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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Your Eyes and Ears on the Organized Electric Markets

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FERC/Federal News

DOE Funding 4 Large Tx Projects, Releases National Tx Planning Study

By James Downing

The Department of Energy on Oct. 2 announced two actions to support the expansion of the transmission grid: investing up to $1.5 billion in four specific projects around the country and releasing the final National Transmission Planning Study.

The $1.5 billion investment from the Transmission Facilitation Program was authorized by the Infrastructure Investment and Jobs Act. DOE is giving the money upfront to four projects, which eventually can sell it to actual users, at which point the department will get its money back to use on future transmission projects, Deputy Energy Secretary David Turk said on a call with reporters Oct. 1.

"Like many things about the clean energy transition, building new transmission is extremely challenging, and it's also extremely urgent," Turk said.

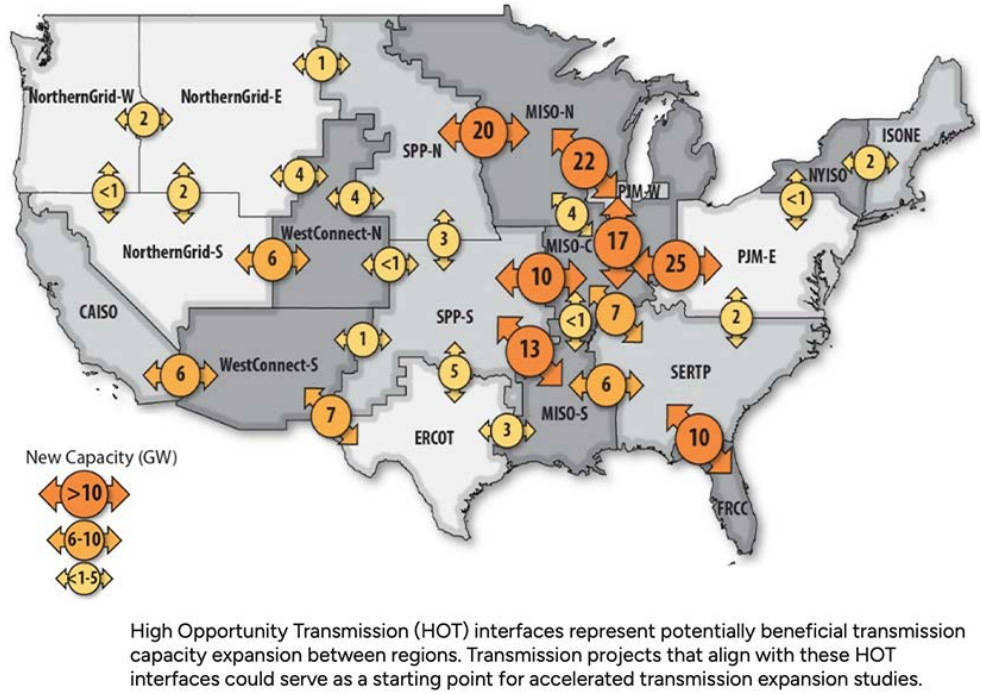
DOE announced the first three lines under the TFP last fall; all three have signed deals with the department, Turk said. In total, the TFP should help build more than 3,000 miles of new transmission by early next decade. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

Avangrid Network's Aroostook Renewable Gateway in Northern Maine will negotiate for DOE for funding of up to $425 million to build out the 111-mile project that seeks to link up to 1,200 MW with ISO-NE. The region lacks direct connections with the rest of New England, and the line would help three mature wind projects connect to the market, with the potential for more wind and solar development.

Invenergy's Cimarron Link Transmission is negotiating for TFP funds of up to $306 million to build its 400-mile HVDC line running from Oklahoma's panhandle to Tulsa in the east, opening 1,900 MW of transfer capacity that can deliver wind and solar to load centers.

Pattern Energy's Southern Spirit Transmission project also is up for negotiations for $360 million to help get the 320-mile, 525-kV HVDC line that would connect ERCOT to the Southeast. The line can ship up to 3,000 MW of renewables from Texas to the Southeast and can ship power the other way if demand spikes in Texas.

Southern Spirit could better help ERCOT make it through a cold snap, avoiding some of the devastation seen during Winter Storm Uri in 2021, White House National Climate Advisor Ali Zaidi said.



Where the National Transmission Planning Study found potential high-value interregional transmission | *DOE*

Why This Matters

The Department of Energy is hoping to help four major transmission projects move forward by serving as a temporary off-taker, while its National Transmission Planning Study promises to be a resource for those interested in expanding interregional transmission.

"This buildout is really transformational in breaking down the barrier between ERCOT and the rest of the country, and it feeds into this broader insight that this administration has pushed, which is essentially [that] interregional transmission translates to lower costs for consumers and higher reliability across the system," Zaidi said.

Southern Spirit has been under development for years, with FERC finding in 2014 that it would not trigger federal regulation over ERCOT, according to a fact sheet from Pattern.

Phase 2 of Grid United and Black Forest Partners' joint Southline Transmission Project would add a 108-mile, 345-kV line capable of delivering 1,000 MW of capacity across New Mexico, helping to support electricity delivery in the Southwest. It is up for $352 million. Southline Phase 1 was in the first set of projects announced last year.

