ISSN 2377-8016 : Volume 2024/Issue 39 ▪ October 1, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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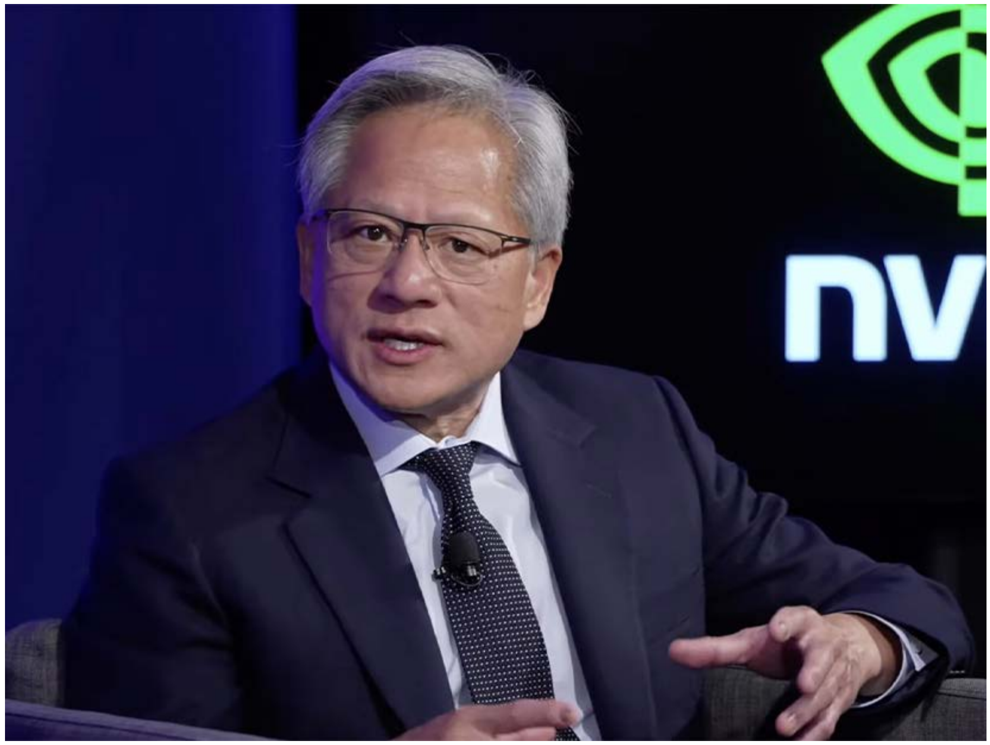
Nvidia CEO Huang Explains What's Behind AI's Energy Demand

From Game Graphics to Smart Grid Applications?

By James Downing



Nvidia CEO Jensen Huang addresses the crowd at the Bipartisan Policy Center on Sept. 27. | *Bipartisan Policy Center*

As new data centers built for artificial intelligence continually increase the demand for electricity in the U.S., one of the leaders in the field, Nvidia, is touting AI's ability to increase the efficiency of the grid, as CEO Jensen Huang *discussed* at the Bipartisan Policy Center on Sept. 27.

In explaining why AI demands so much power, Huang recounted the history of Nvidia and how its approach to computer processing can be applied to the grid.

The company makes the chips, systems and software that have led to the AI boom, but before that became mainstream, it was best known in the video game industry for manufacturing one of the two leading lines of graphics processing units (GPUs) — the GeForce — large chips that can be added to a computer to help it process the now extremely detailed models and 3D images in games.

The standard design for most computers dates back to 1964, called the "IBM system," which uses a central processing unit (CPU), multitasking, and the separation of hardware and software by an operating system. That basic "general purpose computing" design is still used today, though with massive improvements, Huang said. Around 1993, as video game developers began transitioning from 2D to 3D graphics, Huang and his colleagues realized some problems are so specialized that a general-purpose approach does not work well.

"Physics simulations and data processing and computer graphics … image processing — these problems have algorithms inside that are very computationally intensive," Huang said. "And if we could take that and run it on a specialized processor, on a specialized computer, we could add a chip to the computer that makes it go 100 times faster."

GPUs focus on those specialized tasks, while the main CPU is reserved for more general tasks. That opened up efficiencies in computing, which let the technology tackle new and more difficult tasks as video game graphics and physics became more advanced. The GeForce is still going strong for gaming PCs and is also used by Nintendo's Switch console, Huang noted.

"Then one day, artificial intelligence found us, and so accelerated computing … was an observation about the future of computing that turned out to be right," Huang said.

Queries of artificial intelligence use more energy than traditional internet searches, and it takes significant energy for an AI network to "learn."

"The reason why it consumes a lot of energy is that the artificial intelligence network, through trial and error, is trying to figure out how to predict something, and it's recognizing patterns and relationships among tons and tons of information," Huang said.

Eventually, AI networks comb the datasets they are trained on enough so that they understand them and can make predictions based on them. "These data centers could consume, today, maybe 100 MW," Huang said. "And in the future, it'll probably be … 10 times, 20 times more than that."

Those massive loads do not have to be built in one place, Huang said. Data centers can be built where energy supplies are plentiful. (See *Industry Considers Building its Own Generation to Decarbonize*.)

"There are places in the world where we have excess energy," Huang said. "It's not necessarily connected to the grid. It's hard to transport that energy to population, but we can build a data center near where there's excess energy and use the energy there."

Siting new data centers in energy-rich areas is one way of getting around the issue of interconnecting resources to the grid and transmitting energy to population centers, Huang said.

But the promise of AI could lead to more efficient use of energy in other applications, with Huang pointing to work Nvidia is doing around weather forecasting that will make that

Why This Matters

Artificial intelligence uses large amounts of energy, but proponents say AI could help the grid by integrating sustainable energy, operating two-way vehicle charging and finding faults on the grid that can be fixed before they lead to outages.

FERC/Federal News

process much more efficient compared to the super computers used now.

Making the grid smarter is another application for AI that could help save significant energy, he said. AI could help integrate sustainable energy, operate two-way vehicle charging and find faults on the grid so they can be fixed because they lead to a reliability lapse.

The growth in data centers has given a shot in the arm to nuclear power, with Constellation Energy recently announcing a deal with Microsoft that will reopen the recently retired reactor at Three Mile Island. (See *Constellation to Reopen, Rename Three Mile Island Unit 1*.)

"Nuclear is going to be a vital, integral part of this," Huang said. "No one energy source will be sufficient for the world, and so we'll have to find that balance."

Efficiency has fueled Nvidia's success, with its approach using far less energy for complex tasks than standard, general-purpose computing, he added. Efficiency is going to be key to meeting all the new demand going forward too.

"I would really love to see our power grid be smart today," Huang said. "Our nation's power grid was built a long time ago because we're one of the earliest countries to become prosperous, and that power grid could benefit from the insertion of artificial intelligence and smart technology into it. And that smart grid would … help us properly provision technology to the right places."

A Constellation executive asked Huang whether he agreed with some who have argued that new data centers should add clean power to the grid, as opposed to using what is already available for their purposes. The largest nuclear plant owner, in addition to reopening Three Mile Island, is interested in co-locating data centers with plants that are still in operation, which FERC and other regulators are examining. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

Huang answered that, having met with it multiple times, the Biden administration's policy is to allow U.S. companies to build as many data centers domestically as they can, and it is interested in helping the sector with permitting and connecting to the grid to make that possible.

"Building the AI infrastructure of our country is a vital national interest," Huang said. "And although it consumes energy to train the models, the models that are created will do the work much more energy efficiently. And so, when you think about the longitudinal lifespan of an AI, the energy efficiency and the productivity gains that we'll get from it, from an industry, from our society is going to be incredible."

AI is one source of demand that does not require 24/7 reliable power, he added. The processes can be shut down for 5% of the year when demand is peaking elsewhere on the grid and then come back to what was being worked on as other users drop off the grid. ■

FERC/Federal News

The Buzz at NCEW: The Election, Permitting and IRA Tax Credits

CRES Symposium Focuses on GOP Frame for Bipartisan Energy Policies

By K Kaufmann

Rep. John Curtis (R-Utah) runs down the odds for permitting reform in a lame-duck Congress at the NCEW Policymakers Symposium. | © RTO Insider LLC

WASHINGTON — Rep. John Curtis (R-Utah) had "some really good news and some bad news" on permitting reform for attendees at the National Clean Energy Week Policymakers Symposium, held Sept. 25-26 at the Conrad hotel.

"The good news is, everybody wants it," Curtis said, speaking on the symposium's second day. "The bad news is, everybody has a different definition of what that is … even within the Republican Party, the Democratic Party and then particularly between Republicans and Democrats."

For some, streamlining and accelerating federal permitting processes is all about expanding and upgrading transmission, he said. For others, it's about building new pipelines or mining for critical minerals.

"And so, we have some bills and proposals that are out there, and almost all of them have a lot of very good parts to them, but almost all of them are not comprehensive," Curtis said. "So, what do we do? Do we take bits and pieces, or do we wait for a comprehensive thing that hits everything? And I don't have a good answer to that."

With a very close presidential election five weeks away, the fate of permitting reform and the Biden administration's clean energy policies — in particular, tax credits in the Inflation Reduction Act (IRA) — were top of mind for attendees and speakers at the two-day symposium, hosted by the center-right Citizens for Responsible Energy Solutions (CRES).

During the opening panel Sept. 25, for example, Ryan Abraham, principal at Ernst & Young, warned of a looming "fiscal cliff" facing lawmakers in the 119th Congress, pitting expiring tax cuts against clean energy tax credits.

The Tax Cuts and Jobs Act (TCJA) of 2017 expires next year, he said, and whether Republicans or Democrats control the White House or Congress, the outcome will likely be "tax increases for Americans and … it's going to cost a lot of money to fix that."

Should Republicans make a clean sweep of Congress and the White House, they would likely take aim at the IRA's tax credits and incentives to pay for continuing the TCJA's trillions in tax cuts, Abraham said. "There's a lot of revenue there. Eliminating certain incentives, phasing out policies early; this has been one of [Republicans'] talking points."

A Democratic sweep could see an even greater push on clean energy incentives. But divided government could result either in more uncertainty or more opportunities for bipartisan policies, Abraham and other panelists said.

Beth Viola, senior policy adviser at Holland & Knight, said her firm now has a team that works exclusively with companies finalizing contracts for IRA funds with the Department of Energy and EPA.

With billions on the line, Viola said, "those clients are really anxious [about] what happens if we have [another] Trump administration. Are those dollars going to get put on hold? Are they going to be rescinded? … Just across the board, [there's] this sense of uncertainty, and when you have industries that are putting up billions and billions to match the billions that this government is investing, it gives them a lot of pause."

Both DOE and EPA have maintained, repeatedly, that once they finalize funding contracts, the IRA dollars are committed and cannot be clawed back, but Viola is less certain.

"This administration is pushing very hard right now to get as much [money] out the door before Jan. 21 as they can," she said. "But the reality is, we very much expect [that] if [Donald] Trump is reelected, that he's going to come in and … pause and look at every single thing. It may be that they just slow everything down

Why This Matters

The outcome of the elections in November could have major impacts on permitting reform, the fate of the tax credits in the Inflation Reduction Act and whether bipartisan policymaking will be possible in the 119th Congress.

FERC/Federal News

so that nobody gets those dollars or sees those dollars for a very long time, if ever.”

A Trump administration also might put a pause on the Treasury Department’s rollout of guidance on IRA tax credits, such as the still pending rules on the 45V clean hydrogen credits, Abraham said. “I can just see them putting a freeze on all guidance projects,” he said. “They’re going to want to take a fresh look at everything.”

Curtis was more optimistic about the fate of the IRA, pointing to the *letter* he and 17 other GOP representatives sent to House Speaker Mike Johnson (R-La.) in August arguing for the preservation of at least some of the tax credits, which have spurred investments and created jobs in their districts.

In response, Johnson had said that any GOP action on the IRA should use a scalpel rather than a sledgehammer, a statement that has generated *pushback* from more conservative Republicans.

How the GOP Talks Climate

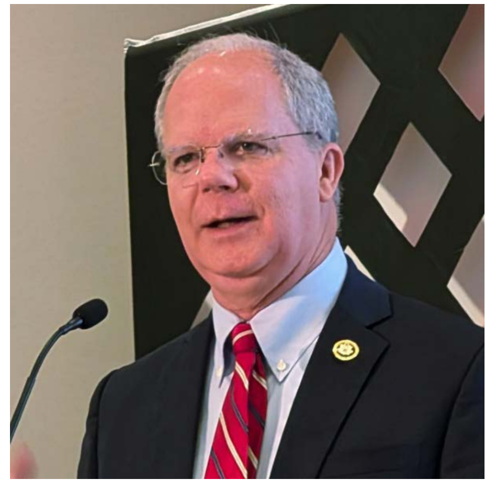
With only one Democratic lawmaker on the agenda — Rep. Scott Peters (D-Calif.), who canceled at the last minute — the symposium was essentially a showcase for the House Republicans’ Conservative Climate Caucus, and its views on what bipartisan legislation should look like.

Curtis started the group in 2021 to find ways to get Republicans to talk about climate, he recalled, and with more than 80 members, it is now the second-largest GOP caucus in the House of Representatives.

But caucus members speaking at the symposium generally avoided talking about climate, instead stressing their support for clean air and water and preserving the environment while framing Democratic clean energy policies as radical or impractical.

Rep. Brett Guthrie (R-Ky.), a caucus member who hopes to replace retiring Rep. Cathy McMorris Rodgers (R-Wash.) as chair of the Energy and Commerce Committee, agreed that “less carbon is better” but said that Democratic climate policies are often based on radical scare tactics or misinformation.

Pointing to California’s Advanced Clean Car II rule, mandating that all new light-duty vehicles sold in the state be zero-emission vehicles by 2035, Guthrie claimed the rule is “just incredibly disruptive; it’s incredibly inefficient, and in the end, does it really save what they say they’re trying to save? I think that’s questionable; so, why take those drastic steps?”


Rep. Brett Guthrie (R-Ky.) | © *RTO Insider LLC*

The opening panel at the NCEW Policymakers Symposium dug into the challenges of tax and climate policy facing lawmakers in the 119th Congress; from left: Tanya Das, Bipartisan Policy Center; Ryan Abraham, Ernst & Young; Beth Viola, Holland & Knight; Emily Domenech, Boundary Stone Partners; and Kellie Donnelly, Lot Sixteen. | © *RTO Insider LLC*

Emily Domenech, a former GOP House staffer and now senior vice president of Boundary Stone Partners, a lobbying firm, argued that Republicans have always supported energy research and development, the National Laboratories and “making sure we keep government out of the way of allowing people to innovate and build in the United States.”

What will be critical post-election is how these “fundamentally Republican ideas” are communicated to the public in the context of a divided Congress, she said.

The issues that could get stakeholders on both sides of the aisle to the table include, of course, permitting reform, as well as U.S. competitiveness with China and artificial intelligence, Domenech said.

AI has “brought a whole range of tech stakeholders to the table in the energy context and thinking about permitting,” she said. “For the first time, I’ve been meeting with folks in the tech space who said, ‘We really want to lean in on this issue, but we haven’t done it before.’

“Now [they] care about nuclear, and they care about fixing [the National Environmental Policy Act], and they care about coming to the table to make sure they can build and grow this infrastructure in the United States,” she said.

Curtis also brought the discussion back to permitting. “A lot of money in the IRA will never be spent if we don’t get permitting reform,” he said. “Worse than that, there is no path to 2050 — clean or unclean, either way — that meets our energy needs without permitting reform. People are seeing a lot of good discussions and healthy discussion about it, but nobody [has] come up with a bill that everybody can support.” ■

CAISO/West News

Pathways Initiative Releases 'Step 2' Proposal for Western 'RO'

Draft Plan Calls for Initially Forming 'Policy-setting' Organization Under 'Option 2'

By Robert Mullin

The West-Wide Governance Pathways Initiative on Sept. 26 released its "Step 2" draft proposal for dividing up functions between CAISO and the new "regional organization" (RO) that initiative backers are seeking to create to oversee the ISO's Western real-time and day-ahead markets.

The draft proposal calls for the RO to launch in the form of the "Option 2.0" structure discussed in Pathways meetings, one in which the RO would serve primarily as a "policy-setting" body around market rules for the Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM).

The plan stops short of adopting "Option 2.5," which would have the RO take on more of CAISO's market functions and legal responsibilities — but also the accompanying financial and legal risks.

But Pathways backers — and the proposal itself — are leaving open the potential for transitioning to the second option once the new entity is established.

"This is really the recommendation for creating a new independent entity that can have sole authority over [CAISO] market services," Kathleen Staks, co-chair of the Pathways Launch Committee, said during a joint meeting of the CAISO Board of Governors and Western Energy Markets (WEM) Governing Body shortly after release of the proposal.

"It was very important to make sure that we were communicating with the West that we intend for this thing to continue to be able to grow as the West wants it, as utilities demand it and stakeholders demand it. We need this new regional organization to be able to add market services," said Staks, who is executive director of Western Freedom.

The Pathways Initiative's Step 2 draft proposal outlines the functions and structure of the new regional organization intended to oversee CAISO's WEIM and EDAM. | *West-Wide Governance Pathways Initiative*

A *fact sheet* accompanying the *proposal* notes the plan (emphasis Pathways') "is *not* a consensus document but a *draft* proposal with wide-ranging recommendations to solicit additional stakeholder feedback."

According to the fact sheet, under Option 2.0, the RO "will have full authority over market rules, sole Federal Power Act Section 205 rights and ultimate authority over associated business practice manual provisions."

Under CAISO's existing tariff, the ISO's board and WEM Governing Body share joint authority over the WEIM and EDAM. In August, both bodies voted to implement the Pathways "Step 1" proposal, which grants the WEM body "primary" authority over the markets, a tariff change still pending approval by FERC. (See *CAISO, WEM Boards Approve Pathways 'Step 1' Plan*.)

Option 2.0 would elevate that "primary" authority to "sole" authority and shift the oversight to the RO, which would effectively

CAISO/West News

assume the role of the Governing Body.

"Sole 205 rights in Step 2 means that the CAISO board does not have any lingering unilateral authority, which exists today and persists in Step 1 in some exigent circumstances, to make a 205 filing at FERC that unilaterally imposes the CAISO board's policy view regardless of the views of the other body," the proposal says.

The only area for which CAISO's board would retain sole 205 authority is for rules "applicable specifically" to the ISO's balancing authority or grid.

But the proposal has the ISO continuing to perform day-to-day market operations "within the scope of its existing corporate authority, with varying levels of input from the RO." Under the plan, RO and CAISO rules would also reside within a "single integrated tariff," and the ISO would remain the counterparty for existing market contracts.

"One premise of the Pathways Initiative is that consumers across the West would be better served by drawing on the existing CAISO software, hardware, facilities and expert operators, rather than designing, building and paying for this infrastructure and expertise from scratch," the proposal says. "This premise goes hand in hand with the notion that the widest possible integrated footprint, inclusive of California, would be better for consumers than the alternative."

Because Step 2 grants the RO sole authority over CAISO markets, its implementation will require a change to California law, according to legal analysis performed by law firm Perkins Coie, an adviser to Pathways. The campaign to begin lobbying lawmakers was already in evidence this past summer, but Pathways supporters say the effort will begin in earnest with the next legislative session starting in January 2025. (See *California Labor Groups Affirm Support for Pathways Proposal* and *California Energy Officials Pitch Pathways Plan to State Senators*.)

Passage of a bill would put the ball back into CAISO's court.

"The ultimate tariff changes will have a [CAISO] stakeholder process, but that wouldn't begin until after a bill passes in California," Staks told *RTO Insider* in an email.

Structure

At 133 pages, the Step 2 draft proposal goes well beyond governance functions to detail the proposed structure of the RO, which would be incorporated as a 501(c)(3) nonprofit corporation in Delaware and maintain its principal place of business in Folsom, Calif., near CAISO's headquarters. It would be overseen by a seven-member board of directors selected to meet FERC's independence requirements.

The proposal's fact sheet says the RO's "articles of incorporation, bylaws and other corporate documents will center on public interest protections and transparency," while a Public Policy Committee of the board "will engage with states, local power authorities and federal power marketing administrations about potential impacts to state, local or federal policies before final board adoption of a tariff change or an initiative through the stakeholder process."

The proposal additionally calls for the RO to engage with the WEIM's existing Body of State Regulators and establish a Consumer Advocate Organization and Office of Public Participation. It would also create a joint structure for CAISO's Department of Market Monitoring to report to both the ISO and RO boards.

The draft plan also outlines formation of the RO's sector-based Stakeholder Representatives Committee (SRC), "which will serve as the primary body responsible for overseeing and guiding the development of new initiatives." The proposal describes the SRC's three-part process, consisting of issue identification and prioritization, discussion and solution development, and RO board approval. (See *Comments on Western RO Stakeholder Plan Show Complexity of Effort*.)

