid Planning Process, because they often have transmission-level interconnections," he said.

"But to the extent that we do see significant adoption of new loads coming on of the system on the distribution network, those will have to be incorporated into the distribution scale load forecast that the utilities will use to identify these infrastructure planning upgrades."

Commissioner Radina Valova said her main concern in considering the draft order had been whether the loads utilities projected actually would materialize.

"Will the commission have the opportunity to review the utilities' proposed forecasting methodologies," she asked, "including their underlying inputs and assumptions, the methodologies that they will use specific to the proactive planning process?"

Matteson replied that it's important to fill the gap "that we think exists right now in terms of really granular, longer-term forecasting for EVs and building electrification."

As part of the filing that's requested, 120 days from now, utilities will propose "those different load forecasts, those planning methodologies." That allows time to evaluate utility proposals, and in "the actual development process of the planning framework, we expect to have some more back-and-forth with the utilities on specifically what data sets are most relevant here."

Commissioner David Valesky also asked about the commission's role going forward.

The PSC will be involved repeatedly and soon, Matteson said.

"We heard about a couple of [urgent projects] through our stakeholder process and through the technical conferences where National Grid and Con Edison have already identified projects that may need to enter construction within the next year or so, so those urgently needed projects would come within about 90 days, and then we'd be able to evaluate the need to fund those projects," he said.

The commission approved the order with a 6-0 vote. ■

NYISO News

NYISO Operating Committee Briefs

SDC St. Lawrence Data Center Requires Substantial Grid Upgrades to Interconnect

The NYISO Operating Committee has approved two study reports and one study scope, all of which involve load projects in northern New York.

The SDC St. Lawrence Data Center interconnection study modeled the impact of the 120-MW load project on the local system. NYISO staff found that the project would cause thermal overload that could not be mitigated with adjustment. In sensitivity scenarios, the project caused voltage violations and voltage transfer degradation.

NYISO estimated the cost to build the attachment facility for the interconnection is $55 million, plus or minus 50%, and it would take about 54 months to complete. The cost to mitigate the thermal overload issues and the voltage transfer degradation issues were $33.6 million and $37.5 million. Voltage violations would cost an estimated $2.5 million to mitigate. An additional estimated $39 million would be needed to mitigate thermal issues at the transformer.

The customer asked if there was a different software package that could be used to help reassess costs.

"We can take it back and consider it, but I don't believe the additional capability of the distributed model at St. Lawrence would resolve these overloads" or alleviate upgrade costs, said Aaron Markham, vice president of operations for NYISO.

In the study report for the Massena Green Hydrogen project, a 110-MW hydrogen electrolysis plant, no adverse impacts to the grid were found. NYISO found that interconnection would be feasible with the construction of a new three-breaker and bus substation. The estimated cost for the interconnection would be about $27.7 million, and the project would take two to three years to complete.

The Cayuga Compute 150-MW data center scoping study was discussed and approved. The study will perform reliability and cost-estimation analysis similar to the reports listed above.

Other Business

The Operating Committee also heard the July 2024 Operations Performance Report. Peak load was 28,990 MW, which set the new summer 2024 peak. Markham said this was because of higher-than-average temperatures.

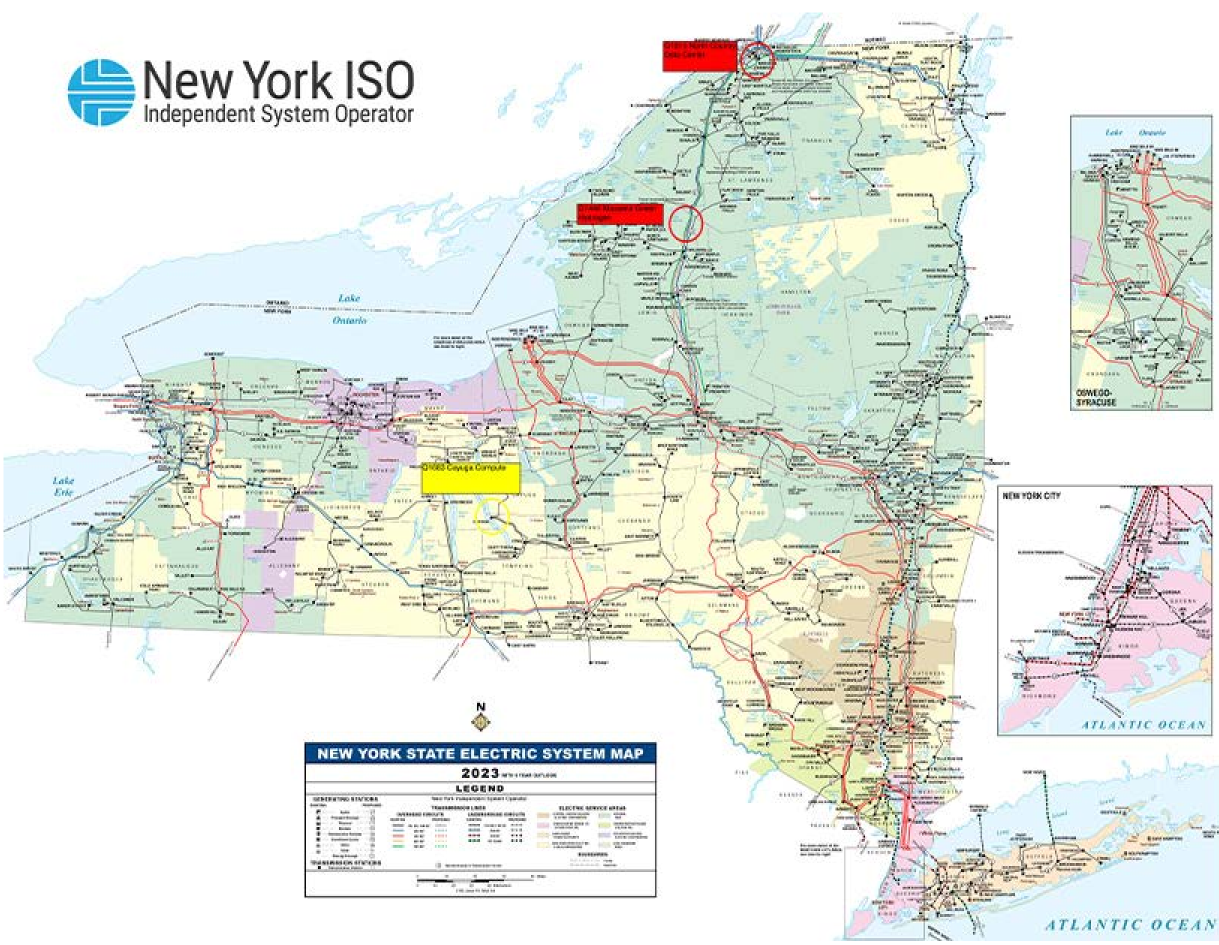
He noted that NYISO also had to call on the Emergency Response Demand Program and Special Case Resources during the evenings of July 15-16. Markham said they hit scarcity pricing on both days.

