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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

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In this week's issue

FERC/Federal News

DC Circuit Vacates FERC Approval of Two LNG Facilities in Texas

By James Downing

The District of Columbia Circuit Court of Appeals issued an *order* Aug. 6 vacating FERC's approval of two Texas liquid natural gas (LNG) export facilities and remanding the cases back to the regulator.

The two facilities are in Cameron County, Texas, which borders Mexico. The facilities' approval already had been in front of the court in appeals filed by Vecinos para el Bienestar de la Comunidad Costera (Neighbors for the Well-being of the Coastal Community). The vacated orders were on remand from those earlier cases.

"The commission erroneously declined to issue supplemental environmental impact statements addressing its updated environmental justice analysis for each project and its consideration of a carbon capture and sequestration system for one of the terminals," said the decision, authored by a three-judge panel. "It also failed to explain why it declined to consider air quality data from a nearby air monitor."

Texas LNG Brownsville filed an application in 2016 to build an LNG export terminal on the Brownsville Shipping Channel. Within six weeks, Rio Grande LNG filed to build a second terminal nearby, while Rio Bravo Pipeline Co. filed to build an interstate pipeline to bring fuel to the second facility. The latter two firms are subsidiaries of NextDecade LNG and the joint pipeline/LNG development is called the Rio Grande project.

Rio Grande filed to add a carbon capture and sequestration system to its facility after losing the first round of litigation. It would seek to capture 90% of the CO_2 produced by natural gas liquefaction and ship it via pipeline to an underground injection site in Texas.

On remand, the commission did an environmental justice analysis that included gathering new, relevant information. But it declined to order a more formal supplemental Environmental Impact Statement (EIS) under the National Environmental Policy Act (NEPA), which would have required giving parties a chance to comment on its analysis.

Petitioners argued FERC should have done an EIS on the projects on remand. The court agreed. NEPA requires a supplemental EIS when significant new circumstances or information related to environmental concerns of the action are available.

| Constellation Energy

"Here, the pertinent 'new information' includes the updated demographic and environmental data submitted by the developers, as well as the commission's entirely new analysis and interpretation of that data, which are substantially different from the previously conducted environmental justice analysis in the final EIS," the court said.

The original EIS covered the impact on just a two-mile radius around the projects, which FERC extended to 50 kilometers (31 miles) in the less formal review on remand. The new analysis was significantly longer and, unlike the initial EIS, found "disproportionately high and adverse" impacts on environmental justice communities. FERC also ordered additional mitigation measures.

FERC argued it did not have to do a formal EIS because it reached the same conclusion that the projects would not have major impacts on air quality.

"That explanation is inadequate for two related reasons," the court said. "First, neither the regulations nor case law condition the requirement to issue a supplemental EIS on a new determination that a particular environmental impact is significant."

The second reason in FERC's argument is that environmental justice analyses, even new and expanded ones, are not important enough to require a supplemental EIS unless they also disclose significant impacts on the physical environment.

Effects on environmental justice communities are impacts that are relevant to environmental concerns, which would require a supplemental EIS, the court said.

FERC took comments on how the developers responded to its new analysis, but it did not let other parties comment directly on its conclusions.

"But NEPA's purpose is to allow the public to see and comment on the agency's interpretation of data, not just the underlying data itself," the court said. FERC therefore deprived petitioners and the broader public of an adequate springboard for public comments, which it would have been legally required to consider in its decision.

Rio Grande's addition of CCS to its project also drew arguments that FERC should have conducted a new EIS based on that change.

"Rio Grande submitted its CCS proposal specifically in response to our 2021 remand — which required the commission to revisit aspects of its environmental analysis and its ultimate approval of the project — such that both approval requests were pending before the commission at the same time," the court said. "Indeed, Rio Grande implored the commission to consider the CCS proposal as part of the reauthorization process precisely because it viewed the two actions as related and thought that the CCS proposal's ability to capture most of the terminal's GHG emissions would make reauthorization more likely."

On remand, FERC must consider the actions together in its environmental analysis before deciding whether to reauthorize the terminal. Even if Rio Grande decided against moving ahead with the CCS, FERC must study it as an alternative in a new EIS on remand.

The court also criticized FERC for failing to properly consider data from a nearby air monitor, and on remand, it must use the data or supply a reasoned argument for not doing so.

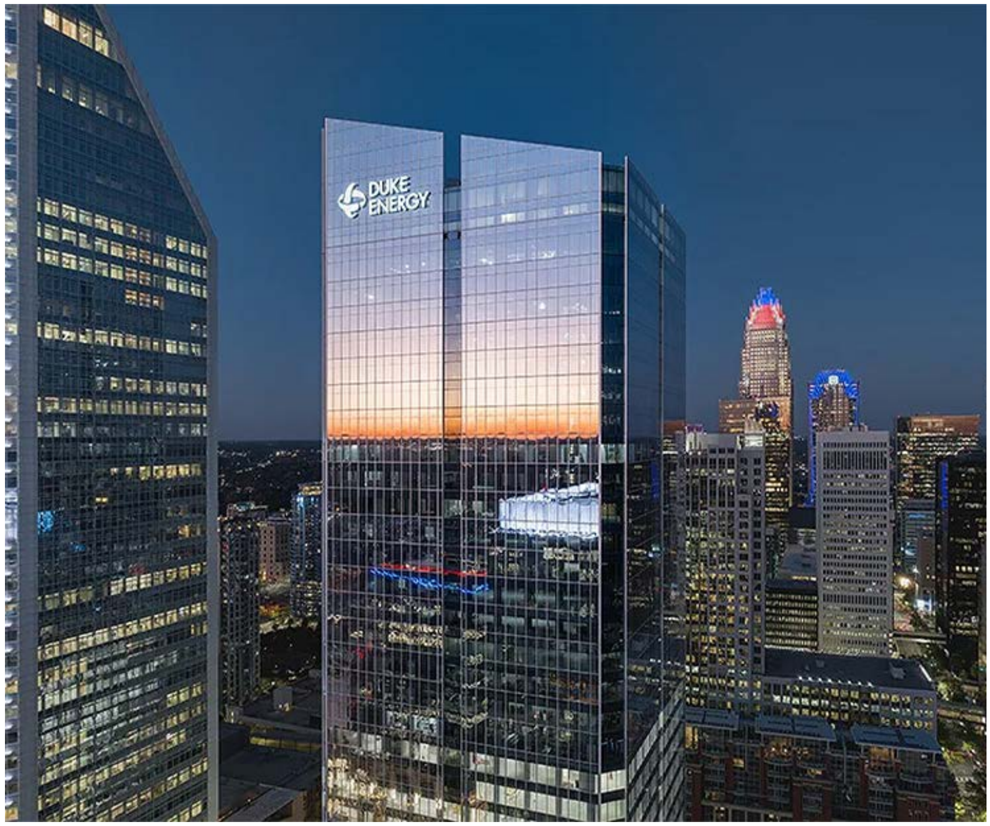
The court noted its decision to vacate the orders could have a significant impact on the two projects, but it was warranted due to FERC's serious "procedural defects." ■

FERC/Federal News

4th Circuit Remands Duke Energy Market Power Lawsuit filed by NTE

Finds Lower Court Failed to Assess Utility's Actions in Totality

By James Downing



| *Duke Energy*

The 4th U.S. Circuit Court of Appeals on Aug. 5 sent back to lower courts a lawsuit alleging Duke Energy abused its market power to prevent a power plant developer from serving a municipal utility in North Carolina.

NTE Energy had pursued a deal where it would build a natural gas plant in part to serve Fayetteville, N.C., as the municipality's contract with Duke was about to expire. But the utility came back with a cheaper contract and kept the business. A lower court found Duke was just competing for its business, but the appeals panel of three judges has open questions on whether market power was abused.

"While we recognize that much of Duke's conduct can be understood to be legitimate competitive conduct, as well explained by very able counsel, we also have found much from which a jury could conclude that Duke's actions were illegitimate anticompetitive conduct that violated Section 2 of the Sherman Act, also as well explained by very able counsel," the 4th Circuit said. "Because genuine disputes of material fact exist, we vacate the district court's summary judgment and remand for further proceedings."

On remand, a different district judge will have to be assigned to the case because in the first round U.S. District Judge Kenneth Bell had recused himself due to a former law partner working for the utility. He was reassigned the case years later and denied a motion from NTE to recuse himself again.

"We conclude, as most courts have, that once a judge recuses himself from a case, he should remain recused from that case, even though his recusal may not have originally been required," the order said.

As an independent power producer, NTE builds power plants and has to rely on utility-owned transmission to transport its power to customers that typically are municipalities. It started construction in 2016 on a new combined cycle natural gas plant in Kings Mountain, N.C., which required access to Duke's system because it controlled more than 90% of the wholesale market in the region.

Duke and NTE signed a standard interconnection agreement for the Kings Mountain plant and at first were not worried about the constitution. But the IPP started attracting customers as its new combined cycle plant provided power at cheaper rates than Duke could offer, and nine customers signed deals for power from the plant.

NTE had cheaper power, but Duke had 20-year contracts with many customers that required several years of advance notice before they could be terminated, which limited the opportunities for customers. Fayetteville and its 500 MW of load had an expiring contract after being served by Duke for a century.

"NTE did indeed then have plans to build additional power plants in the Carolinas," the court said. "But key to its plans for expansion was the rare opportunity — because of the terms of Fayetteville's agreement with Duke — to compete for Fayetteville's business."

The Reidsville Energy Center was planned to be a 475-MW combined cycle plant, but it needed a large anchor customer to get built, and Fayetteville was the most attractive one available. Duke entered into an interconnection agreement with the plant that FERC approved, which had NTE pay it $58.9 million for the interconnection lines plus ongoing charges to use them.

After that deal, NTE poached an additional three Duke wholesale customers, and as of 2017, its costs to supply them still were 30% above the IPP's. Duke identified holding onto Fayetteville as its "biggest upcoming battle" with an opt-out for its contract opening up in 2024, the court said.

Duke reworked its contract with Fayetteville, and executives exchanged emails saying they hoped to get a deal worked out and "ruin NTE's plans" for the Reidsville plant, as any other remaining opportunities to get a municipal customer were more than a decade away, the court said.

"Despite its relative inefficiency, Duke made a highly attractive, multi-faceted offer to Fayetteville, which amounted in the aggregate to a discount of $325 million for Fayetteville and which was unprecedented," the court said.

The discount came on the deal the city already had with Duke, but the terms moved those rates higher starting this year to a price more

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than NTE would have charged. Duke also agreed to quadruple the price it paid for excess power from a fossil plant Fayetteville owned.

Duke expected to lose $100 million on the reworked deal, but in a white paper, company officials argued they could offset the loss through higher charges to other customers.

NTE tried to exercise a suspension of its interconnection agreement, which it thought would have kept its place in Duke's queue, but the utility said it had breached the deal and tried to terminate it outright.

On Sept. 6, 2019, Duke unilaterally terminated the deal with NTE without notifying FERC as the interconnection agreement required. Days later it approved the reworked deal with Fayetteville and signed it while the plant's interconnection was listed as canceled.

FERC approved the reworked Fayetteville deal in early 2020, and NTE's efforts on the Reidsville plant lost momentum. The commission also found a few months later that Duke had improperly terminated the NTE interconnection deal.

NTE argued that Duke's actions destroyed the value of the new plant and left its customers with no choice but to pay the utility higher rates, which led to the lawsuit.

The district court entered a summary judgment dismissing NTE's lawsuit, which NTE appealed to the 4th Circuit.

"NTE alleges that Duke engaged in several, simultaneous courses of conduct that combined to thwart NTE from bringing a more efficient powerplant online and ultimately from competing with Duke in the Carolinas wholesale power market," the court said. "It argues that the district court erroneously 'compartmentalized' the various aspects of Duke's anticompetitive conduct and asked whether each one, independently, was unlawful."

Duke argued the appeals court should reject the holistic approach NTE favors, saying the Supreme Court has set up tests to determine whether conduct abuses market power and the IPP flunked them all. All the activities Duke undertook were legal under those tests.

"In the context of the allegations in this case, we agree with NTE," the court said. "It is foundational that alleged anticompetitive conduct must be considered as a whole."

Anticompetitive conduct comes in different forms and can't always be categorized easily as in the Supreme Court's tests, which can be too rigid for a "complex or atypical exclusionary campaign." Such cases are more challenging than when individual practices are each independently unlawful, but they are not categorical impossibilities under the law, the court said.

While the court agreed with NTE that the lower court should look at Duke's activity (canceling the interconnection deal and offering a discount to Fayetteville) altogether, material disputed facts in the case prevented summary judgment.

"Upon resolution of those disputed facts, a jury might well conclude that Duke's conduct was simply good, old-fashioned competition, which, in the end, favors the consumers of electric power in the relevant market," the court said. "On the other hand, the factfinder might just as well conclude that Duke saw a more efficient competitor in NTE and acted, through a broad range of anticompetitive conduct in various contexts, to eliminate that competition, to the detriment of consumers." ■

FERC/Federal News

Demand Growth and Extreme Weather: The Grid's New Normal

CAISO, MISO and ERCOT Leaders Talk Reliability, Resilience at USEA Briefing

By K Kaufmann

Keeping trees near electric wires trimmed back may not save those wires from damage in a hurricane or tropical storm if branches are flying and trees are uprooted outside a utility's right-of-way, said ERCOT CEO Pablo Vegas.

A big storm, with wind and rain, "can create an environment where trees can fall from outside of the right-of-way into it and create just as much damage," Vegas said during an Aug. 7 online briefing on the grid impacts of extreme weather, hosted by the U.S. Energy Association.

When Tropical Storm Beryl recently roared through Texas, "there was a lot of the vegetation outside of the utilities' right-of-way that came into play," Vegas said, "We're starting to have conversations about — how do we work more closely with homeowners who can see risky vegetation that could be compromising the electric infrastructure that happens to be outside the right-of-way?"

Driven by increasingly frequent and disruptive weather intensified by climate change, discussions of grid reliability and resilience — defined as the ability to bounce back after such events — have become industry imperatives, regularly included at conferences and online forums like the USEA briefing.

What's new, according to Vegas and other speakers at the Aug. 7 event, is the growing power demand from data centers, and the opportunities and challenges it creates, all of which must be factored into plans for extreme weather.

Rather than seeing data centers as passive load requiring firm, baseload power, Vegas looks at the massive new installations as potential grid assets that could help maintain equitable access to electricity for all customers.

Backup generation at data centers, critical for ensuring 24/7 power, could be used for emergency demand management, he said. "We could lean on those customers and say, 'Hey, we need you to disconnect from the grid for a short period of time. We need to you to use your local generation to alleviate the pressure, so that those who don't have [backup power] will have adequate capacity to serve during this time of scarcity."

Andrea Staid, principal technical lead at the Electrical Power Research Institute (EPRI), talked about the need to expand ideas about what "extreme weather" might mean as climate change affects all forms of power generation.

"Extreme from a weather perspective might no longer be extreme from a system stress perspective when you're thinking about the grid with increasing renewables," Staid said. "Wind lulls and solar droughts … are extreme from a resource adequacy perspective, but not so much from a pure weather perspective."

EPRI researchers look at interregional transmission as one possible solution as renewable "resources become uncorrelated across larger spatial regions," she said. "It comes down to data … just having a sufficient amount of data to really capture the [impacts] of these distributions when you're looking at rare occurrences of both wind and solar droughts."

But Ravi Seethapathy, executive chair of Biosirus, an industry consultant based in Canada, countered that different approaches and strategies may be needed when a specific area is hit repeatedly with severe storms. "I'm not quite sure whether that interconnection all over the United States will actually help that area," Seethapathy said.

Resilience will need to be multilevel, he said, isolating and protecting certain sections of the transmission grid, using non-wires solutions, such as microgrids, for local reliability, topped off with better public awareness and education.

"We have not been able to condition the public to take certain quick measures to manage [those storms]," Seethapathy said. "We are constantly on a 24/7, 365, by-the-minute kind of time frame … and maybe all these events are telling us, 'You now need to be a little more resilient, by way of [changing] your daily practices.' …

"That's the approach we're advocating."

| *Eversource*

Managing Costs

The pace and cost of extreme weather events continue to rise, according to industry veteran David Owens, formerly executive vice president of the Edison Electric Institute. In the past three years, the U.S. has seen 66 major weather events causing more than $1 billion in damages. The total price tag, from 1980 to today, is $2.8 trillion, he said.

Owens deftly summarized the challenges for utilities, regulators, grid operators and other industry stakeholders: "How do we mitigate the risk? And how do we, at the same time, not expose electric consumers to exorbitant costs? What are some of the technologies that we can employ?"

FERC/Federal News

Meeting future load growth will be expensive, "regardless of what happens with climate and extreme weather," Staid said. Integrating extreme weather resilience into long-term planning for load growth could result in "only a small adder on top of a very big cost to make sure you can ride through these extreme heat events, these extreme cold events."

"We absolutely need to keep this extreme weather and climate change in mind, but if we plan ahead of time, it shouldn't drive the cost up significantly," she said.

Seethapathy again said a shift in thinking and in relations between utilities and regulators may be needed.

"We have got a system where the regulator [and] the utility have got a relationship and things are moving very slowly. Why are the costs so high? It's because we are using the methodologies of 50 years ago," he said.

For example, undergrounding of transmission or distribution lines need not mean burying them four feet deep, Seethapathy said. "Cable protection" can be laid at ground level or "just shallow, below ground," he said. Existing standards "are just out of whack with today's times."

Lessons Learned

Joining Vegas on the USEA panel, CAISO CEO Elliot Mainzer and MISO Senior Vice President Todd Hillman talked about the lessons learned from previously unprecedented weather events like the 2021 winter storm in Texas, commonly called Uri, and the 2020 August heat waves and rolling blackouts in California.

In the wake of 2020, California tackled resource adequacy — ensuring it has enough power on reserve to cover emergencies — with a vengeance. The state has kept existing generation online — in particular, the Diablo Canyon nuclear power plant — while adding more than 20,000 MW of new generation to the grid and "a pretty amazing fleet of lithium-ion batteries, now over 9,000 MW, managing that evening peak in tandem with solar," Mainzer said.

CAISO also leans on its Energy Imbalance Market, Mainzer said, "taking advantage of transmission connectivity across broad geographies." EIM is expanding with new lines into New Mexico and Wyoming, and implementation of its voluntary day-ahead market — expected to come online in 2026 — will "offer even greater optimization," he said.

"The economics are very compelling, but it's going to be the reliability benefits — by reducing the need for energy emergency alerts, calming down the system and taking advantage of wide-area dispatch — that I think ultimately will provide the greatest customer value," Mainzer said.

Hillman said MISO is following an "all-of-the-above" strategy, including its Joint Transmission Interconnection Queue with SPP, aimed at providing more interregional transfer capacity. The $1.8 billion package of projects is expected to go to FERC for approval "very soon," he said.

Like CAISO, MISO also seeks to beef up its generation, with some of the 350 GW of projects — mostly wind and solar — in its interconnection queue, Hillman said. However, MISO's attempts to set an annual cap on interconnection capacity were turned down at FERC in 2023, and the grid operator has delayed opening the queue for new 2024 applications until it sends a revised proposal to the commission. (See *MISO: New Interconnection Queue Cycle to Wait on MW Cap Filing*.)

Hillman also spoke about a shift in thinking about risk parameters under way at MISO. With operations covering 15 states, "we're looking at any and all resources, that they can stay online as long as they possibly can, despite the pressures on the system. But we're also looking at what the real value of each asset is worth, what's called accreditation. So, really, what are those values when you get into a risk situation?"

The dayslong power outages of Uri notwithstanding, ERCOT has yet to focus on developing more interregional transmission lines. Rather, Vegas said, "we're starting to look at other steps of voltage in our transmission system, stepping up from what we have today across Texas, a 345-kV system. [We are] starting to evaluate, could a 500- or 765-kV system with a strong backbone network built across the state provide added resiliency should we have isolated areas of intense issues that could come from things like weather events?

"We think that there's a lot of potential value to that kind of an infrastructure investment that not only supports resiliency but can also support the tremendous load growth that we're all talking about too." A new surge of solar and storage on the system also could help ERCOT ride through the traditionally high-risk times when solar power drops off the system during summer sunsets, Vegas said.

"This may be the last year that we have real significant risk at solar sunset," he said. "If we continue to see that trajectory by 2025 into 2026, we could see the summer risk period significantly mitigated because batteries are picking up some of the transition solar ramps as we see the wind come on in the evening." ■

CAISO/West News

No Clear Blueprint for Western 'RO' Stakeholder Process

Pathways Initiative Workshops Examine Views on Committees, Sectors, Voting

By Robert Mullin

One thing has become abundantly clear after three intensive workshops this summer: There's no blueprint for developing the stakeholder process for the "regional organization" (RO) envisioned by the West-Wide Governance Pathways Initiative.

"Stakeholder engagement process" is one of six "work streams" the Pathways Initiative launched this summer to lay the foundation for the RO, which would assume the governance of CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). (See *Busy Summer Ahead for Pathways Initiative*.) In some ways, its outcome could be the most vital for the RO's long-term viability.