"By incorporating sector-based representation, the SRC will ensure that a balanced range of perspectives is considered, promoting collaboration and consensus through sector-specific discussions. This structured approach will enable stakeholders to identify and address key issues collectively, thereby influencing policy development outcomes in a meaningful way," the proposal says.

The exact constitution of the SRC is still a work in progress, and the Launch Committee has scheduled an additional meeting to discuss the subject Oct. 7.

Planting a Seed

The proposal additionally calls for the RO to consider transitioning — "over a defined period of several years" — to Option 2.5 after performing more analysis and gathering stakeholder input on making such a move. Under that option, the RO would take on more of CAISO's market functions and legal responsibilities, and potentially reorganize itself under its own tariff while maintaining a vendor contract with ISO as market operator.

"In Option 2.5, deeper division of liability between two corporations, overall higher cost both to the CAISO and RO, and to stakeholders as a whole, plus the extensive negotiations we anticipate will be involved to rework dozens of *pro forma* regulatory contracts in Option 2.5, prevent us as a committee from strongly (as opposed to tentatively) recommending Option 2.5 at this stage," the proposal says.

> **What's Next**
>
> Because Step 2 in the process would grant the new regional organization sole authority over CAISO markets, a change to California law is required. Pathways supporters will work with lawmakers to pass a bill in the next session, starting in January 2025.

A financial table in the proposal shows the RO's estimated annual operating costs under Option 2.5 would be nearly $23.9 million, including $17.7 million for in-house staffing, compared with $13.7 million under Option 2.0, which would incur about $10.6 million for labor.

The proposal calls for the RO board to perform "a deeper feasibility analysis, with stakeholder input, to assess the costs, benefits, possible expanded market functions, implementation details of how to achieve the additional corporate independence and responsibility, and to determine whether a departure from Option 2.5 is warranted."

The analysis should be one of the board's "initial priority tasks," to be started within nine months of the RO's formation, the draft adds.

"The idea here is that we will plant a seed. ... We're working with stakeholders and with you to plant the seed into fertile soil and to help water it and help it grow," Launch Committee Co-Chair Pam Sporborg, of Portland General Electric, said during the CAISO board meeting. "But we do envision that as this organization takes root, that it will grow into what we call Option 2.5, [which] will have expanded authority and take on the actual responsibility, including a lot of the liability and compliance obligations associated with running the market."

The Launch Committee will hold a stakeholder meeting to discuss the draft proposal on Oct. 4 and is accepting written comments on the plan until Oct. 25. It expects to release a final recommendation the week of Nov. 15. ■

CAISO/West News

FERC Grants PGE Extra Time to Prepare for EDAM

CAISO Sought Start Date Waiver to Coordinate Implementation with PacifiCorp

By Robert Mullin

PGE distribution lines in Portland, Ore. | *© RTO Insider LLC*

FERC on Sept. 26 granted CAISO a waiver allowing Portland General Electric to join the ISO's Extended Day-Ahead Market (EDAM) a few months beyond the deadline set out in the EDAM's standard participation agreement (*ER24-2444*).

The *pro forma* EDAM Entity Implementation Agreement on file with FERC allows CAISO and a prospective EDAM participant flexibility to work out a specific start date based on the participant's needs to prepare for market membership, but it also requires that the date be no later than 24 months after the agreement was executed.

CAISO and Oregon-based PGE signed the agreement July 2, but the utility had asked to join the EDAM in fall 2026, which would put its start time outside the two-year window.

In requesting the waiver, CAISO argued that PGE would need more than 24 months from the effective date of the agreement to implement the technology needed to start participating in the EDAM, but that PGE's early signature would allow the utility and the ISO to immediately begin work on implementation issues in parallel with PacifiCorp, which plans to join the market in spring 2026. (See *PacifiCorp Fully Commits to CAISO's EDAM*.)

The ISO said granting the waiver would allow for joint implementation meetings and early engagement with vendors that would not otherwise be possible. PGE would then be able to complete other readiness tasks required for it to be fully equipped to join the EDAM in fall 2026.

> **Why This Matters**
>
> As one of the first participants in CAISO's EDAM, PGE's preparations for joining the market are likely to be among the more complicated as the ISO refines the process over time.

In its comments on the request, PGE said the waiver would be crucial to the success of its entry into the EDAM because of the complexity of integrating its transmission and technology systems with the ISO's technology, and that the complexity could be best addressed by working in parallel with PacifiCorp.

In granting the waiver, the commission found that CAISO had acted in good faith because it had filed the waiver request one business day after the two parties had signed the implementation agreement. It also agreed with the ISO that the request was limited in scope because it was a one-time extension of the EDAM entity implementation date for a "discrete" market agreement.

"Third, we find that granting CAISO's request addresses a concrete problem; CAISO and Portland General state that more than 24 months from the effective date of the EDAM implementation agreement are needed to complete the work necessary to allow Portland General to start participating in EDAM," the commission wrote. "Specifically, the parties represent that [the] waiver will allow Portland General to participate in parallel and joint implementation work with PacifiCorp, which will support Portland General's ability to begin EDAM participation in the fall of 2026."

The commission also determined that granting the waiver would not have "undesirable consequences" or harm third parties.

"Instead, [the] waiver will allow CAISO and Portland General sufficient time to complete their work and coordinate with PacifiCorp," it wrote. ■

National/Federal news from our other channels

Sierra Club Urges Big Customers to Push for Clean Energy to Meet Rising Demand

NetZero Insider

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

CAISO/West News

Updated EDAM Study Shows Doubling of PacifiCorp Benefits

Expanded Footprint also Yields Sharp Increase in Market-wide Benefits, Brattle Finds

By Robert Mullin

PacifiCorp could earn up to $359 million a year in net benefits from participating in CAISO's Extended Day-Ahead Market, nearly double the previous estimate, according to a newly updated *study* prepared for the utility by The Brattle Group.

The update also more than doubles the estimate of benefits for the entire EDAM footprint compared with the original market *study* Brattle produced for PacifiCorp in April 2023.

That study showed the six-state utility reaping $181 million in net benefits from a day-ahead market whose footprint included CAISO, Balancing Authority of Northern California, Idaho Power and Los Angeles Department of Water and Power, with all market participants realizing a total of $437 million in benefits.

The revised study expands the EDAM footprint to include more recently announced participants NV Energy and Portland General Electric, as well as likely joiner Seattle City Light. It also factors in the effects of SPP's RTO West and Western Energy Imbalance Service footprints.

As in the original, the updated study measures PacifiCorp's EDAM benefits against a "business as usual" (BAU) case that consists of the current Western Energy Imbalance Market footprint. It doesn't consider the effect of potential Western participation in SPP's Markets+.

According to Brattle's updated modeling, PacifiCorp's rise in benefits results in part from a $53 million reduction in the utility's adjusted production costs (APC) under the expanded EDAM footprint. The utility sees an even bigger boost from a $120 million increase in EDAM congestion and transfer revenues, with $88 million of that realized on paths with the three newly included market participants.

More specifically, the updated study found that PacifiCorp's benefits in its resource-heavy East (PACE) balancing authority area are driven by increased economic dispatch of gas generation into the rest of the EDAM and rising sales revenues from renewable resources.

"PACE receives $163 million in increased sales revenues on $82 million in increased generation costs, with average day-ahead sales prices increasing from the BAU case to EDAM from $23/MWh to $29/MWh," the study says.

Brattle said PacifiCorp's extensive transmission network would be "extremely valuable" to the EDAM because it connects to more of the market's members than any other participant.

The benefits in PacifiCorp's West (PACW) BAA and Washington territory would derive largely from reduced generation and energy purchase costs.

"PACW is both able to reduce its generation 360 GWh in EDAM (saving $16.4 million) and time purchases better to buy 539 GWh more in EDAM, but for $12.2 million less than in the BAU case," according to the study.

Compared with the 2023 study, the updated study assumes PacifiCorp will be heavier in annual output from renewable and thermal generation, with a 9 TWh increase in wind — mostly in PACE — and a 6 TWh increase in coal-fired generation because of the carbon capture tax credit for the Jim Bridger plant in Wyoming. Nuclear output declined based on removal of one small modular reactor project. Estimates for hydroelectric generation also were lowered to reflect the utility's own hydro capacity updates.

PacifiCorp in April became the first Western utility to fully *commit* to the EDAM and sign an implementation agreement with CAISO.

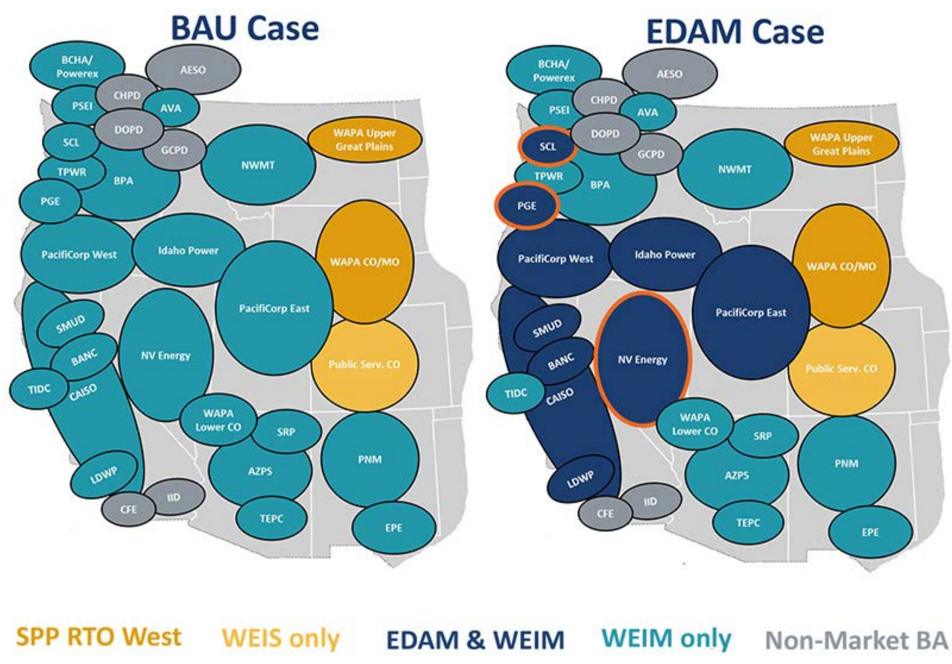
Brattle's updated study increases the EDAM-wide benefit estimate to $837 million, noting the larger footprint produces larger APC savings and increases market revenues.

"New footprint members account for more than $200 million of the [$285 million] increase in trading revenues," the study finds.

The expanded footprint also reduces the region's bilateral trading value by an additional $275 million, for a total decline of $531 million, according to the study. ■

Why This Matters

The updated study suggests to EDAM supporters the market's economic benefits will grow significantly as it attracts more participants. The results also could help sway some Western entities still undecided about which day-ahead market to join.



The Brattle Group's updated PacifiCorp study includes an "EDAM case" that includes three new participants in the CAISO day-ahead market. | *The Brattle Group*

CAISO/West News

CAISO Passes Initiatives to Address Meter Data Reporting, Expand Trading

ISO Board and WEM Governing Body also Discuss Pathways Initiative 'Step 2' Proposal

By Ayla Burnett

CAISO on Sept. 26 passed two separate initiatives: one that removes penalties for certain meter data issues, and another that expands bilateral trading in the Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM).

The first proposal deals with small meter data reporting inaccuracies that the ISO pointed out could be prompting unnecessary penalties. Those inaccuracies, despite being small, trigger full investigations but have minimal impact on settlement outcomes, Becky Robinson, CAISO director of market policy development, told the ISO's Board of Governors and Western Energy Markets Governing Body at their joint meeting.

The proposal also aims to address the concern that scheduling coordinators (SCs) may lack sufficient incentive to submit demand response baseline data, as well as identify certain requirements that pose an unnecessary administrative burden to SCs and the ISO.

Kathy Anderson, senior manager of transmission and markets at Idaho Power, presented an example of a meter data error the utility experienced to help demonstrate the issue to the board and Governing Body.

When Idaho Power joined the WEIM in 2018, the metering for a 19.5-MW resource was inadvertently set up incorrectly in the system, Anderson explained.

"At the time, we didn't realize that the generator meter was actually already compensated for line losses, so we programmed the line losses into our energy accounting system," Anderson said. "This resulted in subtracting more losses than we should have for the actual generator value."

The magnitude of the issue was relatively small, calculating out to an hourly average error of about 0.37 MW, and was fixed after Idaho Power discovered it. However, because of the tariff violation, the utility was fined $639,000.

"We felt this was excessive, given the magnitude of the inadvertent error, so we filed at FERC to have the penalty waived, and FERC did approve that penalty waiver request," Anderson said (EL23-94). (See *FERC Waives Nearly $2M in CAISO Data Reporting Penalties*.)

Following the incident, Idaho Power expressed to CAISO that it felt the tariff had a "disproportionate penalty design." To address the issue, the utility proposed establishing a materiality threshold for incorrect meter data penalties, where inaccuracies less than 3% or 3 MWh won't be penalized.

"We feel comfortable with this change, because we feel that small meter data corrections really don't rise to the level of warranting a penalty or the need for a costly investigation, which is a time-consuming process for both staff and the market participant," Robinson said.

The proposal also recommends establishing due dates and new penalties to incentivize timely DR monitoring data submittal.

"The Department of Market Monitoring has observed some significant and ongoing problems with timely monitoring data submittal, given the lack of well-defined deadlines," Robinson said.

Finally, to ease administrative burden, the proposal introduces a 30-day period where the ISO waits to assess penalties and streamlines the investigation process.

Robinson indicated that there was broad stakeholder support for the proposal, and the board and Governing Body voted to pass it unanimously.

Inter-SC Trades

The board and Governing Body also unanimously passed a proposal to streamline and expand inter-scheduling coordinator trading to the WEIM and EDAM.

The initiative was first introduced in August and moved through the stakeholder process expeditiously. (See *CAISO Kicks Off New Initiative to Streamline Bilateral Trading*.)

Inter-SC trading is an optional market feature that facilitates settlement of bilateral contracts between SCs. It was already used in the ISO's balancing authority area, but not in the WEIM or EDAM.

WEIM and potential EDAM participants indicated to the ISO that expanding inter-SC trading "would be a beneficial service to their participation in the regional markets," Robinson said, and that establishing it would not impose any costly barriers to EDAM implementation in 2026. Stakeholders also expressed that extension of inter-SC trading could support diverse business needs and market participation structures, and help further integrate bilateral markets in the West.

"It provides additional optionality and value to those market participants in the EIM and the EDAM and … it's something we can implement and integrate with the EDAM implementation efforts," said Milos Bosanac, CAISO regional markets sector manager.

The proposal also passed unanimously, with broad stakeholder support.

A 'Distinct Disadvantage'

Members for the West-Wide Governance Pathways Initiative's Launch Committee also presented the "Step 2" proposal, which was released Sept. 26. (See related story, *Pathways Initiative Releases 'Step 2' Proposal for Western 'RO'*.)

Step 2, part of the "stepwise" approach to regionalization in the West, would transfer governance authority over existing energy markets from CAISO to a new regional organization (RO).

The proposal seeks to implement "Option 2.0," which would give the RO full governance authority over the WEIM and EDAM under a single integrated tariff, though an "Option 2.5" was also considered, which would separate the RO tariff from the ISO's.

While the proposal received general support, some board members felt the presentation was premature.

"We are at a distinct disadvantage that the 128 pages that you released today, we have not been able to read," board member Mary Leslie said. (The document is actually 133 pages.) "I wish that this were reverse order — that we would have been allowed to read this and then have you here.

"We are very pro creating a Western energy market, but you can understand our situation as board members, that we have a fiduciary responsibility in California and to the CAISO."

Launch Committee co-Chair Pam Sporborg, of Portland General Electric, reiterated that the process is still underway.

"I think you guys are used to seeing final proposals that are up for a vote, and this is not a final proposal," Sporborg said. "We are here to offer an overview of our 133-page document and hopefully give you enough grounding to be able to parse through that and bring us your feedback."

The final proposal is slated for mid-November. ■

CAISO/West News

California GETs Bill Gets Newsom's Signature

Related Bill on Grid-enhancing Tech Awaits Governor's Approval

By Elaine Goodman

California Gov. Gavin Newsom has signed a bill that proponents say will speed the deployment of grid-enhancing technologies — techniques that can rapidly boost grid capacity and increase the use of renewable resources.

Senate Bill 1006 was signed into law Sept. 25. It will require utilities to study the feasibility of using advanced reconductoring and other grid-enhancing technologies (GETs) and submit reports to CAISO, which will review the findings as part of its annual transmission planning.

A second bill related to GETs is awaiting the governor's signature. *Assembly Bill 2779*, by Assemblymember Cottie Petrie-Norris (D), would require CAISO to report any new use of GETs that it deems reasonable, along with the cost savings and efficiency of that technology, when it approves a transmission plan.

The report would go to the California Public Utilities Commission (CPUC) and committees in the state Assembly and Senate.

Newsom's deadline to sign or veto bills is Sept. 30. If the governor takes no action on a bill passed by the legislature, it becomes law without his signature.

SB 1006, by Sen. Steve Padilla (D), notes that California must "rapidly and cost-effectively" increase transmission capacity to meet its decarbonization goals.

While new transmission lines "will absolutely be necessary," GETs are a way to increase capacity at a fraction of the cost of new lines, Padilla said in a release when he introduced the bill.

"Grid-enhancing technologies can be installed in months and often pay for themselves within a year based on access to lower-cost generation alone," Julia Selker, executive director of the WATT Coalition, said in a letter urging Newsom to sign the bill.

GETs listed in SB 1006 include dynamic line ratings, advanced power flow control and topology optimization, as well as advanced reconductoring.

Under SB 1006, transmission utilities will have two reports due Jan. 1, 2026. The first will look at the feasibility of using GETs to achieve one or more of the following goals:

California's SB 1006 requires the state's utilities to evaluate the use of grid-enhancing technologies at least every two years in transmission planning for seven different categories of benefits. | © *RTO Insider LLC*

- Increase transmission capacity.
- Reduce transmission system congestion.
- Reduce curtailment of renewable and zero-carbon resources.
- Increase reliability.
- Reduce the risk of igniting wildfire.
- Increase capacity to connect new renewable energy and zero-carbon resources.
- Increase flexibility to reduce risks surrounding technology and permitting uncertainties in statewide electrical system planning and improve optionality for load-serving entities.

The second study will evaluate which of a utility's transmission lines could be reconductored to achieve goals similar to those outlined for the first study, with two additions: reducing line losses and increasing the ability to quickly energize new customers or serve increased customer load.

Utilities will repeat the first study every two years and the second study every four years.

Supporters of SB 1006 and AB 2779 include Advanced Energy United.

The bills "will unlock the potential of these revolutionary grid technologies, enabling us to meet rising power demands while minimizing rate impacts so we can keep the lights on without spending an arm and a leg," Edson Perez, Advanced Energy United's California policy lead, said in a statement in August.

Another bill related to GETs, *AB 3246* by Assemblymember Eduardo Garcia (D), died in committee in August. The bill would have streamlined the approval process for advanced reconductoring of existing power lines.

GETs are also called out in a $10 billion climate-resilience bond measure that California voters will decide next month. (See *Calif. Lawmakers Send $10B Climate Bond Measure to Nov. Ballot*.)

SB 867, which sent the bond measure to voters, includes $325 million for clean-energy transmission projects, with preference potentially given to projects that provide multiple benefits, such as reconductoring and other GETs. ■

Data Centers Contribute to 60% Increase in San Jose Load Forecast

Fuel Switching, EVs also Drive Bay Area Load Growth in CAISO Transmission Planning

By Ayla Burnett

Data centers are contributing to significant load growth and project needs in Silicon Valley, according to CAISO representatives speaking at the Sept. 23 kickoff meeting for the ISO's 2024-2025 transmission planning process.

While the San Jose area — a 115-kV network between the Newark and Metcalf substations — has seen the largest forecast increases, the greater Bay Area has also seen large load growth.

In the 2021-2022 transmission planning cycle, the California Energy Commission forecasted about 9,500 MW for the Bay Area, a figure that has since grown to approximately 12,000 MW.

"The Bay Area in general has grown, and that's fuel switching; that's EV; that's just growth in general," Jeff Billinton, CAISO director of transmission infrastructure planning, said in the meeting. "We're also doing a sensitivity because there is a significant number of interconnections that PG&E is receiving for data centers in that area."

The San Jose area saw particularly significant load forecast increases, said Binaya Shrestha, manager of regional transmission north at the ISO. In the 2024-2025 planning cycle, the region saw an increase of approximately 3,400 MW in the base case and 4,200 in the long-term sensitivity scenario. As a result, a project approved in the 2021-2022 cycle, as well as the overall long-term transmission plan for the area, was re-evaluated.

The ISO is considering alternatives to the previously approved project: a multi-terminal HVDC configuration that would connect the San Jose B converter to the Newark HVDC converter, meant to address load serving issues. When the project was approved, the long-term load in the area was about 2,100 MW.