"On the 16th of July, a number of severe thunderstorms, including 10 confirmed tornadoes, occurred in the state as the remnants of Beryl passed through," Markham said. He said that caused simultaneous outages for about 275,000 customers.

"There was a tornado in Buffalo early last week, and from what I saw, that broke the [record for the] number of tornadoes that occurred in the state," Markham said. "That was 25 back in 1992; we are up to 26 this year."

The committee also reviewed and approved supplemental manual updates for constraint-specific transmission shortage pricing. These updates to the day-ahead scheduling manual and transmission dispatch operations manual are described *here*. Drafts may be seen *here* and *here*. ■

— Vincent Gabrielle



| NYISO

NYISO News

NYISO Tariff Revisions Include Uncertainty Reserve

Need to Account for Uncertainty in Solar and Wind Cited

By Vincent Gabrielle

| Convergent Energy and Power

NYISO staff have presented tariff revisions that may be deployed as early as the first quarter of 2026 to account for the uncertainty of wind and solar energy forecasts. The filing date with FERC has yet to be determined.

If accepted by FERC, the revisions would add *two new items to the tariff*, uncertainty reserve requirements and scarcity pricing in 30-minute reserves for the New York Control Area and several downstate zones. These requirements would add a stepwise demand curve to the market.

"Uncertainty reserve requirements for operating reserves are here to account for the forecast uncertainty of node wind and solar energy forecasts," Vijay Kaki, market design specialist for NYISO, said at the Installed Capacity Working Group meeting Aug. 13.

Kaki explained the uncertainty reserve requirements would be calculated for, and apply to, the day-ahead and real-time markets. For the day-ahead market, the uncertainty reserve would apply only to the 30-minute reserve product. In the real-time market, these new reserves would be calculated for both 10- and 30-minute reserve products.

For the day-ahead market, the reserves would be calculated for each hour of the day, before the day-ahead market run.

"It's a daily change," said Kaki, explaining this was based on annual forecast data. "The annual metrics are calculated once a year, and those metrics will be applied to the day and market forecast data on a daily basis."

The NYISO price scheme is intended to encourage generators to respond quickly to requests for energy to meet reliability requirements. The market would pay more for generators who activate when operating reserves and uncertainty reserves are low.

Revisions to the tariff, along with a consumer impact analysis, are expected to be done by the end of the third quarter.

Winter Reliability Enhancements

After discussing the tariff revisions, NYISO presented the winter reliability capacity enhancement *project* that tentatively is scheduled for 2025. The idea is to ensure the capacity market provides the correct price signals all year to ensure reliability as New York transitions to a winter-peaking system.

"We're looking at this project to consider what would be the process for setting winter CAFs [capacity accreditation factors] and would they be any different," said Michael Swider, senior market design specialist for NYISO.

Swider said the market needed to be evaluated to look for elements that are more affected by a more seasonally differentiated capacity market. Currently there is one installed capacity requirement that is applied to an entire year that is forecast based on annual peak load, which occurs in summer.

NYISO projects the system will transition to a winter peak in the 2030s. The RTO has stated its concerns about fuel constraints occurring in winter, particularly if the system is winter peaking. (See *NYISO Braces for the Coming Winter*.) Because the current ICAP is calculated based on summer load, NYISO staff worry the current system may cause reliability and market issues. ■

NYISO News

NYISO Presents Initial 2025 Project Budget Recommendation

Some Stakeholder Favorites Might be Cut

By Vincent Gabrielle

Kevin Pytel, NYISO director of product and project management, presented the ISO's initial 2025 budget *recommendations* Aug. 13 to the Budget and Priorities Working Group.

If approved, the 2025 budget for projects would be about $42.1 million. More than half of that would be spent on labor and professional services to execute projects.

The projects selected for initial inclusion include:

- capacity market structure review: a look at whether changes are needed to send accurate price signals in the capacity market.
- engaging the demand side: a project that would let behind-the-meter solar supply energy to wholesale markets.
- balancing intermittency: an attempt to maintain reliability with intermittent, zero-emissions power via potential market rule changes.
- winter reliability capacity enhancements: a project intended to address the looming challenge of a winter peaking system to the ICAP market.
- winter fuel constraint study: a look at how extreme winter weather could affect the fuel available to natural gas generators and how fuel constraints could change over the next decade.

Detailed project descriptions can be found *here*.

"We're really trying to maximize the value of the markets with this proposal and pay attention to stakeholder scores to ensure that we're choosing projects that have stakeholder support," Pytel said.

"We recognize that there are a lot of high-priority projects that were scored that were not selected in the initial recommendation," Pytel said. "If there are projects that you feel should be in the recommendations, which projects would you like to see come out to accommodate those?"

Kevin Lang of Couch White drew attention to the operating reserves performance project that was cut. "There was one in particular that piqued our interest that isn't about maximizing value; it's about protecting people and making sure that we're not giving certain market participants windfall profits that didn't make your list," Lang said.

The operating reserves performance project would ensure that energy suppliers' stated operating reserves were accurate and that suppliers were compensated to reflect actual performance.

NYISO headquarters in Rensselaer N.Y. | *NYISO*

Pytel said all feedback would be shared with NYISO executives. He said NYISO's CEO was available to speak with stakeholders who felt strongly about some particular project or other.

This is the second-to-last phase of developing the budget before NYISO proposes its initial 2025 budget in September. NYISO will take feedback and return to stakeholders with revisions Aug. 27. The 2025 budget is scheduled to be finalized by Nov. 19.

Pytel highlighted several high-priority projects that were not selected due to resource constraints. The hybrid aggregation model project, which would broaden the number of resources that could use on-site energy storage and share the same interconnection, was put on hold until 2026.

A project to develop an operating protocol to integrate Champlain Hudson Power Express (CHPE) also was removed from the proposed budget. CHPE is a high-voltage connection between Hydro-Quebec and NYISO that's expected to come online in 2026.

Several continuing projects have been delayed until 2026, including the hybrid aggregation model project, which would allow for more generation and storage facilities to exist on the same site.

"The hybrid aggregation model, it's disappointing to see this getting delayed a year," said Chris Hall of the New York State Energy Research and Development Authority. "On top of that … it's a little bit surprising that we're taking continuing projects and pushing them back."

Pytel said projects being pushed back weren't being canceled, but deprioritized. He pointed to a data center project at NYISO headquarters that's being slowed down to free up some money so NYISO can finish other projects.