That's because supporters of SPP's Markets+ day-ahead offering have touted the market's stakeholder-led approach to governance nearly as much as the independence of that governance from state (that is, California) influence, challenging acceptance of CAISO's more staff-driven model.

Scott Miller, executive director of the Western Power Trading Forum, recognized the change in expectations last July, telling *RTO Insider* that Markets+ had been "charmed" by SPP's approach to stakeholder engagement. (See *In Contest for the West, Markets+ Gathers Momentum — and Skeptics*.)

"Now they've been exposed to a stakeholder process that the stakeholders run, and there still hasn't been a stakeholder process [in CAISO] that is developed much differently, even in the context of the EIM," Miller said at the time.

'Little Bit Outside the Mainstream'

A year later, Pathways backers seek to address those changed expectations, beginning with a series of four workshops to determine how stakeholders want to interact with the future RO. The group's Launch Committee considered the subject weighty enough to engage an independent facilitator, Gridworks, to manage the workshop discussions.

Workshop participants are grappling with a broad question of how to create a "hybrid" stakeholder process model that combines the best parts of CAISO's staff-driven process with the stakeholder-driven — and committee-based — processes of the RTOs in the Eastern Interconnection, which themselves vary in their approaches.

Several participants have pointed to benefits of CAISO's approach: its inclusiveness, accessibility and relative informality, despite its top-down nature. They've noted that while CAISO's process does not rely on stakeholder committees, the ISO recently rolled out use

SPP presented to a packed meeting room at BPA's headquarters in June 2023 as the RTO worked with stakeholders to develop the Markets+ tariff. Participants have said they appreciated SPP's stakeholder-driven approach to designing the market. | © RTO Insider LLC

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of stakeholder "working groups" to hash out market initiatives.

"The CAISO process is able to organically capture large ideas [and groups of] stakeholders," Alan Meck, principal market design analyst at Pacific Gas and Electric, said during the Pathways Initiative's July 24 workshop.

Meck said he sees benefit in the ISO's less structured — that is, non-committee — approach to addressing issues because it doesn't entail a process in which "x percent" of votes from certain stakeholder groups is needed to advance markets changes.

Oregon Public Utility Commissioner Letha Tawney said that "as a stakeholder who is not resourced to engage in these processes very deeply," she appreciated the open nature of the CAISO process.

"I like how it doesn't ask, 'What's your standing? Why do you have a voice here? Do you get to have a say in this? It's an all-comers [process], and as a decision-maker myself, who tries to run procedurally equitable processes, I really like that," said Tawney, one of the signatories of the July 2023 letter launching the Pathways Initiative.

Tony Braun, an attorney who represents publicly owned utilities in California, offered an example of how that openness can benefit stakeholders who sit "a little bit outside the mainstream" on a market issue.

"When the flexible capacity product was first introduced, the proposal, which was very mature, was to just peanut butter the costs of it on a load-ratio share basis," Braun said. "We had to fight tooth-and-nail to show ... CAISO that our loads and resources did not look like everybody else's, or at least certain loads and resources."

Braun said the public utilities ultimately convinced the ISO to adopt a more cost-causation approach.

"And I can't help but think that would have not happened in a voting structure — that we would have just been an extraordinarily small minority and we would just get rolled over," he said.

Ryan Millard, West region senior director of regulatory and political affairs at NextEra Energy Resources, said CAISO included elements of "the good, the bad and the ugly." Among the bad, Millard noted, is that CAISO's lack of stakeholder process formality can translate into unclear timelines.

Citing the example of the ISO's interconnection process enhancements initiative, he said, "I don't think there were enough attempts in the beginning to kind of structure how the stakeholder process was going to move forward, and there [weren't] timelines built into the front. In fact, that was my commentary through that process multiple times: 'Pick a date, you have a lot of conflicting or complicated compliance filings at FERC that are going to make this more complicated.' And sure enough, it did."

Other workshop participants pointed to what they see as advantages in SPP's more structured stakeholder process, which they experienced in developing the Markets+ tariff.

Doug Marker, an intergovernmental affairs specialist at the Bonneville Power Administration, said BPA recognizes and supports the fact that Pathways is seeking "to do something different than the older CAISO staff model."

"We would like to see a more stakeholder-led issue development process," he said during the July 24 workshop. In April, BPA staff issued a recommendation that the agency choose Markets+ over EDAM, citing governance and stakeholder processes as two key reasons for its leaning. (See *BPA Staff Recommends Markets+ over EDAM*.)

For BPA, it's important the stakeholder process "get issues defined and developed so that there's a clear majority and minority perspective, if necessary," Marker said.

"The Markets+ process has helped to facilitate developing consensus on some difficult issues. We were really skeptical going into the process about the voting aspect of it, but it served in some instances to really facilitate consensus," he said.

Lauren Tenney Denison, director of market policy and grid strategy at the Portland-based Public Power Council, spoke approvingly of the Markets+ system of standing work groups and ad hoc task forces, both of which include representatives from various stakeholder sectors and rely on forms of voting to advance issues through the stakeholder process.

"While all decisions go to an independent board eventually, they build up through that working group level," Tenney Denison said. "Then there's the Markets+ Executive Committee that has representatives from all the participants and stakeholders. That group is also able to direct work back to those workgroups and task forces. So there's just more structure involved that has stakeholders having an active voice through this voting mechanism on what to prioritize and what needs to be looked at."

'Pleasantly Surprised'

An Aug. 2 Pathways workshop delved into the question of what a "sector-based committee and voting structure" could add to the RO.

Braun said he thinks sector-based representation is essential and provides an "indicia of inclusiveness" to the stakeholder process, helping to "get the right people at the table" and build consensus.

"I think I probably get less worked up about the definitions of the sectors than many do," he said. "I get nervous when sectors get too granular. I think one of the lessons that we've learned is that making the sectors broad forces people to work together to come up with plans for populating the sectors and the relative positions in the stakeholder processes," such as in the WEIM's stakeholder-led Regional Issues Forum (RIF).

"I think one of the benefits of having some similarly situated folks within the same group is that it's helpful to sort of zoom in on areas where there is consensus out of the gate and areas where maybe we're using different terminology to describe the same thing — or with areas also where there isn't consensus," said Ian White, director of regulatory affairs at Shell Trading.

White said the RIF group representing independent power producers, marketers and independent load-serving entities sector — one in which Shell participates — has become "quite an unruly" sector with its 70 members, many of which operate under different business models and therefore don't always share the same interests.

"Regardless of sector size, I think you're always going to have splinter factions form over issues that are of unique concern to an organization's individual goals," NextEra's Millard said. "And that's particularly true in diverse sectors, of which NextEra is one. The less formal structure of CAISO's stakeholder framework sort of allows for that, and you have the ability to collaborate and/or advocate as a subgroup of your sector or even cross-collaborate with other sectors."

Allie Mace, manager of market policy and analysis at BPA, said sector-based representation encourages collaboration among stakeholders.

"In the Markets+ experience, we were pretty pleasantly surprised by the enthusiasm and engagement to dig in on issues and shape compromises and consensus approaches across the sectors," Mace said. "The sector definitions didn't seem like they were a barrier to that collaboration. I think defined sectors can help to provide some good helpful parameters for organizing issues and input."

Voting with Purpose

On the topic of whether the RO's stakeholder process should include participant voting, both Braun and Scott Ranzal, director of portfolio management at Pacific Gas and Electric, expressed support for some kind of voting, but raised the question of the purpose of votes.

As noted throughout the workshop, voting can be characterized as "indicative" (showing a preference during the process), "advisory" (expressing an opinion to a board or other body) or "binding" (advancing a proposal).

"I think voting is a reflection of desire that actually already happens inside the CAISO," Ranzal said. "It's not labeled as a vote, but it is very clear in the CAISO processes where people want to be. So I think if voting is a reflection of desire, and that can help with accountability and visualizing what is happening, adding that to the CAISO process seems like it would have a positive bent to it."

"I think voting has the potential to complicate engagement and sometimes discourage engagement altogether, if you're a minority voice on a specific issue," Millard said, advocating for "narrowing the application of when and how voting" is used in the stakeholder process.

Mace said BPA found voting in Markets+ to be a "positive experience" after the agency overcame a "learning curve."

"We were pretty impressed with how voting helped to move things along," Mace said. "Calling for that advisory vote could be a very powerful tool at times in meetings for getting out of a spinning topic and identifying where people stood, so then you can move forward on the compromise and collaboration."

Natalie McIntire, a senior advocate at the Natural Resources Defense Council, said she wouldn't take a position on whether the RO should include voting and whether such voting should be advisory or binding.

"But if there is voting, I think it's really important that you spend a fair amount of time thinking about the balance of those votes," McIntire said. "I think different regions across the country have different ways that they weight voting based on sectors, and you want to really make sure that that voting is reasonably balanced so that no one sector has control over the outcome of those votes."

Kerinia Cusick, president of the Center for Renewables Integration, said any "effective" stakeholder process she's been involved with has included some form of voting.

"I'm trying to sort of think of examples where there has been no voting, and those have been somewhat frustrating processes," Cusick said. "They've been sort of long, very engaged, and then nothing comes out of it. So there's a ton of value of voting to drive accountability."

Michele Beck, director of Utah Office of Consumer Services, said she agreed with workshop participants who want to find a "middle ground" between the more "prescriptive" voting structure of the Eastern RTOs and the CAISO process, "something that might be more limited, more indicative."

Ranzal said Pathways likely will draw on parts of multiple RTOs to serve the RO's stakeholder process.

"We're going to create our own thing, as we often do in the West, and I think that suits and fits the needs of the West and that's a good thing. That's part of the reason why we're all out here," he said. ■

CAISO/West News

Calif. Energy Officials Pitch Pathways Plan to State Senators

Heads of CAISO, CEC, CPUC Tout Benefits of Broad EDAM Participation to Key Committee

By Henrik Nilsson

California energy agency heads appearing before state lawmakers Aug. 6 pitched the proposed CAISO governance changes being developed by the West-Wide Governance Pathways Initiative, saying that expanding the ISO's electricity market will provide for increased reliability and cost benefits for state residents.

Though the initiative has been in the works since last year, the state Senate Energy, Utilities and Communications Committee discussed the topic for the first time during an oversight hearing on electricity reliability. Representatives from CAISO, the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) participated.

The agency leaders outlined the purported advantages of giving the Western Energy Markets (WEM) Governing Body increased authority over CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). They also touched on the Pathways Initiative's evolving plan to establish an independent Western "regional organization" (RO) that would eventually assume more of the ISO's market functions. (See *New Western 'Regional Organization' Could be Folsom-based*.)

Electricity markets in the West are "very fragmented," Alice Reynolds, president of CPUC, told the committee. "So, this effort is really thinking about the benefits of a larger market, meaning, think about a market with a footprint that is larger than any one weather event."

Reynolds said a shared market would allow stakeholders to optimize resources for reliability and tackle different weather events while also maximizing cost savings for ratepayers. However, she noted that proposed changes under the Pathways Initiative would not involve alterations to CAISO's balancing authority area, a key concern for California labor groups that blocked previous legislative efforts to "regionalize" the ISO and now say they support a bill to enact the Pathways plan. (See *California Labor Groups Affirm Support for Pathways Proposal*.)

Sen. Henry Stern (D) asked what additional economic benefits California ratepayers could expect from the state's participation in the

CPUC President Alice Reynolds (right) and CEC Vice Chair Siva Gunda participate in a California Senate Energy, Utilities and Communications Committee oversight hearing Aug. 6. | *California Senate*

EDAM compared with those currently seen in the WEIM, which provided its participants \$365 million in estimated benefits during the second quarter of 2024, according to CAISO. (See *WEIM Yields \$365M in Q2 Benefits with Hot Start to Summer*.)

CAISO CEO Elliot Mainzer said EDAM could double those benefits "on just the economic side" but emphasized the impact of an expanded market on reliability.

"The reliability element is becoming increasingly important. I think as you see the reduction in the number of energy emergency alerts, that's our goal," Mainzer said. "We want to keep the system calm. We want to have that wide area of visibility. We want to understand not only what's happening in California, but what's happening in the broader West, so that on a day-ahead basis, we'll have the ability to move power to where it's most needed, given the capabilities of the transmission system."

'Really Good Proposal'

On May 31, the initiative's Launch Committee unanimously endorsed Step 1 of the "stepwise" proposal issued in April. The Launch Committee presented CAISO with the proposal on June 5, which would revise CAISO's WEIM charter to elevate the oversight position of the market's Governing Body over WEIM/EDAM matters to "primary" authority, rather than the "joint" authority it currently shares with the ISO's Board of Governors.

CEC Vice Chair Siva Gunda said the proposal focuses on furthering the independence of CAISO's governance structure "to have more people feel confident and comfortable to join the EDAM."

He noted that the proposal also clarified the dual filing — or "jump ball" — process that would occur if the CAISO board disagrees with a market rule filing approved by the WEM Governing Body and submits a parallel filing with FERC.

"There will be a dispute resolution if the boards don't agree," Gunda said. But "if the dispute resolution did not bring the two boards together, there is a jump ball filing to FERC, meaning both boards can put their proposal to FERC."

The CAISO board is expected to vote on the first step of the proposal during a joint meeting with the WEM Governing Body this month.

Gunda told the senators the Pathways Launch Committee expects to issue a proposal on the effort's next steps in the fall. (The committee is targeting a Nov. 15 release.) Not explicitly described by Gunda but widely understood by industry stakeholders is that the Step 2 proposal will cover the changes to California law needed to migrate some of CAISO's market functions to the RO, give the RO sole authority over the WEIM/EDAM and allow the ISO to participate in the new entity.

"I just hope you take the next step," Stern said. "I think you put a really good proposal on the table."

However, Sen. Kelly Seyarto (R) questioned whether there has been enough outreach to inform the public about the initiative's implications, saying, "this is the first time I've even seen this."

"I don't know what our outreach is to the public and when those meetings are, but this is something important for people to understand," Seyarto said.

"If it's something that is just kind of part of a box to check off, 'oh yeah, we did public meetings, we did this, and now we're doing this,' you're going to have a lot of pushback from the public. Because anything that they think might raise their rate right now — they're hypersensitive to it," Seyarto added. ■

Robert Mullin contributed to this article.

CAISO/West News

California Labor Groups Affirm Support for Pathways Proposal

Unions Ready to Work with Lawmakers on CAISO Bill, Lobbyist Tells Senators

By Robert Mullin

Labor groups that blocked past California legislative efforts to "regionalize" CAISO told state lawmakers Aug. 6 they "look forward" to working with the legislature next year to pass a bill to implement the governance changes to the ISO being developed by the West-Wide Governance Pathways Initiative.

The statement by the California Coalition of Utility Employees and the California State Association of Electrical Workers to a key State Senate committee might mark the unofficial start of the legislative campaign to allow CAISO to hand off oversight of its Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM) to the Pathways Initiative's proposed "regional organization" (RO).

It also confirms that Pathways has the support of a key constituency needed to advance that change.

"As you all know, we've been the proverbial fly in the ointment and opposed all three of the prior legislative attempts at regionalization," Scott Wetch, a lobbyist representing the labor groups, told the Senate's Energy, Utilities and Communications Committee during an oversight hearing on state agency efforts to maintain electric reliability in the face of extreme weather and the transition to emissions-free resources.

"Those proposals would have transformed ... CAISO itself into an RTO. In contrast, the Pathways Initiative would preserve ... CAISO and its balancing authority and other functions, except for control over the energy markets," Wetch said during a public comment period at the end of the hearing.

Bills to convert CAISO into an RTO failed three years in a row over the 2016-2018 sessions, largely because of opposition from the International Brotherhood of Electrical Workers (IBEW), as well as resistance from publicly owned utilities in California and some environmental groups worried about the impact on the state's renewable energy goals.

Those bills would have extended the boundaries of the ISO's balancing authority area to include states with utilities opting to join the expanded market. Under California law, that could have meant that the portion of projects that California's renewable portfolio standard requires to be interconnected directly to the ISO's BAA would be built outside the state, reducing job opportunities for IBEW members — a nonstarter for the union.

"I also just want to emphasize that the Pathways proposal being developed would preserve California jobs, unlike previous regionalization proposals," Wetch told senators. He also noted the plan "will enable many more utilities around the West to join" EDAM.

"I want to emphasize that we foresee that the proposal would not affect California's or any other state's ability to protect its policies such as renewable portfolio standards, transmission planning, cost allocation or GHG reduction," Wetch said. "It could even enhance our ability to decarbonize at lower cost by allowing us to use solar, wind and hydro resources more efficiently."

The change of heart among California labor groups became evident last year when Marc Joseph, an attorney for the IBEW, joined the Pathways Launch Committee.

"Frankly, I wouldn't be spending this much time [on Pathways] if I thought this was going to crash and burn," Joseph said during an April meeting of that committee. (See *Past Opponents Now See Legislative Pathway to CAISO Regionalization*.)

No Clear Road Map

During a Pathways workshop Aug. 5 to examine issues related to altering the CAISO tariff and migrating ISO functions to the RO, Launch Committee member Evie Kahl, general counsel for the California Community Choice Association, provided clarification on what a proposed bill would seek to achieve.

"When we talk about the legislative change for any of this, what we're looking at is not a legislative change to enable the CAISO to become a different entity than it is today, but to provide these [market] services and to allow California's BA to participate in the RO market," Kahl said, adding that the legislation will not determine what services the RO can offer. "That's all independent."

Launch Committee members have made clear that the committee itself is prohibited from attempting to influence legislation because Pathways is a nonprofit 501(c)(3) organization, although some of its members could act in that capacity as representatives of their employers.

Asked how specific the legislation would need to be to allow a scenario in which the RO takes on a larger portion of the ISO's market functions and legal responsibilities (what Pathways is calling Option 2.5), compared with a more limited assumption of functions (Option 2.0), committee member Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition, said he hesitated to "get too far into the weeds" about legislation the group is not directly shaping.

"I do think there is a pretty plausible legislative route that is permissive and does not get into the specifics of prescribing changes specific to 2.0 or 2.5. In other words, the legislation could look exactly the same," Gray said.

"What would be different, potentially in the legislative process, is more clarity from the Launch Committee and stakeholders in support of a particular outcome — 2.0 or 2.5 — that would inform the deliberations," he said. "But the actual changes to California law don't necessarily need to be different, and a more prescriptive approach may raise some issues on its own, as opposed to a more permissive approach."

The Aug. 5 workshop offered insight into the broad spectrum of issues and level of complexity that participants in the Pathways CAISO Issues and Tariff Analysis Work Group confront as they sort out the future relationship between the RO and ISO, including relative levels of independence, responsibility and liability for market issues, as well as what services each might provide over time.

"We are really creating something new here," Kahl said. "Everything that's being outlined — there have been pieces of this developed across the country with different RTOs, but we're putting the pieces together differently. In other words, there really hasn't been a clear road map for us to do what we've been doing."

In his comments to the senators, Wetch expressed confidence in the outcome.

"We are pleased with the progress that the [Pathways] Launch Committee has made in the past year. We remain optimistic that the Launch Committee will be able to make a recommendation to create a new regional organization and transfer oversight of the energy markets from the CAISO to the new regional organization," he said. ■

CAISO/West News

Data Centers Bringing ‘Massive’ Loads to Western Grid

WECC Sees Load Growth Outpacing New Generation, Despite Projected Buildout

By Elaine Goodman

Five years ago, load growth from transportation electrification was a major issue for policy makers, according to speakers at a webinar. Now the focus has shifted to data centers.

“Over the last year or so, the data center growth has become one of the major challenges for this industry,” said Branden Sudduth, WECC’s vice president of reliability planning and performance analysis, who noted the centers can consume as much as 3 GW of energy.

“That’s just massive loads that we’re not accustomed to seeing come onto the grid,” Sudduth said.

The discussion came during a WECC *webinar* Aug. 7 on emerging risks to reliability in the West.

In its 2023 Western Assessment of Resource Adequacy, WECC projected that the region’s demand would increase 16.8% over the next decade, nearly double the 9.6% growth predicted in its 2022 assessment. The *2023 assessment* said the biggest driver of the increased demand is the expansion of data centers, especially in the Northwest.

Data center growth is also expected in other parts of the Western Interconnection. In its integrated resource plan filed in May, NV Energy said more than 3,000 acres of industrial land had been purchased in Northern Nevada last year for data center development.

In addition to needing large amounts of energy to process data, data centers require significant cooling, which further increases load.

New Generation Lagging

During the WECC webinar, Sudduth said the data centers can come online as quickly as 18 months, or even sooner if infrastructure is already in place.

“What we know for sure is that generation doesn’t get built that quickly,” said Kris Raper, WECC’s vice president of strategic engagement and external affairs.

Although an increasing amount of generation is being planned each year, much of that is not materializing, Sudduth said.

For example, he said, 14 GW of new energy resources were expected to come online in the Western Interconnection in the first half of 2023. But by the end of 2023, only 55% of those resources had been added.

Projections of new resources for the following two years were even greater: 17 GW in 2024 and 28 GW in 2025, said Sudduth, who noted the figures were near-term forecasts for resources close to or in the construction phase.