"Coming to this cycle, 24/25, when we look at the load in the long-term scenario in 21/22, it's about a 60% load increase," Shrestha said.

A sensitivity case was developed to evaluate how an increase of load in the area would affect the proposed project and whether there was flexibility to expand the plan to serve more load. The ISO found that addition of the project would cause "severe overloads."

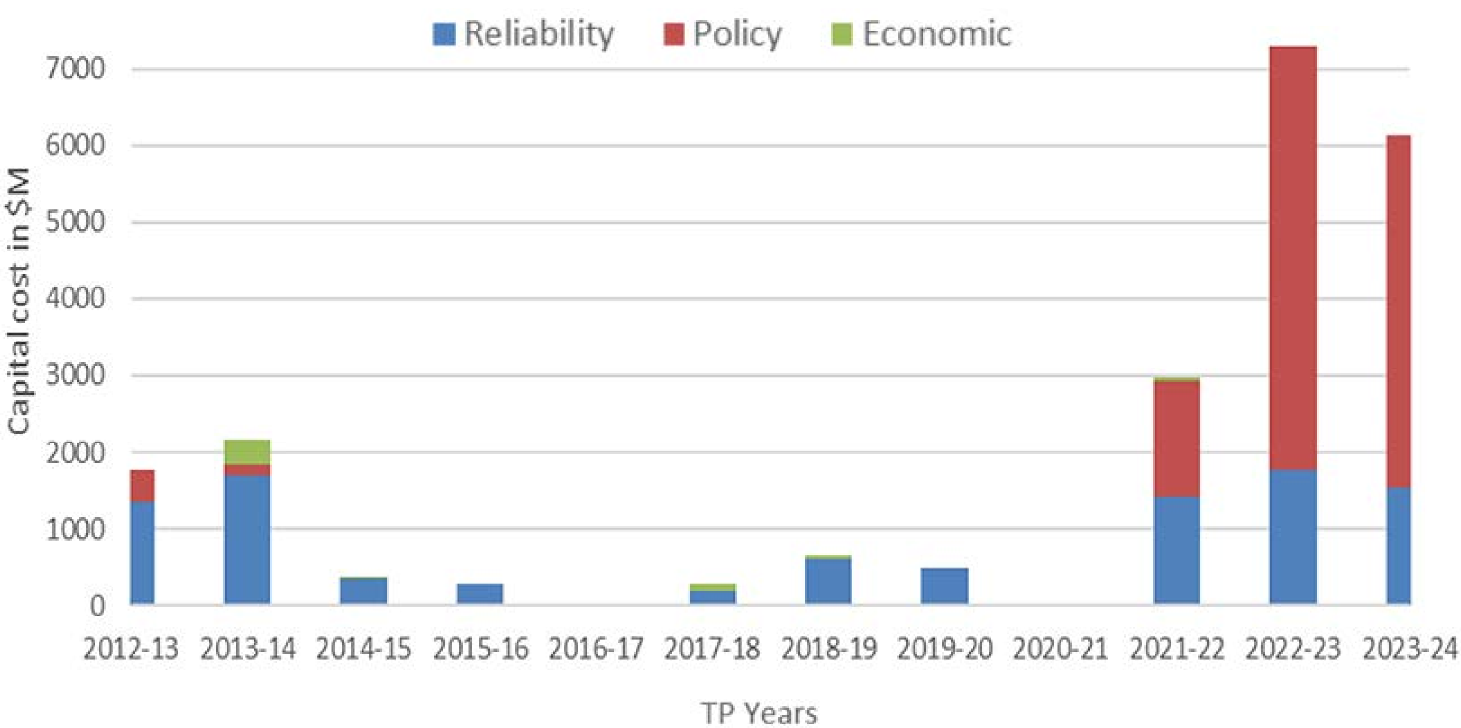
Additionally, LS Power, the project sponsor, identified a cost increase for the HVDC equipment, and worked with the ISO to develop alternatives to the project that could reliably deliver power without significant overloads or price increases.

Multiple alternatives were considered, including high-capacity AC lines, a bi-pole muti-terminal HVDC, and a hybrid AC-HVDC solution.

"Putting that all together, we are recommending a hybrid solution to move forward in this area," Shrestha said. "That recommendation includes a 1,000-MW HVDC link between Metcalf and San Jose B, and we are changing the scope of the Newark HVDC to a high-capacity 230-kV AC line."

CAISO is seeking to expedite approval of the altered project so that it can still meet the 2028 planned in-service date, which "the area needs to be able to serve load."

The ISO is also recommending a new 230-kV line connecting Newark and San Jose B. The scope change will be voted on by the Board of Governors in November. ■



While data centers and other factors have increased load growth forecasts in the Bay Area, policy driven projects are still the main transmission need in the 2024-2025 cycle. | *CAISO*

CAISO/West News

WPP Board Approves WRAP Transition Plan Changes

Changes Include Summer 2027 Start for 'Binding' Phase, Revised Penalty Practices

By Robert Mullin

The Western Power Pool's Board of Directors has approved changes to the Western Resource Adequacy Program's transition plan that include postponing the program's "binding" phase by one year and reducing penalties for participants who come up short on RA obligations.

WPP said Sept. 24 that its board had approved the revised transition plan five days earlier, following through on a request by WRAP participants to push back the start of the program's penalty phase by one year, from summer 2026 to summer 2027.

WPP staff working on the WRAP told *RTO Insider* through a spokesperson that the new timeline does not technically represent a delay because the program's tariff gives WPP flexibility to begin binding operations anytime between 2025 and 2028.

Members of the WRAP's Resource Adequacy Participants Committee (RAPC) requested a shift from the 2026 date in an April 22 letter addressed to "Western Stakeholders," in which they warned that they face "significant headwinds" in securing energy resources in light of supply chain issues, forecasts for faster-than-expected load growth and increasing extreme weather events. (See *WRAP Participants Seek 1-Year Delay to 'Binding' Operations*.)

The RAPC on Aug. 29 voted to approve the revised transition plan, which — in addition to shifting the binding phase — also extends the WRAP's "transition period" by one year to March 2029. (See *WRAP Members Vote to Delay 'Binding' Phase to Summer 2027*.)

Under the updated plan, during the transition period, participants who enter the binding phase but remain deficient in RA are allowed to pay a "discounted deficiency charge" if they fail to secure WRAP Operations Program capacity but show "commercially reasonable efforts" to do so.

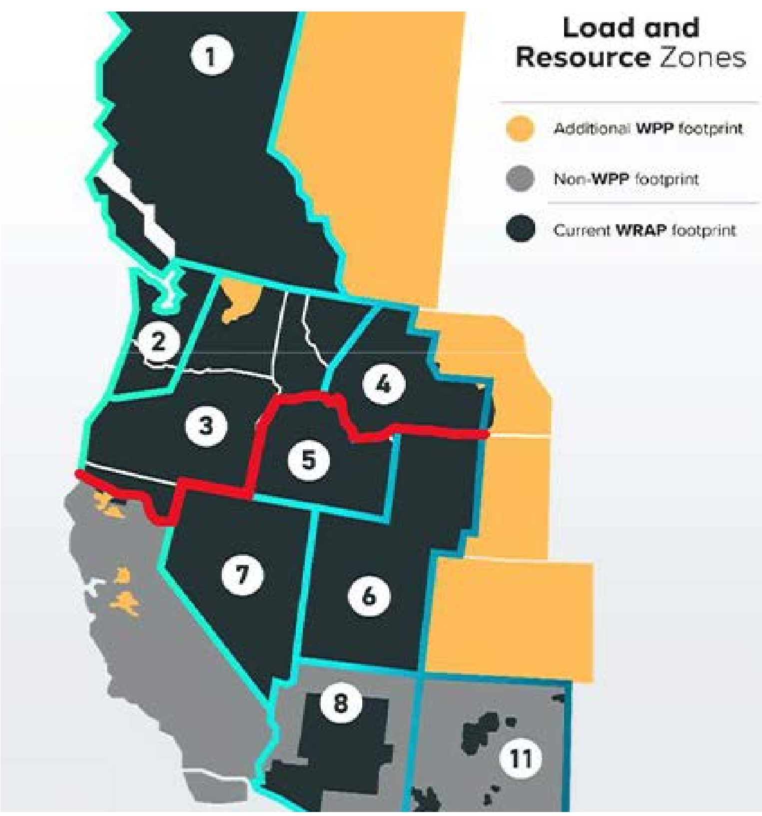
The new plan also introduces the concept of "critical mass" into the program by setting a "participating load volume and participant threshold for a [WRAP] subregion below which participants may participate in a nonbinding manner" after the transition period ends.

Inclusion of that concept entails tariff changes that would allow participants to choose to be nonbinding for seasons when critical mass is not achieved in their subregion. The critical mass thresholds would be 15 GW of load and three participants for the Southwest/East Diversity Exchange (SWEDE) subregion, and 20 GW of load and three participants for the Northwest's Mid-C subregion.

The transition plan changes were put out for public comment and reviewed by the WRAP's Committee of State Representatives before being submitted to the WPP board, which also voted Sept. 19 to approve seven WRAP business practice manuals and a set of corrections to the program's tariff.

"This is our robust stakeholder process and independent governance structure on display," WPP CEO Sarah Edmonds said in a statement. "With the input and direction we've received on both the tariff and the business practice manuals, WRAP is well positioned to move forward."

The WRAP tariff changes will now advance to FERC for approval. ■



Subregion	Zone	Geographical Description
MidC	Zone 1	British Columbia
	Zone 2	West of Cascades
	Zone 3	East of Cascades
	Zone 4	NorthWestern
SWEDE	Zone 5	Idaho Power
	Zone 6	PacifiCorp East
	Zone 7	Nevada
	Zone 8	Arizona
	Zone 11	New Mexico

The summer load and resource zones for the Western Resource Adequacy Program | *Western Power Pool*

Report Calls for $75B in New Tx to Meet Western Needs

'Connected West' Study Says Estimate is 'Floor,' not 'Ceiling' for Addressing Future Requirements

By Henrik Nilsson

The Western Interconnection will need about 15,600 new line miles of high-voltage transmission at a cost of about $75 billion over the next 20 years to meet the anticipated increase in load growth, according to a report commissioned by Gridworks and GridLab published Sept. 23.

Conducted for the two groups by Energy Strategies, the *Connected West* study found that the Western grid's reliability is at risk even if $30 billion of planned grid investments are implemented in the next decade. The current planned investments represent approximately 5,900 line miles, which may not be enough to support "an electrified and deeply decarbonized Western grid in 2045," according to the report.

Instead, the report recommends an additional 15,600 new line miles over 20 years. The study found that approximately 85% of the new transmission capacity across the West can be achieved by upgrading existing corridors. Some 2,400 miles of new greenfield transmission would be needed for the proposed transmission system, the report said.

"The high-voltage investment gap to support reliability and efficiency of the grid, representing the next tranche of regional-scale transmission investments not currently planned for, is on the order of at least $75 billion," the report said. "This investment, at a minimum, is necessary to address the transmission constraints identified in the Connected West scenario."

The report added that the investment gap "should be considered a 'floor' not a 'ceiling' of future transmission need."

Casey Baker, senior program manager for GridLab, said in an email to *RTO Insider* that the study provides stakeholders with recommendations on how to complete transmission plans "that can be implemented in the various FERC Order 1920 compliance efforts kicking off in regions around the country." (See *FERC Open Meeting Showcases Order 1920 Rehearing Debate*.)

"Transmission stakeholders can take the Connected West study and use it in their efforts to promote best practices as their regions move towards completing their own long range transmission plans," Baker added.

The study builds on the Nature Conservancy's 2022 *Power of Place: West* report, which explored the land use requirements and conservation impacts of achieving net-zero greenhouse gas emissions across the Western U.S.

Connected West leveraged Nature Conservancy's findings to analyze transmission needs for a high electrification scenario involving various clean energy technologies, according to the report. The study evaluated three transmission expansion portfolios, with each portfolio exploring different pathways to improve grid capacity, reliability and efficiency.

Baker noted that although the costs are significant, "the benefit to cost ratio for all three portfolios was approximately 1.4 and assumed significant (approximately 70%) load growth over the next 20 years which could be leveraged to support this investment."

Total benefits from the new transmission explored in Connected West would be between $250 billion to $275 billion, including up to $150 billion in avoided investments in power plants, $50 billion in avoided losses from extreme weather and $35 billion in reduced energy costs, among other benefits, according to the report.

"Our analysis shows that this level of expansion is not only achievable but necessary to meet the energy demands of the future," Matthew Tisdale, executive director of Gridworks, said in a news release. "With proper planning, we can build the infrastructure needed to support a robust economy while minimizing costs. Simply put: it will be better for ratepayers, businesses and communities in the West if we make the right investments now to avoid higher costs and greater disruptions later."

'Unprecedented'

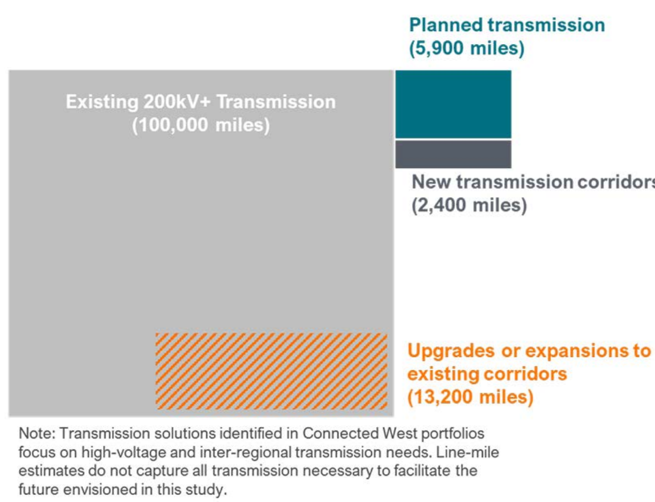
The Connected West study appears well positioned to contribute to Western transmission discussions as two parallel efforts ramp up to spur development of the kind of interregional projects the region has struggled to build.

One of those is the Western Power Pool's Western Transmission Expansion Coalition (WestTEC), which is being guided by electricity industry participants.

The other is the Western States Transmission Initiative (WSTI), which is being facilitated by Gridworks on behalf of the Committee on Regional Electric Power Cooperation's membership of state energy agency officials. (See *In West, Proposals for Tx Planning Proliferate Faster than New Lines*.)

Baker called Connected West an "unprecedented study that provides a template for completing a 20-year, holistic, multi-benefit transmission plan."

"Many other entities, including WECC, CAISO, and the U.S. [Department of Energy], have completed 20-year transmission studies, but this is the first long-range transmission plan to integrate economy-wide decarbonization, multiple benefit streams, transmission technology portfolios and environmental siting considerations across the entire Western grid," he said. ■



This graphic illustrates the shortfall in planned transmission in the West based on the Connected West report's assessment that the region will need more than 20,000 new miles by 2045. | *Energy Strategies*

CAISO Seeks to Dispel CRR 'Myths' Around January Cold Snap

ISO Presents 7 'Facts' and 'Myths' on Topic at Regional Issues Forum

By Ayla Burnett

CAISO focused on congestion revenue rights when it served up the latest volley in the ongoing dispute over what played out on the Western grid during the January cold snap that forced Northwest utilities to import unusually high volumes of energy to avoid blackouts.

"Given all the nuances and complexities with all the dynamics at play during that event, it is always useful to step back and have the opportunity to provide some basic facts of how things actually happened," Guillermo Bautista Alderete, CAISO director of market performance and advanced analytics, said during a Sept. 27 *presentation* to the Western Energy Imbalance Market's Regional Issues Forum (RIF).

"But in order to reach that point in the discussion, it is critical that we first differentiate between the fact and the myth," Alderete said.

The cold snap over the Jan. 12-16 Martin Luther King Jr. holiday weekend saw record low temperatures along with historically high peak demand, prompting five different balancing authority areas (BAAs) to declare energy emergency alerts. Stressed grid conditions also produced price separation between the Northwest and California, with extremely high bilateral prices in the Northwest and at the Malin intertie in particular.

Central to the dispute over the event was CAISO's role in supporting the Northwest during extreme weather conditions, as the disagreement quickly became a proxy for the broader competition for members between the ISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+. (See *NW Cold Snap Dispute Reflects Divisions Over Western Markets*.)

A Feb. 8 *report* by the Western Power Pool found that while CAISO and other California BAs exported nearly 3,000 MW of energy to the Northwest, they were also net importers, suggesting that the Desert Southwest and Rockies regions — and not California — were the origin of most of the Northwest's supporting imports.

That was followed by a Feb. 23 letter from the Portland, Ore.-based Public Power Council (PPC) to Bonneville Power Administration CEO John Hairston, which critiqued the ISO's allocation of congestion revenue rents (CRRs) during the event. The PPC wrote that "CAISO's congestion policies resulted in over $100M of congestion revenues being collected by the CAISO BAA, despite most of the generation serving the Northwest coming from outside California."

In a March 6 report, Powerex expanded on the CRR complaint and even called on Northwest entities to develop ways to circumvent flowing energy through California, while CAISO that same day issued its own 80-page report defending its actions during the cold snap and explaining the mechanisms used by the WEIM to move power around the grid.

'Myth Busting'

Alderete's Sept. 27 "myth-busting" presentation to the RIF drilled further into the CRR issue, offering a series of seven "facts" and "myths" about what occurred and focusing on the congestion occurring at Malin and on the California-Oregon Intertie (COI) — the main interface between BPA and the ISO.

The first "myth" Alderete addressed was the assessment that the ISO unilaterally decides on Malin limits to influence congestion. He emphasized that both BPA and the ISO are path operators on the COI and that there is an agreement between the two operators to have a "coordinated operation of the path" and "always enforce the most limiting constraint on the path."

According to Alderete, this first "myth" set the stage for the second one: that the ISO directly influenced day-ahead congestion on the Malin intertie. His presentation said the day-ahead congestion occurred "simply because the volume of exports requested for the Northwest exceeded the full Malin capability. Exports at Malin were twice as much as the full Malin capacity, and through the day-ahead market, the ISO positioned internal supply economically to support exports to the Northwest."

A third "myth" further perpetuated the belief that CAISO limited COI flows to influence congestion, but Alderete said that COI transfer capability during the MLK weekend was fully available and used in the day-ahead market for the share of the line operated by the ISO.

"Here is the simple fact for these critical days of the MLK weekend: There were no derates on the Malin intertie. The full capacity of the intertie was used and made available in the day-ahead market," Alderete said. "I can see how this myth could have been created out of confusion and maybe not appreciating the time frames of the event, and I can clarify that, specific to the MLK weekend, there were indeed weather-related forced outages in the BPA area, and those eventually resulted in derates to the path."

But the forced outages and derates affected only the real-time market, Alderete said.

Delving further into the weeds, Alderete contested the "myth" that CAISO "charged excessive prices to exports flowing to the Northwest, reiterating that congestion prices on Malin were set by export bids, which reflected the price exports were willing to pay to flow.

Alderete also provided additional color to the process of allocating congestion, saying that while a fifth "myth" holds that parties outside the ISO market have a right to day-ahead congestion revenue, the fact is that it's sourced "only from re-dispatch of participating resources in the ISO market, including exports."

CAISO doesn't have access to resources outside of its market, such as those north of Malin, to re-dispatch and alleviate congestion on ISO constraints, meaning that the sixth "myth," that CAISO collected congestion rents on all Malin capability, is incorrect.

"Congestion on Malin is only collected for the capacity made available to the market, lower than the full capability," the presentation read. "The ISO operates two-thirds of COI capability; only that portion will be managed in the ISO market with Malin intertie."

The final and "biggest myth" that caused significant concern among some Western entities was that CAISO kept all $100 million of day-ahead CRRs collected on the Malin intertie. But Alderete emphasized that CRRs are given to their holders and that any surplus is allocated to demand and exports. Because the Malin capacity wasn't fully exhausted in the CRR release, over $50 million in surplus congestion rents were allocated to measured demand.

Alderete's presentation came after a group of Markets+ supporters released a series of "issue alerts" favorably comparing the SPP day-ahead market with the EDAM. The latest alert, focused on market seams, covered the congestion rent subject. (See *Markets+ 'Equitable' Solution to Seams Issues, Backers Say*.)

Alderete told *RTO Insider* in an email that the ISO will continue the conversation about the issue at the RIF's October meeting, for which an exact date has not yet been announced. ■

ERCOT News

Flores, Heeg Named to Lead ERCOT Board

Bill Flores during an ERCOT board meeting. | © *RTO Insider LLC*

ERCOT's Board Selection Committee has designated Bill Flores and Peggy Heeg as the Board of Directors' chair and vice chair. Previously the board's vice chair, Flores replaces Paul Foster, who announced he was stepping down as chair in June. Flores has been serving as interim chair since then.

Flores, Heeg and Foster were among the first independent directors named to the board after legislation broke up the previous hybrid structure — a mix of independent members and market participant representatives — in the wake of the disastrous February 2021 winter storm. Board members now are required to be Texas residents with executive-level experience in finance, business, engineering, trading, risk management, law or electric market design.