"You need only to look at the recent devastation of Hurricane Helene to know how the climate crisis is already straining our existing grid infrastructure at the precise moment when we need that infrastructure to be larger, stronger and more reliable," White House Senior Advisor John Podesta said.

National Transmission Planning Study

The National Transmission Planning Study features a set of long-term planning tools and analyses that examine potential scenarios through 2050, including various interregional transmission expansions.

It shows the highest level of grid reliability can be maintained at the lowest cost by coordinating interregional transmission. The study was developed by the DOE Grid Deployment Office alongside the National Renewable Energy

FERC/Federal News

Laboratory and the Pacific Northwest National Laboratory, who said they want other planners to use it in their efforts.

A substantial expansion of the transmission system throughout the entire contiguous U.S. delivers the largest benefits of up to $270 billion to $490 billion through 2050. Every dollar invested in transmission leads to returns of $1.60 to $1.80 in system costs saved, the study found.

Being able to coordinate resource adequacy across better connected regions lowers systems costs by $170 billion to $380 billion, the study found.

The use of HVDC transmission technologies with multiple terminals — meaning power can be sent bidirectionally and from multiple entry and exit points in regions — was shown to be the most cost-beneficial way to stitch together a macrogrid across the Lower 48.

"When translating zonal scenarios to nodal network models, HVDC was found useful for transferring power over long distances and between interconnections, but AC network expansion will continue to be the best solution for a large portion of transmission additions," the study said. "Large interregional HVDC network solutions will also require additional strengthening of the regional AC networks they interconnect."

DOE has been working on the NTP since 2022. Its goal was to identify pathways that maintain current levels of reliability and saving costs while meeting local, regional and national interests, Grid Deployment Office Director Maria Robinson said on a call with reporters.

"This study goes down to the nodal level, instead of at the zonal/regional level, and that means that this is a tool that utilities can actually use to help them determine what kinds of investments that they might want to make," Robinson said.

So far, interregional transmission plans have been very limited, with Robinson pointing to MISO and SPP's Targeted Interconnection Queue Study as a rare example of it actually happening.

"So, this is why we think it's important to make sure that these tools are available, so that it is easier for those folks who are looking to do so, and also so that we're able to use the best-in-class modeling available from the National Laboratories," she added.

DOE is not going to tell FERC how to do its job, she added. Chair Willie Phillips has said the commission could look at interregional planning in the future, noting that NERC's interregional transfer capability is due at the end of the year. (See *Webinar Examines How FERC Could Use Interregional Transmission Study*.)

The department has provided some technical assistance to NERC on its interregional transfer capability study and offered updates to it on what was being developed in the NTP, Robinson said.

"Of course, while doing coordination, it doesn't mean that the exact thing will happen in both places," Robinson said. "So, we are really looking forward, as everyone else is, to seeing the ultimate results come out of that study. But a lot of the fundamentals are relatively similar, and it's just nice to see this greater interest in interregional transfer capacity, understanding that it can be so important in times like right now in extreme weather events." ■

FERC/Federal News

DC Circuit Affirms FERC Ruling on Seabrook Circuit Breaker Dispute

By Jon Lamson

The D.C. Circuit Court of Appeals has *affirmed* FERC's ruling that NextEra Energy is responsible for replacing the circuit breaker at its Seabrook Station nuclear plant to accommodate the interconnection of the New England Clean Energy Connect (NECEC) transmission line.

ISO-NE determined the circuit breaker at Seabrook, currently at 99.6% of its capacity, would be overloaded with the additional flow of power from Avangrid's 1,200 MW NECEC project, which is under construction. (See *Avangrid Details Progress on NECEC Tx Line*.)

While FERC found Avangrid is responsible for the direct costs of upgrading the circuit breaker, it ruled Avangrid is not responsible for NextEra's indirect costs of the replacement, including legal expenses and revenue lost during the replacement.

"We hold that the agency had statutory authority to require the upgrade, correctly interpreted the governing tariff and contract to require the upgrade, and permissibly denied compensation for its indirect costs," Judge Gregory Katsas wrote in the court's Oct. 4 ruling.

NextEra argued the circuit breaker is non-FERC jurisdictional because it exists to protect the generating facility, and so the commission doesn't have the authority to require NextEra to make the upgrade (*EL21-3*, *EL21-6*). (See *FERC Resolves NextEra-Avangrid Dispute over Seabrook Circuit Breaker*.)

The court found the upgrade is FERC jurisdictional because "the upgrade directly affects the transmission of electricity in interstate commerce, an area where FERC may regulate."

"If FERC could not order an upgrade in those circumstances, incumbent generators could unilaterally prevent competing sellers from joining the grid, which would directly — and substantially — limit how much electricity could be transmitted," the court added.

The court also pointed to a previous ruling that backed FERC's ability to "exercise jurisdiction over generation facilities to the extent necessary to regulate interstate transmission."

Judge Neomi Rao authored a dissent to the majority ruling, arguing the language in the ISO-NE tariff does not require NextEra to replace the circuit breaker, and therefore the company should not be required to make the upgrade, regardless of the implications on interconnection in the region.