“We’re getting more and more aggressive with the amount of generation that we’re expecting to bring online,” Sudduth said. “But up to this point, we don’t seem to be able to keep up with that aggressive growth.”

Sudduth attributed the delays to supply chain issues, which are making it difficult to get equipment such as transformers. And increasing costs are “forcing people to rethink when and if they’re going to build certain resources,” he said.

One way the generation gap is being filled is through resource retirement delays, Sudduth added.

Data centers can come online as quickly as 18 months, potentially adding large loads to the grid, according to WECC. | *H5 Data Centers*

EV Concerns

Raper, who noted that data centers had taken over from transportation electrification as a hot topic among policymakers, said both sources of load growth remained on WECC’s radar screen.

“We’re trying to watch all of it,” Raper said. “Because all of the things are going to have an impact on reliability to the grid.”

Sudduth said one aspect of EV adoption that makes him nervous is long-haul trucking.

“[Truck drivers] are not going to want to sit around all day and charge their vehicle, and so it’s going to require massive amounts of power to get those long-haul trucks charged quickly,” he said. “What does that do to load forecasts?” ■

CAISO/West News

CAISO Proposal Seeks to Refine Storage Bid Cost Recovery

Some Stakeholders Question Proposal Structure, Timeline

By Ayla Burnett

A new CAISO proposal seeks to address unwarranted bid cost recovery (BCR) payments to storage resources, an issue that has stirred controversy over the past month.

The proposal, which CAISO presented at an Aug. 5 workshop, is part of Track 1 of CAISO's new *Storage Bid Cost Recovery and Default Energy Bids Enhancements*, which began July 8 and has been criticized by stakeholders for its "aggressive timeline." (See *CAISO Kicks Off Storage Bid Cost Recovery Stakeholder Initiative*.) A final proposal is scheduled for a board vote Sept. 26.

"This is a very complicated issue with a lot of moving parts, and I do appreciate that there could be a significant amount of economic burden that's being introduced into the market because of this, but I really do agree that we should slow down," Josh Arnold, senior market and operations analyst at Customized Energy Solutions, said during the Aug. 5 meeting. "It's an incredibly complicated system and I think in some cases it has been oversimplified."

The initiative aims to address what the ISO identified as unusually high BCR payments to storage resources, despite the payments not being aligned with the intent of BCR.

As noted in the ISO's July 26 *straw proposal*, BCR was created with conventional assets in mind, meaning it doesn't consider storage resources' opportunity costs or state-of-charge (SOC) constraints. The differentiated treatment of unavailable energy, the proposal says, has led to two primary concerns: that storage assets aren't exposed to real-time prices for deviating from day-ahead schedules due to SOC constraints, and that it creates incentives for resources to bid inefficiently to maximize a combined BCR and market payment.

CAISO's proposal seeks to address the problem of a storage resource being unable to meet a day-ahead schedule due to an SOC constraint. In that case, the market instructs the storage asset to a 0-MW dispatch because of the SOC being binding, categorizing the energy as "optimal" and making it eligible for BCR.

"Our proposal is really to define that dispatch that is unavailable due to state-of-charge constraints in the binding interval as non-optimal energy, meaning that it would not be eligible for BCR," Sergio Dueñas Melendez, storage sector manager at CAISO, said in the meeting. "We believe that this will materially limit the chances of unwarranted BCR derived from buy- or sell-backs of the day-ahead schedule."

The 230-MW Desert Sunlight Battery Energy Storage System in Riverside County, Calif. | *Bureau of Land Management California*

Because the proposal applies only to the real-time binding interval, it wouldn't fully eliminate BCR, Dueñas Melendez noted.

'Knee-jerk Reaction Initiative'

Track 2 of the initiative addresses how the BCR construct treats energy storage in co-located configurations, as well as dealing with storage and hybrid resource default energy bids (DEBs).

Some stakeholders expressed concern that the proposal didn't consider the complexities of BCR and that Tracks 1 and 2 should be separated into different initiatives.

"There's instances where, yes, the scheduling coordinator of the storage resources is causing the SOC [constraint] [and] that you don't want to get bid cost recovery. But we know that there are market design issues that can result in the SOC being mismanaged," said Don Tretheway, managing director of EES Consulting, representing the California Energy Storage Alliance.

Tretheway also noted that separating Tracks 1 and 2 could solve the problem more efficiently.

"CAISO is basically saying that you're going to try and solve now the two instances that you're concerned of. The first is the ability to inflate your BCR payments so that you can get additional revenues, versus storage resources not being exposed to the real-time bid price when they can't meet their SOC," Tretheway said. "I think you can separate those two issues, and you can address those bidding concerns you have in a very simple BCR settlement versus trying to do all this other complex stuff, which would then give us the time to think about what the appropriate approach would be."

He argued that by solving Track 2 issues related to the DEB first, scheduling coordinators wouldn't need to ensure that real-time energy bids reflect real-time conditions for storage resources.

Several stakeholders agreed with Tretheway's concerns, underscoring the complexity of the topic and the need for more time to resolve issues.

Kallie Wells, senior consultant at Gridwell Consulting representing the Western Power Trading Forum, highlighted the need for a more "robust discussion."

"I think we owe it to ourselves to talk through different ways to address this issue," Wells said. "One of the drawbacks I see of this proposal is it does create an incentive that we haven't really discussed. And I do wonder to what extent this proposal is going to incent resources to now bid in a way to ensure that they meet their day-ahead schedules, which we all know real-time conditions change from day-ahead. So, if they're bidding in a way that basically self-schedules them at their day-ahead schedule, we've now lost all that flexibility that these resources are bringing to the market, and that can cause reliability issues."

Stakeholders continued to ask for more time to address the issue.

"This feels to be a bit of a knee-jerk reaction initiative overall," said Chris Devon, director of energy market policy at Terra-Gen. "It doesn't seem like CAISO is willing or able to talk about storage in a manner that looks at everything that needs to be discussed holistically." ■

Early Heat, Wildfires Signal Increase in California PSPS Events

State's Utilities Present CPUC Outlook for Shutoff Potential This Year

By Ayla Burnett

Intense heat coupled with this summer's early and active fire season will likely increase the need for public safety power shutoffs (PSPS) this year, according to utilities presenting at a California Public Utilities Commission workshop Aug. 7-8.

Southern California Edison COO Jill Anderson spoke about the "relentless heat waves" and "months of wildfires" that have hit the state this summer.

"We've been setting records, certainly in SCE's service area and other places, and all of that for us is a reminder of how critical it is that we are ready with all the tools at our disposal to make sure that we can be managing and responding to extreme weather," Anderson said. "We know that one of those tools — what we consider a last resort tool — is PSPS."

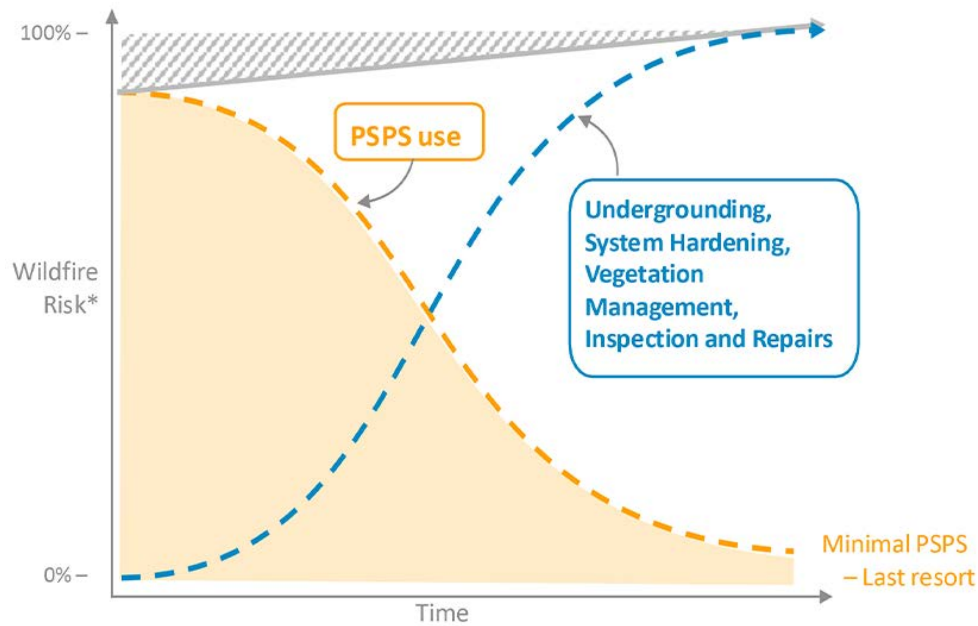
PSPS allow utilities to temporarily shut off power in certain areas to reduce the risk of fires caused by electric infrastructure. Several utilities, including SCE, Pacific Gas and Electric, PacifiCorp, and San Diego Gas and Electric, discussed the summer forecast in their service territories, PSPS predictions, and methods of implementing and preventing power shutoff events.

The transition to the La Niña weather pattern, associated with decreased rainfall in California, could extend high fire danger conditions later into fall and winter and increase the number of PSPS events, the utilities noted.

"We're concerned about the La Niña weather pattern because it historically correlates with more offshore wind days and also less precipitation, and these are not good markers for PSPS," said Tom Brady, principal manager of business resiliency at SCE.

But that correlation isn't always the case, Brady noted. In some instances, meteorologists have seen rains come early during La Niña weather patterns. Additionally, climate change could weaken the relationship between La Niña and precipitation in Southern California, Brady said.

The utilities highlighted that above-normal precipitation this past winter and in the past few years contributed to the vegetation growth that is fueling wildfires across the state.



Pacific Gas & Electric, along with other California utilities, presented at the California Public Utilities Commission's Public Safety Power Shutoff workshop. | *CPUC*

"August fuel levels are now at critical levels, and any moisture benefit from 2024 has mainly elapsed," Brady said. "We're in PSPS season, and in fact, we're activated today for a small event with localized impacts on the border of Kern and Los Angeles counties. We can begin to expect larger events to begin occurring when weather patterns shift and we have more widespread high winds across our service territory."

PG&E painted a similar picture, highlighting extreme weather conditions that have increased the likelihood of PSPS events.

Scott Strenfel, PG&E senior director of meteorology operations and fire science, said historically high temperatures have rapidly dried the fuels and "set the stage for what's already been a very challenging fire season."

"It is more probable than not that this will be a more active PSPS season compared to the last two years, just because of the danger of fuel," Strenfel said. "But all of that is going to depend on how many wind events we get and the timing of rainfall that could occur before or after those dry wind events that we get from the northeast."

Conditions are similar in SDG&E's service territory, with hot temperatures, increased vegetation and high fire risk.

"It's certainly not the forecast that a lot of us want to see going into the fall, but it is one that our situational awareness is very focused on, and we're very prepared," said Brian D'Agostino, vice president of wildfire and climate science at SDG&E.

'Positive Trend'

The utilities all highlighted ways they've worked to prevent PSPS events through system hardening, undergrounding, sectionalizing devices and transmission switches, and using cameras and weather stations.

In 2023, SDG&E completed 72 miles of undergrounding, trimmed and removed 13,000 trees, conducted 15,000 drone inspections, implemented 60 miles of covered conductors and more. In 2024, the utility aims to implement 40 more miles of covered conductors, 125 miles of undergrounding, trimming and removing 11,000 more trees, and conducting 17,000 detailed asset inspections.

PG&E completed 664 miles of underground-

CAISO/West News

ing between 2019 and 2023, hardened 1,664 miles of power lines, and installed 602 cameras and 1,424 weather stations. The utility plans to underground 250 more miles, harden 280 more miles, enable the use of AI for the cameras and continue to optimize the weather stations.

PacifiCorp has made similar progress, replacing over 95 miles of bare conductor with insulated covered conductor in 2023, undergrounding 5 miles of line, upgrading over 35 reclosers, relays and circuit breakers, and installing over 4,000 non-expulsion fuses. The utility also implemented the *FireSight* model to identify areas of heightened fire risk, which led it to identify a new high fire-risk area. In total, high fire-threat districts encompass approximately 1,700 overhead line miles and 54% of PacifiCorp's territory in California.

SCE implemented approximately 5,900 miles of covered conductor and 26 miles of undergrounding, trimmed or removed over 2 million trees, installed or replaced over 14,200 fast-acting fuses and 160 remote-controlled sectionalizing devices, and conducted over 1 million equipment inspections.

The utilities also highlighted the importance of artificial intelligence and machine learning in their modeling, forecasting and preparedness for PSPS events. For example, SDG&E is using machine learning at each of its 222 weather stations to train AI models to predict exactly which areas could experience a shutoff, allowing the utility to more accurately target notifications.

SDG&E also relies on three primary AI-based tools to enhance its PSPS response: gridded AI-based fuel models that provide a holistic look at fuel moisture content, machine learning wind gust models and AI smoke detection. The utilities also rely on enhanced powerline safety settings (EPSS), which allows powerlines to automatically turn off power within one-tenth of a second.

PG&E relies on outage and ignition probability weather models, as well as a fire potential index, to calculate the need for PSPS.

CPUC President Alice Reynolds expressed optimism despite predictions for increased PSPS events.

"I'm really pleased to see the progress that has been made on PSPS events over the last several years," Reynolds said, noting that PSPS customer notifications across all utilities declined from 5.8 million in 2019 to about 500,000 in 2023.

"There's a positive trend for the number of customers that have been de-energized … so clearly significant improvements," Reynolds said. ■

CAISO/West News

FERC Approves Two Enforcement Orders Related to Battery Storage

Several Battery Storage Facilities to Pay Over $1 Million in Fines

By Ayla Burnett

California Valley Solar Ranch | *U.S. Fish and Wildlife Service*

FERC approved two enforcement orders requiring several battery storage operators to pay more than $1 million in fines and remit nearly $1.9 million back to CAISO.

In the first order, issued Aug. 6, the commission found that Vista Energy Storage submitted bids into CAISO that overstated the availability and capability of its Vista Battery (*IN24-11*). The misrepresented bids occurred for over a month during the summer of 2022. As a result, Vista will pay $1 million in fines and disgorge $1,670,000 in profits to CAISO.

Vista is a subsidiary of REV, a renewable power company formed by LS Power in 2021 that operates about 2.8 GW in generation assets. The Vista Battery's maximum storage capacity is 40 MWh, and it offers both energy and ancillary services into the CAISO market.

During a 33-day period in 2022, Vista each day told CAISO that it forecast the battery's initial state of charge the following day to be at or below 4 MWh even though the battery had a 36 MW or larger regulation up award for the final hour of that day.

"Vista knew, or should have known, that because of that regulation up award, the ancillary services state of charge constraint would ensure that Vista's actual state of charge would be around 20 MWh during the final hour that day," the order reads.

Vista received 40 MW regulation down awards for the first hour of the next day due to its 4 MWh lower initial states of charge. It would not have received these awards in the first hour of the day if it had submitted an initial state of charge value of 20 MWh. The lower values also enabled the company to earn awards of 40 MW of regulation down for several hours after the first hour.

"Because the battery was actually at a state of charge around 20 MWh at the beginning of each of the 33 days within the relevant period, there was a conflict between operation of the regulation down product (which seeks to charge the battery to adjust frequency on the grid) and the ancillary service state of charge constraint," FERC stated.

To resolve the conflict, the ancillary service state of charge constraint frequently discharged the battery to make Vista's regulation down awards feasible.

As a result, Vista received approximately $1,485,000 in bid cost recovery payments because of regulation down awards it would not have obtained if it had submitted accurate initial state of charge values.

NextEra Order

The second order, issued Aug. 8, involved Arlington Energy Center III, Blythe Solar 110, Blythe Solar III, Blythe Solar IV, Desert Sunlight 250, Sunlight Storage and McCoy Solar (*IN24-10*).

The companies are all indirect subsidies of NextEra Energy Resources and operate battery energy storage systems co-located with solar generation. Each storage system and solar facility function as separate resources but share the same point of interconnection (POI). As per CAISO's large generator interconnection agreement, the resources cannot exceed the POI limit.

In December 2021, CAISO modified its tariff to prohibit co-located battery facilities from deviating from dispatch instructions. According to the order, NextEra was unaware of the tariff change and thus didn't update its software to comply.

"During the relevant period, when the combined output of a plant's battery and solar facilities approached the POI limit, the programmable logic controllers at the plant that controlled the output of the solar and battery facilities automatically curtailed the battery facility, allowing the solar facility to continue to deliver its output to the CAISO grid, as was permitted prior to CAISO's December 2021 tariff change," the order states. "NextEra's software did so even during intervals in which the plants' batteries received ancillary services awards."

There were 3,835 five-minute intervals during which the plants' batteries deviated from dispatch instructions while holding ancillary service awards, resulting in the companies' receiving approximately $381,724 in revenues.

NextEra has since updated its software and will pay a civil penalty of $105,000 and $381,724 in disgorgement to CAISO. ■

ISO-NE News

ISO-NE Outlines 'Straw Scope' of Capacity Market Reforms

By Jon Lamson

ISO-NE *responded* to stakeholder feedback on its capacity auction reform (CAR) project at the NEPOOL Markets Committee MC meeting Aug. 6, providing clarity on the scope of its capacity market overhaul.

Chris Geissler, ISO-NE's director of economic analysis, outlined the "straw scope" of the reforms, including which topics likely will be included in the project, and those remaining under consideration.

The CAR project is intended to coordinate resource accreditation reforms with *changes* to the time frame of capacity auctions. ISO-NE plans to move from the current forward annual auction format to a prompt seasonal auction for the 2028/29 capacity commitment period (CCP).

This change would reduce the time between the auction and the CCP and would split the yearlong CCP into seasons. (See *ISO-NE Moving Forward with Prompt, Seasonal Capacity Market Design*.)

Geissler presented ISO-NE's initial thoughts on the scope to the MC in July, and stakeholders submitted written comments prior to the August meeting. (See *NEPOOL Markets Committee Restarts Work on Capacity Market Changes*.)

The core aspects of the project include defining the timing and schedule of the prompt reforms, the treatment of new and retiring resources, and the delineation of seasons in the CCP, along with finalizing the accreditation reforms, Geissler said. The project also will include a focus on offer price formation, accounting for gas constraints and updating the current data systems, he added.

ISO-NE also plans to move from a descending clock to a sealed bid, which was recommended by the External Market Monitor. He said sealed bids would help enable simultaneous (instead of sequential) seasonal auctions, which ISO-NE is considering to allow bidders "to submit offers that separately reflect seasonal and annual costs."

Geissler said the RTO still is considering whether to include an evaluation of how it will model resources that are retained via out-of-market mechanisms, tie benefits and correlated temperature-related outages.

He added ISO-NE will consider whether it can improve the existing load model used for accreditation, along with the modeling frameworks used for different resource types. Storage developers argue the RTO's load modeling has produced unrealistic capacity shortfall events. (See *ISO-NE Capacity Accreditation Reforms Spur Energy Storage Concerns*.)

The RTO is unlikely to include in the scope a reconsideration of the underlying software program used for the accreditation modeling, or an evaluation of modeling of resource start time. Some stakeholders argue in favor of modeling resource start time, and the External Market Monitor (EMM) has highlighted the issue.

"Resources with long startup times that do not operate frequently provide less reliability value than more flexible units," the EMM noted *in 2021*.

Scope Feedback

Prior to the meeting, a wide range of stakeholders submitted *written comments* on ISO-NE's scope proposal.

A coalition of clean energy companies and environmental advocacy groups called on ISO-NE to "facilitate more discussion on how the modeled risk relates to observed real-world risk."

Storage developers expressed concern that the new accreditation framework will lead to a significant reduction in capacity market revenue for storage resources. The impact analysis results presented in the previous stage of the accreditation project indicated storage would see the most significant revenue reduction of all resource types. (See *ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%*.)

Several solar companies also submitted comments urging the RTO to consider "enhancements to the modeling framework" for co-located solar and storage resources.

LS Power made the case that accreditation should account for unit-by-unit differences in natural gas availability for gas generation. The company has stressed that gas availability when temperatures decline varies significantly by state and by unit, and ISO-NE's current accreditation proposal would not account for these differences.

"Just as the current Forward Capacity Auction methodology recognizes locational variations and unit-specific characteristics for accreditation, ISO's CAR accreditation approach to natural gas accessibility must do the same," LS wrote.

Meanwhile, RENEW Northeast expressed support for ISO-NE's proposal for accrediting gas resources, writing that "the proposed market constraint for gas, as part of the seasonal market, appears to be a significant improvement and we appreciate that ISO continues to plan for this as part of the initial market reform effort."

Calpine advocated for a simultaneous clearing design for seasonal auctions, writing that it has "grave concerns with a seasonal construct that does not allow or permit resources the opportunity to recover full (annual) costs."

The company also stressed the scope should include an evaluation of tie benefits, and that tie benefits should be treated similarly to other capacity resources.

In contrast, Synapse Energy Economics wrote that re-evaluating the treatment of tie benefits is "not a critical priority at this stage," adding that it likely would have a small impact on overall capacity requirements.

Several stakeholders, including the New England Power Generators Association (NEPGA), said ISO-NE should discuss with stakeholders what costs can be included in a capacity market offer price.