Thomas Gleeson, chair of the Public Utility Commission that oversees ERCOT, said in a Sept. 30 statement that Flores and Heeg are "outstanding choices."

"Both joined ERCOT at a pivotal time and have worked tirelessly to ensure grid reliability," he said. "I look forward to continuing our work to strengthen grid reliability."

Flores is a corporate governance professional who represented Texas' 17th congressional district from 2011 to 2021.

The Selection Committee also announced second three-year terms for five board directors, including Flores and Heeg. Carlos Aguilar, John Swainson and Julie England will begin their terms by Jan. 1. ■

— Tom Kleckner

Texas PUC Approves Permian Reliability Plan

ERCOT Proposes 345-kV, EHV Import Paths into Oil Region

By Tom Kleckner

Texas regulators have approved ERCOT's reliability plan for the petroleum-rich Permian Basin that could rely on the state's first use of 765-kV transmission facilities.

The *plan* includes both 765- and 345-kV infrastructure to support the region's current and future power needs and new and upgraded local projects, as well as new import paths that will bring additional power to the region. The Public Utility Commission approved the plan during its Sept. 26 open meeting (*55718*).

Commissioner Lori Cobos, a native West Texan who has taken the lead on the proceeding, filed a *memo* recommending the PUC authorize the region's transmission service providers (TSPs) to begin preparing applications for infrastructure along eight import paths into the basin to serve its projected load in 2030.

She said that would preserve the plan's "optionality" after recent *ERCOT analysis* indicated that installing transmission elements capable of either voltage would require additional months of engineering studies. The grid operator had initially hoped to use interchangeable import paths capable of both 345- and 765-kV lines.

"The whole goal remains the same in terms of preserving optionality at this time on the import paths into the Permian Basin region, so that ERCOT and the commission can continue their evaluation of EHV [extra high voltage], primarily 765-kV transmission lines," Cobos said.

She said directing ERCOT to work with the TSPs on the import paths that would be needed for 2030 will provide certainty by prioritizing the applications for certificates of convenience and necessity. At the same time, she said, the grid operator and PUC will be able to continue their evaluation of EHV transmission and determine the import paths so CCNs can be filed. ERCOT has designated five of the import paths as 345-kV and the other three as 765-kV.

Cobos set a date certain of May 1, 2025, for the commission to approve the 765-kV lines. Should the PUC decide not to move forward with the EHV buildout, the 345-kV import paths would be considered approved and the TSPs allowed to file their CCNs, she said.

Texas PUC Commissioner Lori Cobos explains her recommendation on the Permian Basin reliability plan. | *Admin Monitor*

The grid operator has projected oil and gas load peaking at nearly 15 GW by 2038 and an additional 12 GW of data center and other non-petroleum load by 2030. Based on those projections, ERCOT has said building the transmission facilities to meet that load could cost more than $15 billion. It is *currently considering* 4,481 miles of 765-kV lines and 20 associated substations. (See *EHV Tx Lines Coming into Focus for ERCOT*.)

"If you look at some of the cost estimates for building out a 765 backbone throughout the state, it's going to cost a lot of money just because of how large the state is," PUC Chair Thomas Gleeson said in a keynote address Sept. 25 at Infocast's Texas Clean Energy summit in Houston. "I think it's important for us, for ERCOT, for the transmission and distribution utilities to not only show that cost, but also speak intelligently and clearly about what the benefits of all these transmission upgrades are, because you don't get all the economic development here unless you're willing to invest in the infrastructure."

"It's going to be a tremendous boon for our state in so many ways," Cobos said of the plan.

Commissioner Jimmy Glotfelty continued to push for EHV lines, saying he was ready "to do 765."

"I continue to believe that the deeper we get involved in the process and the deeper ERCOT's involved in the process, the longer it's going to take," he said. "If we continually kick things to ERCOT, I fear that there are things that we can get tripped up on and slow down, and that makes me fearful of the default back to 345. I don't think that's the right default. The amount of congestion that we see in West Texas that this could help solve is somewhere between $100 [million] and $300 million a year. That obviously would pay for these lines, not even considering the economic development in the Permian."

PUC to Review 4CP Program

The commission signaled it is ready to discuss doing away with ERCOT's *Four Coincident Peak (4CP) program*, a demand charge that alerts industrial users to high energy costs during peak demand periods and was intended to allocate transmission costs to the drivers of new facilities (*34677*).

Staff said they were "supportive of opening the dialogue about 4CP." They noted the program has been in existence for more than two decades and *suggested* it can be revised to maintain an ERCOT-wide rate based on demand but still "modify the allocation method away from 4CP."

"I think it's definitely time to talk about it and be proactive about ... reviewing that decision that was made 20 years ago and make sure that it remains the correct one. And if not, then what should we be moving to?" Barksdale English, the PUC's deputy executive director, told the commissioners, while also noting there is not "uniform [staff] opinion" on the program.

The grid operator's Independent Market Monitor has recommended since 2015 in its annual market reports that 4CP be changed to better reflect the true drivers for new transmission. It said again in its *latest report* that the current method "does not apply transmission costs equitably to all loads."

Under 4CP, pricing signals are sent to industrial customers who might want to avoid peak transmission costs. ERCOT looks at the peak demand over four 15-minute intervals from each of the summer months — June, July, August and September — and then assigns transmission costs to transmission and distribution service providers (TDSPs) based on their share of total peak load.

The TDSPs recover their transmission-cost obligations through wires charges on all loads. Staff use those obligations to calculate 4CP demand charges for industrial customers based on the facilities' peak demand during the four 15-minute windows. The 4CP charges are then distributed over a 12-month period as part of the facility's bill over the next year.

"Customer demand during the peak summer hours is no longer the main driver of new transmission in ERCOT today," the Monitor said in its 2023 State of the Market report. "Decisions to build transmission are based on transmission congestion patterns throughout the year and an analysis of whether generation can be delivered to serve customers reliably."

Cobos agreed the discussion on 4CP is worth having, given the need to build out the grid to meet demand that continues to increase.

"We have to make sure that we start proactively looking at how we are allocating costs and developing cost allocation and rate design in our rate cases now," she said. "I'm concerned that all of the massive transmission infrastructure that we're looking at as a future will be primarily allocated to the small business and residential consumers, so I think that the 4CP discussion needs to start as soon as possible."

Staff made the suggestion as part of a response to the IMM's latest market report. They gave an opinion (support, neutral or disagree) on each of the Monitor's 16 recommendations from the current and previous reports.

The PUC also approved a *proposed rulemaking* that establishes procedures for utilities outside ERCOT's footprint to apply for grants from the *Texas Energy Fund*. The TEF includes an Outside ERCOT Grant Program that will award grants for the modernization of infrastructure, weatherization, reliability and resilience enhancements, and vegetation management for facilities outside ERCOT.

The commission will accept comments on the proposal through Nov. 7 (*57004*). ■

ISO-NE News

With FERC Inaction, ISO-NE Delays Order 2023 Implementation

Transmission Committee also Receives Briefing on Order 1920

By Jon Lamson

ISO-NE has suspended its implementation of Order 2023 compliance and rescinded transitional cluster study agreements because of FERC's lack of action on its compliance filing, Manager of Resource Qualification Alex Rost told the NEPOOL Transmission Committee on Sept. 25.

The RTO submitted its compliance to the commission in May, requesting an Aug. 12 effective date (*ER24-2009*). However, FERC has yet to rule on the proposal, throwing a wrench in ISO-NE's implementation timeline.

Order 2023 requires grid operators to transition from first-come, first-served serial interconnection process to a first-ready, first-served process using cluster studies to evaluate multiple projects at a time. (See *FERC Updates Interconnection Queue Process with Order 2023* and *NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance*.)

Hoping to stick to its proposed timeline, ISO-NE issued transitional cluster study agreements to eligible interconnection customers on Aug. 12. The RTO was planning to start work on the transitional cluster study on Nov. 11 and provide a final report on the cluster on Aug. 7, 2025.

ISO-NE wrote in a Sept. 23 *memo* that it is rescinding the study agreements because of FERC's inaction. The RTO had *announced* that it was pausing its work on Order 2023 compliance in early September.

A delay of the transitional cluster would also affect the timing of the first standard cluster study, with the first activities for this subsequent process set to begin immediately after the end of the transitional process.

FERC's delay also has dealt a blow to ISO-NE's plan to enable late-stage projects to participate in reconfiguration auctions (RAs). Currently, resources need to gain a capacity supply obligation and associated capacity interconnection rights in a Forward Capacity Auction (FCA) in order to participate in RAs, but ISO-NE has delayed its next FCA by three years to make significant changes to its capacity auction process. (See *ISO-NE Outlines 'Straw Scope' of Capacity Market Reforms*.)

ISO-NE has proposed a "Transitional CNR [Capacity Network Resource] Group Study" to provide a "one-time opportunity for late-stage interconnections to achieve capacity interconnection service through the 2024 interim reconfiguration auction qualification activities."

However, the RTO wrote in its compliance filing that the Aug. 12 effective date for the order is necessary to "align the Order No. 2023 transition process" with the RA qualification timeline, noting that "a delayed order in this proceeding would result in these interconnection customers needing to wait until a later auction cycle, which would not only be detrimental to those interconnection customers, but would result in a less robust auction."

ISO-NE determined in early September that it "will no longer proceed with the Transitional CNR Group Study proposed in the compliance proposal."

The RTO is planning to proceed with interconnection studies under its existing tariff rules going forward.

"When FERC issues an order addressing the compliance proposal, the ISO will assess how to move forward on implementation based on the timing and content of the order," ISO-NE spokesperson Mary Cate Colapietro said. "We can't speculate until we actually receive the order."

Transmission Planning

Also at the TC, Brent Oberlin of ISO-NE *provided a comparison* of ISO-NE's new Longer-Term Transmission Planning (LTTP) process and the requirements of FERC Order 1920. (See *FERC Approves New Pathway for New England Transmission Projects*.)

In general, the Order 1920 process is broader than the LTTP, requiring long-term planning to consider future interconnection needs and how asset condition projects could be right-sized to reduce overall costs. The LTTP also includes more state discretion around when the planning process is initiated, the assumptions used in studies and which projects are selected.

In future meetings of the TC, Oberlin said ISO-NE "plans on breaking down the order into manageable pieces for stakeholder review and discussion," detailing what new processes will need to be created, and what existing processes will need to be modified, to comply with the order.

He added that ISO-NE will develop changes to its interregional planning procedures separately from its regional planning procedures. The RTO will begin discussing compliance changes in more detail at the TC's meeting in October, ultimately aiming for a Participants Committee vote in May 2025. The deadline for regional compliance filings is June 12, 2025, and the deadline for interregional compliance filings is Aug. 12, 2025. ■

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MISO News

RTOs Continue Glacial Pace at Replacing 'Freeze Date'

2004 Reference Point Still Being Used in Flowgate Management

By Amanda Durish Cook

MISO, PJM and SPP have been failing for years to find a suitable replacement for a 20-year-old system reference they use to portion out flow rights on their system — and they don't appear to be any closer to a solution.

The three RTOs establish market flows and firm entitlements on jointly managed flowgates using a snapshot of the neighboring systems in 2004 before their seams existed; they refer to it as their "freeze date." So far, the three grid operators haven't found a substitute for using a static list of generation resources and transmission service requests that remains unchanged from when Usher's "Yeah!" topped music charts.

MISO Independent Market Monitor David Patton has expressed frustration with the three not being able to land on a more suitable system representation.

"The problem is we're so far beyond the freeze date that it's untenable," Patton told the MISO Board of Directors' Markets Committee on Sept. 17.

Instead of adhering to their tariffs and joint operating agreements, the RTOs have resorted to patchwork processes to oversee flow entitlements, he said. The "impossibly stale" depiction of the systems is leading the grid operators to violate their rules, he argued.

Patton indicated to the committee that talks between the three RTOs to find a substitute for the freeze date recently broke down.

"MISO's put the most reasonable negotiations on the table. MISO is not the problem here," Patton said, avoiding naming any party who might have been difficult in negotiations. "I want to alert you that something needs to be done about this. … They've been negotiating for a decade."

MISO Monitor David Patton | © *RTO Insider LLC*

Why This Matters

The failure to resolve the flowgate issue is emblematic of how elusive solutions can be to seams issues, and could lead the grid operators to violate their rules.

Patton implied that if MISO had agreed to some terms contained in the proposed agreement, it would have resulted in unreasonable outcomes for its members.

WEC Energy Group's Chris Plante characterized RTOs' inability to replace the freeze date as one of the seams issues that "seems like low-hanging fruit that refuses to fall off the tree."

"We've been trying to resolve that issue for more than a decade," Plante said during a meeting of MISO's Advisory Committee on Sept. 18. He said the issue is emblematic of how elusive solutions to seams issues can be.

SPP Manager of Interregional Strategy and Engagement Clint Savoy confirmed before the RTO's Seams Advisory Group on Sept. 11 that a comprehensive freeze date solution was voted down. He said the initiative is now being reworked among the RTOs for future evaluation.

PJM also said the RTOs' Congestion Management Process Working Group is actively working on an alternative solution. The RTO said it believes an "updated model" is needed to "better align current congestion patterns with planning processes while accounting for centralized dispatch." The current freeze date takes into account "generation dispatch in the historic control areas rather than the current centralized dispatch approaches in the participating markets," spokesperson Jeffrey Shields said in a statement.

PJM did not respond to *RTO Insider*'s request for comment on where solution discussions currently stand and if it viewed any party as making unreasonable demands.

MISO acknowledged that using the April 1, 2004, date to determine firm rights on flowgates based on pre-market flows is suboptimal.

"RTO systems have changed considerably over the last 20 years, making it more of a challenge for MISO to balance the needs of our system as well as our neighboring grid operators. MISO recognizes the inherent errors that occur with mapping a 2024 market system back to the historic 2004 framework," spokesperson Brandon Morris said in a statement.

MISO said it has proposed a solution "based on approved industry standards," which is being discussed, though there is no timeline on when it could be implemented.

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Savoy said SPP "remains committed to developing a solution that will facilitate equity, transparency and mutually beneficial outcomes for all involved, including the customers and facilities that we represent as the RTO."

However, Savoy added that replacing the freeze date is a complex endeavor "involving numerous parties with diverse interests."

"We're grateful for our partnerships with MISO, PJM and the rest of the Congestion Management Process operating entities, and for the engagement of many of our stakeholders through our Seams Advisory Group. We look forward to sharing more about our approach to this matter in the upcoming joint SPP-MISO Common Seams Initiative meeting in November," Savoy said in a statement.

For years, the RTOs kicked around a proposed solution that would have divided flowgate rights by age, with priority given to network resources from 2004 and earlier, followed by network resources after 2004, then transfers between local balancing authorities to make up shortages on a *pro rata* basis, and finally RTO load served by RTO dispatch. The solution would have increased transfer rights for markets over nonmarket entities, and the seams might have experienced a reduction in nonfirm transfer availability and increased curtailments of nonfirm transfers.

MISO and PJM had hoped to implement this flowgate merit order by mid-2022. MISO in 2021 said the sticking point was the firm flow limits calculations with nonmarket entities, who said a large increase of firm rights for market entities could increase the need for transmission loading relief. At the time, MISO reported that nonmarket entities party to the RTOs' Congestion Management Process were still resistant to changes that would affect firm flows in the region. (See *MISO, PJM Eye Nov. Freeze Date Defrost*.) The nonmarket neighbors remain concerned that an increase in firm limits for post-2004 network resources could lead to more curtailments for those outside the markets.

From MISO and PJM's Joint and Common Market meetings in the last few years, the RTOs appeared to be ready to use a new model in their respective Energy Management Systems. Last year, the two said they were readying a mock analysis tool to test scenarios.

The RTOs also completed a white paper on the freeze date in 2021; at the time, it was a diplomatic turnaround from late 2019, when staff said they were mulling filing a proposed solution that would all but certainly be opposed by nonmarket parties and leave it up to FERC's discretion. ■

MISO Affirms Commitment to $21.8B Long-range Tx Plan in Final Workshops

By Amanda Durish Cook

MISO staff are resolute that a collection of 24 proposed, mostly 765-kV projects totaling $21.8 billion is a "least-regrets" avenue to achieving members' resource plans, despite misgivings from some members.

MISO held a two-day workshop Sept. 24-25 to emphasize the importance of building the second long-range transmission plan (LRTP) portfolio in MISO Midwest. Planning Coordination and Strategy Advisor Ashleigh Moore characterized the workshop as a "two-day finale" for the second LRTP portfolio; MISO will present the portfolio to its Board of Directors in December for consideration.

Director of Cost Allocation and Competitive Transmission Jeremiah Doner said after "fine-tuning" electrical facilities and substation design, the portfolio cost now stands at $21.8 billion, up from the previous $21 billion estimate. Doner said MISO anticipates the projects would go into service in about 10 years.

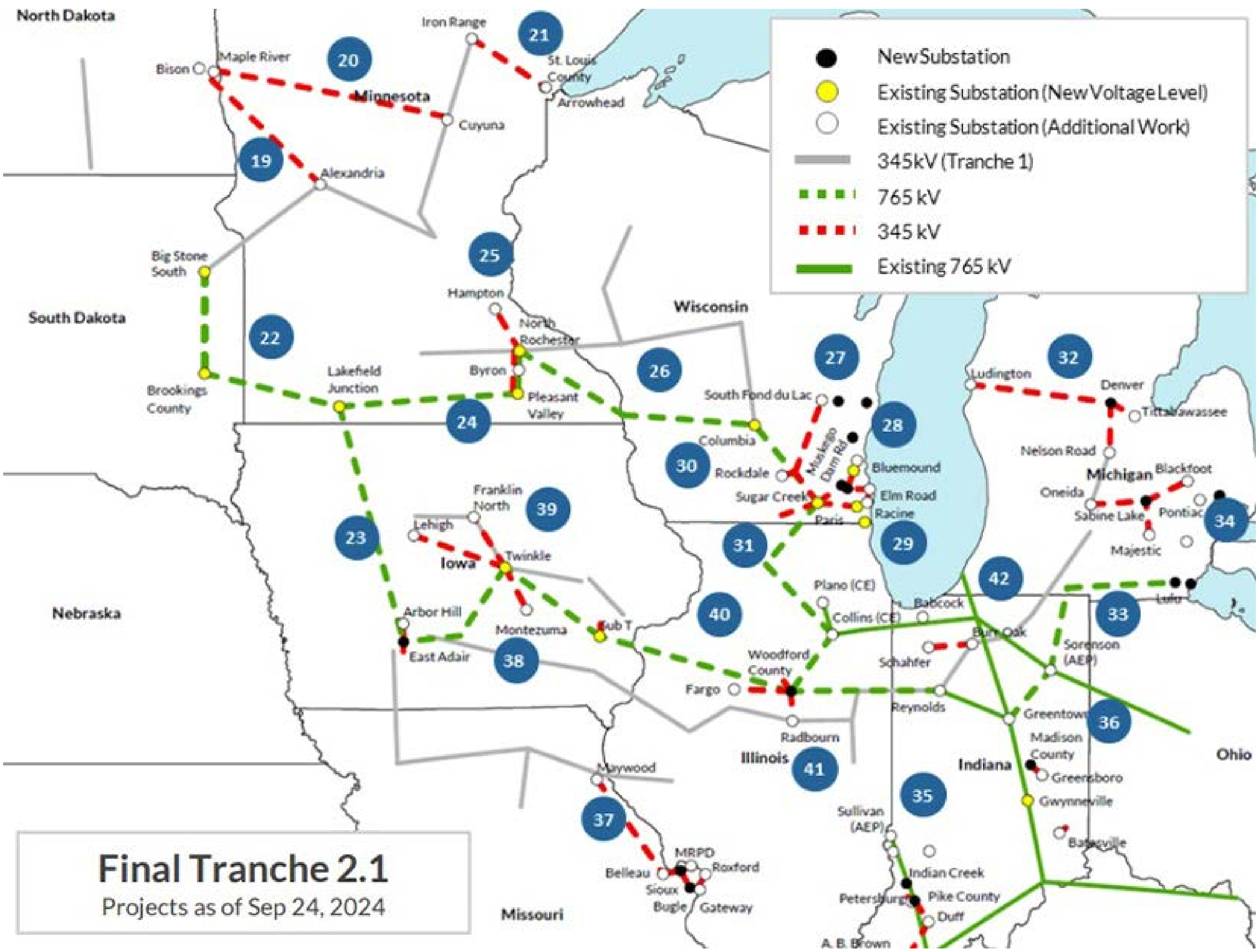
With the increase in cost, MISO has slightly scaled back its benefits-to-cost ratios. The RTO now anticipates a benefit-to-cost ratio of between 1.8:1 and 3.5:1 over the first 20 years of the projects' lives through reliability improvements, production costs, new capacity that won't have to be built and environmental benefits. (See *MISO Says 2nd Long-range Tx Plan to Cost $21B, Deliver Double in Benefits*.)