Pytel said some of the projects were dropped because of newly discovered resource constraints. One project, storage as transmission, was found to be more resource-intensive than NYISO initially estimated. A stakeholder pointed out that NYISO was working to comply with FERC Order 1920, which calls for incorporating non-transmission solutions into the transmission planning process. The dropped project could be rolled into the compliance process. Pytel said he would need to discuss that more with NYISO staff. ■

PJM News

Maryland Report Details PJM Cost Increases for Ratepayers

By Devin Leith-Yessian

The Maryland Office of People's Counsel (OPC) has published a *report* on how a spike in capacity prices and generator deactivations will affect state ratepayers, finding monthly costs could increase by as much as 24% for some.

The largest share of the impact is due to the significant jump in Base Residual Auction clearing prices seen in the 2025/26 auction results released last month, which saw prices across the RTO reach \$269.92/MW-day from \$28.92/MW-day the year prior. The Baltimore Gas and Electric (BGE) region surged higher to \$466.35/MW-day due to a lack of internal generation, and transmission constraints. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

At the same time, ratepayers are expected to cover the cost of a reliability-must-run (RMR) agreement to pay Talen Energy to keep its Brandon Shores and H.A. Wagner generators operational while transmission upgrades are built to accommodate the plants' deactivations. Talen has requested \$774 million in a pending FERC filing to keep the generators online (*ER24-1787*, *ER24-1790*). (See *FERC Orders Settlement Judge Procedures in Two PJM Generator Deactivations*.)

The cost of those transmission upgrades also likely will fall squarely on Maryland ratepayers: Of the \$726 million in upgrades required before the Talen generators can retire, 81%, or \$630 million, is estimated to be allocated to the state. (See *FERC Approves PJM RTEP Projects over State Protests*.)

In an *announcement* of the report, Maryland People's Counsel David Lapp said the same resource deactivations are hitting Maryland ratepayers on multiple fronts, raising capacity costs and saddling them with high transmission upgrade and RMR costs while those plants are paid to remain idle, but not contributing capacity.

"Customers are facing massive rate increases from potential retirements of old and uneconomic fossil fuel power plants — potential retirements that were entirely foreseeable and that PJM should have planned for," Lapp said. "Customers will bear the brunt of PJM's planning failures and other dysfunctional market rules, while generation companies will walk away with record profits."

Conducted by Synapse Energy Economics on behalf of the OPC, the analysis estimates

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

that BGE rates could increase by 5% to cover the RMR costs and an additional 14% due to the higher capacity costs, which amounts to an additional \$21 for the average residential customer. The capacity market impacts also will be felt in the APS, DPL-S and Pepco zones, which could see rates increase by 24, 2 and 11%, respectively.

Taking Brandon Shores and Wagner out of the capacity market had a significant impact on prices in the BGE zone, Synapse wrote, stating that in the years running up to the 2025/26 auction, about a third of the capacity consumed in the region was produced locally. Removing the two generators brought that figure down to about 10%. The report estimated that if Brandon Shores and Wagner had remained in the capacity market, the BGE zone would not have seen price separation from the rest of the RTO, which would have seen the clearing price halved to \$163.46/MW-day.

"At that price, electric customers across the RTO would save over \$5 billion in that delivery year. Further, comparing this counterfactual analysis to the actual results of the capacity market and Talen's proposed RMR, we found that Talen's revenues for the 2025-2026 delivery year are \$360 million higher than what they would have been had Talen's units participated in the capacity market," the report said.

Lapp said a small number of deactivations are causing an outsized spike in rates.

"The fact that the retirement of such a relatively small amount of generation could cause capacity market price spikes that cost customers across PJM more than \$5 billion shows ... PJM's market is stacked against the customers that pay the bills," Lapp said.

Market Changes and Queue Backlog Contributing to Higher Prices

The report notes that several changes to the capacity market structure were implemented in the 2025/26 BRA, including using a marginal effective load carrying capability (ELCC) approach to accrediting resources and risk modeling that shifted the riskiest hours toward the winter. Those redesigns had the effect of shifting the variable resource rate (VRR) curve to the left, reducing available supply and likely increasing costs. Forecast peak loads also increased by over 3 GW in the 2025/26 delivery year, increasing demand. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

The report also argues that PJM has left customers vulnerable to high prices by delaying capacity auctions while rule changes are implemented, compressing the auction schedule and leaving little time for generators to be planned to take advantage of high prices and to increase available supply. Under the current schedule, the 2026/27 BRA is scheduled to be conducted in December, 1.5 years before that delivery year begins. Paired with a backlogged interconnection queue, it says it's unlikely any large generators will come online before Brandon Shores and Wagner are set to deactivate in 2028, potentially leaving high prices in place for years.

"Thus, the strong price signal sent by the high-capacity market prices in the BGE LDA (and the RTO as a whole) may not induce timely new generation into service within the LDA before the completion of the transmission lines that end the need for these RMRs (or to help alleviate prices seen across the region). Instead, the clogged queue could lock in a windfall for the existing generating units continuing to operate in the BGE LDA and across the PJM region generally," the report says.

There are 13 projects pending in the interconnection queue that would be sited in the BGE zone, amounting to about 1.2 GW of capacity. Construction on those projects could begin in mid-2025, according to PJM's queue timeline, to begin mitigating capacity prices in 2026/27. The amount of time needed for construction, though, could result in many units coming online after that auction. Historical completion rates also suggest a share of those projects will be canceled, the report says.

The report states there's a great deal of uncertainty on the transmission side, stating that 3.5 years to complete the upgrades necessary to allow the Talen generators to retire without issue could prove to be too short. If more time is needed, the RMR agreement could be extended.

"If the transmission projects are not complete by the end of 2028, and/or the continued operation of the RMR units are required beyond December of that year, the RMR costs for electric customers would necessarily increase," the report said.

Deputy People's Counsel William Fields told *RTO Insider* he doubts there will be time for the price signal sent in the 2025/26 auction to lead to new resources coming online ahead of future auctions. The interaction of a backlogged interconnection queue and compressed auction schedule leaves ratepayers with the worst of both worlds: paying generators to remain online without them being in the capacity supply stack to offset auction prices.

"A price signal without an ability to respond to it doesn't accomplish much other than customers paying more money," he said.

He said concerns about the auction outcome were mounting ahead of the posting of the results, leading the OPC to commission the report. While the spike in prices will have a significant impact, he said transmission costs have been steadily making up an increasing share of consumers' rates. Some of those new projects could lead to reduced congestion, but whether that will come to pass is not yet apparent.

Stakeholders Discussing Changes to RMR Rules

PJM stakeholders are considering changing several areas of how RMR agreements function, including the timeline generators must provide PJM ahead of their desired deactivation date, how the compensation rate is determined and possible alternatives to the RMR structure. The Deactivation Enhancement Senior Task Force met Aug. 19 to discuss proposals from the Independent Market Monitor and PJM that would seek to use actual incurred costs to be the basis of RMR compensation.