The Massachusetts Attorney General's Office recommended ISO-NE "develop a longer-term strategic plan and road map for consideration and implementation of needed capacity market reforms that are outside the scope of CAR for CCP 19."

Financial Assurance

A *proposal* by NEPGA to amend ISO-NE's proposed updates to the financial assurance policy failed to gain the support of the MC, with 50% of votes in favor.

NEPGA's proposal would direct ISO-NE to allow bilateral trading of capacity supply obligations (CSOs) until five business days before each obligation month and would require ISO-NE to review trades within five business days of their submission. (See *NE Generators Propose Financial Assurance Changes*.)

"The current rules create incremental risk and increase the cost of assuming a CSO," said Bruce Anderson of NEPGA. "The ability to trade closer in time to the obligation month improves reliability, in that it allows for timely substitution of anticipated Capacity Scarcity Condition performance." ■

NYISO News

NYISO Presents Draft Recommendations for Demand Curve Reset

ISO Sticking with Battery as Proxy

By Vincent Gabrielle

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NYISO presented its draft recommendations for the demand curve reset Aug. 1, including the choice of a two-hour battery electric storage system resource as the proxy unit in calculations.

The ISO said it agreed with the findings of Analysis Group, even after some stakeholders — mostly generators — opposed the choice. (See *NYISO Stakeholders Continue Debate over Battery as Proxy Unit*.)

The presentation to the Installed Capacity Working Group was proceeded by a long discussion of various financial parameters employed by NYISO's consultants.

"Hopefully I don't need to cover this," said Zach Smith, senior manager of capacity and new resource integration market solutions for NYISO, referencing a background slide. "We just spent the past two hours talking about" it.

Smith said that NYISO staff concurred with the recommendations of Analysis Group. Based on the data analyzed so far, a 200-MW, two-hour lithium battery storage system is the technology that represents the highest variable and lowest fixed cost for all zones in New York.

"There are a couple of areas we are continuing to investigate, to sharpen our pencils on," Smith said. "The first is an assessment of the capital parameters for the battery storage option. … We are also looking at the appropriate derating factor for battery energy storage."

Smith added that NYISO was looking at the appropriate indices and weightings used for updating the cost of new entry.

Doreen Saia, a lawyer with Greenberg Traurig, said she was unsure how well Analysis Group captured the risk portfolio of the two-hour battery as compared to other storage options. Earlier she said she believed the analysis was "too aggressive" on an eight-hour battery but not enough on the two-hour.

"While I'm not conflating capacity accreditation factors with this, from a risk perspective, I think you have to project or assume or presume that investors are going to see that distinction and manage it with a risk assessment," Saia said. "I think that's where the train fell off the tracks a little."

Other stakeholders seemed concerned about the derating factor for energy storage. Derating factors measure the availability or performance of specific resources. They are combined with duration adjustment factors to account for a resource's capacity accreditation.

Smith outlined a problem with the derating factor for the two-hour battery. Analysis Group and its consulting partners, 1898 and Co., recommended a 2% derating factor. However, NYISO's ICAP Manual establishes that the initial derating factor for new classes of energy storage entering the capacity market is set to the NERC class average of pumped hydro storage, 9%.

"There is a potential misalignment between the assumed proxy EFORd [equivalent forced outage rate – demand] value for energy storage directed by the ICAP Manual *versus* the potential operating performance anticipated for such resources," Smith said. "We are continuing to evaluate what the appropriate derating factor should be for battery energy storage systems in the demand curve reset."

"You're acknowledging that there's a problem," said Mark Younger, president of Hudson Energy Economics. "But you have not committed yet to fixing the problem."

"We are committed to investigating the problem," Smith answered. "I don't know what the solution to the problem is, but we will have a resolution to it."

Smith went on to say that NYISO would work with Analysis Group to investigate the appropriateness of the composite escalation factor methodology in the indices used for determining the gross CONE. Composite escalation factors combine inflation and potential market shifts to try to estimate the future cost of longer-term projects.

"Despite our best efforts, which everyone seems to be having including the state in their contracting efforts, the issue of how to manage escalation has taken on a life on its own. … It's cumbersome and unmanageable," Saia said.

Smith said NYISO was still soliciting feedback and it would post the comments received. It will post the final staff recommendations Sept. 5. The final reports from NYISO and the consultants will then be posted on Sept. 19 and referred to the Board of Directors for approval. Final stakeholder comments for the board should be filed by Oct. 9.

The ISO is required to file a proposal with FERC by Nov. 30.

"Then I'm going to take a vacation," Smith said. ■

NYISO News

NYISO Previews Work on Compliance with FERC Order 1920

By Vincent Gabrielle

NYISO last week began gathering stakeholder input on its FERC Order 1920 compliance plan, which it expects to file on time without any need for delay.

The ISO gave an *overview* of the 1,300-page order, issued in May, to the Transmission Planning Advisory Subcommittee. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

"What I am reviewing here, from NYISO's perspective, are the highlights," said Yachi Lin, the ISO's director of systems planning. "But absolutely please do your own review, bring back your points, and we can start a discussion."

The rule requires regional transmission planners to plan on a 20-year horizon with several benefits. Cost allocation plans for projects must ensure only customers who receive those benefits pay for projects.

"You're going to hear these terms repeated over and over again throughout the order: 'sufficiently long-term,' 'forward-looking,' 'comprehensive,'" Lin said.

The order went into effect Aug. 12. Lin said NYISO needs to submit its compliance filing with the regional planning requirements to FERC by June 12, 2025. Interregional planning requirements are due later in August.

Between October and December of this year, NYISO will be drafting a straw proposal to comply with the order, followed by tariff revisions during the first six months of 2025.

NYISO will be required to develop three long-term scenarios that project out 20 years based on seven factors prescribed by FERC. Once projects have been winnowed down to the selected projects, the reasons for the selections and rejections will be explained to stakeholders.

One TPAS member pointed out that the process looked similar to parts of NYISO's extant three-pronged process and wondered how much this would change the ISO's existing process.

"That is the question we are very much interested in hearing your opinion on," Lin said.

She went into detail on the NYISO planning process and then asked whether it was better to expand the existing process or build an additional tracker on top to comply with the order. "I don't have an answer to tell you. What we really need to do is hear from you."

One stakeholder said it was unclear to him whether NYISO was the "transmission provider" under the rule or whether that was the New York Public Service Commission.

"The transmission provider has an affirmative obligation to determine the need," Lin said. "The relevant state entity does have a role to play in providing the input for how the scenario is developed, how the need is established. So there's also an affirmative role for the relevant state entity to play."

Lin also noted the four technologies that were specified as grid-enhancing technologies, which under the order must be considered for efficiency and cost-effectiveness against new facilities or upgrades that do not incorporate them. They are dynamic line ratings, advanced power control devices, advanced conductors and transmission switching. ■

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PJM OC Briefs

PJM Presents Operations Road Map

VALLEY FORGE, Pa. — The Operating Committee discussed PJM's *timeline* for addressing technological and operational challenges the RTO plans to address over the next four years.

The document is one in a series of outlines PJM has formed to track the various stakeholder and internal staff efforts to address reliability issues identified in its *Ensuring a Reliable Energy Transition* analyses. The market-oriented road map was presented during the July 10 Market Implementation Committee meeting, while its planning sibling remains under design as staff work on FERC Order 1920 compliance. (See "PJM Presents Road Map of Market Design Changes," *PJM MIC Briefs: July 10, 2024*.)

PJM Senior Director of Market Design Rebecca Carroll said the road maps are meant to be updated as new efforts begin or are completed, with the aim of ensuring none of the working areas fall through the cracks.

The operations road map includes:

- Enhancing forecasting of intermittent resources, behind-the-meter generation and changing load behavior.
- Implementing the Control Room 2030 plan to build dispatcher tools to facilitate the deployment of large volumes of intermittent, distributed and storage resources.
- Continuing upgrades to PJM's suite of energy management system (EMS) software, focusing on network application, training system and model management tools.
- Developing risk-based operations approaches that account for variance in forecast error, generator outage performance and time of year considerations. That could impact reserve and regulation procurement or other operational decisions.
- Continuing gas-electric coordination efforts to incorporate information about the gas pipeline and generation fleet into PJM operations.
- Incorporating intermittent forecasting into the transmission outage analysis and approval process.
- Ensuring any changes to reserve market structures remain aligned with operational needs.

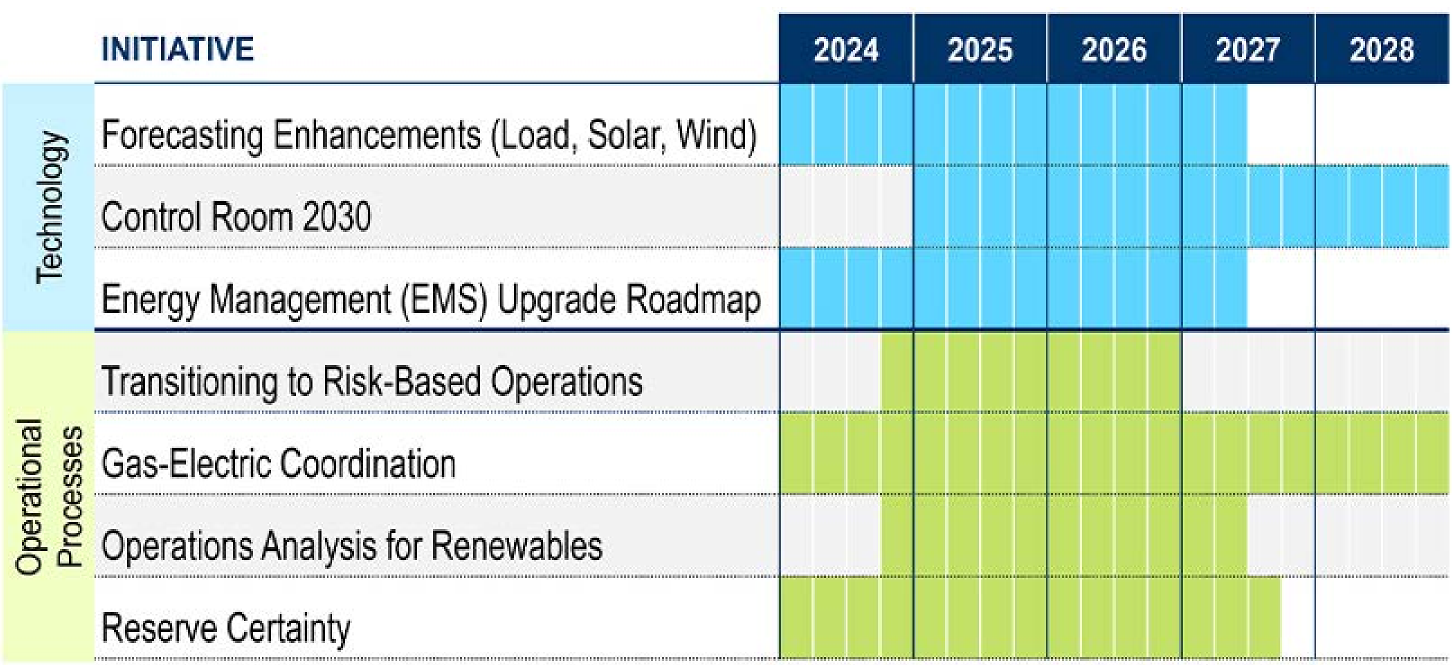
PJM's Chris Pilong said the number of risks the grid faces is increasing, challenging the ability for operators to schedule the appropriate generation with optimal lead times. Some of the initiatives likely will require the focus of stakeholders and the RTO indefinitely, such as the electric-gas coordination efforts that have been ongoing for a decade and are likely to continue as the gas industry evolves with shifting economics and policies.

Several stakeholders recommended PJM publish the three road maps and their related materials in one place for easy retrieval and provide more insight into in which forums each issue will be discussed.

Paul Sotkiewicz, president of E-cubed Policy Associates, said all of the items on PJM's road map are interrelated topics, and he's concerned that if they're addressed in siloes, holistic solutions may remain out of reach.

Pilong said staff are coordinating across departments and when topics are brought to stakeholders PJM wants to make sure they're brought to the correct working group.

Sotkiewicz also argued it's inappropriate for the RTO to include the facilitating of decarbonization policies reliably in its three "Pillars of Strategy" guiding the focus of the road map. Instead, he said the focus should remain locked



PJM presented its road map of changes to its operations to the Operating Committee on Aug. 8. | *PJM* in on reliability amid changes external to PJM.

Voltage Reduction Action Test Planned

PJM *plans* to conduct a voltage reduction test Aug. 14 and 15 to validate a capability the RTO has not used for more than a decade.

Senior Dispatch Manager Kevin Hatch said the test is one of the recommendations in a PJM report on the performance of the grid in the wake of the December 2022 Winter Storm Elliott, when a voltage reduction warning was issued, and one additional generator trip could have required an action. The previous voltage reduction action PJM issued was in January 2014. (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

The Mid-Atlantic region will undergo testing at 2 p.m. ET on Aug. 14, followed by the western and southern regions the following day at the same hour. If the test cannot be conducted as scheduled, Aug. 28 and 29 have been identified as alternatives. The test is scheduled to run for half an hour.

The test will simulate a 5% voltage reduction on a load level above the seasonal upper quartile.

Hatch said the goals of the test are to determine whether changes in the characteristics of PJM load have led to any shifts in the efficacy of voltage reduction actions, to examine the functionality of updated procedures and to provide training for staff and members. PJM does not have a regular voltage reduction testing regimen, but Hatch said ISO-NE and other regions conduct tests twice a year.

Operating Error Metrics Improve in July, 153 GW Monthly Peak Load

July 16 saw one of the highest peaks for the month in PJM's history at 153 GW. *Presenting* the month's load forecast error, PJM's Marcus Smith said the month as a whole averaged 5 GW higher than an average July.

PJM's average peak and hourly forecast error rates for July both fell squarely at their 25-month averages of 1.64% and 1.52%, respectively.

The day-ahead forecast error did exceed PJM's 3% target on a handful of days. July 13 saw a 5% under forecast as temperatures came in hotter than expected, while the following day was over forecast by about 6.5% because of storms bringing temperatures 15 degrees lower than anticipated.

Eight shared reserve events, three spin events and eight hot weather alerts were issued across the month. Generator trips led to two shortage cases on July 28 and one on July 8.

Social Manipulation Attacks a Rising Cybersecurity Threat

Artificial intelligence increasingly is being used in social manipulation cyberattacks, PJM's Jim Gluck said, warning stakeholders that critical infrastructure is experiencing attacks at a higher rate than the economy as a whole.

He pointed to a software company that was targeted recently through its hiring process by attackers impersonating a prospective employee. Four video interviews, validation of credentials and background checks failed to identify that a stolen identity was being used and profile images augmented with AI. Once the individual was hired for the position, a company computer was mailed out, malicious software was installed on it and a breach was attempted. The company identified the attack and revoked the computer's access before systems could be compromised.

Attackers also have taken advantage of widespread disruption caused by an issue with antivirus software developed by CrowdStrike. Individuals have impersonated CrowdStrike employees offering assistance with recovery to gain access to Microsoft systems.

"We've got to make sure we've got the processes in place to detect these kinds of situations wherever they are," Gluck said.

Implementing multi-factor authentication, patching software regularly and staying vigilant for phishing attacks can reduce the risk of attacks being successful, he said. ■

— Devin Leith-Yessian

Stakeholders Endorse PJM EE Measurement and Verification Proposal

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The Market Implementation Committee endorsed a PJM proposal to revise how the capacity offered by energy efficiency (EE) resources is measured and verified, rejecting competing proposals from EE providers and the Independent Market Monitor. The package passed with 65.5% support during the Aug. 7 MIC meeting. (See *PJM Hears Proposals to Redesign EE Participation in Capacity Market.*)

The proposal requires that EE providers demonstrate that capacity market revenues were the only factor in allowing a project to come to fruition and that it would not have occurred otherwise. The package also would reduce the period for which an EE project can participate in the capacity market from three years to one year after completion, which would address a possible delay in load-serving entity cost savings on lower peak load contributions (PLC).

Any EE megawatts that did clear the Base Residual Auction (BRA) under PJM's proposal would continue to be tacked onto the load forecast in a process known as the addback, which is meant to ensure that EE cannot act on both the supply and demand side. A withdrawn proposal from CPower included language that would have opened a separate problem statement and issue charge to consider the continued role of the addback, which also is the subject of a FERC complaint filed by three state consumer advocates (EL24-118). (See *PJM Consumer Advocates File Complaint on EE Market Design.*)

The ability for EE to participate in fixed resource requirement (FRR) plans also would be eliminated on the grounds that the option has not been used and would be redundant, as cleared EE would be added back to the FRR obligation.

"It's a complicated package, but if members choose and they want to keep energy efficiency as a market product, we think this package can help put those checks and balances in there," PJM's Tim Horger said while presenting the proposal Aug. 7.

The resource has been the focus of stakeholder attention over the past year, as PJM contends that under the current framework, EE providers have not demonstrated the capacity market revenues they receive have a causal link with reduced load and should not receive capacity market revenues until that link can be demonstrated. Several complaints have been filed at FERC during that time, alleging PJM's market structure discriminates against EE, its treatment of market participants is unfair and EE resources have not demonstrated they meet the Reliability Pricing Model (RPM) participation requirements.

PJM CEO Manu Asthana speaks about the role of energy efficiency in the RTO's capacity market. | *© RTO Insider LLC*

Presenting PJM's first read of the proposal during the July 24 Markets and Reliability Committee meeting, PJM's Pete Langbein said he believes there's a large amount of "naturally occurring" EE from consumers wanting to reduce their carbon footprint or energy bills by buying more efficient devices. He argued those installations should not be eligible for BRA revenues.

PJM CEO Manu Asthana gave the example of a recent washing machine purchase he made, where the deciding factor was appliance features rather than the efficiency of the device. He said it's possible it had a lower load than competing models and therefore would qualify for mid- or upstream EE programs that seek to use capacity market revenues to discount the purchase price, even though the purchase would have occurred regardless. While in aggregate EE programs may be successful in shifting consumer behavior in favor of reducing capacity needs, he said the capacity market isn't entirely designed for that kind of cost allocation.

Several stakeholders said the causal link sets an impossible standard for EE providers to meet and would result in all programs being eliminated from the market.

Market participants proposed competing visions of how the accuracy of market participating EE could be improved. Affirmed Energy proposed a standardized approach for the measurement and verification (M&V) methodologies providers submit, an EE registration process akin to the rules around demand response, and third-party review for PJM's verification. Mid- and upstream EE programs that use capacity market revenues to discount efficient devices in an effort to incentivize their purchase would not be required to obtain contracts with each consumer to offer the capacity associated with the energy savings into PJM's market.

The Affirmed proposal initially sought to eliminate the addback by increasing the amount of EE data PJM incorporates into its load forecast. That component was dropped as the number of complaints pending at FERC regarding EE market design multiplied. The proposal received 2.2% support.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said there's a concern the addback leads to capacity market payments going to EE providers without any corresponding increase in reliability.

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A *proposal* from Exelon aimed to preserve the ability for utilities administering EE programs on behalf of their states to enter savings into the capacity market by positing that programs run "under the direction, authorization and/or supervision of state public utility regulatory authorities are de facto qualified as EE capacity market products."

The proposal also would differentiate the state directed, authorized and supervised programs from those offered by third-party EE providers with respect to the approval of M&V plans. Those plans outline how the EE provider intends to demonstrate the amount of capacity it will offer and validate that figure, as well as PJM's evaluation of post-installation measurement and verification (PIMV) reports, where providers describe how they put those methodologies into practice.

Exelon's Alex Stern said the utility believes that if PJM approves a M&V plan, it should not reject PIMV reports that accurately follow through on the described approach that has been reviewed and accepted by the states. The proposal received 37.2% support.

Stern said for as long as the states want their programs to have the ability to participate in the PJM capacity market, a distinction should exist between the rigor and regulatory scrutiny states already exercise over utility-run EE programs and EE that is bid into the capacity market by other EE market participants.

"We certainly don't oppose other energy efficiency market participants ... so long as the rules are fair. And by fair, I mean allowing opportunities for all, but [respecting] that the state programs are different in regard to measurement and verification," he said.

The Independent Market Monitor *proposal* would go the furthest by removing EE from the capacity construct entirely, arguing that the energy savings have been incorporated in PJM's load forecast since the 2016/17 delivery year and there is no basis in the tariff for keeping them in the market. Though the package received 54% support over the status quo, it failed to receive endorsement with a tie.

"The IMM's proposal is the only one to recognize the current reality. EE is factually not a capacity resource under the tariff, EE is not in the capacity market, and PJM has not treated EE as a capacity resource since 2016. It is not PJM's role to choose to subsidize EE outside the market. The lack of credible measurement and verification and the absence of causality make the subsidies even more unsupportable," Monitor Joe Bowring told *RTO Insider* in an email.

He noted that the votes were not on a sector-weighted basis and the results of PJM's proposal and the IMM's proposal in a sector-weighted vote could be quite different, whereas rejection of the other packages likely would not have changed with sector weighting.