Doner said at a minimum, each cost allocation zone would see a 1.2:1 benefit-to-cost ratio under MISO's most conservative analysis. Cost allocation zones in Lower Michigan, Illinois and Missouri would experience the most modest benefits, MISO said, at 1.2-1.3 in its conservative estimate. Cost Allocation Zone 2 in Wisconsin and Michigan's Upper Peninsula would see the most benefit, at a minimum of 2.8:1 and a maximum of 5.5:1 over 20 years.

MISO said the portfolio would free up access to regional resources, reducing the need for

What's Next

In December, MISO will present this $21.8 billion version of its long-range transmission plan portfolio to its Board of Directors for consideration.



Routes of MISO's final LRTP II portfolio in dotted lines | *MISO*

MISO News

almost 28 GW in hypothetical future resource additions and delivering $16.3 billion over 20 years in avoided capacity.

MISO also estimates LRTP II would support almost 116 GW in new resources across MISO Midwest. Local Resource Zone 1 in Minnesota, the Dakotas and Wisconsin and Local Resource Zone 3 in Iowa would see the most resource expansion because of LRTP II, at about 32 GW and 27 GW, respectively.

Lingering Disagreement over Benefits

Bill Booth, consultant to the Mississippi Public Service Commission, asked what would happen if the resources MISO anticipates aren't built, particularly the 29 GW of undefined but flexible resources MISO identified as necessary and assumed in its modeling.

North Dakota Public Service Commission staffer Adam Renfandt said he wondered if benefits would dim if MISO tried siting resources in its hypothetical future more eastward, nearer load centers where locational marginal prices are higher. He also said he worried MISO might hinder new technologies by assuming a conventional mix of resources 20 years out.

Doner said the second LRTP's design is flexible enough to support a multitude of directions in resource planning. He said MISO isn't building specific routes for any prospective facilities. But he said MISO nevertheless will need a fleet that's spread across the region to support local clearing requirements of MISO's resource adequacy zones.

"We're trying to have a regional backbone plan to support energy transfers. What resources are built is ultimately up to members," Director of Economic and Policy Planning Christina Drake said.

Executive Director of Transmission Planning Laura Rauch said MISO isn't trying to send signals on where to build resources. She stressed that MISO needs regional transmission expansion, and generation will continue to interconnect to an expanded system via individual network upgrades.

"Resource adequacy and transmission planning in aggregate are in the same house. … We aren't building for specific units as much as we are regional needs," Rauch said. She added that the LRTP is planned intentionally on a long-term horizon and allows for resource planning to "continue to evolve and change."

WPPI Energy's Steve Leovy said he continued to have concerns that MISO's reliability benefit assumptions are overstated. He said absent the portfolio, MISO members would tender reliability projects incrementally under annual transmission expansion plans to maintain NERC standards.

Stakeholder doubts over the realistic chances of MISO's assumed future fleet and MISO's reliability value projections mirror those made by MISO's Independent Market Monitor. (See *MISO, Monitor at Stalemate over Need for $21B Long-range Tx Plan*.)

"We're not assuming that these issues would go unaddressed and that we would experience future load shed," Doner said. However, he said MISO cannot ignore the fact that the LRTP portfolio would resolve "hundreds" of reliability issues and subdue substantial risks.

"There is a value in proactively planning to mitigate these risks … rather than chasing what's happening year after year," MISO planner Joe Reddoch said. "There's obviously value, or we wouldn't be doing it."

WEC Energy Group's Chris Plante said MISO shouldn't measure reliability benefits of the LRTP through expected unserved energy, but through the annual reliability projects MISO would avoid. MISO planners have said it would be extremely difficult to predict the multiple reliability projects that might be avoided.

"It seems like this metric is destined for a lot of time on the witness stand," Plante said, hinting that the metric will be contested.

Doner countered that MISO is using a "very dated" $3,500/MWh value of lost load to gauge reliability impacts, making for a conservative view of reliability benefits.

Support for LRTP II

American Transmission Co.'s Bob McKee said he "really wanted to push back" on the notion that transmission owners should continue to address reliability risks individually. He said MISO's purpose is to examine its system and prescribe regional plans.

"If you step back and look back at [the directives of [FERC's] Order 1920 and even Order 890 and Order 1000, this is exactly what MISO is doing. We've been litigating these benefit metrics for a year now. MISO's metrics are pretty much in lockstep in what FERC is directing other RTOs to do," McKee argued.

ITC's Brian Drumm also said it's appropriate for MISO to gauge reliability value, especially considering the "wave" of generation retirements and extreme weather conditions bearing down on the footprint.

Drumm said the $14.8 billion reliability value MISO has placed on LRTP II is "incredibly conservative."

"I mean, that number could be $100 billion, $200 billion. And when you're talking about human lives, I don't even want to place a number on that," he said.

Great River Energy's Jared Alholinna said his utility believes MISO has done a "remarkable" job analyzing its portfolio. He added that the portfolio most likely will demonstrate the most value in the times that are the hardest to predict, like punishing winter storms.

Alholinna said MISO's overall, minimum 1.8:1 ratio probably is understated because the footprint's fleet transition is occurring faster than the RTO's 20-year scenario predicts.

Xcel Energy's Madeleine Balchan said while it's possible for Xcel's Northern States Power to build to meet needs on its own, that's not why the utility joined MISO.

Kavita Maini, a consultant representing MISO industrial customers, said she wasn't suggesting MISO shouldn't engage in regional planning; however, she said stakeholders are disturbed by some "problematic" and "overexaggerated" benefits MISO is crediting to the portfolio.

Rauch said the second LRTP portfolio is a culmination of more than 40,000 hours of labor from MISO staff, expertise from outside consultants, about 300 meetings and numerous discussions with stakeholders.

Rauch said generally, members reacted to the draft LRTP II map released months ago with, "You all need to go bigger," which was a "shock" to MISO planners. She said MISO evaluated 97 stakeholder submissions for additional projects, eventually landing on seven and creating an even "stronger portfolio at the end of the day."

Rauch said the final LRTP II is an exceptionally valuable portfolio that creates a reliable, "765-kV transmission backbone to support high system transfers under a new resource plan" that members have charted.

"We've come to the end of a very, very long journey," Vice President of System Planning Aubrey Johnson summed up. "I think we're better off because of the dialogue. … We've often said, 'this is hard,' and this should be hard."

Johnson said at the end of the day, MISO has heard stakeholder objections over the value of LRTP II, investigated them and disagreed with them. ■

MISO News

MISO Dips Toes into Potential New Resource Adequacy Standard; States Demand Key Role

By Amanda Durish Cook

MISO is questioning whether its current loss of load standard remains the best method for establishing resource adequacy and initiated a daylong meeting with industry experts and regulators to probe alternatives.

"The one-day-in-10 years resource adequacy criterion has a number of limitations, and many industry experts recommend change," MISO Director of Strategic Initiatives and Assessments Jordan Bakke said in opening the Sept. 26 special teleconference.

Bakke said MISO is exploring the concept of a more comprehensive resource adequacy benchmark. He said MISO needed a "natural, long-form discussion about what's needed going forward."

The grid operator has hinted in public meetings that it might turn to conditional value at risk, loss of load hours or expected unserved energy as possible new measures of resource adequacy risk.

Bakke said any potential solution MISO might put forward will be developed in partnership with its regulatory and stakeholder community. He emphasized that MISO doesn't have a preferred approach, timeline or proposed tariff revisions. He said MISO plans to draft a road map for evaluating new standards.

"We don't know when and if something will change," Bakke said.

Derek Stenclik, representing Energy Systems Integration Group, said he thought MISO is doing the right thing by raising the possibility for change among its stakeholder community.

He said as far as "setting the threshold for an acceptable level of risk," MISO needs to land on something transparent and economic.

Stenclik said MISO should begin by quantifying the size, frequency and duration of outages.

Why This Matters

State regulators demand a voice in developing resource adequacy standards because of the "political reality" that they receive calls from customers and governors when outages occur.

MISO also should incorporate a "suite of reliability metrics," he said, putting more emphasis on expected unserved energy. He said MISO's move to an energy-limited system heavy on renewables necessitates multiple metrics.

He said, for example, MISO could use a combination of its current 0.1 days/year loss of load expectation in addition to a 0.3 hours/year loss of load hours analysis and a 1,000 MWh/year expected unserved energy, as PJM has considered.

"We don't have to have just one," Stenclik said.

Zach Ming, of energy consultancy E3, pointed out that ERCOT recently announced it will use a three-pronged reliability standard that marries the usual one-day-in-10-years standard with a 12-hour limit on outage duration and a 19-GW limit on the magnitude of outages.

EPRI's Aidan Tuohy also recommended reducing reliance on a single measurement.

"Adequacy exists on a spectrum and should not be a binary choice," he said.

Tuohy said while LOLE conveys the expected number of days when loss of load occurs, it doesn't capture the magnitude of the loss. MISO likely needs a more detailed look, Tuohy said, where it considers outlier events, assessing risk by month or hour of day and describing involuntary load-shedding events.

"More high-impact, low-probability events" are on the way, Tuohy predicted.

Meanwhile, the Organization of MISO States is positioning itself to have a voice in MISO resource adequacy criteria.

OMS Executive Director Tricia DeBleeckere said regulators have a collective awareness that the standards need to shift. She reminded attendees that states have resource adequacy jurisdiction and want a "key seat at the table" when designing new criteria.

DeBleeckere said the 0.1 days/year standard has been in use so long that changing it will be a "huge initiative."

"A big thing for OMS is who is going to be making the call when these changes are made," she said, adding that OMS's support of MISO's road map will hinge on how much MISO includes state regulatory standpoints.

DeBleeckere said though no one can develop a perfect reliability standard, a replacement should be data-driven and not "overcorrect" acceptable levels of risk.

Concept art for Alliant Energy's planned, CO_2 long-duration Columbia Energy Storage Project in Wisconsin. Alliant hopes to have the project running in 2027. | *Alliant Energy*

OMS President and Iowa regulator Josh Byrnes has said state regulators will work on a guiding principles document on resource adequacy standards. It will focus on ensuring states' leadership on a new reliability standard and allow enough time to understand what's expected and to meet whatever threshold is set.

At a Sept. 12 Organization of MISO States board meeting, North Dakota Public Service Commissioner Julie Fedorchak said states should do more to steer discussions on resource adequacy benchmarks.

"It feels like OMS should enter this area … and take a more leadership role in this resource adequacy metrics discussion," Fedorchak told other state regulatory staff.

Byrnes said MISO "probably needs to do a better job" engaging state regulators if it suggests crafting a new resource adequacy target.

Michigan Public Service Commission Chair Dan Scripps said states "absolutely" should be at the center of those discussions because the "political reality" is state regulators receive calls from customers and governors when outages occur.

"No one wants to hear that, 'Oh, that was our one event in 10 years,'" Scripps said.

Bill Booth, a consultant to the Mississippi Public Service Commission, said he thought NERC, not MISO or state commissions, should establish a resource adequacy standard.

"Do you want to have a MISO standard and a PJM standard and an SPP standard?" Booth asked rhetorically.

MISO again will discuss reliability standards at its Oct. 9 Resource Adequacy Subcommittee meeting. ■

MISO News

MISO and TVA to Enter Agreement on Emergency Purchases

By Amanda Durish Cook

| Tennessee Valley Authority

INDIANAPOLIS — MISO and the Tennessee Valley Authority say they are poised to strike an agreement on emergency energy transactions after months of RTO leadership complaining that TVA doesn't return the favor of energy transfers in times of need.

The two have confirmed they will file an agreement with FERC to codify emergency purchases between the federal utility and the RTO.

According to TVA, the agreement is between MISO and two authorized TVA purchaser utilities. It will allow MISO to "act on their behalf to purchase power from TVA during certain emergency conditions, consistent with TVA's obligations under the TVA Act," TVA spokesperson Scott Fiedler said.

MISO said the draft agreement is not publicly available yet.

"We are focused on establishing a process for the provision of emergency energy during emergency events to support reliability on our respective systems, as well as provide terms for compensation," MISO spokesperson Brandon Morris said. MISO did not comment on the degree it expects emergency transfers from TVA to benefit its operations.

During MISO Board Week in Indianapolis on Sept. 17, Vice President of System Planning Aubrey Johnson said in early October, TVA operators will visit MISO's control room in Little Rock, Ark., to perform desktop exercises to familiarize themselves with MISO operations.

Johnson said he and other MISO leaders in turn will travel to Chattanooga, Tenn., to celebrate the emergency energy agreement the two should have completed by then.

The agreement is meant to forge a more symbiotic relationship between the two. Prior to the agreement, MISO leadership expressed disappointment in TVA because although MISO has assisted TVA with exports — especially during the late December 2022 winter storm — TVA as a rule didn't flow power to MISO. (See "JOAs with Neighboring Systems?" *MISO Winter Recap Centers on December Emergency*.)

"TVA is an interesting animal in the Eastern Interconnect. They are limited in who they can sell power to," Executive Director of Market Operations J.T. Smith said when the agreement was in the works in spring. ■

MISO News

MISO Tries to Win over Stakeholders on New LMR Capacity Accreditation

By Amanda Durish Cook

INDIANAPOLIS — Stakeholders appear wary of MISO's proposed, availability-based accreditation method that it plans to file with FERC by the end of the year for the RTO's approximately 12 GW of load-modifying resources (LMRs).

MISO wants to accredit LMRs based on past performance levels by the 2028/29 planning year. It would split them into two categories — those that can respond in 30 minutes or less and those that can't — and accredit them accordingly. (See *MISO Proposes to Split LMR Participation, Accreditation into Fast/Slow Groups*.)

The LMR Type II category would have a maximum response time of 30 minutes and presumed availability for all maximum generation emergency step 2 events. An LMR Type I class would carry a maximum response time of six hours and be called up earlier, when MISO declares a maximum generation alert. The RTO has long said it needs to be able to access LMRs outside of actual emergency declarations.

MISO plans to use a similar accreditation to its proposed, availability-based method for its more traditional generation resources. However, to measure demand response, MISO said it would use backward-looking meter data from hours when capacity advisory declarations are in place to accredit resources. The RTO plans to draw on data from a minimum of 65 historical hours per season over the past year and will give more weight in accreditation to performance during hours when capacity advisories escalate into maximum generation events, alerts or warnings.

The RTO would cap accreditation at an LMR's maximum stated capability during registration and reduce accreditation when LMR owners submit inaccurate availability information. Currently, MISO does not tie the accuracy of LMR availability data to accreditation values.

During a Sept. 23 stakeholder workshop, WPPI Energy's Steve Leovy said he was concerned that the sample size of hours during which capacity advisories are in effect is too small to be a good indicator of LMR performance. He said MISO's capacity advisories seem too infrequent to use as a basis for accreditation.

Other stakeholders said one year's worth of data might not be adequate to create a stable, year-to-year accreditation. They pointed out that a particularly heat wave-laden or mild summer could skew the numbers, especially for those LMRs tied to air conditioning loads.

MISO said it will turn to other previous years as needed if the past season doesn't have the requisite 65 hours. Joshua Schabla, an economist in MISO's market design group, also said the RTO intends to account for temperature-based adjustments in the accreditation.

MISO said it needs the split classification because its long-lead-time LMRs are incapable of deploying in the time it takes for emergencies to materialize. The RTO experiences maximum generation alerts most frequently, with 20 occurring between 2020 and 2023, compared to 10 warnings, four maximum generation emergency step 1 events and five maximum generation emergency step 2 events in the same time frame.

"Resources that deploy earlier can be used effectively, even if the event escalates quickly," Schabla said. "In practice, we need these long-lead resources to be called up during maximum generation alerts."

MidAmerican Energy's Dennis Kimm asked for more nuance beyond the two capability classes. He said MidAmerican has several LMRs that can respond within two hours but none that are ready within 30 minutes. Leovy advocated for the 30-minute requirement to be bumped up to a two-hour response time.

Schabla said LMRs are more highly accredited than any other in its resource stack, yet the LMRs are less available than any other in its resource stack. "There's a fundamental disconnect here."

Though MISO officially has about 12 GW of LMRs, staff have said MISO receives only about 7 GW to 8 GW worth of movement during emergencies.

Schabla said the gap does not necessarily mean LMR owners are doing anything wrong or gaming the system. He said it likely represents a "misalignment between what is accredited and what is available."

In August, Reliability Subcommittee Chair Ray McCausland called the LMR response rate "eye-opening" and "a huge concern."

The RTO currently has an "inability to access many of the megawatts available in a useful time frame," Executive Director of Market and Grid Strategy Zak Joundi said at MISO Board Week last month. The inability is magnified by the fact that MISO currently must declare an emergency before gaining access to load adjustments, he said.

"We want to make sure [that] if someone is clearing the Planning Resource Auction, we can access those resources and they can deliver," Joundi said.

Joundi acknowledged to board members that stakeholders were dissatisfied with MISO's timeline.

"Ultimately, we want to make sure the rules we file at FERC are effective," Joundi said. "Our goal is not necessarily to discourage the megawatts that are important. We want to make sure there are megawatts that we can leverage under the circumstances that we do."

MISO will again discuss LMR accreditation with stakeholders at its Oct. 9 Resource Adequacy Subcommittee meeting. ■

MISO control room | *MISO*

NYISO News

Brattle Paper Weighs Pros and Cons of Utility-owned Generation in NY

By James Downing

Allowing utilities to own generation again in New York state could speed up their deployment, according to a Brattle Group *white paper* prepared for Consolidated Edison released Sept. 24.

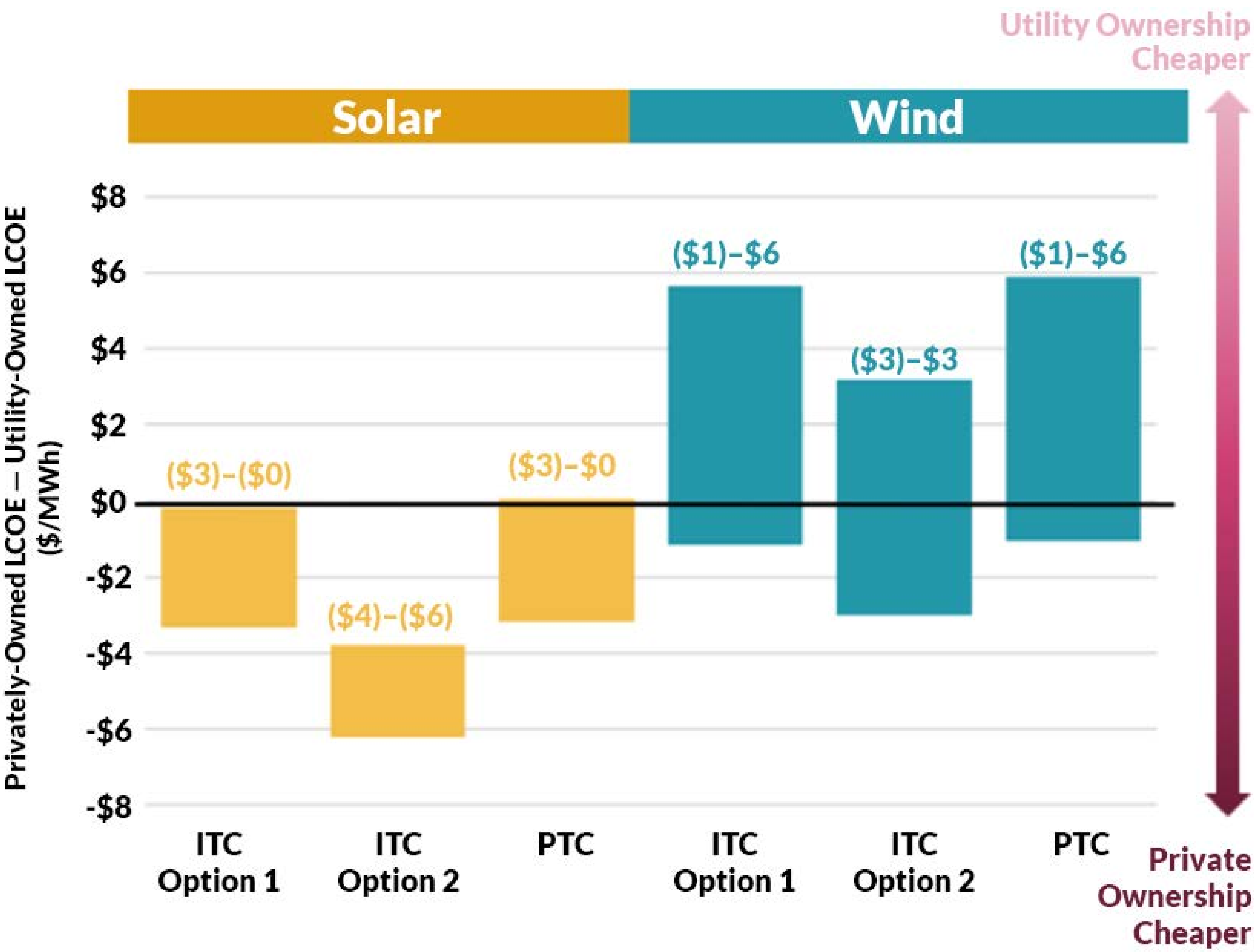
"Con Edison has been the champion for renewable energy generation for its customers for decades," Vice President of Distributed Resource Integration Raghu Sudhakara said in a statement. "We believe that utility ownership of renewable energy will provide New Yorkers with additional renewable generation for the green energy that they need when they need it, and with the highest value."