"The broader regulatory context and policy concerns cited by the majority may be relevant to FERC's determinations when setting just and reasonable rates and practices. These considerations, however, are impermissible for the judicial task of identifying the plain meaning of existing tariffs and contracts," Rao said. She added that FERC could initiate a Section 206 proceeding to amend the tariff if it deems changes to be necessary.

Rao also argued the majority opinion "reverts to a Chevron-like framework, insisting its interpretation is 'textually permissible' and consistent with regulatory goals."

In response, Katsas wrote that the RTO's interconnection procedures require NextEra to follow "good utility practice" to maintain the breaker and other devices needed to prevent short-circuiting on the grid, adding that the tariff does not grant NextEra "a unilateral right to veto Avangrid's interconnection." ■

The Seabrook Station nuclear plant in New Hampshire. | *Jim Richmond, CC BY-SA 2.0, via Wikimedia Commons*

CAISO/West News

Regulators Who Launched Pathways Praise Western 'RO' Plan

Proposal Applauded for Prioritizing 'Parity' Between CAISO, Other BAs

By Robert Mullin

State utility commissioners who launched the West-Wide Governance Pathways Initiative in July 2023 have praised the initiative's "Step 2" proposal to create a "regional organization" (RO) to oversee a Western electricity market and gradually take on more functions of an RTO.

Oregon Public Utility Commissioner Letha Tawney | © *RTO Insider LLC*

"I'm really, really struck by the power of what has been proposed," Oregon Public Utility Commissioner Letha Tawney said during an Oct. 4 Pathways Initiative meeting to discuss the plan.

The Pathways Initiative's Launch Committee released the proposal Sept. 26 after a year of discussions and a summer of intensive stakeholder workshops. (See *Pathways Initiative Releases 'Step 2' Proposal for Western 'RO'*.)

The plan, which calls for the RO to launch under the "Option 2.0" refined over the past year, would see the new organization initially serve as a "policy-setting" body for CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM), operating under a tariff shared with the ISO.

The proposal defers the adoption of an "Option 2.5" in which the RO takes on more of the ISO's responsibilities and liabilities, leaving that decision to the RO and its board in the future.

Tawney was one of nine Western state energy commissioners to sign the July 2023 *letter* that kicked off Pathways by proposing "creation of an entity that could serve as a means for delivering a market that includes all states in the Western Interconnection, including California, with independent governance."

The commissioners sent the letter to the chairs of the Committee on Regional Electric Power Cooperation and Western Interstate Energy Board just as SPP's Markets+ day-ahead offer emerged as a serious challenger to the EDAM and WEIM, raising the prospect that the West could become divided into two markets separated by a complex seam, depending on the footprints of each. (See *West Entered Pivotal Period for RTO Development in 2023*.)

"At its core," Tawney said, the new Pathways proposal intends to "set up real parity between the [CAISO] BA and all of the other BAs in the West" and puts "everybody on the same footing, making decisions at the timing that works for them, for their community, for their regulatory agencies or bodies."

"It is really creating an opportunity for customer value that we had hoped would be there when we put the letter out, and it's exciting to see it really emerge in the framework that is encapsulated in this proposal" she said.

New Mexico Commissioner Pat O'Connell said he took a "leap of faith" when he helped write the letter.

"One thing that I just wanted to acknowledge in this moment is congratulations to the Launch Committee for getting to this point — and then thank you very much to the stakeholders for helping build it up to this point," O'Connell said.

"So just in a moment where we went from leap of faith to now, I can see it: that this idea that the largest possible footprint is [viable] and that we could maximize consumer benefits that way," he said.

O'Connell said much of the analysis that utilities and other entities have performed has "put the math behind the concept" that consumer benefits increase "if we can get to the widest possible footprint."

A recent study by The Brattle Group found New Mexico's utilities would see greater financial benefits from joining EDAM rather than Markets+, even if Arizona utilities were to join the latter. (See *Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+*.)

"I don't want to sugarcoat it — there's still a lot of work to do — but this is an important milestone, and the fact that there are so many folks on this [Pathways] call this morning is another affirmation that the idea was sound," O'Connell said.

"This has just been a tremendous process with so many different stakeholders from across the West looking to create something that's going to work for the entire West," said Darcie Houck, a member of the California Public Utilities Commission, whose president, Alice Reynolds, signed the letter. "I've just have been very, impressed with the process, the engagement by all of the different states and stakeholders, and [am] really looking forward to seeing the comments that are coming back and moving forward on the next step."

'Unreasonable Ask'

Tawney said the failure of previous attempts to transform CAISO into an RTO couldn't be attributed to "a lack of trying by a lot of really thoughtful folks over many years."

Tawney said she understood why California lawmakers had been reluctant to pass a bill that would relax state oversight over the ISO and place it under independent governance.

Requiring one balancing authority to "regionalize" itself ahead of other BAs is "unreasonable," she said.

"Because if somebody had come to me and said, 'I want to take [Portland General Electric's] balancing area and put it under regional governance, and maybe some folks will join me later,' I'd have immediately said, 'What about PGE's customers?' … And I might have had a big reaction [and said], 'No, I think we will be keeping those decisions to protect PGE customers a little closer to home," Tawney said.