The OPC sought a wider scope for the task force, including education on transmission technologies, such as energy storage or grid-enhancing technologies (GETs), that can provide an alternative to traditional upgrades, comparable structures RTOs employ to keep resources online when they are needed for transmission reliability and cost-effective alternatives to RMRs. (See "Consumer Advocates Seek Wider Scope for Deactivation Task Force," *PJM MRC/MC Briefs: June 27, 2024*.)

The office also has advocated for proposals that require RMR resources to participate in the capacity market, which both the Monitor and PJM have declined to include. In a May protest of Talen's RMR filing, the OPC argued the agreement would not subject the generators to the same performance requirements resources participating in the capacity market are held to, raising the question of whether they would be capable of responding to a PJM deployment. (See *FERC Orders Settlement Judge Procedures in Two PJM Generator Deactivations*.)

The Planning Committee also is considering proposals on how revising capacity interconnection rights (CIRs) can be transferred from a deactivating generator to a new resource. One aim would be reducing the need for RMR agreements by creating an expedited process for planned resources that could resolve identified transmission violations. The five packages are slated to be voted on during the Sept. 10 PC meeting. That could, however, be delayed to October if the components are changed substantially. (See "Manual 14B Revisions Include Change to Light Load Model," *PJM PC/TEAC Briefs: Aug. 6, 2024*.) ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Aug. 21. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

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

Markets and Reliability Committee

Endorsements (9:10-11:30)

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

PJM's Anita Patel and Eric Scherling will present a *proposal* to tighten PJM's know your customer (KYC) rules, which require members to provide information to facilitate the due diligence PJM conducts on key decision-making leadership. The tariff changes would require nonpublicly traded members to provide the names of beneficial owners, board of director members and principals. PJM then would conduct background checks on them. The committee deferred voting on the language during the July MRC meeting to review changes to the definitions of principal and beneficial owners added to the language after its first read. (See "Vote on Enhanced Know Your Customer Deferred," *PJM MRC Briefs: July 24, 2024*.)

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

Issue Tracking: *Enhanced Know Your Customer*

2. Re-evaluation of Financial Parameters Used in CONE for 2027/28 BRA (9:30-9:50)

PJM's Skyler Marzewski will present a *proposal* to recalculate the after-tax weighted average cost of capital (ATWACC) and bonus depreciation values for the 2027/28 Base Residual Auction (BRA). Both of the values are used in the calculation of the cost of new entry (CONE) and have been the topic of discussion as some stakeholders argue that changing market conditions, interest rates in particular, have substantially changed the financing of new generation. (See "PJM Proposes Increased CONE Parameters," *PJM MRC Briefs: July 24, 2024*.)

The committee will be asked to endorse the proposed solution and corresponding revisions to the tariff and Manual 18. Same-day endorsement may be sought at the MC.

Issue Tracking: *Financial Assumptions Used to Calculate Gross CONE*

3. Automating Bid Duration for Economic DR Participating in Energy Markets (9:50-10:10)

PJM's Pete Langbein is set to present a *proposal* to create two new energy market parameters for demand response (DR) resources: a minimum down time and minimum release time.

The committee will be asked to endorse the proposed solution and corresponding Manual 11 revisions.

Issue Tracking: *Automating Bid Duration for Economic Demand Response Participating in Energy Markets*

4. Evaluation of Energy Efficiency Resources (10:10-11:30)

Langbein will present a *proposal* to revise how PJM measures and verifies the capacity offered by energy efficiency (EE) resources. The changes would require EE providers to demonstrate a causal link between capacity market revenues and the viability of their projects, obtain exclusive rights to offer energy savings associated with a project as capacity and reduce the period for which installations can be offered as capacity from four years to one. (See *Stakeholders Endorse PJM EE Measurement and Verification Proposal*.)

The committee will be asked to endorse the proposed solution. Same-day endorsement may be sought at the Members Committee.

Issue Tracking: *Evaluation of Energy Efficiency Resources*

Members Committee

Consent Agenda (4:05-4:10)

B. Endorse proposed tariff and Operating Agreement (OA) *revisions* addressing the performance impact of the multi-schedule model on the Market Clearing Engine. The proposal would use a formula to select one schedule for each generator to be modeled in the real-time market in an effort to prevent multi-schedule modeling from leading to an untenable increase in MCE computation times. (See "Schedule Selection Formula Endorsed," *PJM MRC Briefs: July 24, 2024*.)

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

C. Endorse proposed tariff and OA *revisions* intended to resolve delays in how reserve resources are deployed. The changes would transmit deployment instructions through resources' basepoints, in addition to the existing automatic spin event and all-call notifications, as well as empowering operators to dispatch reserves at a percentage of their maximum commitment. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

Endorsements (4:10-4:40)

1. Enhanced Know Your Customer (KYC) (4:10-4:20)

Patel and Scherling will review the proposed KYC tariff revisions.

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

2. Re-evaluation of Financial Parameters Used in CONE for 2027/28 BRA (4:20-4:30)

Marzewski will review the proposed changes to the financial parameters underlying the gross CONE value in the most recent quadrennial review.

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

3. Evaluation of Energy Efficiency Resources (4:30-4:40)

Langbein will review the proposed changes to energy efficiency measurement and verification.

The committee will be asked to endorse the proposed solution and corresponding governing document revisions. ■

PJM News

Fate of Appalachian Power's Coal Plants Debated in RPS Proceeding

By James Downing

Appalachian Power's John Amos Power Plant in Virginia | *Tikilucas, CC BY-SA 4.0, via Wikimedia Commons*

The fate of two massive coal plants owned by AEP's Appalachian Power is generating debate in a proceeding to approve the utility's renewable portfolio standard (RPS) plan at the Virginia State Corporation Commission (*PUR-2024-00020*).

While most of the plan is devoted to expanding renewable energy in compliance with Virginia's Clean Economy Act, the utility is required to study the potential retirements of its John Amos and Mountaineer coal plants, with a combined capacity of 4,235.1 MW. The State Corporation Commission has required the utility to include early retirement of the two plants as a sensitivity to its RPS plans the past couple of years. Appalachian now argues it will not retire the plants until 2040 so it should be relieved of that requirement.

"The prevailing headwinds facing coal-fired generation — headwinds that the company itself has acknowledged — suggest that abandoning the commission-mandated retirement sensitivity would be imprudent in any year within recent memory," the Sierra Club said in a filing this week.

Especially with EPA set to unveil final regulations on coal plants that could affect the economics of the John Amos and Mountaineer plants, Sierra Club argued it makes sense to keep planning around their potential retirement.

EPA's greenhouse gas rules for power plants under Section 111 of the Clean Air Act and a new, more stringent rule for Effluent Limitation Guidelines could lead to the firm retiring the plants in the 2030s to avoid compliance costs, the Sierra Club said.