The state's Climate Leadership and Community Protection Act requires 70% of load be met with renewables by 2030 and full decarbonization by 2040, which translates into the need to add tens of thousands of megawatts to the grid over the next decade.

Currently renewables outside of Long Island are largely procured with New York State Energy Research and Development Authority contracts and New York Power Authority ownership, the paper says. NYSERDA runs competitive solicitations, and while it has attracted some new supplies, since the end of 2020, it has only procured 2.7 GW of new onshore wind and solar.

"New York greatly needs to add large amounts of renewable resources in the next decade if it is going to meet the state's ambitious decarbonization and renewable generation goals," Brattle Principal and report co-author Metin Celebi said in a statement. "Utility ownership of renewables alongside private ownership of assets could not only help expedite the development of new renewable resources but ultimately even save utility customers in the state money, alongside other benefits."

The paper evaluated the costs customers would incur during the first 30 years of operation for a new 100-MW onshore wind or solar facility under both utility and private ownerships, with different scenarios based on energy market prices, financing costs, contract



The potential cost savings of utility-owned and privately-owned wind and solar under different scenarios | *The Brattle Group*

NYISO News

durations and repowering assumptions. The renewable projects were identical except for the different ownership, with the only difference in final costs to customers based on cost recovery mechanisms, expected rates of returns and how tax credits are treated.

Allowing utility ownership "with sufficient guardrails against anticompetitive behavior" could allow customers to benefit from the advantages of both utility ownership and private ownership of renewables. When power prices are high and the cost of capital is high for private developers, utility-owned generation saves up to 14% compared to private developers, but other scenarios have privately owned renewables coming in cheaper for consumers by up to 11%.

The data for the costs of the power plants and how much money they are likely to make in the energy markets came from the National Renewable Energy Laboratory. The utility cost of capital is based on what the New York Public Service Commission has approved — 6.75% — while the private cost of capital is based on current market conditions at 6.99%.

"The cost of capital for private renewable developers is uncertain, especially recently due to supply chain constraints, which have put further risk on the development of renewable energy projects in the United States and New York in particular," the report says.

To account for uncertainty, the study includes higher costs in one scenario: 7.5% for private solar developers and 9% for wind developers.

"We find that the customer costs are broadly comparable between the utility ownership option and the private ownership option," Brattle said. "However, in the scenarios we analyzed, customer costs for new solar generation tend to be slightly lower under private ownership, while utility ownership tends to result in lower costs for new onshore wind generation."

Ultimately, both ownership models result in a similar level of costs, and the different ownership models come with their own pros and cons, the paper says.

Utility-owned generation can help bring more renewables online and offers effective project execution and risk management to provide benefits and cost savings under some circumstances.

"However, utility ownership would likely shift most risks currently borne by private owners to electricity customers with respect to asset performance and investment cost overruns," the report says. "In addition, depending on the implementation rules, utility ownership may raise concerns about cross-subsidization of costs and the availability of open access to information on the transmission and distribution systems to all developers of renewable generation in the state."

The state will need 110 GW of nameplate capacity and 240 TWh of energy by 2040, but most of the projects in NYSERDA's last five solicitations have been canceled, the paper notes. Of the 85 projects awarded by the authority between 2018 and 2021, all but eight have been canceled.

In its most recent solicitation in November, of the 68 projects that bid, 60 of them had been previously awarded contracts from which they backed out. NYSERDA ultimately picked 24 of those, representing 2.4 GW of capacity.

With the cancellations, the percentage of load served by renewables in 2022 was down compared to 2014. And with demand growth back in the mix, the gap is only getting wider.

The paper specifically highlights Dominion's Coastal Virginia Offshore Wind Project as a successful utility development, noting that the firm financed and built a Jones Act-compliant vessel to install the project. The lack of such vessels was overlooked by some competitive suppliers, which led to project abandonments.

"Ideally, regulated utilities' particular understanding of the regulatory and permitting environment in New York state, a direct interest in a highly reliable energy system in the state and a long-term commitment to the state increase the likelihood of project completion," the paper says. "However, there is still no guarantee in this regard, given utilities' exposure to similar market forces that would also impact competitive suppliers, including financing costs, rising capital costs and supply-chain limitations."

In addition to competitive concerns, which crop up in part because the utilities own the transmission and distribution systems their competitors also need to connect with, the paper also says that letting the utilities into development would put the risk of failed projects onto customers.

"Despite the significant project cancellations described above, as a result of New York's competitive procurement model, which allocates risks and benefits to private companies instead of customers, customers have not borne the costs of these canceled projects," the paper says. "In contrast, if the costs of a canceled utility-owned project were determined to be prudently incurred, those costs would be recoverable from customers." ■

NYISO News

With Final Class Year Approval, NYISO Marks End of an Era

NYISO's Operating Committee on Sept. 26 approved the system upgrade facilities (SUF) and system deliverability upgrade (SDU) studies for *Class Year 2023* — the last using the ISO's current interconnection process as it transitions to a new cluster-based approach.

"Next week marks my 20th year with ... NYISO, and in my 20 years, we have worked through all kinds of challenges with the class year interconnection process," said Zach Smith, vice president of system and resource planning. "The team has been fantastic through all of this, but it really has been tremendous with what we expect to be our final class year as we transition to the new cluster process."

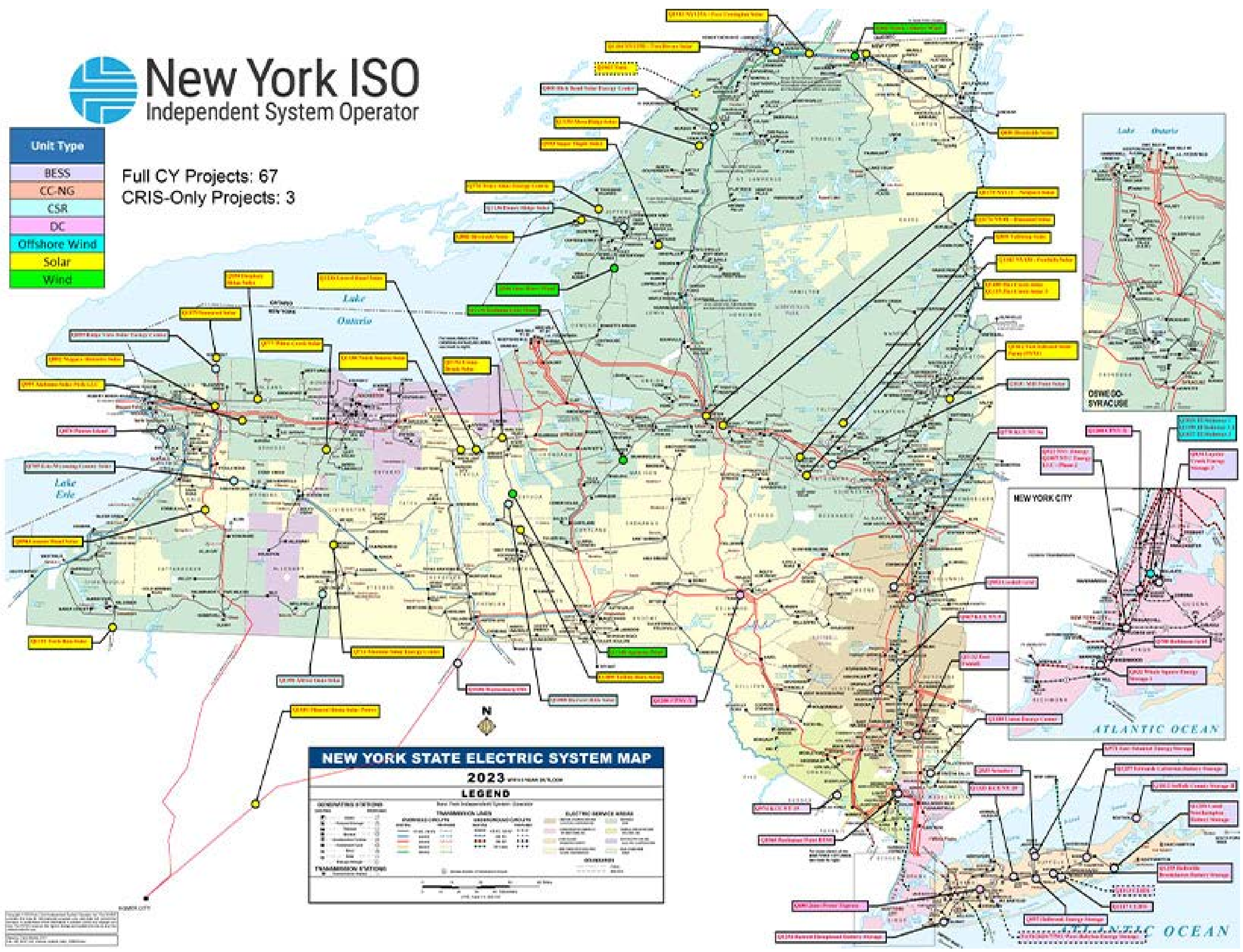
The SUF study identifies which interconnection facilities and developer attachment facilities would be required to reliably interconnect a group of projects to the grid under the minimum interconnection standard. The SDU study determines whether each project is deliverable at its requested capacity resource interconnection service level.

CY23 includes 67 projects. If all are interconnected, the generators would add about 14,000 MW to the grid, while the HVDC projects would inject 1,300 MW. The total cost for developers would be about $2.398 billion.

Developers have until Oct. 28 to accept their cost allocations. The studies would have to be updated if there are any rejections.

The first transitional cluster study began Aug. 1. ■

— Vincent Gabrielle



| *NYISO*

NYISO News

NYISO ICAP Working Group Briefs

Demand Curve Reset and Transmission Security

NYISO's Market Monitoring Unit, Potomac Economics, presented its *recommendations* for addressing what it calls inefficient market outcomes caused by setting locational capacity requirements based on the transmission security limit (TSL).

The MMU told the Installed Capacity Working Group at its meeting Sept. 24 that the current rules overvalue surplus capacity, setting "inefficiently high prices" while also overcompensating resources that don't help satisfy transmission security requirements.

"We focused in on the last couple of years here," said Joe Coscia, a director at Potomac Economics. "It's possible that the current LCR is quite a bit higher than it would otherwise be as a result of the TSL. … We expect that divergence to grow in the coming years with the entry of [the] Champlain Hudson [transmission project] and other resources like offshore wind as well."

The Monitor first made the recommendations in its 2023 State of the Market *report*, after NYISO had changed how it calculates the TSL floor.

"Large resources and SCRs [special-case resources] are overcompensated when the LCR of their locality is set at its TSL floor," it said in the report, released in May. "This is because the presence of these resources causes the TSL floor to increase, so they provide less net supply towards meeting capacity requirements than they are paid for in the capacity market."

Thus, the MMU recommended paying resources for capacity based on the requirements they actually contribute to meeting. SCRs should be compensated at the price that would prevail in their locality absent the TSL floor, while large, intermittent and storage resources should be paid the full capacity price for the portion of their capacity that does not cause the TSL floor to increase and the capacity price that would prevail absent a TSL floor for the rest of their capacity.

Coscia said bulk electrical consumers would save roughly $380 million if the Monitor's recommendations were implemented.
The payments for reliability assurance and transmission security should be paid for and determined with separate curves, he said. Implementing sloped demand curves that reflect the marginal value of capacity for transmission security would avoid excessively high prices.

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Multiple stakeholders representing the generation sector asked whether this suggestion would be compatible with the proposed peaker unit being a storage resource for the upcoming demand curve reset.

"I'm thinking through a lot of how you would set one, particularly with a two-hour battery, and I'm getting a lot of circular reference errors in my mind while thinking through it," said Shawn Picard, vice president of engineering for TigerGenCo, which operates in the Bayonne Energy Center in New Jersey.

"The short answer for that is that you put in a different value for the CAF [capacity accreditation factor] [than] is used in the model, and you would get a different value if you assume that the battery, or any of the other technologies, would have a different CAF for [transmission security] than what it has for [resource adequacy]," Coscia answered. "I just don't want to speculate on what that value might be."

Others brought up that making a separate demand curve for transmission security would probably involve creating additional proxy units and make the whole system more complicated. Howard Fromer, director of regulatory affairs for TigerGenCo, asked how real the savings to consumers were that Potomac had calculated.

"Did you take into account the potential that what you're ending up doing is creating this much more complicated system and simply shifting payment dollars from the market to subsidies?" Fromer asked. "How much of this $380 million is real versus just a shift, and we just end up having to pay a higher incentive to attract those resources?"

"I think our position is that it plays a useful role in sending signals accurately: What are the subsidy values that different resources require?" Coscia said. "It may have an effect on what policy-sponsored projects come in based on how much they can get from the market, or from other sources of payment."

Final Demand Curve Reset Recommendations

Both NYISO and its consultants presented their final *recommendations* for the demand curve reset for a last look before stakeholders make oral arguments to the Board of Directors this month.

Some changes were made to assumptions in response to stakeholder feedback, including the following:

- Peak load window hours for the battery energy storage system (BESS) peaker unit were updated to reflect the seasonal periods for 2024-2025.
- Voltages assumptions for the BESS were revised downward for all zones outside Long Island.
- Operations and maintenance estimates were revised to include land lease payments for the construction period.
- Sales tax was added to O&M expenses.
- Costs associated with the mortgage reporting tax were added.

Fromer asked why the consultants had apparently ignored FERC precedent of discretionary programs not being available for offsets for potential developers. He said that when his company built the last peaker plant in New York City, it could not get an exemption.

Daniel Stuart, a manager at the Analysis Group, replied that they had tried to come up with a reasonable scenario to model that might fit a potential developer.

"We do think it's reasonable and perhaps standard for new developers seeking to build batteries or gas turbines in New York," Stuart said. "That is the logic we applied for the mortgage reporting tax."

Fromer and other stakeholders brought up several other issues they felt had been left out, including investment tax credit eligibility, whether a battery system would need to be removed at the end of a land lease, government incentives and future cost reductions. Analysis Group members said that they had not ignored or dismissed these suggestions but that not all of them were convincing enough to warrant revisions. ■

— Vincent Gabrielle

NYISO News

NYISO: Large Load Flexibility Eliminates 2034 Shortfall Concern

By Vincent Gabrielle

NYISO made significant *updates* to its assumptions as part of its final Reliability Needs Assessment, which now shows no concern of a capacity deficiency and a loss-of-load expectation of less than 0.1 in 2034.

The dramatic change came from considering certain large loads as flexible, with the ability to reduce total consumption during the summer and winter peaks by about 1,200 MW, the ISO told the Electric System Planning Working Group and Transmission Planning Advisory Subcommittee on Sept. 27.

"Based on recent operating experience and outreach to load developers, cryptocurrency mining and hydrogen-production large loads are considered as flexible during peak load conditions," NYISO said. "This type of load is assumed to be more price responsive and likely to participate in demand response programs than other loads."

The change in assumptions reduced the forecasted LOLE in 2034 from the preliminary 0.289 that the ISO expected in July to 0.094. NYISO had warned of a potential shortfall of as much as 1 GW in its preliminary results in July. (See *Prelim NYISO Analysis: 1-GW Shortfall by 2034*.)

"We feel comfortable in certain large loads, primarily like cryptocurrency and hydrogen-producing large loads, to consider them flexible," said Ross Altman, senior manager of reliability planning for NYISO. "When you have peak load conditions due to either price responsiveness or participation in demand response programs, they would curtail under peak conditions."

Altman said that semiconductor plants, other data centers and most other large loads were not assumed to be flexible.

Several stakeholders asked whether the flexible loads were also modeled as special-case resources formally enrolled in the DR program. Altman replied that they were not, merely that they were assumed to be price responsive in some manner.

One stakeholder asked whether there was anything binding cryptocurrency miners to stay as cryptocurrency miners. He made the point that the servers could be put to other, less flexible uses than arbitraging the cost of energy against the purported value of the currency.

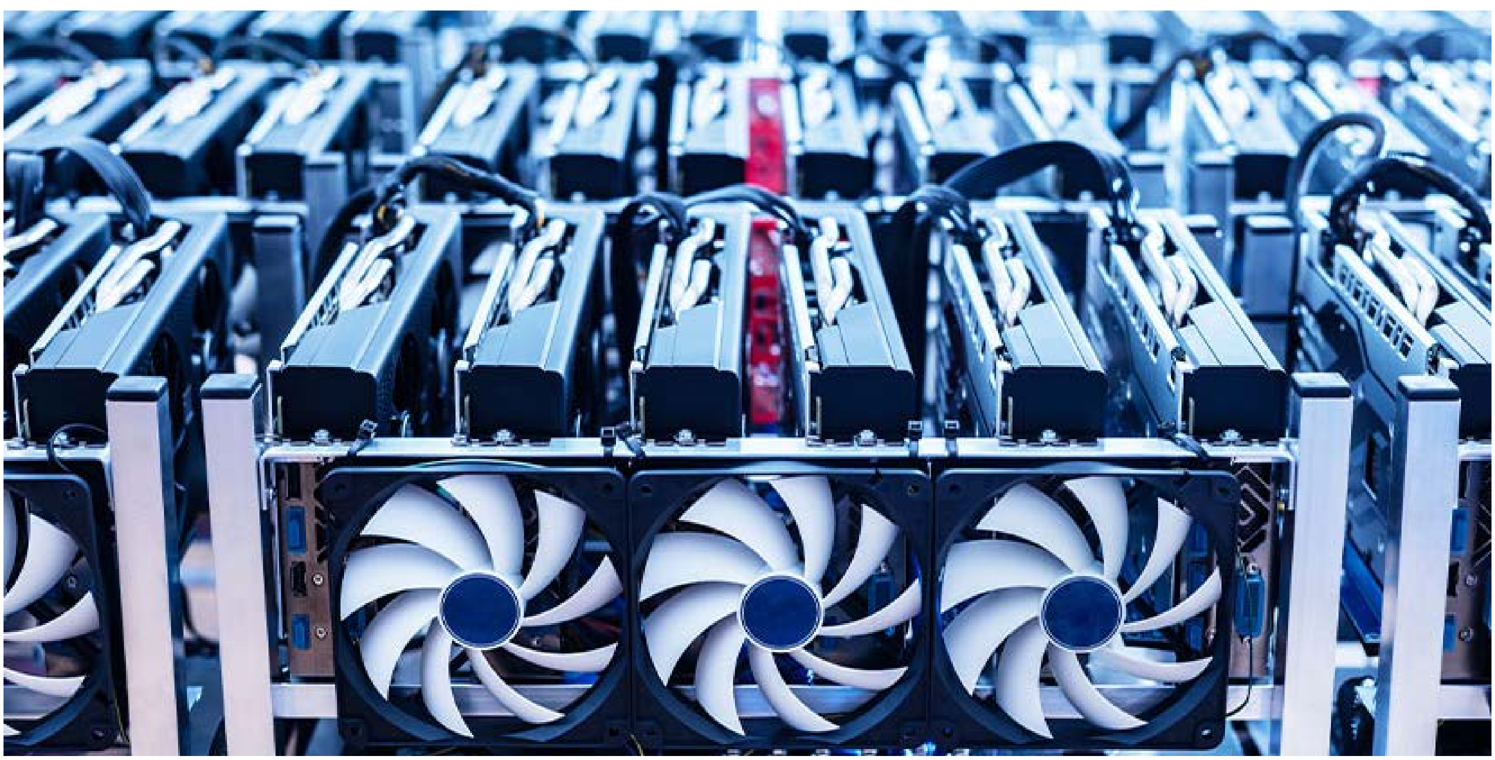
"If one or two of them change their use case, it'll produce a very different outcome in this study," they said. "You'll lose that flexibility."

"That is true," Altman said. "Hold on to that thought. I'll show scenarios that will show what things change on the higher end of the forecast, which includes large loads that are not flexible."

NYISO stressed that "there is a lot of uncertainty about key assumptions over the next 10 years." In a high-demand forecast risk scenario, the LOLE would jump to 2.744. The delay of the Champlain Hudson Power Express transmission project is also a concern.

"This still seems to be somewhat gambling," another stakeholder said. "If these loads aren't in the SCR [program] or they're not participating in the emergency demand response program, unless you have a tariff or contract under a dynamic load management program, you don't have any commitments to them to vary their load."

The working group will review the full draft Reliability Needs Assessment report on Oct. 4. The Operating Committee and the Management Committee will review and vote on the final report on Oct. 17 and 31, respectively, and the Board of Directors will review and post the final report in November. ■



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PJM News

With Three Mile Island Restart, Debate Continues on Co-located Load in PJM

By Devin Leith-Yessian

Data centers and other concentrated electric consumers are increasingly seeking to purchase their power directly through nuclear generators in PJM, raising concerns among state regulators, consumer advocates and utilities that they may be able to skirt paying their fair share.