Tawney said Pathways showed that stakeholders across the West are "deeply aligned on protecting our customers, on protecting affordability, on thinking through reliability and how we can all work together," put participants on "equal footing" and allowed each state to move at its own pace in deepening the relationship with the RO.

Launch Committee Co-Chair Pam Sporborg, PGE's director of transmission and markets, said the Step 2 proposal differs from past regionalization efforts because it focuses narrowly on governance of the energy market, rather than taking on all the functions of an RTO at once.

The plan also establishes a "parity relationship" between CAISO and other EDAM/WEIM participants by allowing the ISO to maintain its balancing authority reliability functions — just like other BAs — while handing oversight of the joint market to a "fully independent governance structure," Sporborg said.

Committee member Scott Miller, executive director of the Western Power Trading Forum, said the committee "wrestled with" the question establishing the RO under the "lighter touch" of Option 2.0 or the "more robust" 2.5.

"There was good, healthy debate, and I think where we ended up reflected the good nature and well-intentioned efforts of the Launch Committee to try to reach compromise that met everybody's needs," Miller said. ■

CAISO/West News

FERC Approves CAISO Plan to Streamline Interconnection Process

Revised Rules Meant to Complement the ISO's Order 2023 Compliance Filing

By Robert Mullin

FERC has approved CAISO's proposal to streamline its generator interconnection process to deal with the "unprecedented volume" of interconnection requests it received in 2023, in part stemming from the aggressive push to decarbonize California's economy.

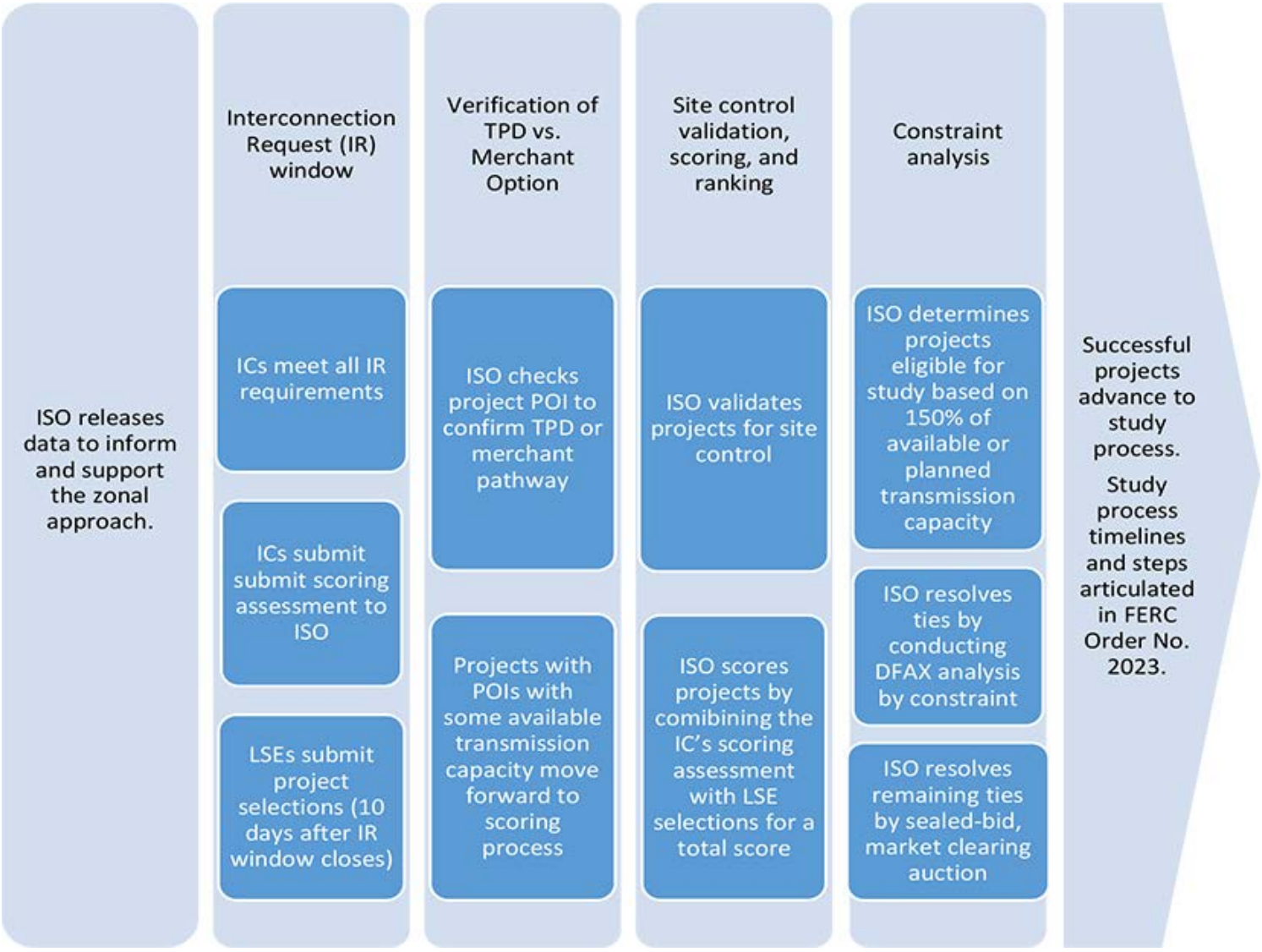
The product of more than a year of stakeholder engagement, the Interconnection Process Enhancements (IPE) proposal was designed to speed up CAISO's interconnection queue by reducing the number of projects the ISO must review in its queue cluster study process through use of a new screening procedure that prioritizes projects based on transmission availability and commercial viability. (See *CAISO Board Approves Interconnection Enhancements Proposal*.)