CPower withdrew its proposal during the Aug. 7 meeting, which focused on standardizing M&V and creating a separate process to reconsider the addback. It threw its weight behind the Exelon package while urging stakeholders to vote against the proposals from PJM and the Monitor.

"The Market Monitor's proposal would by definition eliminate [EE] from the market ... and as others have noted as well … the PJM proposal would de facto eliminate it because it continues to include this unmeetable 100% causality test," CPower's Aaron Breidenbaugh said.

CPower Complaint on PJM Guidance Ahead of 2025/26 Auction

In a July 17 complaint to FERC, CPower argued PJM has improperly taken a step toward implementing some of those changes, in contravention of the reigning tariff and manual language. It did so by issuing a guidance document on June 13 that informed EE market participants that it was limiting the project installation years eligible to participate in the 2025/26 BRA to the 2023/24 and 2024/25 delivery years.

The document also revised how PJM determines the standard baseline used for measuring EE savings for lightbulbs, requested documentation showing that providers hold exclusive capacity rights, and added a process where the Monitor can review PIMV plans to provide comments and recommendations to PJM (*EL24-128*).

The complaint asks FERC to allow CPower to participate in the Incremental Auctions (IAs) for the 2025/26 delivery year under the status quo rules and establish a settlement process or an administrative law judge to mediate disputes around PJM's market rules for EE in the 2025/26 BRA. The amount of EE that cleared in the 2025/26 auction fell to 1,459.8 MW from 7,668.7 MW for the prior year.

CPower argued that the PJM tariff and the 2010 FERC order establishing EE participation in the RPM hold that resources can offer into four auctions and that limiting that period would constrain participants' ability to use past projects as replacement capacity to cover any shortfalls caused by new installations not being completed by the start of the delivery year.

The change to the standard baseline resulted in LED lightbulbs being set as the standard practice for consumer behavior. The standard baseline determines the device that more efficient devices included in EE plans are measured against. CPower argued that the shift was made with little evidence that it reflects typical consumer behavior, stating that a *memo* sent from Apex Analytics to Rutgers University staff was the basis for the change.

"PJM does not offer any robust sets of studies or analyses about standard practice. It conducted no stakeholder process to seek input on standard practice. Allowing PJM to issue edicts about what standard practice is throughout the region with alleged support as flimsy as the Apex memo would set damaging precedent and allow PJM to wield an inordinate amount of power outside of the commission's just and reasonableness FPA [Federal Power Act] review process, both as to EE and beyond," the company wrote in its complaint.

The company took issue with including the Monitor in the approval of PIMV reports on the grounds that complaints have been filed against EE providers by the Monitor, calling into question whether it can be impartial and independent when reviewing reports submitted by those parties. CPower said it received two letters from the Monitor on June 26 stating it would recommend PJM not approve its M&V plan for the 2025/26 delivery year unless the company provided several items to the Monitor, including its justification for opposing PJM's June 13 guidance.

"PJM is thus effectively denying CPower's ability to withhold from the IMM what amounts to discovery outside of a commission-mandated process. Given the consequences of not providing the information, which included precluding its participation in the upcoming BRA, CPower had no real choice but to provide it to the IMM, despite its legal objections," CPower said.

PJM responded on Aug. 5, stating that the tariff language provides that EE may participate in the auction for four delivery years but does not mandate it. It also argued that the M&V review is within the Monitor's scope and responding to its inquiries is a condition of PJM membership.

"CPower unreasonably claims it is entitled to a four-year installation period for EE projects that clear a BRA even under a compressed auction schedule when two of the delivery years have already been completed and the load forecast reflects those efficiency projects as having already been installed. CPower's

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position is irrational from an economic or operational perspective and is grounded in a gross misinterpretation of the tariff, RAA and PJM Manual 18B," PJM said.

PJM Argues Addback Necessary to Implement EE

PJM has responded to a complaint filed by the New Jersey Division of Rate Counsel, Maryland Office of People's Counsel and Illinois Citizens Utility Board arguing that the RTO's use of the addback deprives consumers of the reliability benefits EE can offer while still requiring them to pay market participants. Given the significance of the addback, they also state that it should be enshrined in the governing documents, rather than business manuals, and be subject to FERC review.

In a July 10 response, PJM said the addback is necessary to avoid contravening tariff language prohibiting the double counting of EE resources as a capacity resource while also reducing peak load forecasts. PJM argued that the addback is envisioned by the tariff and can be accomplished through the manuals under the "rule of reason" as a mechanism to implement tariff language. Without the addback, it said the reliability requirement for the 2024/25 BRA would have been 142,973 MW, short of the 151,631-MW peak summer load requirement.

"The addback was designed to address changes in the methodology for determining the PJM load forecast to preserve the ability of EE resources to qualify for capacity payments as they had under the previous load forecast methodology. Thus, far from being a 'fundamental change' that undermined the participation of EE resources in RPM auctions, as complainants argue, the introduction of the addback preserved the status quo for EE resources seeking to receive capacity commitments," PJM wrote.

Both Advanced Energy United and the PJM Power Providers submitted comments supporting the consumers' call for FERC to convene a technical conference to consider the addback and EE market design more thoroughly.

In its July 10 complaint against PJM, the Monitor also argued that PJM's implementation of the addback violates the tariff, stating that EE is permitted to offer capacity only for savings that are "not reflected in the peak load forecast prepared for the delivery year for which the energy efficiency resource is proposed." The complaint says PJM should have eliminated EE from the capacity construct once it revised its load forecast approach to include EE data produced by the Energy Information Administration's Annual Energy Outlook (*EL24-126*).

"When EE was added to the forecast and EE was removed from the capacity market, PJM should have simply followed the tariff, recognized that EE was not capacity, recognized EE resources do not meet the definition of EE resources in the filed tariff and eliminated payment to EE resources. Instead, PJM recognized that EE resources are not capacity, stopped including EE resources in the capacity auction, and began to pay EE resources an uplift payment equal to the capacity market clearing price without making any provision for such payments in the filed tariff," the Monitor wrote.

PJM responded that the addback is permitted under the rule of reason and that it cannot change the results of the 2024/25 BRA because of the filed rate doctrine, citing a March 2024 3rd U.S. Circuit Court of Appeals decision rejecting a post-auction change to a regional reliability requirement. (See *3rd Circuit Rejects PJM's Post-auction Change as Retroactive Ratemaking*.)

The New Jersey Board of Public Utilities asked FERC to reject the Monitor's request to cease EE payments, consolidate the remainder of the complaint with the consumer advocates' filing and convene a technical conference centered on EE's role in the capacity market.

"The New Jersey BPU supports a holistic review of [energy efficiency resource] eligibility and discussions around whether including EE in the market clearing mechanism is preferable to the EE addback. However, this decision must be the result of a process that allows for participation and input from all relevant stakeholders," the board wrote.

PJM Responds to Monitor Complaint Against EE Providers

In a July 3 response to a complaint filed by the Monitor alleging that several EE market participants have not demonstrated they were eligible to participate in the 2024/25 and subsequent capacity auctions, PJM defended its approach to reviewing PIMV reports and said the Monitor proposed an unworkable approach to determining what qualifies as EE (*EL24-113*). (See *Monitor Alleges EE Resources Ineligible to Participate in PJM Capacity Market*.)

The complaint argued that EE mid- and upstream programs must be able to demonstrate that the more efficient products purchased with EE rebates actually were installed and are being operated within the PJM footprint. It asks the commission to either bar the EE providers from receiving capacity revenues in the 2024/25 delivery year or open an investigation to determine eligibility.

"For instance, short of conducting on-site audits for every location where EE is claimed right before the start of each delivery year, it is unclear whether any other methodology or estimate would satisfy the Market Monitor's allegation that the post-installation M&V reports fail to establish that the indicated energy efficiency sellers have actually installed the resources in homes or businesses," PJM wrote. "However, such an approach would clearly [be neither] feasible nor cost-effective given that 7,716 MW of EE resources cleared the capacity auction for the 2024/2025 delivery year alone, which could include tens of thousands, or even hundreds of thousands, of individual end-use customer sites that would need to be audited."

While PJM agreed that improvements should be made to measurement and verifications, it said that should be done through the stakeholder process instead and indicated it plans to file M&V changes within the coming months. It also stated it intends to solicit an independent third party with expertise in EE to review the PIMV reports submitted for the 2024/25 delivery year.

"These audits will confirm or amend the final nominated EE value and capacity performance value for the EE resources that comprise the indicated energy efficiency sellers' portfolios for the 2024/25 delivery year," PJM said.

The American Council for an Energy Efficient Economy commented that a technical conference would be the proper forum to resolve the dispute and that the approaches favored by PJM and the Monitor would constrain EE's ability to participate in the capacity market.

"ACEEE believes that PJM and IMM are not appropriately assessing the benefits of energy efficiency, not assigning it its deserved value and trying to kill its role in capacity markets to the detriment of electricity consumers. Energy efficiency with appropriate evaluation belongs in the capacity system, both to benefit consumers and to ease growing demand for new electric generation," the trade group wrote.

The Environmental Law and Policy Center argued that the Monitor's complaint is a collateral attack on past FERC orders mandating the ability for EE to offer capacity. ■

PJM MIC Briefs

PJM not Planning to Refile Components of Rejected CIFP Proposal

VALLEY FORGE, Pa. — PJM has scuttled plans to refile several components of its proposed capacity market redesign that was rejected by FERC in February (ER24-98).

Drafted through the Critical Issue Fast Path (CIFP) process conducted last year, the filing sought to rework the market seller offer cap (MSOC) and Capacity Performance (CP) structure, and establish a forward-looking energy and ancillary service (EAS) offset for the MSOC and minimum offer price rule (MOPR). The filing was one of two arising from the CIFP process last year; the other was approved by the commission in January and focused on risk modeling and generation accreditation. (See *FERC Rejects Changes to PJM Capacity Performance Penalties*.)

During the MIC's meeting June 5, Chief Economist Walter Graf said PJM was considering refiling components that the commission either seemed supportive of or did not comment on in its rejection order. That included "clarifying revisions" to the definition of Capacity Performance quantified risk (CPQR), MSOC values for planned generation based on net cost of new entry, segmented offer caps and the forward-looking EAS offset. (See "PJM to Refile Portions of Rejected CIFP Proposal," *PJM MIC Briefs: June 5, 2024*.)

But last week, PJM Lead Market Design Specialist Pat Bruno said the decision to not refile was made following mixed stakeholder feedback during the June meeting, as well as outreach to members over the past two months. He said the overall sentiment seemed to be that there is not a major imperative to refile at this time, particularly given the Quadrennial Review and second phase of the capacity market redesign, both expected to begin next year. Those two forums may be where PJM seeks to propose the items it intended to refile. (See "PJM Presents Road Map of Market Design Changes," *PJM MIC Briefs: July 10, 2024*.)

The RTO envisions the phase 2 discussion to center around a seasonal or sub-annual capacity construct, Bruno said.

PJM's proposal did not subject intermittent resources to the must-offer requirement, but the RTO had considered doing so as part of a sub-annual market design while forming its proposals. A sub-annual design would allow for greater alignment of intermittent resource performance expectations and accreditation, he said.

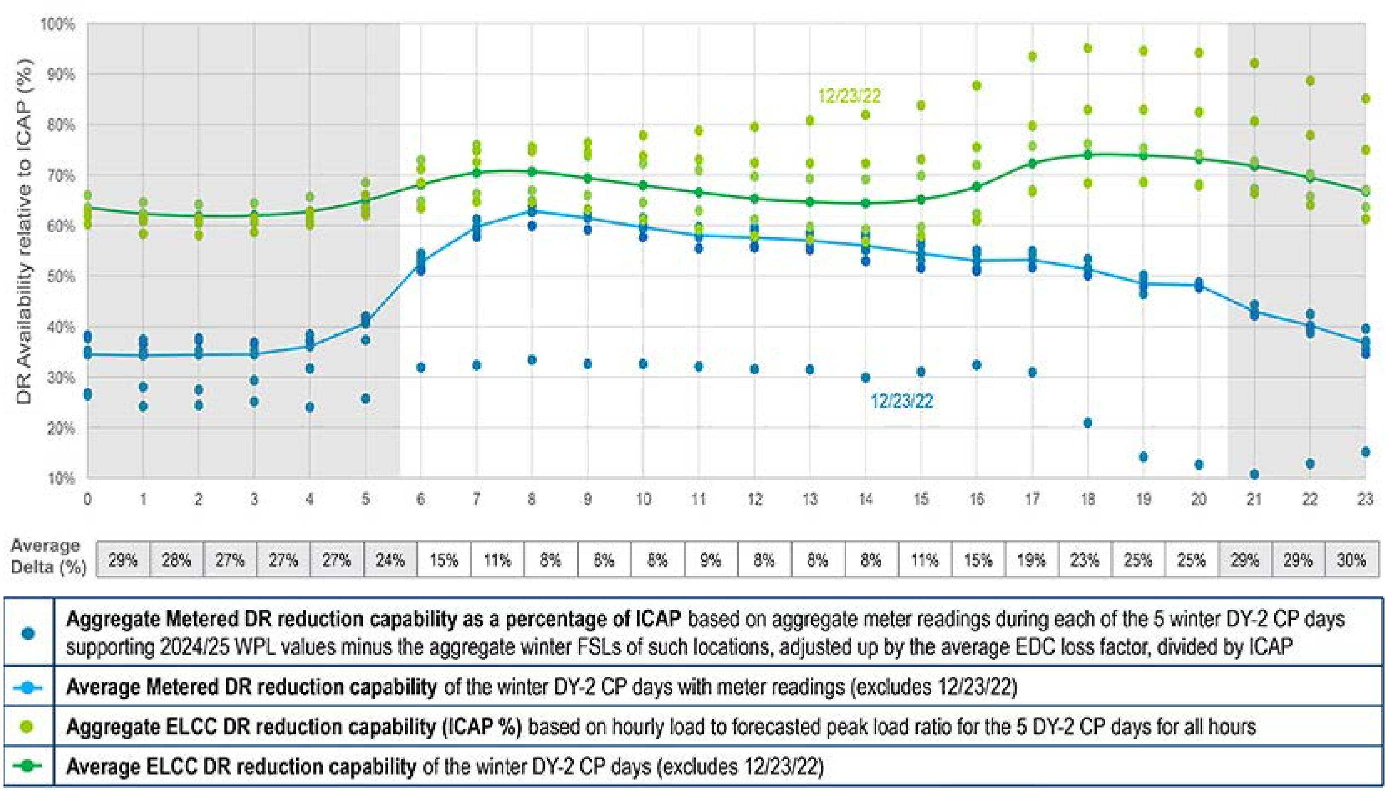
Stakeholders Endorse FTR Manual Revisions

The MIC endorsed *revisions* to Manual 6: Financial Transmission Rights to conform with three FERC orders on storage, hybrid resources and bilateral trade agreements (ER19-469, ER22-1420 and ER24-374).

The revisions state that transmission customers using firm service to deliver energy for charging storage or open-loop hybrid resources cannot receive auction revenue right allocations. (See *RTOs Move Closer to Full Order 841 Implementation*.)

They also require reporting bilateral trades to PJM, including confirming that the seller has no continuing interests in the FTR once it has been transacted.

The revisions are set to go before the Markets and Reliability Committee for a first read Aug.



PJM presented analysis of demand response availability during the top five weather load days in 2022 and 2023, compared to the ELCC rating assumptions for the resource class. | *PJM*

21 and move to an endorsement vote Sept. 25.

PJM Proposes Elimination of 2 Interface Pricing Options

PJM presented a quick-fix *proposal* to remove its high/low and marginal cost proxy interface pricing options because of lacking utilization. The quick fix process allows for an *issue charge* and proposed solution to be voted on concurrently.

Since their implementation in 2009, the options have only been used once, when Duke Energy Progress received FERC approval of a dynamic schedule with PJM, according to the RTO's problem statement. That agreement was terminated in 2019, and the options have not been used since.

"PJM and its stakeholders have the opportunity to retire the aforementioned processes associated with the development of interface pricing points for non-market entities," the *problem statement* reads. "There is an opportunity to simplify the existing language to remove outdated processes no longer used and better align with the existing language for the current interface pricing process in use."

PJM's Phil D'Antonio said the marginal cost proxy option required a congestion management agreement to be reached, but the RTO removed the management process in 2021.

Updated Guidance for Entering Dual-fuel Units into Markets Gateway

PJM's Joseph Tutino reviewed the RTO's updated *guidance* for how dual-fuel generators should reflect their fuel availability in Markets Gateway.

Resources assigned a cost schedule through the day-ahead or real-time markets are unable to subsequently switch their schedules, so dual-fuel generators that intend to switch the fuel they are operating on should update their schedule to state the fuel they will be consuming and the associated price, Tutino said.

If a gas-fired dual-fuel unit is committed to run on gas and then becomes unavailable later in the operating day, its gas cost schedule, incremental offer curve and no-load cost should be updated to reflect the cost of oil. The "reference schedule" field should also be updated to reflect the cost schedule ID of the alternative fuel.

PJM Presents Data on DR Availability

PJM *analysis* of demand response availability during the 10 days in 2022 and 2023 that comprised the top five weather load days for each year suggests that actual metered load reductions required to meet winter curtailment obligations were below the effective load-carrying capability (ELCC) rating assumptions for the resource class during the winter availability window hours. (See "Voltus Discusses DR Market Issues," *PJM MIC Briefs: July 10, 2024*.)

The data were presented as part of a stakeholder discussion on whether the window in which DR resources are considered available to supply capacity should be expanded during the wintertime hours to reflect changes to PJM risk modeling that shifted focus to the evening.

Bruno said the ELCC analysis assumes that there is zero reduction capability outside the availability window of 6 a.m. to 9 p.m., which curtailment service providers argue undervalues the capacity they could offer. Bruno said the other side of the coin is that the data suggest that capability within the window is lower than ELCC ratings expect, and performance falls off even more outside the window.

Dave Mabry, of the PJM Industrial Customer Coalition, said the December 2022 data are skewed by emergency conditions overlapping with a holiday weekend, as PJM data for Dec. 23, a Friday, show many DR participants shutting down ahead of the holiday weekend starting as early as the morning prior to the load management event that occurred later in the evening.

Calpine's David "Scarp" Scarpignato said the difference between thermal generation's winter and summer capability is also not well captured in ELCC ratings. He said it would be more efficient for stakeholders to focus on overall ELCC improvements rather than having several complex stakeholder processes focused on the construct.

Several Corrections to Formulas Included in Proposed Manual 15 Revisions

PJM's Jennifer Warner-Freeman presented a *package* of revisions to Manual 15: Cost Development Guidelines drafted through the document's biennial review. The changes mainly focus on correcting formulas throughout the manual.

The revisions would also remove a table displaying variable operations and maintenance costs to prevent any confusion about which values should be used. Freeman said the costs are updated annually to account for inflation, and staff are concerned that members may believe the manual values are static. The updated values are posted to the PJM website. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

PJM Models Suggest Capacity Shortfall Possible in 2029/30 Delivery Year

PJM could see a growing capacity shortfall starting with the 2029/30 delivery year, the RTO *found* after running its effective load-carrying capability (ELCC) model on a generation mix forecast through the 2034/35 DY, PJM's Patricio Rocha Garrido told the PJM Planning Committee during its Aug. 6 meeting.

Rocha Garrido said adjustments to resource accreditation drive a declining forecast pool requirement (FPR) in the analysis, leading to the forecast peak load surpassing the solved peak load.

In other words, the resources PJM expects to come onto the grid will have a declining marginal capacity contribution each year that, paired with generation deactivations, may lead to accredited capacity falling below forecast peak loads.

Rocha Garrido cautioned that the analysis should not be seen as a forecast and is instead the result of applying its ELCC modeling to a resource mix forecast supplied by a PJM vendor, which carries "significant uncertainty." While the vendor's assumed resource mix cannot be released publicly, Rocha Garrido said it can be supplied to individuals upon request.

"We're getting lower reliability value of the additions," Rocha Garrido said, adding that the declining capacity value is the driving factor "rather than demand-side adjustments."

If peak loads were driving the imbalance, Rocha Garrido said the FPR would be trending up in the analysis.

PJM received deactivation requests for combustion turbines that led to a higher CT rating in the 2026/27 Reserve Requirement Study (RRS) after the analysis was initiated, so they are not reflected in the assumed resource mix. (See *PJM Presents Revised Reserve Requirement Study Values*.)

Rocha Garrido said a decline in the capacity contribution of demand response resources is due to risk modeling concentrating expected unserved energy in winter hours outside the DR availability window.

Paul Sotkiewicz, president of E-cubed Policy Associates, questioned whether the vendor would readjust the resource mix forecast given the spike in capacity prices in the 2025/26 Base Residual Auction. He said it could make sense for generators to undergo retrofits rather than retire, given the possibility of higher capacity revenues, particularly for coal units that could see upgrades to comply with coal combustion residuals requirements becoming economically viable. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

PJM Senior Manager of Transmission Planning Sami Abdulsalam | *© RTO Insider LLC*

Several stakeholders questioned the accuracy of the resource mix forecast and urged PJM to conduct additional sensitivities. Rocha Garrido said more sensitivities would be helpful, but staff did not have time for this analysis while preparing the 2026/27 RRS parameters.