Five years after shuttering, Three Mile Island Unit 1 is being resurrected as the Crane Clean Energy Center (CCEC) to supply Microsoft with energy through a power purchase agreement, while Talen Energy is seeking to amend the interconnection service agreement (ISA) for its Susquehanna Nuclear Plant to reduce its output to PJM and instead supply a co-located data center sold to Amazon Web Services. (See *Constellation to Reopen, Rename Three Mile Island Unit 1* and *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

Talen Energy's Susquehanna Nuclear Power Station | *Jakec, CC BY-SA 4.0, via Wikimedia Commons*

The latter has drawn protests from Exelon, American Electric Power and the Pennsylvania Public Utility Commission arguing that more information is needed about how the configuration may affect the grid and whether it will benefit from ancillary services, such as black start and regulation, without being assessed proper transmission fees.

During a Sept. 24 hearing on co-located load held by the Maryland Public Service Commission, FirstEnergy Chief Risk Officer Abigail Phillips said nuclear generation can help meet a resource adequacy gap identified in 2029, with load forecasts driven by data centers and thermal resource deactivations outpacing development in PJM.

"Right now it doesn't seem like the capacity markets are paying for those capital costs of generation, and the price signals that PJM talked about this morning are increasing the prices, but in the past auction, no new dispatchable generation is going to come online," she said. "So how long is it going to take to make those price signals work, and how long are we willing to wait and depend on that before we need to do something to get new generation on in Maryland and the rest of PJM?"

Data center developers could be choosing to co-locate with dependable generators out of a concern that the PJM grid may not offer the same security it traditionally has, Phillips said, which underscores the need to determine how to ensure adequate capacity. Additional nuclear generation could hold the promise to meeting resource adequacy needs and climate goals at once, she said.

"Nuclear is getting back into the conversation as a part of a zero-carbon solution. I know Maryland has clean energy goals, and I think that having nuclear back in the game is going to be helpful with achieving long-term capacity and long-term goals, not only for Maryland, but for PJM and the country," Phillips said.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, drew a distinction between the CCEC and co-located load requests, saying that most advocates are supportive of bringing new nuclear generation online as the balance between supply and demand grows increasingly tight in PJM. Whereas the CCEC will bring about 835 MW of new generation online to serve existing load, he said co-location may be taking generation out of the markets to serve load not considered part of the grid and exempt from service charges.

Where Poulos does see common ground between the CCEC PPA and co-located load configurations is the potential for major market impacts caused by the addition of large data centers, whether they are in or out of PJM's market.

He stressed that consumer advocates are supportive of the economic development that data centers promise the states they locate within, so long as there are rules to ensure that they pay their fair share for any services they consume or grid impacts they prompt. Co-location could also push transmission costs lower by reducing the need for new lines, he said.

Advocates are also concerned about market power, Poulos said, with the potential for generation owners with a broad portfolio within a tight zone having the ability to pick a resource to take out of the market and push energy and capacity prices higher. Generators could contract with a data center to provide power well below the regional clearing price, knowing that other resources in their portfolio will clear at a higher price. Co-located configurations have the potential to distort price signals even without market manipulation by removing large volumes of load and generation from a zone, he said.

"The market is supposed to provide the appropriate price signal, but if you have this other massive load being served in the same area offline, so to speak, it could impact the price signals. It could make them not accurate so the price signals aren't reasonable in the market and for consumers," Poulos said.

PJM stakeholders had considered several proposals to change the market rules for co-located configurations last year, but none of them received majority support, and the topic was dropped. Poulos said it's unlikely stakeholders will be able to make progress while FERC and state commissions are looking at the topic, and

PJM News

it will likely have to be FERC that makes the first move on the broad legal and jurisdictional questions. (See "Proposed Rules for Generation with Co-located Load Rejected," *PJM MRC Briefs: Oct. 25, 2023*.)

The RTO issued guidance around co-located configurations recommending that parties receive firm transmission service while stating that it does not have the authority to prevent private contracts between generators and load seeking to co-locate off the grid. (See "Additional Guidance on Co-located Load," *PJM MRC Briefs: April 25, 2024*.)

During the PSC hearing, Aftab Khan, PJM's executive vice president of operations, planning and security, said the RTO has requests to study about 8 GW of co-located load configurations, mostly to serve data centers, crypto-mining and hydrogen production. When such requests are received, he said PJM conducts the "necessary studies" to ensure there is no adverse impact to the grid. Any required transmission upgrades to support the configuration are identified and must be implemented at the cost of the generator before the co-located load can come online.

He said PJM considers non-network load co-located with interconnected generators to also be electrically connected to the RTO's grid and benefiting from ancillary services, but it has no way of assessing fees.

"Under any configuration, co-located load is electrically connected and synchronized to the PJM system when consuming power and therefore benefits from the use of the transmission system and ancillary services, such as black start and regulation services," Khan said. "PJM network load accounts for such services, but there are no transmission or ancillary service charges to the off-system load. PJM previously tried to address this with proposed rule changes for ancillary services, but the proposal did not achieve the consensus of the PJM members."

Independent Market Monitor Joe Bowring also said the load is part of PJM's grid and the broad impact should be holistically studied to identify impacts, rather than examined through amendments to generators' ISAs.

"All load, including co-located load, is on the grid, affects the grid and benefits from the grid," Bowring said. "As a result, decisions about co-located load affect all customers."

Bowring said the Monitor's analysis of co-location configurations did not find a substantial difference between cost allocation to consumers regardless of whether the load is considered part of PJM's network or if the large load additions were made miles away from the generator. Instead, he said the underlying issue is how PJM identifies and studies large consumers.

"It's not just a question of co-located load; it's a question about load in general. ... What that illustrates and emphasizes is that the analysis has to be done carefully," he said.

Phillips told the PSC that it's critical that the consequences of allowing generators to take their output off the market to serve non-network load is fully understood, both in terms of costs and reliability.

"Any reduction in dispatchable, on-demand generation that's available to serve residential customers should be analyzed before we make any changes to policy or regulation. We have to really understand when you co-locate and what that does to capacity, both short term and long term, how does that trickle down into who's paying for it, who gets the benefit, and we have to make sure it's not only cost affordable, but [also] we maintain that reliability," she said.

In a *white paper* published Sept. 23, Tony Clark, former FERC commissioner and senior adviser at Wilkinson Barker Knauer, and Vincent Duane, principal at Copper Monarch and former senior vice president of law, compliance and external relations at PJM, argue that allowing data centers to co-locate with nuclear generators allows them to avoid lengthy waiting periods while transmission upgrades necessary to accommodate their load are planned and built. But it can also alter power flows to require network upgrades before other networked loads can interconnect. They call for a cost allocation methodology that recognizes the benefits co-located load and generators receive from being part of the grid.

"We would not advocate assigning to the co-locating generator the full cost impact of its withdrawal (as is done under the 'but for' test for new interconnections)," they wrote. "Nevertheless, the underlying principle — rooted in cost causation — offers a path to assign to the co-location arrangement its share of these cost impacts, thus restoring them to the position they would be in had they connected in the traditional manner."

Clark and Duane raise similar concerns about cost allocation for ancillary services and note that nuclear units receive public benefits, such as tax credits, grants and accelerated depreciation from the federal government and states. They argue that makes it especially questionable to allow units to leave RTO markets to serve private load.

"From this perspective, nuclear generation is uniquely imbued with the public interest, making it unsettling if not unseemly for units, once the first data center comes knocking, to pull up stakes and desert customers that for decades have had their back," they wrote. ■

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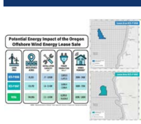

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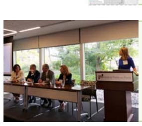

State, Industry Reps Debate Future of Gas at NECA Fuels Conference

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PIO Complaint Faults PJM Treatment of Deactivating Generation

FERC Filing Contends PJM Capacity Market Inflates Prices by Not Counting RMR Resources

By Devin Leith-Yessian

Several public interest organizations (PIOs) have filed a complaint with FERC contending that PJM's capacity market is inflating consumer prices by not counting generators operating on reliability must-run (RMR) agreements as a form of capacity (*EL24-148*).

The complaint argues that RMR contracts already require units to be online and available to PJM dispatchers in the event of a capacity emergency, which positions them similarly to committed capacity.

The PIOs said consumers are being asked to pay for capacity twice: once for an RMR unit's availability and again to procure the capacity the unit would have offered had it participated in the RTO's Base Residual Auctions (BRAs).

The complaint was submitted by the Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and Union of Concerned Scientists.

"Failing to account for resource adequacy provided by RMR units produces capacity market price signals that are disconnected from the actual supply and demand balance on the grid," the complaint says. "This distorted supply-demand balance is economically inefficient because it signals a degree of scarcity that does not exist. The result is artificially elevated prices that harm the markets by encouraging inefficient decisions by both supply and demand side market participants."

The complaint argues also that PJM's position on modeling RMR resource capacity is inconsistent because it does not include RMR units' output when analyzing the amount of generation available within a locational deliverability area (LDA) when analyzing transmission capability during potential capacity emergencies.

The PIOs present two visions for how RMR resources could interact with capacity markets. The most straightforward would be requiring them to offer into the market at $0/MWh as price-takers; however, the complaint acknowledges the change could make generation owners wary of accepting an RMR agreement — which is a voluntary election in PJM. The alternative they propose would be to model RMR units when determining the reliability requirement and reduce the amount of capacity that must be procured through BRAs.

The complaint also requests that the commission delay the 2026/27 BRA, currently scheduled for December, to allow the changes to be implemented for that auction.

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

RMR Impact Set to Increase

The impact of RMR agreements on consumer rates is likely to substantially increase in the 2025/26 delivery year, when agreements take effect between PJM and Talen Energy to keep the 1,273-MW Brandon Shores and 702-MW H.A. Wagner generators online from June 1, 2025, through Dec. 31, 2028.

The complaint cites *analysis* from Synapse Energy Economics, on behalf of the Maryland Office of People's Counsel, and a separate *report* from the Independent Market Monitor, which found that not counting RMR units as capacity could cost PJM ratepayers $4 billion to $5 billion in 2025/26. (See *Maryland Report Details PJM Cost Increases for Ratepayers*.)

The terms of the Talen agreements are being negotiated through settlement judge proceedings the commission ordered in June. The company requested $175 million in annual fixed costs and $29.9 million in project investments for Brandon Shores and $40.3 million in fixed costs and $4.5 million in additional investments for Wagner. (*See FERC Orders Settlement Judge Procedures in Two PJM Generator Deactivations*.)

Stakeholders are also discussing changes to PJM RMR resources in the Deactivations Enhancement Senior Task Force (DESTF), which is set to open a vote on five proposals during its Oct. 2 meeting. The DESTF packages largely focus on extending the notice generation owners must provide PJM ahead of their desired deactivation dates and how compensation under RMR contracts is determined.

None of the DESTF proposals include a capacity must-offer requirement for RMR units, but a proposal from the Sierra Club would model the expected output of RMR resources that do not participate in the capacity market when determining the reliability requirement.

The parties to the complaint argued that even if a proposal passed that satisfies their concerns, changes are unlikely to be implemented in time for the December auction. The PIOs noted also that the PJM Board of Managers rejected a request from six state consumer advocates in an Aug. 30 letter to launch a critical issue fast path (CIFP) process to require RMR units to participate in the capacity market. In its Sept. 19 response, the board wrote that doing so would undermine the capacity market's price signals to replace the outgoing generator or make investments to keep units operational.

In the first of a series of reports on the 2025/26 BRA, the Monitor estimated that not including RMR units in the supply stack as capacity price takers would have increased the cost of capacity procured by over $4 billion, or 41.2%. The Monitor said this would recognize that RMR resources provide reliability while transmission upgrades to address their deactivation are constructed.

"There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete," the Monitor wrote.

Monitor Joe Bowring told *RTO Insider* that requiring an RMR unit to offer into the capacity market could also lead to costs for consumers, as generation owners would be more wary of entering into RMR agreements and would seek to recover the risk of being subject to capacity performance (CP) underperformance penalties. Instead, he suggested including them in the supply curve as a zero-cost offer.

Bowring said one of the issues with how generation deactivations are treated in PJM is the lacking ability for merchant generation to compete with transmission to address any identified reliability violations. He argued that an expedited interconnection process is needed to give new resources a chance to provide a solution to violations or when reliability issues are identified in general, such as the capacity shortfall PJM has been warning about in the 2029/30 delivery year. He has proposed a similar concept at the Planning Committee for allowing PJM to transfer capacity interconnection rights (CIRs) from a deactivating resource to resources which could resolve associated violations. (See "Voting on CIR Transfer Proposals Deferred to October," *PJM PC/TEAC Briefs: Sept. 12-13, 2024*.) ■

PJM News

PJM Working to Speed Development of New Capacity

Growing Number of Approved Resources Have Not Entered Operations

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The Markets and Reliability Committee discussed how the development of new capacity can be sped, as a growing number of resources have cleared the interconnection queue but not entered commercial operation.

PJM Vice President of Planning Paul McGlynn said the cluster-based approach to studying interconnection requests has increased the pace of processing projects, estimating that 72 GW of new generation will clear the queue by the end of 2025. Thus far, only 2 GW has actually come into commercial service, and most of that is solar resources with a relatively small capacity contribution.

Lead time for equipment, local opposition and financing all remain obstacles for developers, McGlynn said, adding that this represents a call to action for stakeholders to identify and work to remove those barriers.

"We need to get the resources that are going to move forward, we need to get them connected to the grid so they can help us out with the resource adequacy issues that we are having," he said. During the Aug. 6 Planning Committee, PJM stated that generation deactivations, rising load forecasts and sluggish resource entry are contributing to a possible capacity shortfall in the 2029/30 delivery year. (See "PJM Models Suggest Capacity Shortfall Possible in 2029/30 Delivery Year," *PJM PC/TEAC Briefs: Aug. 6, 2024*.)

The growing number of resources with service agreements that have not entered operation presents planning staff with challenges when identifying possible transmission reliability violations. PJM's Jason Shoemaker said planned generation resources are modeled the same as operating units, creating instances where resources are assumed to be injecting MWs onto the grid when they actually still will be under development. That is driving up the number of violations and their complexity, he said.

Vitol's Jason Barker said PJM has implied that developers are moving through the interconnection process and leaving projects idle, a characterization he said misses work like permitting and siting that must be completed before the "boots on the ground" phase can begin. While some of the legwork used to be done while projects moved through PJM's interconnection queue, he said the amount of time it now takes for projects to be processed has transformed a concurrent interconnection, permitting and siting process into a serial one.

PJM CEO Manu Asthana | © *RTO Insider LLC*

Why This Matters

Grid planners assume planned resources with service agreements will contribute to the grid. So when approved projects don't enter operation in a timely manner, reliability problems emerge.

"Permitting is time consuming [and] costly, and permits expire. So the development community, as I think you've acknowledged, has real work before the shovels go in the ground, boots go on the ground. So, we have a really strong concern with the messaging that PJM has provided here," primarily because it misleads the stakeholder community as to the diligence developers have in completing their projects, Barker said.

Some of the same procurement challenges developers have faced also are affecting transmission owners' ability to complete network upgrades necessary to allow resources to come online, with transformers, breakers and other components in short supply worldwide.

"We very much want to bring our projects to completion and are working diligently to do so," he said.

Rather than focusing on the number of projects that still are in some phase of development, Barker said the focus should be on PJM's success in canceling the queue positions of projects it has determined are not advancing toward commercial operation.

Shoemaker said PJM has a cure process when a project misses development milestones, which typically lasts a few months before either a suspension is granted, the breach is remedied or the project is removed from the

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queue. He said about 75% of developers' requests to change their agreements are granted by PJM.

Tangibl Group Director of RTO and Regulatory Affairs Ken Foladare said PJM is making good progress in clearing projects faster. But the amount of time projects already have been in the queue has affected their ability to progress with permitting and financing. He said one project was seeking commercial operation in 2027, but the transmission owner said the earliest that would be possible was 2030 to 2031. Any permits received that far out would expire before work could begin. And financing also is unlikely to materialize that far in advance.

Shoemaker said transmission delays can happen, and projects affected would be considered in the engineering and procurement phase. He said PJM's focus when negotiating milestone deadlines is a project-specific review of whether a developer is doing everything in its power to move projects toward completion. On the other hand, he said granting delays can affect other developers in line behind that project, who need to be given a fair shot at advancing as well.

Calpine's David "Scarp" Scarpignato said there have been issues with how project suspensions and delays affect others in the queue, as well as possible reliability impacts as PJM models the injection of power from resources that are not built according to schedule. Even if network upgrades are completed on time, he said that could lead to energy not being available where it was expected.

PJM CEO Manu Asthana said blame is irrelevant and the focus should be on what would improve completion rates. Capacity costs increased in the last Base Residual Auction (BRA) and the price cap is set to increase in the 2026/27 auction, stressing consumers. On the other side, he said forecasts of load growth continue to accelerate and could remain an undercount.

He said PJM views a recent transaction in the footprint to purchase power outside the market for 20 years as a data point showing that demand is real. He encouraged stakeholders to deconstruct the deal and its implications on the capacity market. On Sept. 20, Constellation Energy announced an agreement with Microsoft to reopen and rename its 835 MW Three Mile Island Unit 1 the Crane Clean Energy Center with a 20-year power purchase agreement. (See *Constellation to Reopen, Rename Three Mile Island Unit 1*.)

While solar and wind are viable in PJM and more renewables are beneficial, Asthana said they don't provide the capacity needed by the end of the decade. If new construction is needed, he said there should be a corresponding price signal and that resource adequacy solutions must come through the interconnection queue.

"I think it's a generational challenge for us and we're going to have to solve it together," he said.

Foladare commented that PJM's wholesale market rules and price signals are leading developers to drop the storage component of some hybrid resources, leaving products that have limited utility as capacity. How batteries are accredited under PJM's marginal effective load carrying capability (ELCC) approach has made standalone and hybrid installations less economically attractive.

"Something has to be done in this area if you want to see more solar with storage or wind with storage," he said.

Asthana pointed to record-high clearing prices in the 2025/26 BRA and said he is hearing that high prices are needed to enable widespread storage development while consumers are stating prices are unsustainable.

"We want more storage ... but we hear it loud and clear that consumers don't want high prices and right now those two things do not match," he said.

Foladare said capacity prices make up a relatively small portion of the potential revenue for storage. The overall cash flows from energy, ancillary services and capacity are not sufficient to cover the incremental cost of installing storage, he said. He suggested a fast-ramping product could fit the capabilities of storage better. ■

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PJM MRC Briefs

PJM Proposes Reopening Discussion of Storage as a Transmission Asset

VALLEY FORGE, Pa. — About four years after PJM stakeholders shelved deliberations on rules around how battery storage can be used to address transmission constraints, PJM Director of Stakeholder Affairs Dave Anders presented a first read on reopening the topic with a refreshed *problem statement* and *issue charge*.

Anders framed the issue charge as the second phase in developing market rules for battery storage, following on the implementation of rules for how storage can participate in the markets. A possible third phase could consider how a battery installation could serve simultaneously as transmission and a market asset. But PJM's Becky Carroll said staff prefer to develop clear rules on the market and transmission sides before trying to create a dual-use structure.

"It's not a never, it's just not right now for the dual-use piece of it," she said.

Vistra's Erik Heinle questioned whether stakeholders should embark on developing a new structure for a class of transmission assets while tackling several other major efforts. He suggested instead waiting six months before initiating the work.

Anders said staff also was concerned about inundating stakeholders with additional meetings, which played into the issue charge designating the work to the Operating Committee.

Tom Hyzinski, of the GT Power Group, said the classic use case could be a substation where a transformer failure could lead to excessive loading on other facilities. Rather than installing an additional transformer, he said a battery could alleviate the loading while potentially being cheaper and easier to install. He agreed that transmission rules should be developed before considering how that same battery could participate in the markets.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said there are advocates who believe it should be a priority to enable dual-use storage as quickly as possible. He said the possible elimination of energy efficiency as a resource class and de-rating of demand response have limited the ability for load to respond to market signals and that increased storage could present an ability to mitigate capacity prices. Some advocates may seek an amendment to PJM's issue charge or an alternative with dual use included.

Exelon's Alex Stern said he believes it's best to take "crawl before we walk approach" to avoid consideration of storage as a transmission asset (SATA) being derailed by arguments over dual use.

Bowring said market-oriented assets, including storage and generation, can be used as transmission, such as when PJM dispatches them to provide voltage support. He said the capability to install SATA could be practically limited to transmission owners.

The dual-use concept presents even greater concerns, Bowring said, by creating an "impossible task" of determining if one side is subsidizing the other, either markets or transmission with a regulated return.