The IPE proposal approved Sept. 30 by FERC is intended to complement — and not replace — CAISO's FERC Order 2023 compliance filing. The commission said the approval is subject to its action on the ISO's Order 2023 compliance filing.

The IPE tariff revisions will apply to the ISO's outsized interconnection Cluster 15 — from 2023 — and subsequent cluster periods.

Why This Matters

FERC's approval marks the successful conclusion of a yearlong stakeholder process intended to give the ISO the tools to more quickly move through the huge volume of interconnection requests it received in 2023.



This graphic illustrates CAISO's newly approved interconnection request (IR) intake process. | *CAISO*

CAISO/West News

"CAISO has demonstrated that applying the proposed revisions to Cluster 15 will enable CAISO to effectively process the largest queue cluster it has ever received," the commission wrote in its 103-page order (*ER24-2671*).

A central aspect of the IPE proposal is adoption of a zonal approach that prioritizes interconnection of resources that use existing available transmission capacity in areas where capacity additions have been approved in the ISO's transmission plan, as set out in state and local regulatory authority resource planning portfolios.

The zones are defined by available capacity based on transmission constraints and the California Public Utilities Commission's resource planning portfolio. A zone containing at least 50 MW of available transmission capacity is defined as a transmission plan deliverability (TPD) zone. Generation projects seeking to interconnect outside TPD zones "may proceed as merchant projects and will self-fund their associated network upgrades" in those so-called "merchant zones," according to the proposal.

The proposal also introduces scoring criteria that rank projects based on factors such as project readiness, load-serving entity interest and commercial — or non-LSE — interest.

Under that part of the process, LSEs will award points to projects based on a 1-to-100 scale, with the points representing the percentage of transmission capacity the LSEs would assign to the projects. Non-LSEs can award a maximum of 25 points, which CAISO attributed to the fact that LSEs must meet specific resource adequacy and procurement requirements while non-LSEs have no such obligations, although they might be serving a commercial interest.

"Notably, in evaluating commercial interest, the ISO will incorporate preliminary, non-binding feedback on specific projects from load-serving entities," the proposal says. "In addition, the ISO provides an opportunity for non-LSE offtakers (e.g. commercial entities) to express an interest in specific projects. These commercial selections will improve the scores of certain projects, increasing the likelihood of those projects advancing to the study process and ultimately competing for transmission plan deliverability (TPD) and offtake agreements."

The highest-ranking projects then advance to the study phase in descending order of project scores, until the available and planned transmission capacity within a zone (and behind constraints) is filled to 150% of that capacity. CAISO will resolve ties by selecting projects with the lowest distribution factors (DFAX). If a tie persists, the ISO "will conduct a market-clearing sealed-bid auction to advance to the study process that will align with the process required under FERC Order No. 2023," according to the proposal.

'Monitor the Efficacy'

In approving the IPE tariff rules, the commission said it found the revisions fulfill the purposes of FERC's Order 2003 and Order 2023 rules on generator interconnection "by helping to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent and timely manner."

FERC found the zonal aspect of the plan, which subgroups projects based on transmission deliverability, "links the CAISO interconnection process with the transmission planning process and resource planning process, ensuring that interconnection requests in zones with sufficient deliverability to serve them are prioritized, which will improve certainty for developers while addressing queue backlogs."

The commission also rejected the arguments of protestors who called the proposal's distinction between "merchant" and TPD zones discriminatory, determining the proposal's process requiring interconnection customers outside TPD zones to self-fund network upgrades is consistent with FERC's interconnect pricing policy.

"The commission has previously allowed RTOs or ISOs with locational pricing to require interconnection customers to bear the cost of all facilities and upgrades not needed but for the interconnection, stating that providing reimbursements or service credits for network upgrades that would not be needed but for the interconnection mutes the incentive for a customer to make an efficient siting decision that accounts for transmission costs," it wrote.

FERC also dismissed the concerns of Shell and Vistra regarding the transparency of the zonal approach, finding CAISO's plans to publish supplemental information on its website describing conditions and constraints in each transmission zone, along with the ISO's "commitments to provide information about its zonal determinations, provides sufficient transparency to inform the preparation of interconnection requests under the proposed cluster study criteria."

The commission further rejected the arguments of multiple protestors in accepting the proposal's scoring criteria.

"Specifically, prioritizing those interconnection requests that are more advanced in their technical planning and design can help CAISO eliminate speculative interconnection requests and identify potential interconnection customers that have completed more of their project development in advance of the cluster request window, and are therefore more likely to reach commercial operation," the commission wrote.