Stakeholders Endorse LAS Charter Revisions

The PC endorsed *revisions* to the Load Analysis Subcommittee (LAS) charter aimed at reflecting a shift in the group's function toward reviewing the load forecasts produced by PJM and soliciting stakeholder comments on the forecast inputs.

PJM's Andrew Gledhill said much of the status quo charter language is a holdover from when transmission owners presented their own forecasts to PJM and stakeholders through the LAS. The proposed changes were approved by the LAS on July 29.

Calpine's David "Scarp" Scarpignato said stakeholders' role at the LAS goes beyond reviewing PJM's load forecasts, which he said was the focus of the original proposed charter revisions. He proposed that PJM's language be amended to reflect that stakeholders provide substantive comments on how the forecast is

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Delivery Year	Total ICAP (MW)	Total UCAP (MW)	Solved Peak Load	Forecasted Peak Load
2027/28	201,027	155,158	165,306	159,859
2028/29	204,723	155,778	165,949	162,972
2029/30	203,079	153,199	161,939	165,681
2030/31	208,725	153,625	163,288	167,873
2031/32	212,381	152,760	162,882	170,008
2032/33	218,786	154,039	165,383	172,109
2033/34	224,808	152,113	167,149	174,366
2034/35	230,286	148,432	168,549	176,822

PJM analysis found a potential capacity shortfall beginning in the 2029/30 delivery year based on projected resource accreditation ratings and a vendor's forecast generation mix. | *PJM*

prepared.

Gledhill said language in the "responsibilities" section of the charter was intended to reflect stakeholder comments and noted that members do not vote on or approve PJM's forecasts. He accepted a friendly amendment to the revisions from Scarp to add "and is responsible for soliciting stakeholder input and providing review of PJM reports" to the charter's mission statement.

Monitor Presents CIR Transfer Proposal

The Independent Market Monitor presented its *proposal* for an expedited process for transferring capacity interconnection rights (CIRs) held by deactivating generators to planned resources in the interconnection queue. (See "Elevate Reviews CIR Transfer Proposal," *PJM PC/TEAC Briefs: July 9, 2024*.)

The biggest distinction between the Monitor's concept and the four competing designs is that CIRs would not be bilaterally traded between market participants but would instead be made available to the next planned resources that could take advantage of the underlying transmission capability. If PJM identified that a deactivating resource would create transmission violations that would require offering the owner a reliability-must-run (RMR) agreement to keep the plant in operation, PJM would initiate an expedited process where it would assign the CIRs to the next resource in the queue that could address the violations.

If PJM did not identify projects within the interconnection queue that could resolve the transmission violations, it would conduct an auction, or a solicitation could be held for project designs.

Scarp questioned what guarantees can be provided to ensure that generation projects selected by PJM through the expedited process are built if they are meant to replace an RMR contract and constitute reliability projects.

"If you're doing it for RMR purposes, I'm wondering if you need more of a solid commitment more than what is already in the generator interconnection process," he said.

PJM, Gabel Associates, MN8 Energy and Elevate Renewables have also sponsored *packages*, differentiated by the resources that would be eligible to receive transferred CIRs, how potential impacts to the grid would be studied and the standard that would disqualify replacement resources from using transferred CIRs due to identified grid upgrades.

PJM's Becky Carroll said the proposals are slated to go for first reads and an endorsement during the Sept. 10 PC meeting, but voting could be deferred to the Oct. 8 meeting if substantial changes are made over the next month.

Manual 14B Revisions Include Change to Light Load Model

Stakeholders endorsed *revisions* to Manual 14B: Region Transmission Planning Process to rework the inputs to PJM's light load case, which is used in the Regional Transmission Expansion Process (RTEP) load forecast to reflect the growth of load with flat profiles unaffected by weather and season.

The light load case is designed to create an accurate representation of shoulder periods by scaling load down to 50% of the summer forecast peak using bus-level data provided by transmission owners. PJM's Stan Sliwa said that practice has been challenged by the growth of non-scalable load, such as data centers. The revisions would remove non-scalable load from the light load case.

The Manual 14B changes also expand the NERC TPL standards examined during generator deliverability analysis to match current practice, updating the system operating limit definition and adding new standards created by NERC.

The language is set to go before the Markets and Reliability Committee for a first read Aug. 21 and an endorsement vote Sept. 25.

Transmission Expansion Advisory Committee

PJM Presents Results of 8-year RTEP Model

PJM has *updated* the needs in its 2024 RTEP Window 1 solicitation to include a longer eight-year model designed to capture issues that might take longer than the typical five-year cycle to resolve.

PJM News

The additional three years capture the remainder of the New Jersey offshore wind being interconnection through the State Agreement Approach (SAA), the completion of the Coastal Virginia Offshore Wind (CVOW) project and the 1 GW Chesterfield gas generator near Richmond, Va.

Despite the additions, load growth and resource deactivations are expected to cause Dominion and the West regions to each lose over 1-GW of dispatchable energy in the summer, while the capability in MAAC would grow by 2 GW over the 2029 model. Dominion would lose 2 GW in the winter case, while MAAC and West would both gain around 1 GW. Both MAAC and the West would likely export energy as demand grows in Dominion.

PJM's Sami Abdulsalam said a conservative approach is taken when considering which planned resources are expected to be available in the RTEP analysis. Both Chesterfield and CVOW have advanced queue positions that provide a strong certainty of them coming online, while the New Jersey SAA projects have commitments to PJM from a state backer.

More than 100 new thermal overloads were identified in the longer model, 76 of which were in the summer, 48 in the winter and 40 in the light load case. Abdulsalam said the analysis is meant to allow transmission owners submitting RTEP solutions to right-size their projects to meet the needs identified in the 5-year model with an eye toward long-term needs.

The solicitation window opened July 15 and is set to close Sept. 13, but Abdulsalam noted that the new analysis was released after the window opened

Several ratepayers in Northern Virginia called for alternatives to the series of transmission projects built or that are planned to crisscross the region to supply rapid load growth, with residents particularly interested in the concept of an undergrounded DC line. They also questioned whether higher capacity prices will lead to generation development that could reduce the need for transmission projects.

PJM's Susan McGill said the RTO's role is to identify needs and it's up to developers to propose transmission or generation solutions through the RTEP or interconnection queue.

Supplemental Projects

PPL presented a *project* to interconnect a 1,980-MW load sited near Hazleton, Pa., for $196.55 million. The customer would be supplied by a new 230-kV switchyard named Tomhicken, which would be cut into the Susquehanna-Harwood double circuit 230-kV line, as well as a new Nescopeck 230-kV switchyard.

Tomhicken would be configured as a six-bay, breaker-and-a-half facility with a 125-MVAR capacitor bank for $45 million, and Nescopeck would be configured as a three-bay breaker and a half switchyard for $29.5 million. Nescopeck would be cut into the Susquehanna-Sunbury 230-kV line with a partial rebuild of the portion between the new facility and Susquehanna to upgrade it to be double circuit for that portion. Additional 230-kV lines would be constructed between Nescopeck, Tomhicken and Harwood.

The customer is expected to come online in 2026 starting with a load of 240 MW, growing to 720 MW in two years, 1,440 MW by 2031 and reaching its full consumption in 2033. The project is in the conceptual phase, with a projected in-service date of June 1, 2027.

Exelon presented a $158 million *project* to provide service to a customer seeking to bring 378 MW of load to the Elk Grove area in its ComEd zone. The customer would be served by a new 138-kV substation with 16 circuit breakers and in a double ring bus configuration and five 138/34-kV transformers. The facility would be cut into the Elk Grove-Schaumburg line.

The project would require a new 345-kV bus in a breaker-and-a-half configuration to be installed at the Elk Grove substation, including 12 new 345-kV circuit breakers. The bus would be cut into the Des Plaines-Lombard 345-kV double circuit line. Two 345/138-kV autotransformers would also be installed.

The customer expects to bring 117 MW of load in December 2026 and reach 333 MW in 2028. The project is in the conceptual phase, with a projected in-service date of Dec. 31, 2026.

Exelon presented an additional $40.6 million project to serve a customer in the Elk Grove region with 260 MW of load. A new 138-kV substation would be built with 15 circuit breakers in a double ring bus configuration with six 138/34-kV transformers. It would be connected to the Elk Grove East substation with new 1.7-mile, 138-kV lines.

Two 345/138-kV autotransformers would be required at the Itasca substation, as well as two 345-kV and two 138-kV circuit breakers.

The customer anticipates 25 MW of load in June 2027, 87 MW in 2028, growing ultimately to 260 MW. The projected in-service date for the transmission upgrades is Dec. 31, 2027.

FirstEnergy presented a $38.7 million *project* to replace steel H-frame structures along its Perry-Ashtabula-Erie West 345-kV line, reconductor 7.2 miles of the 20-mile line and replace insulators and related equipment. The line is around 60 years old, and the insulators, H-frames and guying are corroded. The line has experienced seven scheduled outages for repairs and four due to equipment failure since 2014. The project is in the conceptual phase, with a possible in-service date of April 9, 2027.

The utility also presented two *projects* amounting to $15.5 million to replace obsolete and misoperating relay equipment at its Doubs, Ringgold, Lime Kiln and Montgomery 230-kV substations in the APS zone. The work is in the engineering phase, with an estimated in-service date of Oct. 31, 2026, for Lime Kiln and Montgomery and Dec. 31, 2026, for Doubs and Ringgold.

Dominion presented a $180 million *project* to address reliability violations along its Fredericksburg-Possum Point 230-kV line, as 3 GW of load is expected to come online served by 13 new substations along its length.

A new Allman switching station would be built north of the Fredericksburg substation, with 10 230-kV line terminals in a breaker-and-a-half configuration. It would cut into 230-kV lines between Fredericksburg and the Cranes Corner, Aquia Harbour and Birchwood substations

About 4.5 miles of the line from Allman to Cranes Corner and 0.7 miles of line from Allman to Hospital Junction would be rebuilt with double circuit structures. The Cranes Corner substation would be expanded to support line realignment. The line to Aquia Harbour would be upgraded to double circuit and rebuilt with vacant arm positions to host two additional 230-kV lines to run from Allman, past Aquia and onto Possum Point on a new 7.1-mile double circuit pole line.

The project is in the conceptual phase, with a possible in-service date of June 1, 2029.

Dominion also presented a $30 million project to power a data center customer in Stafford, Va., with a projected summer 2029 load of 136 MW. A new Centreport switching station in a four-breaker ring bus configuration would be cut into the Spartan-Cranes Corner line with 2.5 miles of new double circuit line. ■

— Devin Leith-Yessian

SPP News

Governance is 'Key Consideration' for West, Markets+ Backers Say

Entities Issue 1st 'Alert' Touting SPP's Western Day-ahead Offering

By Robert Mullin

Chelan County PUD in Washington is among the group of Western utilities contributing to the "issue alerts" supporting SPP's Markets+. | *Omnis*

Governance should be a "key consideration" for the West in the competition between day-ahead electricity markets because the outcome potentially affects $25 billion a year in energy transactions, according to an "issue alert" issued Aug. 7 by 10 entities that helped develop the SPP Markets+ tariff.

The "governance" *alert*, addressed to the Markets+ States Committee, is intended to be the first in a series of seven such notices published in the coming months by the "Markets+ Phase 1 Funding Parties."

The contributing parties include Arizona Public Service, Chelan County Public Utility District (PUD), Grant County PUD, Powerex, Public Service Company of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation and Transmission Association, and Tucson Electric Power.

Those entities, along with the Bonneville Power Administration, which did not sign on to the alert, represent some of the strongest supporters of Markets+ in its competition for participants with CAISO's Extended Day-Ahead Market (EDAM), designed to extend the capabilities of the Western Energy Imbalance Market (WEIM).

In April, BPA staff issued a "leaning" that cited CAISO's state-run governance as one of the top reasons the agency should choose Markets+ over EDAM. (See *BPA Staff Recommends Markets+ over EDAM*.)

In their Aug. 7 alert, the Funding Parties noted the "considerable industry dialogue focused on the market seams that will exist between EDAM/EIM and Markets+, as well as the EDAM/EIM governance enhancements being pursued through" the West-Wide Governance Pathways Initiative, a multistate effort launched last year to create the framework for an independent organization to oversee those markets.

"While both topics are important, the Markets+ Phase 1 Funding Parties believe this dialogue is incomplete without also considering the numerous governance and market design differences between Markets+ and EDAM/EIM that are driving continued support for Markets+," they said.

The parties derived their $25 billion annual impact estimate from the assumption that transitioning to a full day-ahead and real-time market will likely replace much of the region's bilateral transactions still occurring today "while also impacting forward transactions and the utilization of the Western transmission grid."

"Sound governance is a foundational requirement for a day-ahead organized market to provide the benefits of increased efficiency and enhanced reliability while also ensuring equitable outcomes for all participants and all Western subregions," they said.

That entails having a "durable, effective and independent governance structure" that fairly represents all market stakeholders, who would "initiate, develop and own outcomes," they said.

According to the alert, the Markets+ governance framework "fully achieves" those requirements by having:

- a "geographically diverse" board that is independent of market participants and has authority over "all aspects" of the market;
- a "transparent and consensus-based market development process" that is led by stakeholders, who have voting rights to determine whether market design proposals advance;
- a "fully independent and impartial market operator that does not also act as one of the participating balancing authorities with its own interests"; and
- a stakeholder framework in which "all generators, load and BAAs are participating in the same manner with equivalent rules, rights and responsibilities."

The alert additionally notes that the Markets+ governance framework is already up and running, having underpinned the decision-making in developing the market's tariff, which last week received a deficiency notice from FERC. (See *FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas*.)

'Uncertain Outcome'

In contrast, the parties said, the Pathways Initiative "remains in development, with an evolving scope and an uncertain outcome. Changes to the CAISO governance structure require action at the California legislature."

(See *No Clear Blueprint for Western 'RO' Stakeholder Process* and *California Labor Groups Affirm Support for Pathways Proposal*.)

They expressed additional skepticism that Pathways would create a governance framework "comparable to" Markets+, saying the initiative's starting point is an EDAM/WEIM tariff designed under CAISO's existing governance model, and that Pathways has not proposed to replace it with a "stakeholder-driven design."

The parties also contended that Pathways has not addressed the fact that "EDAM and EIM were built as extensions of a legacy institutional framework with embedded dependencies on, and obligations to, California state agencies" and has not ensured that CAISO, as the operator of the markets, "will balance the interests of all stakeholders and avoid undue influence from California interests."

They additionally argued that the stakeholder-driven Markets+ process has produced a market design "substantially different" from EDAM in "several key respects," which will be the subject of future alerts. Design differences can influence the level of participation in a market, "while also encouraging or discouraging generation and transmission investments," they said.

"For example, a market that inaccurately suppresses peak prices will discourage flexible generation and storage solutions. Similarly, a market that misallocates congestion costs will generally lead to less economically efficient transmission investments," the parties said, touching on two issues particularly important to entities in the Northwest, the latter sparking especially sharp controversy after a January 2024 cold snap left the region severely short of energy. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

The parties concluded by touting the benefit of competition — in this case between markets.

"Experience in the East demonstrates that the ongoing existence of two or more competing organized markets provides the opportunity for participants to continuously evaluate which organized market provides the best value for its customers. This places ongoing competitive pressure on each organized market to continuously evolve to deliver value to all of its participants and all of its subregions, driving immeasurable value for consumers while also reducing risk." ■

SPP News

SPP Considering 765-kV Solution for Permian Basin

By Tom Kleckner

TULSA, Okla. — SPP is considering a 765-kV solution and several 500-kV proposals in its Permian Basin footprint in Texas and New Mexico, its first dabble with extra high voltage (EHV) transmission lines.

Staff have proposed a 300-mile, 765-kV transmission line in New Mexico that will address "extreme" forecast load growth beyond its next two Integrated Transmission Planning (ITP) portfolios. They say it's part of a proactive approach to get ahead of the region's growth.

"It's kind of the big one we're going to look at," SPP planning engineer Nick Parker told stakeholders during the Markets and Operations Policy Committee's July meeting.

Growing electrification of oil and gas activity fuels much of the region's load growth, although large industrial and data facilities also are contributors. SPP forecasts the Permian's drilling load in New Mexico to increase by 5.3 GW in 2032. Southwestern Public Service (SPS), the incumbent utility for the region, says its load projects have grown by more than 2,750 MW since the 2023 ITP.

SPP staff said load growth will continue to aggravate issues in an already stressed area of the system and that solutions must address conditions beyond the 2024 ITP due to expected rate of growth.

The 765-kV solution offers other technological and operational advantages. The line's capacity is nearly three times that of a double-circuit 345-kV line and its cost per MW-mile is less than one-third the cost per MW-mile of 345 facilities, SPP says. Because 765-kV lines use the highest voltage available in the nation, their load is less than lower-voltage lines and they can carry power over longer distances.

"We expect these loads to continue to grow. They're still coming, and we know that electrification is still coming," Parker said. "We think it's just the more proactive approach to go ahead and move forward with the beginning of a 765-transmission system to ensure we can deliver to this area."

Staff also are considering about 525 miles of 500-kV projects in the same area. They said with anticipated load growth beyond the 2024 and 2025 ITP studies, "a more robust solution" is required to address voltage and power delivery issues in southern New Mexico.

ERCOT staff has projected the SPS projects will cost about $750 million, or almost as much as the 2022 and 2023 ITP portfolios. The entire portfolio could end up costing between $2 billion and $3.5 billion. The costs are conceptual in that they are more "rough estimates" until SPP receives study-level estimates.

SPP's Casey Cathey explains potential high-voltage solutions in the Permian Basin. | © *RTO Insider LLC*

"This portfolio is the largest that we've ever had in an annual cycle. It is reflective of load changes," engineering vice president Casey Cathey said, noting the last ITP cycle's load forecast exceeding two-year-out models in just one year.

"We recognize that there are a number of projects in our queue that probably don't really need to be in our queue," he added. "We also recognize there are a number of projects that need to stay, and they need to interconnect."

ERCOT faces similar challenges addressing the Permian's explosive growth. In a *report filed* with Texas regulators, the grid operator said transmission operators expect oil and gas load to peak at 11.96 GW in 2030 and 14.71 GW in 2038. It expects an additional 12 GW of data center and other non-petroleum load by 2030, with the combined total amounting to about a third of the system's current summer peak (*55718*).

Based on those forecasts, ERCOT projects a total cost of between $12.95 billion and $15.32 billion for the transmission facilities to meet the coming load. The ISO sees EHV lines as part of the solution, pointing to their "generally known" benefits over 345-kV counterparts: reducing losses for long-distance transportation, increasing short circuit strength and improving voltage stability.

"ERCOT recommends the [Public Utility Commission] give serious consideration to an EHV solution — particularly a 765-kV solution — to meet the forecasted transmission needs," staff told the PUC.

The commission also is *gathering stakeholder input* on EHV transmission lines in ERCOT. ERCOT has said *in response* that incorporating 500-kV and 765-kV lines could reduce or eliminate the need for large underbuilds on the 138-, 115- and 69-kV systems (55249).

"An EHV system would likely remain the backbone of the bulk power system for decades without an increase in voltage," the grid operator said. It said 500- and 765-kV systems are expected to provide "ample capacity to meet substantial long-term load growth and accommodate large power transfers" and they offer greater flexibility in siting generation resources. ■

SPP Board of Directors/RSC Briefs

SPP's board and stakeholders gather at their August meeting. | © RTO Insider LLC

Board Approves 36% PRM for Winter over Stakeholder Objections

ST. LOUIS — SPP directors and state regulators have approved the grid operator's first winter planning reserve margin, endorsing a base PRM that is 3 percentage points higher than many of its utilities wanted.

The Board of Directors during its Aug. 6 meeting approved a 36% PRM for the winter season and a 16% margin for the summer season, effective 2026/27 and 2026, respectively. In doing so, the board sided with the Regional State Committee's recommendation over that of the Market and Operations Policy Committee, which endorsed a 33% winter PRM.

The approval of the tariff change (*RR622*) capped months of discussions and deliberations by several stakeholder groups, including the Resource Energy and Adequacy Leadership (REAL) Team that is responsible for resource adequacy issues. (See *SPP Markets and Operations Policy Committee Briefs: July 16-17, 2024*.)

"I'm very disappointed that we did not agree to common ground with implementing the PRM," SPP CEO Barbara Sugg said after the vote. "There are things I want to focus on that we all agree with. We agree that we have to get more steel in the ground, and we can't do that fast enough. We agree nobody wants to explain why we have to shed load or why we've been turning away load. Nobody wants to tell customers why the rates are going up. It goes without saying nobody wants to find themselves paying for [RA] deficiencies.

"Again, I'm disappointed when we can't reach consensus. It's not who we are. But I know we all want the same thing. We want a reliable, affordable system. We have more work to do to achieve that"

Minnesota PUC Commissioner John Tuma | © RTO Insider LLC

SPP said the action marks the first time a winter PRM requirement has been defined separately from the summer requirement and was necessary to ensure member utilities acquire enough generating capacity for both seasons. The RTO's load-responsible entities must have access to enough generating capacity to meet their peak consumption by at least a 36% margin during the winter and at least 16% margin during summer.