LS Power Issue Charges on Accreditation Transparency, Unit-specific Performance

LS Power presented two issue charges focused on PJM's marginal effective load-carrying capability (ELCC) accreditation framework. One would focus on making the calculations more transparent and replicable for market participants. The other would aim to replace class accreditation with adjustments for each unit with unit-specific ELCC ratings. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Vice President of Wholesale Market Policy Dan Pierpont said a more comprehensive understanding of how ELCC values are determined and how they influence final unit accreditations could allow generation owners to make investments that would improve unit capacity.

Pierpont said the issue charge seeks a way for generation owners to validate their accreditation values, understand how physical or managerial changes to a unit would affect accreditation and a set date for PJM to lock in changes to ELCC values to provide more market certainty ahead of auctions.

"The complexity of the marginal ELCC methodology remains an important determining factor in the ability of PJM's capacity market to send transparent price signals and attract investment where needed," the transparency *issue charge* states. "To make that determination, significantly more data and analytical transparency is needed."

The document would hold discussion of alternative accreditation frameworks and a sub-annual capacity market to be out-of-scope. It targets having any changes approved to be implemented for the 2029/30 Base Residual Auction (BRA), scheduled for December 2025.

Dave Anders, PJM | © *RTO Insider LLC*

Susan Bruce, representing the PJM Industrial Customer Coalition (PJM ICC), said more transparency around ELCC could be beneficial for all market participants and suggested an amendment to provide more data access for all members. LS Power Director of Project Development Tom Hoatson said the company would be open to such an amendment to the issue charge, as long as market sensitive information is protected.

The unit-specific ELCC *issue charge* seeks to expand the data considered in the ELCC unit-specific performance adjustment to allow accreditation to reflect any changes made that could improve performance. Pierpont said the adjustment considers a narrow number of hours in which load drop occurred, which in practice results in accreditation values weighted toward performance during the 2014 Polar Vortex and weather and load during winter storms in 1994. Investments made in resources since that event would have minimal impact on how that unit's potential performance is evaluated compared to the rest of the resource class, he said.

The problem statement argues the issue is twofold: The incentive for generators to make investments to improve performance could be limited if accreditation values would remain static, and maintenance costs may be ignored if no capacity derate is likely. The issue charge targets a FERC filing in the first quarter of 2025.

The issue charge focuses on how much historical data PJM includes in its performance, load and weather data; the unit-specific performance adjustment and possible use of a unit-specific ELCC accreditation; how ELCC class average values are applied to new resources; and how transmission headroom factors into ELCC values.

PJM CEO Manu Asthana said it takes a long

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time for performance improvements to be reflected in resource accreditation and it's a valid inquiry to look at how investments can be accounted for more quickly.

LS Power Senior Vice President of Wholesale Market Policy Marji Philips said if a turbine fails during a performance assessment interval (PAI) and the generation owner replaces the equipment and makes changes to avoid that happening again, that event can lead to diminished accreditation for years.

"That bad experience during a PAI haunts us for years," she said.

The PJM Public Power Coalition's Carl Johnson said the ELCC construct can be improved upon, but any stakeholder efforts must be approached cautiously to ensure they do not conflict with changes likely to be made through the second phase of PJM's capacity market redesign.

Vitol's Jason Barker said it's logical to reflect capital expenditures, but the issue charge seems focused on speeding accreditation for thermal resources without addressing the increased accreditation for renewables resources that could be unlocked through a sub-annual market design. He also questioned whether it's reasonable to expect changes to the ELCC structure could be accomplished within the envisioned 4.5-month timeline.

Independent Market Monitor Joe Bowring said stakeholders discussed related issues at length during the Critical Issue Fast Path (CIFP) process last year, and he said membership is capable of acting in a disciplined and focused way.

Poulos said the compressed capacity auction schedules makes the implementation timeline especially important and recommended prioritizing working areas to ensure changes can be in place for the earliest auction possible.

Stakeholders Endorse Creation of Electric Gas Coordination Subcommittee

The MRC endorsed the *sunsetting* of the Electric Gas Coordination Senior Task Force (EGCSTF), to be replaced with a new Electric Gas Coordination Subcommittee (EGCS), which is intended to have a wider scope and be more flexible in the topics it can address. (See "PJM Proposes Sunsetting Electric Gas Coordination Senior Task Force," *PJM MRC/MC Briefs: Aug. 21, 2024*.)

The MRC voted in June to endorse part of a proposal drafted by the EGCSTF, greenlighting changes to the day-ahead energy market commitment cycle to align with daily gas pipeline nomination deadlines. Stakeholders rejected a second component that would ask generators to voluntarily notify PJM of whether they have procured fuel necessary to meet their commitments or intend to do so. (See "Stakeholders Endorse Revised Proposal to Align Energy, Gas Schedules," *PJM MRC/MC Briefs: June 27, 2024*.)

A subcommittee would allow a more long-term focus on harmonizing aspects of PJM's markets with how gas pipelines are operated and consider revisions to a broader swath of PJM's market rules.

The draft *charter* states that the responsibilities and scope of the subcommittee include reviewing market and operational conflicts between the electric and gas sectors, assessing and updating participants on state and federal initiatives affecting gas-electric coordination, and "[recommending] necessary enhancements to PJM rules, systems and procedures which can improve grid reliability, efficient market operations, and greater availability and flexibility of natural gas-fired generating resources."

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned how it can be ensured that stakeholder efforts to improve market rules around gas generation do not become siloed between different working groups. Anders said part of subcommittee's charge would be to keep tabs on those efforts with regular updates.

"The important part is to keep the communication lines open ... and frankly I think that's one of the things this new subcommittee can do, to make sure we're thinking across the whole horizon," Anders said.

Hourly Notification Times in Day-ahead Market Endorsed

Stakeholders endorsed a *proposal* to add hourly notification times to the day-ahead (DA) energy market, expanding the capability from the real-time (RT) market. (See "Hourly Notification Times," *PJM MRC/MC Briefs: Aug. 21, 2024*.)

PJM's Joseph Ciabattoni told the MRC that generators are limited to daily notification in the DA market. But reserve price formation market changes have increased the importance of notification times for determining the eligibility and capability of offline resources to be committed as non-synchronized and secondary reserves.

Sotkiewicz said notification times are an important factor for gas resources and more discussion is needed to continue to refine how they are committed.

PJM Proposes Elimination of Two Interface Pricing Models

PJM's Brian Chmielewski *presented* a first read on tariff revisions to remove the high/low and marginal-cost proxy interface pricing options. (See "PJM Proposes Elimination of 2 Interface Pricing Options," *PJM MIC Briefs: Aug. 7, 2024*.)

Both were designed for pricing imports and exports with neighboring nonmarket regions. But they have gone unused since July 2019, when Duke Energy Progress terminated its dynamic interface, which used marginal-cost proxy pricing. Chmielewski said a nodal aggregate pricing approach has since been implemented, which PJM believes creates accurate price signals based on other interfaces.

The proposal is set to be voted on by the MRC on Oct. 30 and the MC on Nov. 21 and to be filed at FERC in December.

First Read on Increased Review of Credit Risk for Bilateral Capacity Transactions

PJM *presented* a first read on a proposal to strengthen its ability to collect capacity performance (CP) penalties from market participants who have bilaterally sold their capacity rights and revenues.

Assistant General Counsel Eric Scherling said bilateral transactions separate the payments received by the buyer from the performance obligations held by the seller, which can present issues if the seller does not have proper credit or revenues to cover any possible performance penalties.

PJM would conduct a credit review of bilateral capacity transactions before they can be completed and both parties' creditworthiness and the impact the transaction might be considered before PJM signs off. Transactions where both the buyer and seller have external investment grade ratings, and the total notional value of the transaction is less than their unsecured credit allowance would be considered approved unless PJM states otherwise.

If PJM is notified of a transaction before 1 p.m., it would complete the credit review by the end of the next business day; if the notification came after 1 p.m., PJM would have two days to complete the review.

PJM's Gwen Kelly said the intent is not to create any changes to the credit risk evaluation, but to provide more visibility into the transactions before they're created to allow proactive, rather than reactive, actions to be taken if issues are identified. ■

— Devin Leith-Yessian

Southeast

Utilities Working to Restore Power After Helene Tears Through 10 States

DOE Reported 2M Customers Still Without Power as of Sept. 30

By James Downing

The U.S. Department of Energy said Sept. 30 that about 2 million customers were still without power after Hurricane Helene knocked out power to about 6 million across 10 states stretching from Florida to Ohio.

The most impacted states were Georgia, North Carolina and South Carolina, which sustained over half the outages. As of the morning of Sept. 30, about half of those customers remained without power, said a *report* from DOE's Office of Cybersecurity, Energy Security and Emergency Response (CESER).

The storm hit Florida's Gulf Coast late on Sept. 26 and moved north the next two days through Georgia, South Carolina, North Carolina, Virginia, West Virginia, Tennessee, Kentucky, Ohio and Indiana. It brought strong winds and heavy rains, which led to flooding in some states, DOE said.

Restorations are underway as utility mutual assistance crews totaling about 50,000 workers from 27 states, the District of Columbia and even Canada were working to restore power, though the hardest-hit areas were expected to be without power through the end of this week.

"Restoration efforts after Helene will be a complex, multiday effort in many locations due to the extent of damage and ongoing access issues," CESER said. "Utilities have been encountering widespread flooding and debris impeding access to damaged infrastructure. Communications disruptions are also impacting restoration efforts."

Duke Energy owns utilities in several states the storm impacted, including its Florida subsidiary's territory covering the area where Helene landed — the state's "Big Bend" region where the panhandle meets the peninsula. Florida saw more than 1.3 million customers lose power, but Duke reported that 95% had been restored by Monday afternoon.

Georgia Power reported that it had 15,000 personnel working to restore power to all of its customers, having completed restoration to 840,000 customers by afternoon of Sept. 30, with 370,000 still without electricity.

Those remaining without power were in the hardest-hit parts of Georgia, in its eastern, southern and coastal regions, including Augusta and Savannah. The Southern Co. Affiliate has to replace more than 7,000 power poles, 15,000 spans of wire equivalent to 700 miles and more than 1,200 transformers and also remove more than 3,000 trees from power lines, it said.

A screen shot of footage Duke Energy posted of flooding in Asheville, N.C., on Sunday. | *Duke Energy*

By 4 p.m. on Sept. 30, Duke Energy Carolinas reported that it had restored power to 1.35 million customers, with 443,000 still without power in South Carolina and an additional 346,000 out in North Carolina. It expects to restore service to most of the 790,000 customer outages by the night of Oct. 4.

"We're beyond grateful to the state and local government workers who have been on the job 24/7 to clear debris, reopen roadways and help those whose lives have been changed forever by this storm," Jason Hollifield, Duke Energy's storm director for the Carolinas, said in a statement. "Our thousands of lineworkers and other storm workers are gaining better access to the destruction — allowing them to remove trees, broken poles and downed power lines, log each piece of damaged electrical equipment, and begin repairing and rebuilding major portions of the power grid that were simply wiped away."

North Carolina's Electric Cooperatives reported an additional 90,602 customers among its members without power the afternoon of Sept. 30.

Around the same time, Duke Energy Ohio still had 1,180 customers out, according to its outrage map, while American Electric Power subsidiary Appalachian Power, which serves western Virginia and parts of West Virginia, reported 110,197 customers still without power. ■

SPP News

SPP's Desselle to Retire After 18 Years at RTO

Michael Desselle, SPP vice president and chief compliance and administrative officer, is retiring after 18 years with the RTO and 40 in the industry. His departure will be effective Jan. 2.

"We'll definitely miss Michael," SPP CEO Barbara Sugg said in a Sept. 30 *statement*. "His dedication to SPP is clear. He's respected by his peers, as exemplified by his service as chairman of the Board of Directors and CEO of the North American Energy Standards Board. We wish him the best in his well-deserved retirement."

Mike Riley, SPP senior director and deputy general counsel, has been promoted to vice president of corporate services and chief compliance officer to fill Desselle's position. He begins a transition period Oct. 1.

Attorneys Tessie Kentner and Chris Nolen have been named associate general counsels with Riley's promotion. ■

—Tom Kleckner

Michael Desselle takes notes during an SPP meeting. | © *RTO Insider LLC*

Company Briefs

Nuclear Startup Oklo Gets Greenlight for First Microreactor

Oklo last week announced it has finalized an agreement with the Department of Energy to move forward with its first commercial microreactor.

The company will start site investigation work at the Idaho National Laboratory in Idaho Falls.

The startup is the only advanced fission company with a DOE site use permit. The department awarded Oklo the site use permit in 2019, though the Nuclear Regulatory Commission rejected its first application to build the microreactor in 2022. The NRC still needs to sign off on the plan, which is scheduled to break ground in 2026 and come online a year later.

More: *Newsweek*

First Solar Opens Plant in Alabama

First Solar last week announced it has opened its $1.1 billion thin-film solar manufacturing plant in Alabama.

The plant is expected to generate 3.5 GW of vertically integrated solar manufacturing capacity.

More: *Business Alabama*

Avangrid Shareholders Approve $2.55B Buyback by Iberdrola

Spanish utility Iberdrola last week announced that Avangrid shareholders approved its proposal to acquire the remaining 18% stake in the company for $2.55 billion.

Shareholders will receive $35.75 per share — a 15.2% premium over the 30-day weighted average price before the acquisition announcement in March.

More: *Power Technology*

Federal Briefs

TVA to Give Executive Bonuses for Adding Solar, Storage

The Tennessee Valley Authority will reward its executives for adding renewables and batteries to the grid, according to a report filed to the Securities and Exchange Commission.

For the 2024-26 period, TVA will need to add about 900 MW of renewables and storage for executives to get the full bonus. By 2027, TVA must reach 1.3 GW of renewables and storage.

More: *WPLN*

US Net Natural Gas Exports Remain Flat in First Half of 2024

U.S. net natural gas exports averaged 12.6 billion cubic feet per day for the first half of 2024, 1% more than the same period last year and 2% less than in 2023, according to Natural Gas Monthly.

In the first six months of 2024, net pipeline imports from Canada averaged 5.4 Bcf/d, an increase of 11% compared with the same period in 2023. Net exports to Mexico averaged 6.3 Bcf/d in the first six months, 7% more than the same period last year and 2% more than the 2023 annual average.

More: *EIA*

Origis to Develop Solar, Storage Project with TVA

Renewable energy provider Origis Energy last week announced it has signed a power purchase agreement with the Tennessee Valley Authority for a 200-MW solar project with a 200-MW storage facility in Mississippi.

Origis will develop, build and operate the Hope solar plus storage complex and sell the electricity to TVA.

The project is expected to come online in 2028.

More: *Renewables Now*

State Briefs

REGIONAL

Study: Reaching 45% Solar Generation Would Save Southeast Utilities $20B

A Lawrence Berkeley National Laboratory study found that six Southeastern states could achieve 45% solar generation by 2035, and in turn cut utilities' cost by $20 billion a year.

A baseline scenario modeled in the study would reach 23% solar by 2035, amounts that are still "significantly" higher than the amounts of solar and storage currently installed in the region.

The region studied encompassed Kentucky, Tennessee, Alabama, Georgia, North Carolina, South Carolina, and parts of Missouri and Mississippi.

More: *pv magazine*

ILLINOIS

AG, Teleperformance Reach Settlement over Deceiving Tactics

The Attorney General's Office has reached a $10 million settlement with Teleperformance over allegedly deceiving customers of Ameren and other utilities into switching to higher-price providers.

The AG's complaint claimed Teleperformance or its subsidiaries worked to secure sales for alternative retail electric suppliers. But in doing so, the company used deceptive online advertisements leading consumers to believe they were calling Ameren or ComEd rather than a Teleperformance sales agent. The agents would sign consumers to more expensive contracts with those alternative suppliers.

Teleperformance also agreed to not engage in marketing activities in the state through July 31, 2026.

More: *The Journal-Courier*

KANSAS

Corporation Commission Approves Tx Lines

The Corporation Commission last week approved of a siting plan for two 345-kV transmission lines to connect wind and solar farms to the Grain Belt Express.

One line is set to run 46 miles through parts of Ford, Mead and Gray counties, while the other is 16 miles and will move through parts of Ford County.

More: *KSNT*

MICHIGAN

Audit: DTE, Consumers Outage Durations 'Worse Than Average'

A third-party audit issued by the Public Service Commission found that DTE Electric and Consumers Energy had "worse than average" interruptions and restoration delays when compared to other utilities.

The audits of the companies — which serve about 80% of the state's electric customers — were ordered in 2022 "amid a string of widespread outages and public frustration with unreliable service." The audits found that both Consumer and DTE's average interruption duration index in 2022 and 2023 was worse than average among other utilities. The report also noted the number of Consumers and DTE customers who experienced four or more outages as well as customers who experienced outages of 8 hours or more was "greater than usually acceptable for utilities."

DTE Electric President Matt Paul said the utility has a goal of reducing outages by 30% by 2029.

More: *The Detroit News*

MINNESOTA

Minnesota Power Plans Solar Projects

Minnesota Power last week announced plans to build two large-scale solar farms near Royalton and Cohasset.

The 85-MW Boswell Solar project would cover 600 acres and would use existing infrastructure at the Boswell Energy Center, a coal-fired power plant. The 120-MW Regal Solar project would cover 800 acres.

The projects will help the utility meet its goal of providing more than 80% renewable energy by 2030.

More: *MPR News*

NEBRASKA

EDF Renewables, OPPD Agree to Wind Farm PPA

EDF Renewables and Omaha Public Power District last week announced a power purchase agreement for the 300-MW Milligan 1 wind farm.

OPPD will procure electricity from Milligan 1 for 20 years. No other details were disclosed.

More: *Renewables Now*

NEW MEXICO

PRC Approves Carbon Limit Rule for PNM

The Public Regulation Commission last week voted 2-1 to approve an order that will outline compliance with an emissions requirement in the state's Energy Transition Act that applies only to the Public Service Company of New Mexico.

PNM is the only utility that has used the financing provisions of the ETA to shut down a coal-fired power plant. Because of that, PNM is limited in how much carbon dioxide it can emit per megawatt hour. The limit of 400 pounds per megawatt-hour went into effect on Jan. 1, 2023.

While PNM may not currently be meeting that emissions limit, compliance is measured on a three-year basis and is based on average emissions over those three years.

More: *NM Political Report*

NEW YORK

ORES Issues Permits for Large-scale Solar, Wind Projects

The Office of Renewable Energy Siting and Electric Transmission (ORES) last week issued siting permits for the Rich Road Solar Energy Center and Prattsburgh Wind projects.

The solar project will generate 240 MW, while the wind farm will generate 147 MW.

More: *Solar Industry Magazine*

Small Fire Trips Nuclear Plants

Constellation's Nine Mile Point Unit 2 and FitzPatrick Unit 1 tripped offline automatically Sept. 23 due to an electrical fire at Nine Mile.

The NRC later said the fire happened on the turbine deck of unit 2. The fire disturbed the grid enough to then trip the Fitzpatrick plant.

More: *WSYR*

SOUTH CAROLINA

Google Unveils $3.3B Investment in Data Centers

Google last week broke ground on a pair of data centers in Dorchester County, publicly announcing an investment of $2 billion that will employ 200 people.

The company also said it will spend $1.3 billion to expand its Berkeley County center.

Construction of the two centers will take a year to 18 months.

More: *South Carolina Daily Gazette*

VIRGINIA

Botetourt County Wind Farm Delayed Again

Construction of the 75-MW Rocky Forge Wind farm in Botetourt County was delayed by another year, pushing back the start date into 2025.

A year ago, Apex said it planned to start construction of the 13 turbines this summer or fall and finish by late 2025, which would have been a decade after the plan was first announced. At least a dozen aspects of the plan are still under review.

More: *The Roanoke Times*

Hanover County Denies Solar Farm

The Hanover County Board of Supervisors last week unanimously denied what would have been the largest solar farm in the county.

The 72-MW project, submitted by Strata Clean Energy, was amended after receiving an unfavorable recommendation from the planning commission in July. Strata was asking Hanover to rezone around 1,500 acres of timber land in the Beaverdam District.

More: *VPM*

Youngkin Admin Launching Green Bank

The state's Department of Energy last week announced the launch of the Virginia Clean Energy Innovation Bank within the department's State Energy Office.

According to Gov. **Glenn Youngkin's** administration, the new project, which will use $10 million in seed money, aims to accelerate the deployment of clean power and energy infrastructure.

The General Assembly passed legislation this year that would have established a similar system. Youngkin vetoed the bill. In a statement at the time, Youngkin said he vetoed the bill because legislators failed to adopt his recommended changes.

More: *Virginia Scope*

WASHINGTON

PSE Announces First Solar Project, Battery Storage System

Puget Sound Energy last week announced its first large-scale solar and battery storage projects to comply with the state's clean energy law.

The 142-MW solar project will be built in Garfield County, while the 200-MW storage system will be in Pierce County.

The projects are slated to come online in late 2026 and midyear 2027, respectively.

More: *The Seattle Times*

National/Federal news from our other channels

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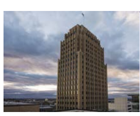

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