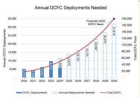
The commission said it still will evaluate CAISO's compliance with each requirement in Order 2023 and that "nothing in this order prejudges the outcome of that evaluation." It also noted CAISO's commitment to "monitor the efficacy" of the IPE revisions and said it expects the ISO to continue to engage with stakeholders on "further enhancements to improve the interconnection process as needed."

"Our tariff filing for a reformed interconnection process was complex and we fully acknowledge that stakeholders had a variety of opinions on some of the details," CAISO CEO Elliot Mainzer said in a statement.

"We appreciate the ruling by FERC and what it will mean for more efficient planning and onboarding of resources, and we are committed to moving forward in partnership with our many stakeholders to effectively and transparently implement the reforms. As the order requires, we will also closely monitor how well they are working," Mainzer said.

The new rules became effective Oct. 1. ■

National/Federal news from our other channels



EEI Projects Need for 42.2M Charge Ports by 2035

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CAISO/West News

CAISO Board Approves Moving Forward with SWIP-N Transmission Line

Idaho Residents Appear Before Board to Raise Concerns

By Ayla Burnett

The CAISO Board of Governors on Oct. 4 unanimously approved changes to the Southwest Intertie Project-North (SWIP-N), a 285-mile, 500-kV line in Nevada that would enable access to Idaho wind resources, despite opposition from Gem State residents.

In April, the Department of Energy signed a facilitation agreement to provide $33.1 million to fund Idaho's potential 22.831% share of the project to expedite the process. CAISO had asked the board to approve two motions: to allow the DOE funding, and to approve project developer Great Basin Transmission's application to become a participating transmission owner in the ISO.

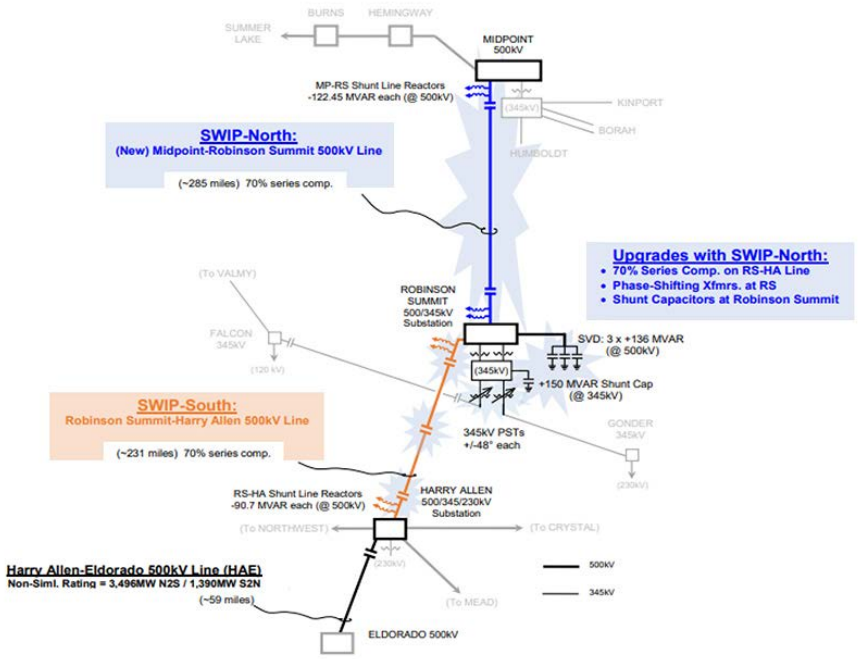
The project would enable CAISO to meet the California Public Utilities Commission's Integrated Resource Plan requirements, which call for just over 1,000 MW of Idaho wind power in the 2024-2025 transmission planning cycle. According to transmission planners at the ISO, SWIP-N is the only known transmission project that would provide California load-serving entities with Idaho wind by 2027.

While SWIP-N was conditionally approved by the board in December 2023, moving to the construction phase still relied on the approval of the two motions.

"Unlike a project directly assigned to an incumbent transmission owner under the Transmission Control Agreement, this did not move the project straight to execution," Neil Millar, vice president of infrastructure and operations planning at CAISO, said at the board's meeting.

Deb Le Vine, executive director of infrastructure contracts and management at CAISO, presented details on the status of the project, as well as the two motions. The project was initially approved under four conditions: that Idaho Power file and receive approval for the project with the Idaho Public Utilities Commission by Sept. 30; that the California PUC reaffirm the need for Idaho wind in its 2024-2025 transmission planning process portfolio; that Great Basin declare its intent to become a PTO by July 1; and that FERC accept Great Basin's proposed tariff and transmission revenue requirement rate structure.

Idaho Power has not yet filed with the Idaho PUC, meaning that FERC has not yet approved Great Basin's tariff. The other two conditions were met.



The CAISO Board of Governors approved two new motions that would move the Southwest Intertie Project-North to the construction phase. | *CAISO*

"It's critical to enable Idaho wind to reach California, consistent with the CPUC system plan," Le Vine said.

Opposition from Idaho Residents

While SWIP-N isn't tied to any specific generators in Idaho, some residents opposing the Lava Ridge Wind Power project and others in the region expressed concern about SWIP-N.