The greenhouse gas rule exempts coal plants that retire by January 2032 from doing anything. Those that retire by Jan. 1, 2039, will have to co-fire with natural gas. Those that want to keep operating past 2039 will have to install 90% carbon capture and storage. EPA has finalized the rule, but Virginia and other states have until May 2026 to come up with compliance plans.

EPA offered states some flexibility, but they can't drop below EPA's minimum requirements and can offer plants delays in compliance for only one year.

"That will not be an inexpensive endeavor," the Sierra Club said. "Even if the company chooses to retire by Jan. 1, 2039, it faces the still-substantial costs of retrofitting the plants for co-firing and of securing fuel supply."

The ELG rule requires elimination of discharge from three coal plant waste streams: flue gas desulfurization, bottom ash transport water and leachate. Coal plants have to comply by the end of the decade unless they stop burning the fuel by Dec. 31, 2034.

In litigation against the ELG rule, an AEP executive said it could cost $680 million over the first decade of compliance at the two plants, costing residential ratepayers an average of $42 to $60 per year.

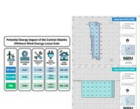
SCC staff agreed the firm should have to keep studying the plants' potential retirement given the uncertainty around how the two federal regulations will affect them. Their combined capacity of more than 4 GW means the regulator can't afford to wait until the rules are finalized and should plan for generation to replace them, staff said.

Appalachian Power continues to support the request but in its brief this week acknowledged the two EPA rules could affect the plants' "continued economic viability as coal plants," though the regulations' future also is uncertain.

"It would be of more use to the commission if the company models various scenarios that could result from such regulations," it said. "Similarly, the company should be able to use the most current and relevant information available for its modeling assumptions." ■

Mid-Atlantic news from our other channels

New Jersey Works to Electrify Buses, Heavy-duty Trucks NetZero Insider



Dominion and Equinor Win OSW Lease Auction NetZero Insider

NJ Awards $4.5M for Local Clean Energy Projects NetZero Insider

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

PJM News

FirstEnergy Pays Ohio $20M to End Bribery Scandal Litigation

By James Downing

| FirstEnergy

FirstEnergy has reached an agreement with the Ohio Attorney General and the Summit County Prosecutor to resolve all outstanding proceedings on the firm's bribery scandal.

The $20 million deal with the state and the county prosecutor comes three years after the firm agreed to pay a $230 million fine to the U.S. Department of Justice in a deferred prosecution agreement. (See *DOJ Orders $230 Million Fine for FirstEnergy*.)

In addition to sinking the careers of leadership at FirstEnergy, its $61 million in bribes and dark money campaign contributions brought down former Ohio House Speaker Larry Householder and former PUCO Chair Sam Randazzo, who committed suicide this year. (See *Scandal-ridden Former PUCO Chair Sam Randazzo Found Dead*.)

"We are pleased to have reached a resolution with the Ohio Attorney General's Office and the Office of the Summit County Prosecutor, which recognizes the substantial actions FirstEnergy has taken to establish a highly effective compliance program and instill a culture of ethics and integrity at every level of the organization," FirstEnergy CEO Brian X. Tierney said in a statement. "FirstEnergy, led by a new Board of Directors and executive team, is a stronger organization today, energized by our commitments to our stakeholders and well positioned for the future."

The scandal involved trying to get the Ohio Legislature to pass subsidies for nuclear plants FirstEnergy used to own, which it since has spun off into Energy Harbor. That firm was purchased by Vistra Energy in a deal that closed early this year.

FirstEnergy filed the *settlement* with the Securities & Exchange Commission, which credits the firm with cooperation and says the state will not pursue any charges against it for the conduct covered by the deferred prosecution agreement it signed with DOJ in 2021.

In addition to paying $20 million, FirstEnergy agreed to set up a new Office of Ethics and Compliance and to develop a compliance program designed to prevent violations of U.S. and Ohio regulations and law. The program will include companywide campaigns to get employees and contractors to report any concern about potential violations.

Of the $20 million, $500,000 is set aside to fund the compensation and expenses of an independent consultant to review the efficacy of its compliance programs.

The deal covers only the firm FirstEnergy and specifically does not cover any litigation against former employees or executives. The state has indicted former CEO Charles Jones and former Senior Vice President of External Affairs Michael Dowling. (See *Ex-PUCO Chair, Ex-FirstEnergy Execs Indicted in Ohio*.) ■

Southeast

SEEM Members Respond to FERC Briefing Request

By Holden Mann

Members of the Southeast Energy Exchange Market (SEEM) told FERC in a filing that, contrary to what SEEM's opponents claim, the market "is bringing savings to customers and should be allowed to continue" (*ER21-1111*, et al.).

Participants in the Aug. 13 filing included Southern Co., Dominion Energy, Duke Energy and Louisville Gas & Electric, all of which were among the founding utilities that first proposed SEEM in 2021. They aimed to answer questions commissioners posed in a June 14 filing seeking information on whether SEEM qualifies as a loose power pool under FERC Order 888 and whether the market's requirements that entities transacting in it have a source and sink inside its footprint violate Order 888. (See *FERC Requests Briefings on SEEM After DC Circuit Order*.)

FERC ordered the briefing as a step toward satisfying last year's order by the D.C. Circuit Court of Appeals that remanded the commission's approval of the market — which occurred by default when the commission split 2-2 when the deadline for approval arrived. (See *DC Circuit Sends SEEM Back to FERC*.)

The court also found FERC failed to explain why SEEM should not be considered a loose power pool. Opponents argued the market's nonfirm energy exchange transmission service (NFEETS) made SEEM a loose power pool, which under FERC's rules must be open to nonmembers.

FERC provided a series of questions for SEEM members, including whether SEEM is a loose power pool and, if so, whether and how SEEM meets or exceeds Order 888's open-access requirements for power pools and, if not, whether it is consistent with the pro forma open access transmission tariff (OATT). The commission also asked whether NFEETS should be considered a non-pancaked rate and whether entities with a source or sink outside of SEEM's territory could conform with the technical requirements of the market's matching platform.

In their response, SEEM members argued that SEEM does not quality as a loose power pool because "the commission has already found that NFEETS is neither a discount not a special rate" and that the D.C. Circuit did not find fault with FERC's reasoning on that point.