The grid operator says severe extreme weather has become "increasingly common" in recent years. The February 2021 winter storm forced SPP to shed load for the first time in its then-80 years of operation. During the December 2022 winter storm, the RTO's staff was forced to *curtail almost 6.5% of demand* to prevent uncontrolled outages after a higher-than-expected level of coal-fired generator outages and derates.

"Winter is becoming our trouble season," RSC President John Tuma said.

SPP's 2023 loss-of-load study, the first to directly analyze seasonal risk beyond summer, found that a 15% PRM would not meet a 1-in-10 loss-of-load expectation in either season.

The grid operator's Market Monitoring Unit said it saw 36% as a minimum threshold. It preferred a 37% PRM to allow for extra maintenance outages during winter.

Tuma likened SPP's quest for the appropriate resource adequacy requirements to a fellowship's travails straight out of fantasy novels.

"It's a long journey that we're on here at SPP ... We're at one of those points where you have a difficult lift," he said. "You see that the trail turns ahead of you, and you don't know exactly where it goes. This is difficult stuff. We understand that, but it's unclear what's coming around the corner, and we still need to go forward."

"I wish someone would put together a trajectory that was giving us a pathway to growth and future ... so that we know how much water to pack," American Electric Power's Richard Ross said. "I don't want to get down that target and find out we're going another 20 miles and not having enough water. Let's not go on that trail and not be prepared."

Ross was one of 12 Members Committee representatives to oppose the 36% PRM in the committee's advisory vote for the board, with eight in favor and three abstentions. He

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said MOPC's 33% recommendation "strikes the proper balance between what is needed to maintain reliability in the system and what is actually achievable, given the situations that we have."

"What we really need to do, though, is figure out what we're going to do for the long term, so we don't yet again repeat this exact same conversation where SPP is cranking up the reserve margin," Ross said. "I think you've heard from everyone that it takes five to six years to bring a resource online."

"At 36%, the region as a whole has enough capacity to meet that requirement, but in all likelihood, the reality is a number of LREs [load-responsible entities] would be short in the near term," said MOPC Chair Alan Myers, with ITC Holdings.

All 64 of SPP's LREs *met the 15% requirement* for this summer.

However, Xcel Energy has issued a *request for proposals* as it faces the need for more than 3 GW of accredited capacity in its Southwestern Public Service (SPS) footprint. Arkansas Electric Cooperative Corp. CEO Buddy Hasten has said the organization will have to spend $2 billion on new dispatchable generating capacity to meet the requirements.

Tuma agreed that staff, the REAL Team and several stakeholder groups recognize the need for "critical, long-vision steps" beyond the current path.

"We're soberly going into this knowing that there's a lot more work in front of us. SPP is on an industrial transition, and it's not going to be cheap," he said. "We need to take this back to our commissions, take it back to our state leaders. It will cost money, but we need to do it smartly and wisely. If we don't do it as part of SPP or MISO, it will be more costly. This is where reliability happens."

Texas Public Utility Commissioner Lori Cobos cast one of two dissenting RSC votes against the 36% requirement, expressing concern over rising rates and supply chain issues that have increased construction costs.

"The challenge that I have on my end is trying to get to a place where I believe my LREs can feasibly work on these reserve margins that are coming in the next several years in a feasible but also affordable manner," she said.

The board and RSC also approved a fuel assurance policy (*RR621*) that SPP says will further strengthen RA policies by placing additional emphasis on conventional resources' performance during the season's most critical hours and reduce the PRM's socialization of capacity

Richard Ross, AEP | © *RTO Insider LLC*

allocation.

The MC unanimously endorsed the change, with the Natural Resources Defense Council abstaining.

Rate Cap Increased 10.8%

The directors and members both approved the Finance Committee's recommendation for a 10.8% increase in SPP's rate cap, from the 46.5 cents/MWh set in 2021 to 51.5 cents/MWh, effective next year.

FC Chair Stuart Solomon said the bump in the rate cap is in line with previous increases that have averaged 11.2% every three years and will serve as a bridge between the current cap and projected expenses through 2028. He said the compound annual growth of inflation has outpaced the billing units and net revenue requirement (NRR) from 2018-2024.

SPP calculates its rate cap by dividing the budgeted NRR, including a true-up from prior periods, by the estimated amount of transmission service to be provided under the tariff in the coming calendar year.

"The rate cap is a longer-term planning measure that provides predictability for planning purposes," Solomon said. "SPP has shown the cost-control over time, from 2018 to the present day, as the services increased very significantly over that period."

More services mean additional staff, but Solomon noted the RTO's staff ran a "whole lot" of model runs, all of which indicated a need to increase the cap.

The MC endorsed the increase with a 19-4 vote. AEP, Google, Oklahoma Gas & Electric and SPS all voted against the measure. Several members said they will support the rate increases but will focus more closely on the budget, which will be brought before stakeholders and the board in October.

"I am sympathetic [that] FERC's continuing orders are getting more and more responsibility into the hands of the RTO. More and more compliance," said Denise Buffington, Evergy's director of federal regulatory affairs. "I just encourage the organization to continue their focus on their core mission. It's nice to have staff, but really, how do we get steel in the ground, how do we get generation connected, how do we get transmission planned in an appropriate way? I will be looking at the budget very closely."

GI Waivers to be Filed

The board approved staff's proposal to file two waiver requests with FERC following a unanimous vote by the MC that will help SPP clear the backlog in its generator interconnection queue.

The first waiver would allow SPP to delay the 2024 definitive interconnection system impact study (DISIS) cluster's first phase. The phase would begin after the 2023 DISIS second phase's restudy is completed and posted in August 2025; without the waiver, the phase would start before the second phase of the 2022 and 2023 clusters and likely lead to unplanned restudies, staff said.

The second waiver would pause the opening of the 2025 DISIS cluster. Together, staff say they will ease conflicts with their effort to clear the GI queue's backlog and transition to a new planning process. (See "DISIS Waivers Endorsed," *SPP Markets and Operations Policy Committee Briefs: July 16-17, 2024*.)

"This really just reflects the reality of the situation that we're in, in terms of the sheer magnitude and our customers' generation figures that we're seeing in the restudies that are resulting from that," said Natasha Henderson, senior director of grid asset use for SPP.

"I know efforts to clear the queue are challenging ... but it's not fast enough," Buffington said. "I still have a lot of concerns about the timing. We're just asking you to be creative about how we can get the process moving more quickly. There's a lot of concern about alleged queue jumping, but at some point, we've got to cut out speculative developers and get a concrete study and concrete development."

SPP plans to transition to the consolidated planning process (CPP) in late 2026 after a transition period. Opening the 2025 DISIS would mean the cluster's generation would "significantly" overlap with the CPP's transition study and first annual assessment.

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FERC's approval of the waivers would enable the timely completion of backlog studies and allow time to further develop CPP. The grid operator has 416 requests in the GI queue totaling about 84 GW in proposed capacity, down from the original backlog of 1,139 requests for 221 GW of capacity.

SPP Responds to Deficiency Letter

CEO Sugg said staff are working to address FERC's questions about the Markets+ tariff filing and "some of its nuances, particularly transmission usage."

The commission on July 31 filed a deficiency letter asking the RTO to address 16 issues with its proposed day-ahead market offering in the Western Interconnection. FERC gave SPP 60 days to respond. (See *FERC Finds SPP Markets+ Tariff 'Deficient' in Several Areas*.)

"We've been working on formulating a response," Sugg said. "We anticipate filing the response to those questions in the deficiency letter within the next 60 days."

The Markets+ Participant Executive Committee has set aside an hour during its Aug. 13 meeting in Westminster, Colo., to discuss the deficiency letter with SPP legal staff.

OCC's Hiett Leaves RSC

Oklahoma Corporation Commissioner Todd Hiett was a no-show for the RSC meeting Aug. 5, two days before he would give up his seat on the committee to seek treatment for alcoholism.

OCC staffer Jason Chaplin represented the state in Hiett's absence.

Hiett, the RSC's vice president, also *stepped down* as the OCC's chair Aug. 7 but remains on the commission. Some lawmakers have asked for a special session to impeach Hiett. His fellow commissioners have called for his resignation and an independent investigation following two instances of public drunkenness and allegations of sexual misconduct. Hiett has refused to resign but offered to step down as chair.

The OCC elected Vice Chair Kim David as its new chair, and she will replace Hiett on the RSC.

The allegations against Hiett were first publicized last month by *The Oklahoman*, which reported that one incident occurred June 9 in the lobby of the hotel where the Mid-America Regulatory Conference was being held in Minneapolis. Hiett acknowledged to the newspaper that he had had too much to drink but could not remember any of his alleged actions.

In an additional piece of business, the RSC selected an "F Troop" as its Nominating Committee: Kansas' Andrew French, Louisiana's Mike Francis and South Dakota's Kristie Fiegen. They will be responsible for selecting the committee's 2025 term leadership.

2025 Operating Plan Endorsed

The board's approval of its consent agenda included SPP's *2025 operating plan*, as recommended by the Finance and Strategic Planning Committees.

The plan is meant to provide a reference point for the highest priorities that will drive "significant" long-term gains for SPP and its members.

The consent agenda also contained recommended in-service date changes for a pair of competitive project certificates of convenience and necessity (CCNs) recently awarded to NextEra Energy Transmission Southwest (NEET SW). Staff urged approval of the transmission developer's new in-service dates for its 345-kV Wolf Creek-Blackberry project in Missouri and Kansas and the 345-kV Minco-Draper line in Oklahoma, from Jan. 1, 2025, to July 15, 2025, and from July 1, 2024, to Jan. 31, 2025, respectively.

Staff also recommended new language for Evergy Kansas' 345-kV Wolf-Creek-Waverly line to include re-termination at Wolf Creek, allowing NEET SW's Wolf Creek-Blackberry project to progress without crossing the two lines.

NEET SW has been awarded SPP's last three competitive projects. (See "Expert Panel Awards Competitive Project to NextEra Energy Transmission," *SPP Board of Directors/Members Committee Briefs: Oct. 26, 2021* and *SPP Board of Directors/Markets Committee Briefs: April 26, 2022*.)

The consent agenda additionally included: Emeka Anyanwu's (the CEO of Lincoln Electric System) nomination to fill a vacant transmission-using member's seat on the Human Resources Committee; cost increases for a 138-kV Western Farmers project and Omaha Public Power District upgrades; a sponsored upgrade study for terminal equipment at several Western Area Power Administration substations; and the withdrawal of NTCs for Western Farmers substation work and SPS 115-kV terminal upgrades.

Finally, the agenda had two tariff changes that:

- *RR602*: add process structure, tracking and improved criteria for evaluating potential transmission reconfigurations.
- *RR619*: add application programming interfaces as an acceptable submittal process. ■

— Tom Kleckner

SPP News

SPP's Sugg Announces Retirement from RTO

By Tom Kleckner

SPP CEO Barbara Sugg addresses her Board of Directors during its August meeting. | © *RTO Insider LLC*

SPP CEO Barbara Sugg announced Aug. 8 that she will retire from the RTO on April 1, 2025, after 35 years of service.

Sugg was appointed to the RTO's top position in 2020, replacing longtime CEO Nick Brown. Under her guidance, SPP has earned designations as one of the best places to work in Arkansas the past three years; expanded its service offerings and territory into the Western Interconnection with RTO West, Markets+ and other services; and garnered consistently high stakeholder satisfaction ratings.

During her tenure, the RTO has navigated historic challenges that included the COVID-19 pandemic and resulting changes to workplace norms; increasing extreme weather that has affected regional electric reliability; and the ongoing growth in demand for electricity and challenges to resource adequacy.

Sugg said in an email to *RTO Insider* that she has "bittersweet, mixed emotions" about her planned retirement during an "exciting and rewarding time to be part of the electric utility industry."

"I have no doubt that SPP's future is as bright as ever," she said.

Golden Spread Electric Cooperative's Mike Wise, one of SPP's more senior and involved members, noted Sugg's career has virtually matched his. He commended her for bringing out the best in people and encouraging them to grow.

"Barbara's leadership and vision guided the SPP through some very difficult times," Wise told *RTO Insider*, alluding to the COVID-19 pandemic that hit just after she was named CEO. "She had to create a new corporate culture around remote work and still maintain effective RTO operations. Then she was forced to navigate the highly destructive Winter Storm Uri as an RTO which faced circumstances never seen before in the region.

"She exhibited amazing strength of character and never wavered from her strong belief in the exceptionalism of her employees and the committed stakeholders in the SPP. A big three cheers for a good friend and great leader."

Joe Lang, Omaha Public Power District's director of generation strategy and origination and vice chair of the stakeholder-led Markets and Operations Policy Committee, wished the best for Sugg and congratulated her on a "fulfilling" career.

"Barbara has been a strong leader as SPP's CEO through significant challenges in the electric power industry," he said. "Barbara will be remembered for her leadership that guided SPP through the pandemic, generation interconnection backlog efforts, navigating resource adequacy constraints during extreme weather events, as well as successes expanding into the West."

"Barbara's dedication, passion and support of SPP's mission and people have been evident throughout her tenure," John Cupparo, chair of the Board of Directors, said in a news release. "Her impact as a CEO will be felt for years to come, and the board joins SPP's stakeholders in thanking her for the high standard of leadership she's set."

The board plans to name a new CEO before Sugg's departure, and it has engaged search firm Heidrick & Struggles to assess internal and external candidates as her potential replacement.

"I'm not done until I'm done. I still have much work to do," she said, crediting SPP's "dedicated" staff and "diverse" stakeholders. "For now, I remain energized, committed and focused on ensuring SPP's success and partnering closely with my replacement to ensure she or he is prepared to take the reins."

Sugg joined SPP in 1997 after eight years with Louisiana Energy and Power Authority. Because LEPA, which comprises 20 municipal power systems, was an SPP member at the time and new hires from members were able to bridge their service years, Sugg is credited with 35 years with the grid operator.

Her career has spanned every level of the RTO's leadership, including roles as senior vice president of information technology and chief security officer.

Michael Deselle, SPP's chief compliance and administrative officer, also has announced his retirement, effective at year-end. He joined the RTO in 2006 after 14 years at Central and South West and American Electric Power. ■

Company News

Duke Energy Executives Discuss Demand Growth on Q2 Earnings Call

By James Downing

Duke Energy executives highlighted how the return to load growth is impacting its utilities during its second-quarter earnings call with analysts Aug. 6.

The trend started to impact the utility at the start of the year, when it had to file an update to a still-pending integrated resource plan at the North Carolina Utilities Commission after load forecasts increased.

"We operate in some of the most attractive jurisdictions for both economic development and customer migration, which provide conviction in our 2% load growth forecast in 2024, and 1.5 to 2% load growth CAGR (compound annual growth rate) over the five-year planning horizon," CFO Brian Savoy said.

Residential customers are moving at high rates to Duke's territories in the Carolinas and Florida, where demand was up 2.4% in the first half of the year. Commercial demand growth exceeded Duke's expectations, while industrial demand saw somewhat slower growth in its territory. Some large customers in Duke's territory were impacted by interest rates and worries of a possible economic downturn, but the company expects growth in advanced manufacturing and data centers to rise significantly in the long term.

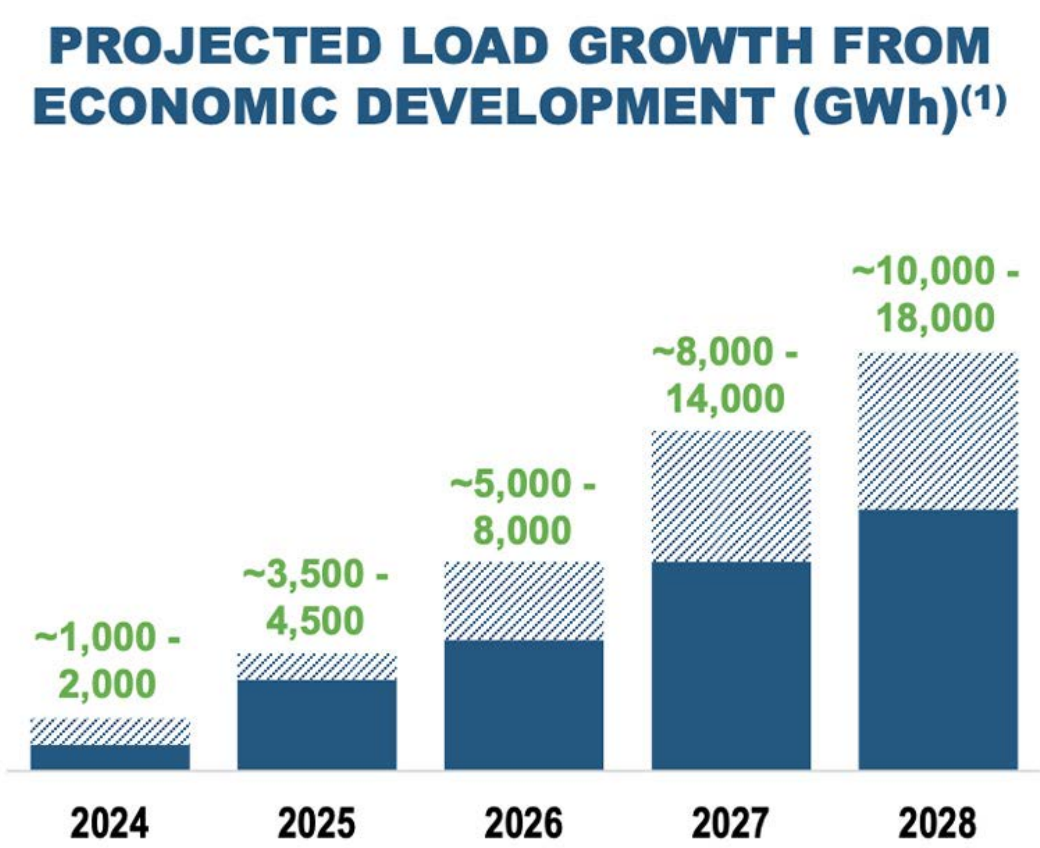
"It's primarily what I would call our legacy industries of textile and paper that are feeling the pressure," CEO Lynn Good said. "And we continue to track with all of that industrial volume we're expecting from economic development; that is exactly on track. So, it's a little bit of an old-industry/new-industry story that we're seeing in the Carolinas in particular, and a little bit in Indiana."

Duke recently entered into memoranda of understanding with large customers in the Carolinas, including Amazon, Google, Microsoft and Nucor, to explore tailored solutions to meet large-scale energy needs and lower the long-term cost of investing in clean energy, Savoy said.

"These voluntary programs, which are subject to commission approval, would be open to any large customer and would include protections for nonparticipating customers," Savoy said. "We look forward to continued collaboration with all stakeholders as we work to meet the accelerating demand in our service territories."

Of the forecasted "economic development" demand growth through 2028, just 25% comes from data centers, though Good said that in the longer term, that is forecasted to be a bigger chunk of new demand. The MOUs are meant to not only help the firmer load growth in its pipeline, but also encourage continued expansion in Duke's territories, Good said.

"The discussions are early," she added. "I think there's a clear understanding that we are trying to do a couple of things here. We're trying to meet the load. We're trying to meet their sustainability goals. We're trying to do so in a way that protects retail customers. We're trying to meet their timelines. And I would say the discussion is very constructive, and the notion of risk sharing is something that we're very clear on and have lots of experience in talking with customers about."



| *Duke Energy*

Nucor has signaled interest in using nuclear power to fuel its steel-manufacturing operations, even *investing* $35 million in a potential fusion plant. Good was asked whether the MOUs with it and the others included work on nuclear.

"They have an interest, obviously, in carbon-free generation, and nuclear represents an around-the-clock option," Good said. "But we all recognize we're [in] the early stages of development. So, is there a structure? Is there premium pricing? Is there some method of equity investment? Is there some structure that would encourage the development at a perhaps a more rapid pace, or sooner, because of the partnership? So, all of that is being explored as we talk with them."

Duke *reported* $886 million ($1.13/share) in net income for the second quarter, a big improvement over its loss of $234 million in the same quarter last year. ■

Company News

Exelon Prepping for Major Load Growth in Utility Service Territories

BGE Could See Double-digit Rate Hikes from PJM Capacity Prices, CFO Says

By Devin Leith-Yessian

Exelon is focused on meeting rising demand from data centers and manufacturing while also working with regulators to ensure that Commonwealth Edison's integrated grid plan meets the requirements of the Illinois Climate and Equitable Jobs Act, company officials said during its second-quarter earnings call Aug. 1.

CEO Calvin Butler said that a revised grid plan, *filed* in May, is on track for approval after the Illinois Commerce Commission rejected the original in December. The company has reached agreements with the city of Chicago, the Building Owners and Management Association, and environmental organizations, he said.

"These affirmations are good examples of what differentiates the process this year. Approval of the plan will ensure that Northern Illinois will receive the investment needed to maintain an affordable, resilient, reliable and clean grid for its customers and will support the state's success in attracting new business," Butler said.

CFO Jeanne Jones said data centers, energy-intensive manufacturing, economic development and electrification are leading to increased transmission spending over the next four years.