Dan Sakura, a fourth-generation Japanese American whose ancestors were interned at the Minidoka War Relocation Center in Idaho — a National Historic Site — said the area is now located in a "dense transmission network" because of its proximity to a railroad. Sakura, along with the Seattle-based *Minidoka Pilgrimage Planning Committee*, has been fighting LS Power since 2009 when it sought to build the SWIP-N line over the site. The organization is also fighting the Lava Ridge Wind Project, which it believes to be associated with SWIP-N.

Sakura asked the board to delay its decision until its meeting in December to allow for more time to "get a better analysis of the legal, regulatory, policy and electoral risks associated with wind energy from Idaho."

Another Idaho resident, Dean Diamond, a farmer whose property borders the Minidoka site, echoed Sakura's concerns.

"There is a lot of strong local opposition to the SWIP line and to the wind projects. I think that it poses a really significant risk that the wind projects most likely aren't going to be built," Diamond said.

"We're not aware of that high opposition, just an attempt from those against the wind projects to link SWIP-N to that," responded Mark Milburn, senior vice president of LS Power. "I think it's also important to address that the commenters thus far haven't acknowledged that in [the Bureau of Land Management's] preferred alternative for the final environmental impact statement for the Lava Wind Ridge Project, they significantly scaled back the project to address the concerns raised by different stakeholders in that process."

Milburn noted that the project footprint was reduced by 50% and the number of turbines by 40%, along with a 10% reduction in turbine tip height.

Board Chair Jan Schori thanked the commenters for participating in a process that "can be quite challenging to understand."

"We do appreciate the fact that you're participating with us today and helping educate us," Schori said. ■

CAISO/West News

CAISO Launches Phase 2 of Pricing Issues Initiative

Effort Seeks to Address Scarcity and Fast-start Pricing, Market Power Mitigation

By Ayla Burnett

CAISO on Sept. 30 launched Phase 2 of its Price Formation Enhancements Initiative, aimed at addressing issues specific to market power mitigation, scarcity pricing and fast-start pricing in its markets — including the Western Energy Imbalance Market and Extended Day-Ahead Market.

"These enhancements aim to improve the accuracy of our market clearing prices, provide better market price signals, and enhance incentives for resources to perform," James Friedrich, CAISO lead policy developer, said during a meeting to launch the effort. "It is the general view of the [Price Formation Enhancements] working group that enhancements in these areas could help the market become a more effective steward of reliable outcomes."

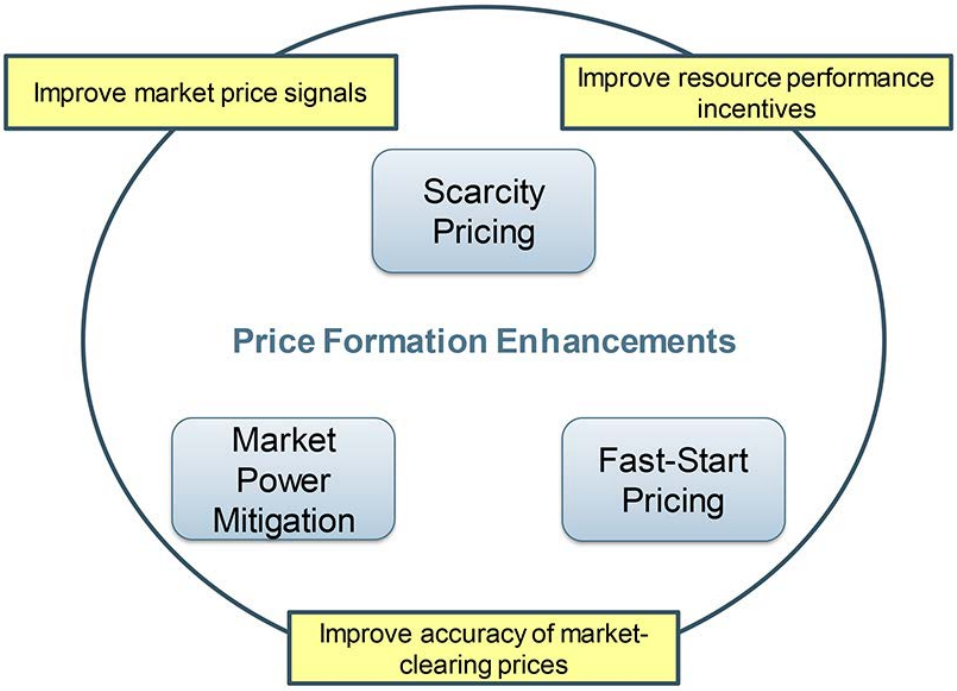
Phase 1 of the initiative hosted 18 working group meetings and resulted in a FERC-approved tariff change that allows hydroelectric and energy storage resources to bid above the ISO's $1,000/MWh soft offer cap. (See *FERC Approves CAISO Request to Lift Soft Offer Cap for Hydro, Storage*.)

Scarcity Pricing

Scarcity pricing, a mechanism to determine market prices when supply falls short of demand, came into focus for CAISO following grid emergencies during the summers of 2020, 2022 and 2023, Friedrich said.