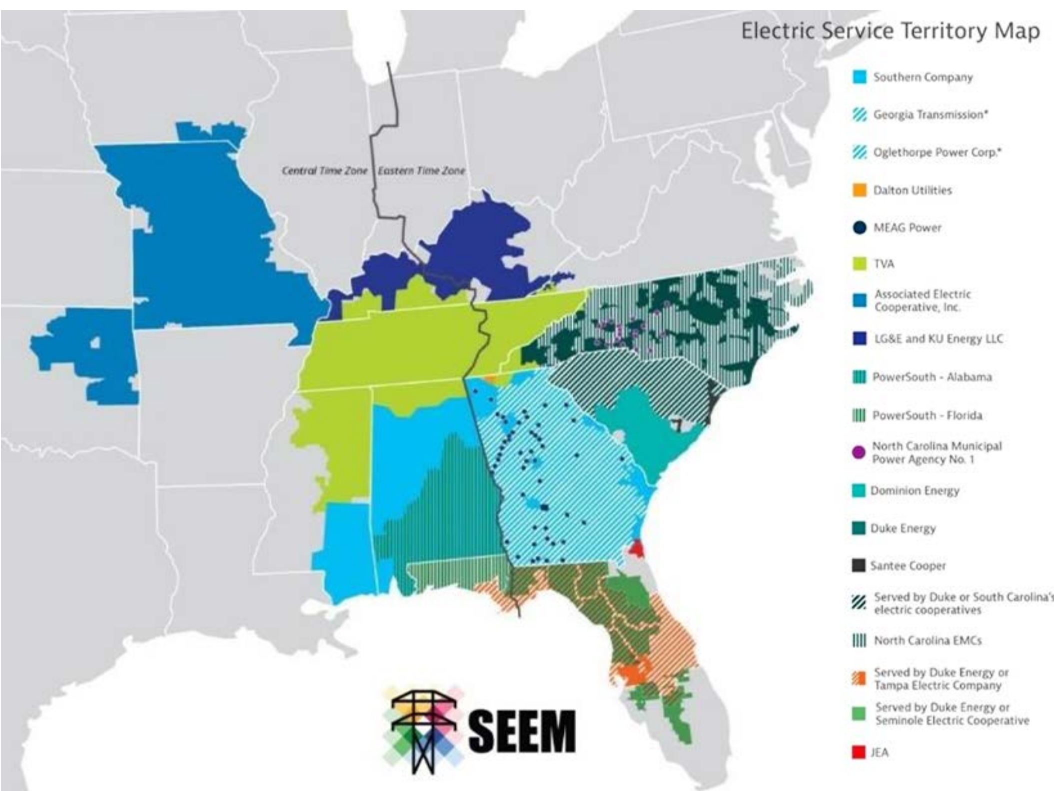
Members claimed the court instead was concerned about a possible inconsistency because it read part of Order 888 to "equate a discount with a non-pancaked rate." The filing countered this by claiming that NFEETS is pancaked because charges for losses and imbalances are cumulative across balancing authorities (BA). In addition, members asserted that NFEETS is "available to everyone, including SEEM members, on the same terms and conditions, and at the same price, under the [OATT] (or equivalent) of each member."

The respondents confirmed that owning a source or sink connected to a SEEM transmission provider is necessary for SEEM to be technically feasible, explaining that SEEM was never intended to be a "fundamental, ground-up reconstruction of the market design in the Southeast," quoting the initial SEEM filing.

However, they argued the requirement is not "unduly discriminatory to entities outside the SEEM territory" because there are other ways loads and resources outside the SEEM territory can participate in the market. Members held up pseudo-ties — which are used to represent interconnections between two BAs where no physical connection exists between the load or generation and the power system network — as one possible means of participation by outside entities.

Finally, members urged FERC to maintain SEEM as the best choice currently available for Southeastern ratepayers, claiming that despite their technical arguments, the market's opponents have an overarching motive for their objections.

"At the outset of this litigation, petitioners made their real objective clear: They want a different kind of market for the Southeast," members said. "But … every prior effort at increased coordination in the Southeast has failed. More importantly, SEEM benefits customers, and those customers should not become victims of petitioners' ulterior objective. SEEM is the proposal on the table now and must be evaluated on its own merits. And it passes the test easily." ■



The Southeast Energy Exchange Market covers all or parts of 12 states following the addition of territories in Florida last year. | *SEEM*

SPP News

SPP Dispels Concerns over Markets+ Deficiency Letter

Staff Working on Response to FERC Filing, Says 'Routine Process'

By Tom Kleckner

DENVER — Meeting with potential Markets+ participants for the first time since FERC filed a deficiency letter over SPP's tariff filing for the proposed day-ahead market, the grid operator's staff assured the Markets+ Participant Executive Committee that recent developments have not hindered the RTO's commitment to Western expansion.

"So far as we're concerned, nothing's changed," Carrie Simpson, SPP's senior director of seams and Western services, told *RTO Insider* following the MPEC's Aug. 13 meeting. "We're creating what we think is a great product for the West and the best product for the West. We will determine over the next several months who participates, but right now, our focus is the tariff approval."

FERC issued the deficiency letter July 31, directing SPP to respond to a list of 16 questions related to the tariff. It gave the RTO until Sept. 30 to respond. (See *FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas*.)

SPP's legal staff pointed out that the commission's letter is not a rejection or a likelihood of future rejection, but a "routine process" that SPP has participated in over the years.

"None of the questions indicate to me there's a serious risk to Markets+," General Counsel Paul Suskie told the committee. "They indicate to me that FERC is just trying to get additional information."

Suskie said FERC has sent SPP 41 deficiency letters since 2010. The vast majority (32, or 78.05%) were resolved with SPP's first response. Of those tariff revisions that SPP refiled, all were approved — including its tariff for the Western Energy Imbalance Services market, in operation since 2021 — except one that is still pending, he said. (See *FERC Approves SPP's Western Market Tariff*.)

"I've responded to my share of those 41 deficiency letters. This deficiency letter reads to me like FERC wants education. They've asked for an explanation," staff attorney Christopher Nolen said. "Of course, I would prefer the order, but as deficiency letters go, I'm good with this one."

Nolen said most of the commission's questions dealt largely with transmission. He noted there were no questions on governance, seams or market fundamentals, saying, "To me, that's at least as important as the questions they asked."

"I can't stress enough that they seem to be especially interested in education on how transmission will work in Markets+. If you step back and think about Markets+, how it's designed and how it works, that's perfectly reasonable," Nolen said. "It's a number of others, a number of parties, a number of balancing authorities, all bringing transmission together for us to effectuate a day-ahead, first-in-class market."

Staff said they are working quickly to meet the deadline, using examples from stakeholders to respond to the questions. The effort is not expected to delay the 2027 target go-live date or the overall timetable, as SPP has built in additional time to the schedule to serve as a buffer.

SPP's Antoine Lucas (right) addresses the MPEC during its July meeting as Director Steve Wright listens. | © RTO Insider LLC

"When I ran through these questions on my first pass-through, I thought, 'Wow, these are all answerable questions.' So, we have an idea how to answer all these questions," Nolen said. "I don't think it will take 60 days."

SPP said CEO Barbara Sugg's pending retirement will do nothing to slow its Western expansion, in which the Markets+ service offering will play a large role.

"Our commitment to the West is the strongest it has ever been," said Antoine Lucas, vice president of markets, stressing that Markets+'s role in the strategy is "unchanged" by Sugg's decision.