She said the growth is exemplified by a partnership between Exelon and Compass Datacenters to build one of the largest data centers in Illinois. She also noted the 235-acre *Baltimore Peninsula* mixed-use development, which includes 100 MW of load and is supported by rebuilding or constructing several new substations.

"This growth in high-density load, not just in data centers, but also in solar panel production, [electric vehicle] battery manufacturing, hydrogen production, quantum computing and other industries, is one of several drivers for why our transmission spend increased by 45% in our four-year plan," Jones said.

ComEd CEO Gil Quiniones said data center growth is likely to continue in the utility's region.

"It's been a robust market for data centers here in Illinois. We have over 5 GW in what we call engineering phase where data centers have paid us to start engineering their projects," he said. "Some of them actually have

Calvin Butler | *Exelon*

made deposits so that we can order large equipment like transformers and breakers. And then behind that, we have another 13 GW in what we call prospects. So they're not yet in engineering, but they are knocking on our doors, making inquiries very interested in coming to our jurisdiction."

Exelon reported net income of $448 million ($0.45/share) in the second quarter, up 30.6% over the same period last year.

PJM Capacity Auction

A substantial increase in PJM capacity prices will likely push consumer rates up, Jones said, potentially leading to double-digit increases in the Baltimore Gas and Electric region, which reached its $466.35/MW-day price cap in the latest Base Residual Auction because of limited local capacity and constrained transmission. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

Butler said both Exelon and PJM have been signaling concerns about future resource adequacy as baseload generation is replaced by renewable resources and load growth fueled by data centers.

"The price signals that we saw clearly indicate a need for infrastructure investments in our footprint, particularly in BGE, both generation and transmission," he said.

Jones said utilities have been working to keep costs down, such as with energy efficiency programs that have led to $9 billion in ComEd consumer savings since their inception in 2008. A ComEd rebate program has also facilitated the development of 1 GW of distributed energy resources.

Co-located Load

Butler discussed the utility's *protest* of PJM's request for FERC to amend the Susquehanna nuclear generator's interconnection service agreement (ISA) to reduce the facility's capacity interconnection rights (CIRs) and shift 480 MW of its output to a co-located data center (ER24-2172).

The ISA already contains language allowing 300 MW of the facility's output to be dedicated to co-located load. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

Exelon urged the commission to set the matter for hearing and argued that the proposed amendments do not address how the configuration would prevent the load from receiving energy from the PJM grid. It also said the configuration would create a new category of PJM load that does not yet exist in the governing documents and that it should be required to pay for ancillary grid benefits.

Butler said Exelon is supportive of co-located load and data centers, but it should be recognized that they benefit from being a part of the PJM grid and should pay for those services.

"Users of the grid should pay their fair share. And while there may be unique opportunities to leverage land and equipment at generation plants to get data centers online quickly, they are still connected to the grid and are benefiting from a host of services that the grid provides to serve all of the load connected to it," he said.

Colette Honorable, Exelon's executive vice president of public policy, said the company's priority is making sure that the rules for co-located load are equitable.

"Look, this demand is coming either way, whether it's co-located or not," said Honorable, a former FERC commissioner. "And our focus is making sure the investment gets done for the needs of our customers and that everyone has a fair and equitable allocation of the cost of using the grid. And I think that's the bottom line." ■

Company News

Constellation Raises Earnings Guidance amid Rising Demand

Company Pursuing Agreements for Data Centers Co-located with Its Nuclear Plants

By John Cropley

Constellation Energy turned in another *solid quarterly report* Aug. 6, boosting its earnings guidance for the year and offering a rosy picture for the future of its nuclear power fleet.

During a conference call with financial analysts, much of the conversation surrounded data centers and the prospect of Constellation helping to meet their immense load demand with long-term behind-the-meter supply agreements.

CEO Joe Dominguez said the company is moving ahead with negotiations for co-located data centers even as the regulatory structure for such agreements is examined.

He presented this as a win-win-win — helping to place the nation at the forefront of the artificial intelligence revolution, reducing the amount of new infrastructure utility ratepayers must fund and locking in a market for Constellation's zero-emissions generation for decades to come.

"We're confident that any thorough examination of co-location with nuclear plants will show that it is both the fastest and most cost-effective way to develop critical digital infrastructure without burdening other customers with expensive upgrades," he said.

Long-term behind-the-meter agreements also give Constellation the economic certainty it needs to seek relicensing of its plants, Dominguez said.

The issue has gained prominence as Talen Energy has proposed a deal to power a growing data center on the site of its nuclear plant in Pennsylvania, drawing protests from Exelon and American Electric Power, which drew rebuttals from Talen and others, including Constellation. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

On Aug. 2, FERC said it would hold a *commissioner-led technical conference* this year on co-location of large loads at generating facilities.

Dominguez said the Aug. 2 actions at FERC "may have slowed things but ultimately will be constructive, in our view. Notably, FERC did not grant requests by a small number of utilities to set the Talen Energy ISA for hearing or in the alternative to reject it outright."

Co-location is not always the right solution, but neither is it a new or unfamiliar concept, he added.

"As we see it, utility connection will continue to make sense for some applications and in some parts of the grid. But when it's an option, we will continue to see customer interest in co-location, strong interest, because there are just too many advantages of connecting large load directly to large forms of generation, especially clean generation."

The protest to FERC about the Talen deal may slow the finalizing of facility co-location agreements or change their details, but it will not block co-location, Dominguez said.

"We really don't see an outcome here where the FERC is going to say, 'You can't do this.'"

An analyst asked if the recent PJM auction increased a sense of urgency among potential customers to lock down these co-location agreements. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

Dominguez said it did, just as it has increased the urgency for front-of-meter deals, because the marketplace is tightening.

Another analyst asked whether Constellation expected to get regulatory clarity on the prospect of co-location this year or next.

Dominguez did not offer a prediction but said Constellation is not waiting for absolute clarity in the FERC process.

"I do think the Talen ISA is going to be instructive, and folks are watching that, to make sure it goes through, what conditions might get attached to that, but we independently are working on contractual provisions that allow us to manage whatever outcome comes out of those proceedings."

He added: "So, at least for the moment, we're working with our customers [toward] finalizing deals."

Customers and policymakers have an interest in resolution of the dispute, Dominguez said.

"Talen's not our deal, but I'll use it as an illustration: That arrangement is bringing $10-plus billion, maybe more than $20 billion, of economic development to a region that if we're going to be honest, hasn't seen a lot of sunshine from an economic development standpoint of this dimension in a long, long time.

"I think it's fair to say that policymakers around Pennsylvania like to see that for communities like this that need jobs and economic opportunities. And I think it's fair to extrapolate from that, that they won't like it very much if people interfere with those things and cause it to come off the rails."

Constellation reported second-quarter GAAP net income of $814 million or $2.58 per share, compared with $833 million or $2.56 per share in the same quarter of 2023.

The company raised its full-year 2024 net earnings guidance from $7.23 to $8.03 per share to $7.60 to $8.40 and maintained its earlier forecast of annual earnings growth greater than 10% on average through 2028.

Constellation Energy Corp.'s stock price closed 6.5% higher in heavier-than-average trading Aug. 6. ■

Constellation's Calvert Cliffs Clean Energy Center in Maryland | *Constellation Energy*

Company Briefs

Carlyle to Sell Cogentrix Energy to Quantum Capital in $3B Deal

Carlyle is selling one of the largest portfolios of natural gas power plants in the US for $3 billion amid a surge of investor interest in the energy sector linked to the soaring demand for electricity from digital networks.

The U.S. private equity firm will sell Cogentrix Energy to Quantum Capital Group, a Houston-based private equity group focused on energy investments. Cogentrix, which is headquartered in North Carolina, owns 11 natural gas power plants in PJM, ISO-NE and ERCOT.

Carlyle initially bought the power producer from Goldman Sachs in 2012 for an undisclosed sum. It has roughly doubled Cogentrix's assets since then by purchasing new power plants and expanding its business.

More: *Financial Times*

SunPower Files for Bankruptcy, Plans to Sell off Assets

Rooftop solar installer SunPower filed for bankruptcy last week after struggling for months in the face of high interest rates and allegations of misconduct in its reporting practices.

SunPower stock dropped nearly 44% on Aug. 6 to close at 45 cents/share. Its shares have collapsed more than 90% this year.

The company listed assets and liabilities between $1 billion and $10 billion in its Chapter 11 protection filing Aug. 5 in U.S. Bankruptcy Court for Delaware. It is selling its Blue Raven Solar and new homes businesses, as well as its non-installing dealer network, to Complete Solaria for $45 million subject to court approval, according to a statement. The company has asked the court to approve the sale by mid-September.

More: *CNBC*

Sunrun Stock Rises on Strong Cash Generation in Q2 Earnings

Residential solar and energy storage provider Sunrun reported $524 million in revenue for the second quarter last week, meeting analyst expectations and delivering promising guidance for cash generation in 2025.

The company delivered a surprise earnings per share of 55 cents, up from an expected loss of 40 cents. It reiterated its guidance of $50 million to $125 million in cash generation for the fourth quarter and introduced guidance of $350 million to $600 million for 2025.

Sunrun added 26,687 customers in the second quarter, about 94% of which were lease or power purchase agreement customers.

More: *pv magazine*

Federal Briefs

DOE to Loan $1.45B to Qcells to Build Solar Manufacturing Plant in Ga.

The Department of Energy is making its first loan to a crystalline silicon solar plant, loaning $1.45 billion to South Korean solar module manufacturer Qcells to help it build an industrial complex in Georgia.

The company plans to take polysilicon refined in Washington state and make ingots, wafers and solar cells — the building blocks of finished solar modules — in Cartersville, northwest of Atlanta.

"This loan is special, because it's one of the first facilities where we're not just making modules, but we're making cells and wafers as well," Jigar Shah, director of DOE's Loan Programs Office, said in a telephone interview last week with The Associated Press. "So we're bringing a lot more of the supply chain into the United States."

More: *The Associated Press*

18 House Republicans Ask Johnson not to Target IRA Tax Credits

More than a dozen House Republicans wrote to Speaker **Mike Johnson** (R-La.) last week asking him not to axe clean energy tax credits in the Inflation Reduction Act if the GOP maintains or expands its majority next year.

In the letter, members led by Rep. Andrew Garbarino (N.Y.) criticized the IRA as a whole but wrote that repealing the credits could undermine the growth in the energy sector spurred by its tax provisions. They noted that a number of companies have already broken ground on investments they made assuming the credits would remain in place and that eliminating them could lead to a "worst-case scenario" in which billions of dollars have already been spent for financial benefits that no longer exist.

"Energy tax credits have spurred innovation, incentivized investment and created good jobs in many parts of the country — including many districts represented by members of our conference," they wrote.

More: *The Hill*

EIA Expects Mixed Bag for Energy Prices in 2024

The Energy Information Administration expects that U.S. residential electricity prices will increase by about 1% in 2024, the slowest rate of year-over-year growth since 2020.

Natural gas prices have been falling since late 2023, and those lower prices are now being factored into retail electricity rates. Conversely, EIA forecasts that the Brent crude oil price could increase to about $87/barrel by the end of the year.

"The good news from a consumer perspective is that even though we expect oil prices to increase, we expect gasoline prices through this year and next year to remain lower than they were in 2023," EIA Administrator Joe DeCarolis said. "U.S. motorists are using less gasoline than they did before the pandemic, and we expect that to help keep gasoline prices from climbing with oil prices."

More: *EIA*

State Briefs

REGIONAL

NARUC Selects Tony Clark as Next Executive Director

The National Association of Regulatory Utility Commissioners last week selected former FERC Commissioner Tony Clark as the group's incoming executive director.

Clark will succeed Greg White, who announced his Dec. 31 retirement in April. Clark's effective date is Oct. 1, serving as executive director-elect, and he will transition to executive director on Jan. 1, 2025.

Clark is currently a senior adviser for Wilkinson Barker Knauer, where he provides expert analysis and strategic advice on regulatory and public policy issues. Prior to FERC, he chaired the North Dakota Public Service Commission, and also served as president of NARUC from November 2010 to November 2011.

More: *NARUC*

ARIZONA

Utilities Set Records for Energy Delivered on Day Phoenix Hit 116 F

Salt River Project and Arizona Public Service set records for energy delivered to customers Aug. 4 when the temperature in Phoenix reached 116 degrees Fahrenheit.

SRP hit a new peak of 8,219 MW between 5 and 6 p.m., surpassing the previous record of 8,163 MW on July 18, 2023, according to a press release. APS peaked at 8,212 MW, besting its previous record of 8,162 MW set on July 15, 2023.

The 116-degree heat tied a daily record in Phoenix. Both utilities said a multitude of factors, including extreme high temperatures, high overnight temperatures and an increasing customer base, contributed to the new records.

More: *KTAR*

BRITISH COLUMBIA

Power out for 2.9K After U-Haul Truck Driver Hit Pole in View Royal

A U-Haul truck last week crashed into a distribution power pole along Island Highway in the town of View Royal, northwest of Victoria, knocking out power for about 2,900 residents.

According to West Shore RCMP, the driver lost control of the vehicle. Fire crews had to carefully extract the driver and a passenger, both of whom sustained minor injuries, from the vehicle because of the danger posed by the live power lines, police said. The 30-year-old male driver was cited for driving without due care, resulting in a $368 fine.

Power was quickly restored to about 1,300 customers, but the remaining were without power for about six hours until BC Hydro fixed the line around 7 p.m.

More: *CHEK*; *Victoria Buzz*

MICHIGAN

Nessel Calls for Reduction of Proposed DTE Rate Increase

Attorney General Dana Nessel this month submitted opposition against DTE Energy's proposed $456.4 million revenue increase with the Public Service Commission, arguing the requested increase is "excessive and unnecessary."

The Department of Attorney General said the company's requested rate increase would result in a 10% hike for residential customers, with Nessel arguing DTE should instead receive a $139.5 million annual increase, representing a 2.5% increase for residential customer rates.

Community advocates and organizers with We the People Michigan hosted a gathering outside DTE headquarters in Detroit, calling for the PSC to host a hearing in Detroit, rather than its office in Lansing, and to reject DTE's requested rate hike. The PSC's next meeting is Aug. 22.

More: *Michigan Advance*

MINNESOTA

Summit Pipeline Segment Enters Final Permitting Stages in State

Minnesota agencies have released an environmental impact statement and set hearings on a small section of a huge project to capture carbon from ethanol plants in five states for underground storage in North Dakota.

The environmental impact statement filed last week by the Department of Commerce says the Summit Carbon Solutions project would have a net benefit on greenhouse gas emissions.

"The CO_2 sequestered from ongoing annual operations would outweigh construction and operation emissions. This benefit would vary depending on the capture rate and final end use of the captured CO_2," the report says.

More: *Iowa Capital Dispatch*

MONTANA

PSC Asks if NorthWestern is Working Contrary to Law

The Public Service Commission voted unanimously last week to ask NorthWestern Energy to address allegations it selected members of an advisory committee contrary to state statute and has held meetings closed to the public — possibly illegally.

The request for information comes after three renewable energy groups raised concerns about the formation of the Electric Technical Advisory Committee and how it's operating. The committee is charged with making recommendations to the public utility about its electricity system, according to state law.

More: *Daily Montanan*

NorthWestern Botched Application for Higher Rates, PSC Says

NorthWestern Energy said it is "under earning" and needs more money from customers, but the Public Service Commission said last week that the materials it filed fail to meet the minimum standards to make the case.

For one thing, the utility didn't provide its most recent quarterly balance sheets and income statements, according to a PSC staff

memo.

"The commission has identified multiple instances where the application falls short of full compliance with the minimum filing standards and several instances where the application patently fails to substantially comply with those standards," the PSC said in its order.

More: *Daily Montanan*

NEBRASKA

Residential Electricity Could be Exempt from State Sales Tax

The Legislature's Revenue Committee considered an amendment to Legislative Bill 9 last week that would exempt the purchase and sale of residential electricity from sales or use taxes.

Committee members said the intention is to exempt the 5.5-cent/dollar state tax, but not the local rate — up to 2 cents in select cities or villages. Chair Lou Ann Linehan said recent storms across the state have shown the necessity of electricity.

"Electricity is definitely, in our world today, a necessity," Linehan said. "This would also provide a source of tax relief for homeowners and renters alike."

More: *Nebraska Examiner*

OREGON

CUB Asks State to Intervene on Proposed Double-digit Rate Hikes

Oregon Citizens' Utility Board

The Citizens' Utility Board has asked the Public Utility Commission to cap any residential rate increases for Portland General Electric and Pacific Power at 7% plus the rate of inflation, or 10% annually, whichever is lower, rather than the 11% and 15%, respectively, that the utilities have requested.

The utilities say their latest proposed increases are because of the rising cost of insurance and needed investments to expand electrical grids and make them resilient to extreme weather. But the board says the companies are using rate hikes to make massive investments in infrastructure in too short a period, as well as creating slush funds for potential wildfire payouts in the future.

The PUC will make a decision in December, and the rates will go into effect in January.

More: *Oregon Capital Chronicle*

National/Federal news from our other channels

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CISA Launches Cybersecurity Software Buying Guide — ERO Insider

NERC Report Identifies Persistent CIP Violation Themes — ERO Insider

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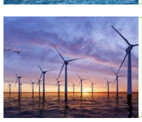

New England States Delay OSW Solicitation to Account for DOE Funding — NetZero Insider

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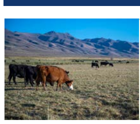

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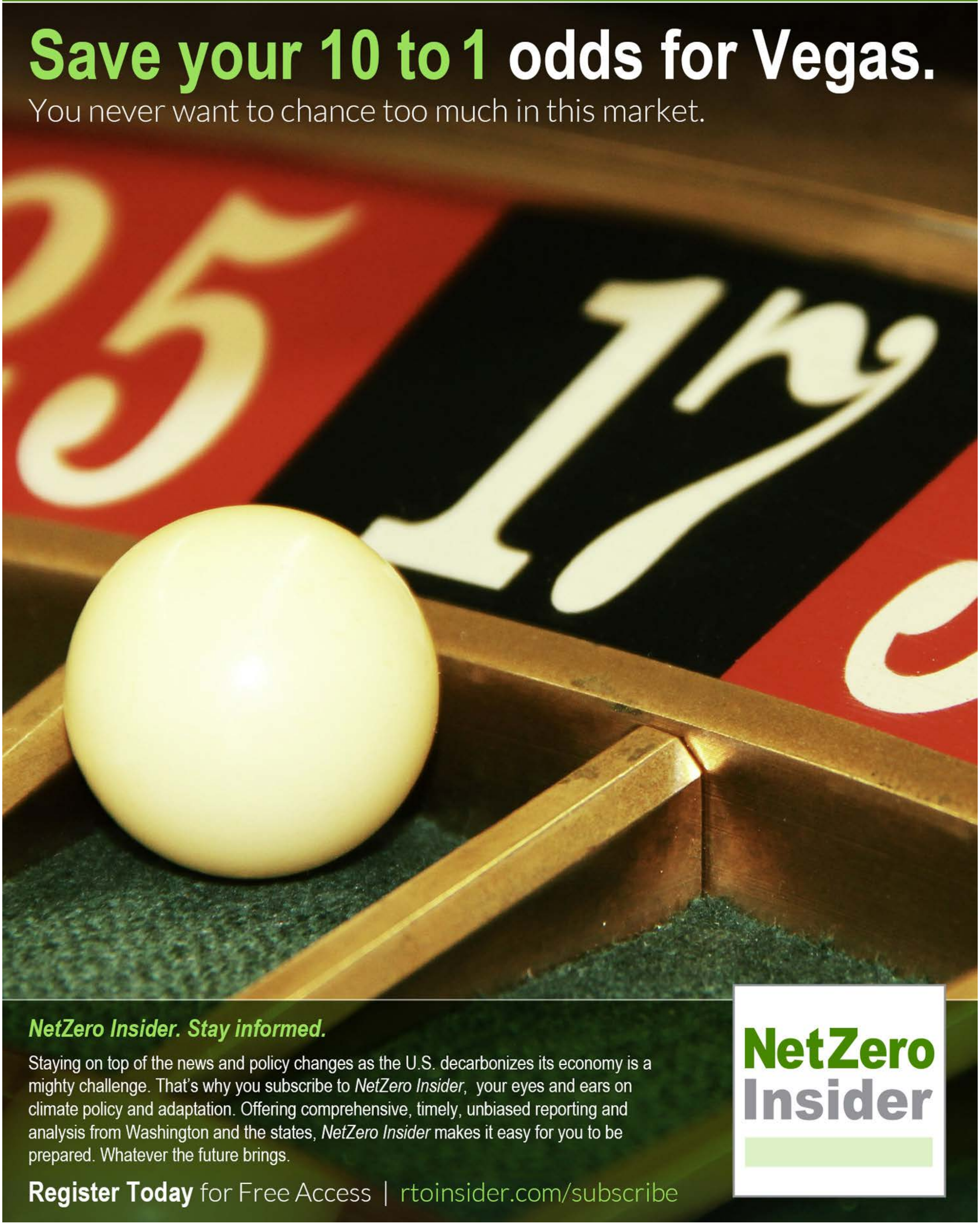
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