Director Steve Wright said Sugg has done an "outstanding" job and is "extremely committed" to both the RTO and its Western expansion efforts.

"Having said that, there are nine other board members who have been very actively engaged in this process," he said. "The [board's] other members have been very interested in this activity as well and have been kept fully briefed as we move along and understand the status of this project, and have been very supportive of it."

In the meantime, potential Markets+ participants are working on the protocols that will set the market's mechanics. Three different working groups presented their first batch of protocols for consideration. All were approved unanimously.

The MPEC also approved two chairs to fill vacancies in the stakeholder groups. Puget Sound Energy's Jessica Zahnow will lead the Markets+ Interim Governance Task Force, and Bonneville Power Administration's Libby Kirby will chair the Markets+ Operations and Reliability Working Group.

Staff told stakeholders they have board approval to engage with lenders over Markets+'s second-phase funding agreements that will be extended to participants by year-end. SPP expects its administrative costs to run between $65 million and $70 million annually.

Until then, SPP can only wait on FERC's response to the RTO's response.

"We anticipate more certainty at that point related to FERC," Simpson said. "That'll be the time period when I think parties will decide what they plan to do. We just want them to have choices, at that point." ■

SPP News

FERC Accepts Changes to SPP's WEIS Market

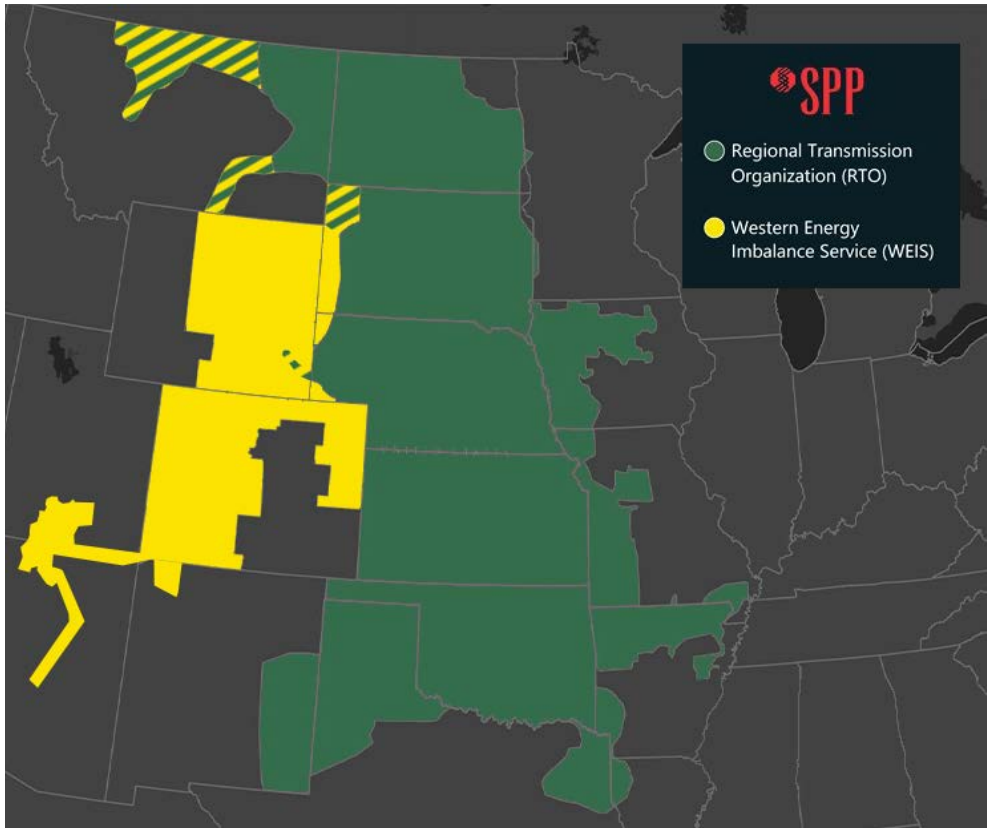
By Tom Kleckner

FERC has accepted SPP's revisions to its Western Energy Imbalance Service (WEIS) market's tariff related to the residual supply index (RSI) and ensuring that affiliated market participants' resources are evaluated together (*ER24-2208*).

In its Aug. 15 letter order, the commission found the revisions will help identify and address structural market power in the WEIS market by ensuring a market participant affiliate's online resource capacity is evaluated in the RSI calculation. It said the proposed revisions modify the market's existing definition of "affiliate" by incorporating FERC's regulations and require market participants to affirmatively identify affiliates when they register in the WEIS market and on an ongoing basis.

SPP's Market Monitoring Unit determined in 2020 that the WEIS market had a high level of structural market power when viewed through the RSI, or the ratio of residual supply to total market demand. The RTO said that under the calculation, affiliated market participants' total capacity is not evaluated together and creates a situation in which an entity can split its fleet of resources into multiple market participant registrations to avoid any one of the market participants failing the RSI calculation.

The grid operator's proposal addressed FERC's concerns when it rejected SPP's first attempt in December. The commission found that allowing the MMU to exclude affiliated capacity from the RSI calculation if the monitor determined there were sufficient safeguards and corporate controls was not just and reasonable. The MMU, which supported SPP's revisions, now can exclude affiliated capacity from the RSI calculation.



FERC has approved tariff revisions for SPP's WEIS market. | *SPP*

The RTO still must make an informational filing notifying FERC of the revisions' actual effective date no less than 30 days prior to their implementation.

SPP has administered the WEIS market on a contract basis since February 2021. It serves 12 participants. ■

Company Briefs

GM Signs PPA for 3 Assembly Plants

General Motors last week announced a 15-year renewable energy purchase from NorthStar Clean Energy to supply three U.S. assembly plants.

The power from NorthStar's Newport solar panel project in Newport, Ark., will provide electricity to the automaker's Lansing Delta Township Assembly and Lansing Grand River Assembly plants in Michigan and the Wentzville Assembly plant in Missouri.

GM said the move is an "important milestone" in its goal to be carbon neutral by 2040.

More: *The Detroit News*

Judge Says Tesla Lawsuit Can Move Forward

Judge Nöel Wise last week said a class-action lawsuit against Tesla over treatment of Black workers at its Fremont electric car factory will go before a jury on Sept. 8, 2025.

The lawsuit is the largest of several lawsuits — including by the state and federal governments — claiming the automaker has allowed rampant, anti-Black racism at the plant. Nearly 6,000 current and former Black employees and contractors at the plant have signed onto the lawsuit, and the number could climb past 10,000 in coming months, a lawyer for the workers said.

Black workers claim they experienced racist epithets, graffiti, discrimination and harassment at the plant.

More: *The Mercury News*

Federal Briefs

Wind Beats Coal 2 Months in a Row for US Generation

Wind turbines generated more electricity than coal-burning power plants across the U.S. in March and April, outstripping the fossil fuel for two consecutive months for the first time, according to the EIA.

Wind generated 45,879 GW and 47,689 GW in March and April, respectively. Those numbers outpaced coal, which totaled 38,360 GW and 37,223 GW in the same months. However, through the first four months, coal still leads wind by about 25,000 GW.

More: *The New York Times*, *EIA*

US Battery Storage Climbs 87% Year-over-year in Q2

Total U.S. battery storage capacity climbed 87.3% year-over-year to reach a total of 23.775 GW by the end of second quarter this year, with 5 GW expected to be added in the third quarter.

There was expected to be 6.9 GW added in Q2. However, only 3.976 GW came online, an increase of 20% from Q1, according to an S&P Global Commodity Insights compilation of various government filings.

WECC is projected to climb to 15.838 GW of storage capacity by the end of 2024 and surpass 20 GW in 2025, according to the North American Electricity Long-Term Forecast Supplement. ERCOT is expected to reach nearly 7.2 GW in 2024 and surpass 10 GW in 2025. ISO-NE is slated to surpass 1 GW in 2025, while NYISO and MISO are expected to reach that milestone in 2026, followed by PJM and SERC in 2027. SPP and Florida Reliability Coordinating Council are not expected to reach 1 GW of capacity until 2029.

More: *S&P Global*

State Briefs

ARIZONA

TEP to Build Second Battery System

Tucson Electric Power last week said it plans to build a second, large battery system in southeast Tucson to meet peak power demand.

TEP's planned 200-MW Roadrunner Reserve II system will be a twin to the Roadrunner Reserve system currently under construction and store 800 MW hours of energy. It is scheduled to begin operation in early 2026, a year after the first system begins operating on the same site.

Construction on Roadrunner Reserve II is scheduled to begin later this year.

More: *Tucson.com*

CONNECTICUT

AG Takes Legal Action Against Solar Companies, Individuals

Attorney General William Tong last week initiated legal action against two individuals and three companies for allegedly committing multiple crimes, including impersonation of homeowners and the unauthorized installation of solar panels.

The lawsuit targets Sierra Howes and Dakota Grumet, principals at Elevate Solar Solutions, Bright Planet and Sunrun, the company responsible for the installations and system ownership. In one instance, known as the Windsor Transaction, Howes and Grumet proposed a project to a homeowner who rejected the offer. Subsequently, an employee from Bright Planet is alleged to have forged the homeowner's digital signatures. The lawsuit also includes a recorded call of a Bright Planet employee impersonating the homeowner to Sunrun. About a week after the call, Sunrun installed a system without permits.

Tong's complaint enumerates 15 counts of legal violations, with four charges each against Sunrun, Bright Planet and Elevate Solar Solutions. These charges include unfairness, deception, per se violations (violations that are inherently illegal) and willfulness.

More: *pv magazine*

PURA Approves Rate Increases for Eversource, United Illuminating

The Public Utilities Regulatory Authority last week approved a rate adjustment for Eversource and The United Illuminating Co.

The increase will go into effect on Sept. 1 and will add 0.385 cents and 0.4592 cents per kWh to Eversource and United customers' bills, respectively. Eversource officials estimate the increase will add $3 per month for typical residential customers.

More: *News Times*

MASSACHUSETTS

Family Suing Eversource for $450M in Fatal Blast

The family of a man killed in a 2021 gas explosion in Maynard has filed a $450 million wrongful death lawsuit against Eversource, alleging negligence.

Greg Sharrigan was killed in 2021 when his home exploded. The blast was caused by a leak in a corroded gas line.

The suit accuses Eversource of knowing about the corroded gas line and not fixing it.

More: *WCVB*

State to Expand New Bedford OSW Terminal

The state last week said it is expanding its first marshaling terminal to handle bigger and heavier turbine components as several staging sites come online along the East Coast.

MassCEC said the expansion plan was formed via input from developers, turbine manufacturers and installation companies to meet the "evolving needs" of the industry. When completed, the project will expand the available heavy-lift storage area by 5 acres to a total of 26 acres and increase the

total heavy-lift quayside available to 1,200 feet.

The agency has committed $45 million to the project, with an anticipated completion date of December 2026.

More: *The New Bedford Light*

NEW YORK

PSC Approves National Grid Rate Hike

The Public Service Commission last week approved a National Grid rate hike that will be phased in over three years.

The average bill will go up by about $33 per month in the first year, $8 per month in the second and $19 in the third. In total, the average bill will increase by about $60 per month by September 2026.

More: *News12 Long Island*

NORTH CAROLINA

Utilities Commission Approves Duke Tariff Proposal

The Utilities Commission last week approved a Duke Energy green tariff proposal that will allow large electric customers to chip in extra for renewable projects Duke is already mandated to build, as well as speed up construction of new solar farms by about two years.

The commission said the amendment to speed up construction was an "improvement" because the change "adds additional accelerated capacity" of renewable energy.

More: *Energy News Network*

TENNESSEE

PUC Approves Chattanooga Gas Rate Increase

The Public Utility Commission last week approved a rate increase for Chattanooga Gas Co.

The increase, which the company said was needed to recover costs it incurred in 2023 to meet the region's growing demand for natural gas, will raise the average monthly bill by $4.21.

In its April request to the state, Chattanooga Gas said it is experiencing unprecedented growth, which it expects to continue for the foreseeable future.

More: *Chattanooga Times Free Press*

VIRGINIA

Dominion Installs 50th Monopile for Coastal Virginia OSW Project

Dominion Energy last week reported installing the Coastal Virginia Offshore Wind project's 50th monopile foundation, 33 miles off the coast of Virginia Beach.

Dominion is trying to install 70 to 100 monopile foundations by the end of October, before critically endangered North Atlantic right whales begin migrating for the season. Monopile installation will pick back up again in May 2025.

More: *WVEC*

Mecklenburg County Nixes Solar Facility

The Mecklenburg County Board of Supervisors last week voted down a proposed deal with solar developer Longroad Energy to build its 80-MW Seven Bridges facility near Chase City.

The board voted 7-2 to extend its embargo on solar power despite requests by Chase City officials for the board to approve the project and the revenue it would bring. Board members who voted down the siting agreement gave no explanation for their opposition.

More: *Mecklenburg Sun*

WEST VIRGINIA

Natural Gas Companies File to Decrease Rates

Natural gas companies serving southern West Virginia and other parts of the state last week filed for rate decreases with the Public Service Commission that would change residential customers' bills starting this November.

Mountaineer Gas Co. (12.24%), Hope Gas (13.6%) and Cardinal Natural Gas Co. ($10.45) all filed for decreases. Hearings will be scheduled for all requests.

More: *Bluefield Daily Telegraph*