The increased risk that comes with declining reserves and a rising loss-of-load expectation should translate into the market's willingness to pay more for additional reserves to maintain reliability. And while the ISO already relies on a number of different scarcity pricing mechanisms — including the scarcity reserve demand curve, the flexible ramping product and bidding above the soft offer cap — ISO staff and stakeholders saw a need to improve on those mechanisms to ensure more efficient market outcomes and maintain grid reliability.

"It's important to note that while these mechanisms provide a good foundation for scarcity pricing in our markets, this initiative considers potential enhancements to ensure that they accurately reflect scarcity conditions across the entire market footprint and across all market intervals," Friedrich said.



CAISO's Price Formation Enhancements Initiative has three main areas of emphasis, shown here. | *CAISO*

Why This Matters

CAISO staff say addressing problems around scarcity pricing, fast-start pricing and market power mitigation will lead to a more reliable market. Supporters of SPP's Markets+ also pointed to the absence of fast-start pricing as a shortcoming in the ISO's Extended Day-Ahead Market.

Staff and stakeholders have identified four key issues around scarcity pricing.

First, the market is inconsistent in how it procures ancillary services, a function not applicable to the WEIM or EDAM. The real-time market only procures incremental ancillary services for the CAISO balancing authority area (BAA), rather than fully re-optimizing them, Friedrich said. The market also doesn't re-optimize in the five-minute market, leading to less efficient scarcity pricing outcomes and procurement.

Second, prior working groups had also identified potentially outdated penalty prices, which are currently tied to the market bid cap and may not accurately reflect the true reliability value of a resource during scarcity events, Friedrich explained. Stakeholders also expressed concern that the prices may be too low to provide effective incentives.

The third issue relates to potential disconnects between market prices and grid conditions during emergencies. The current market design may not adequately reflect the severity of emergency conditions in market prices, Friedrich said, leading to situations in which prices don't align with the actual scarcity level indicated by emergency operator actions.

The last problem centers around insufficient scarcity signals. The scarcity reserve demand curve and power balance constraint violations in the market only get triggered during actual shortages, Friedrich said, which can result in price spikes that are "volatile and unpredictable."

"Collectively, these issues point to the need

CAISO/West News

for reform of our scarcity pricing mechanism, and by addressing these problems we aim to improve market efficiency, enhance reliability and provide more accurate price signals that reflect real-time grid conditions," Friedrich said.

Elaborating on the initiative's main objectives, Friedrich highlighted three main goals:

- to improve market signals during tight supply conditions so that prices accurately reflect the true state of the grid;
- to incentivize resource performance and demand reduction; and
- to align prices with real-time grid conditions across the WEIM.

But two significant hurdles stand in the way of achieving these goals, Friedrich said. The first is the need to address discrepancies in how scarcity pricing applies across different balancing authorities in the market, while the second is the need to identify a "consensus-driven method to scale and anchor penalty prices."

Market Power Mitigation

Friedrich said CAISO must also change rules around market power mitigation, which prevents the exercise of structural market power when a BAA is price-separated from CAISO.

Three main problems were identified in prior working groups: structural market power may be overestimated in individual BAAs; the CAISO BAA is excluded from the market power mitigation test; and the frequent mitigation during off-peak hours with low prices raises questions about current triggers.

The top priority is to ensure competitive pricing while refining mitigation mechanisms for WEIM and Extended-Day Ahead Market (EDAM) BAAs.

Fast-start Pricing

Friedrich also gave an overview of fast-start pricing, which integrates commitment costs of fast-start resources into market prices.

"Fast-start pricing recognizes that fast-start resources may serve as the marginal resource used to meet the next increment of energy or operating reserves demand," Friedrich's presentation said. "However, they often have output levels that prevent them from being fully dispatchable and thus are often ineligible to set the LMP."

Phase 1 included a stakeholder-requested analysis to determine the potential market impact of fast-start pricing and whether it should be implemented. The analysis demonstrated a "generally moderate" impact, and some stakeholders saw value in continuing to prioritize the topic in discussion, while others didn't. While members of the working group haven't reached consensus, they mostly supported a deeper analysis of fast-start pricing.

Supporters of SPP's Markets+ have pointed to the absence of fast-start pricing as a shortcoming of the EDAM.

The working group's next Phase 2 meeting is tentatively scheduled for Oct. 23, and the target date for a straw proposal is May 25, 2025. ■

CAISO/West News

Newsom Signs Bundle of Grid-related Bills from 2024 Session

Legislation Covers Tx Approval Rules, EV Charging, GETs, Reliability

By Elaine Goodman

California Gov. Gavin Newsom has signed a bill to streamline approval of transmission projects by removing a requirement for regulators to evaluate non-transmission alternatives such as demand-side management.

Assembly Bill 2292, by Assemblymember Cottie Petrie-Norris (D), is just one in a bevy of bills the governor signed into law in the days leading up to a Sept. 30 bill-signing deadline. Other new laws relate to bi-directional EV charging, industrial energy use and hydrogen fueling stations.

Proponents of *AB 2292* said the bill makes a modest but important change to the California Public Utilities Commission approval process for transmission projects.

The bill removes a requirement for the CPUC to consider cost-effective alternatives to transmission facilities "that meet the need for an efficient, reliable and affordable supply of electricity." Those alternatives may include demand-side options such as targeted energy efficiency or ultraclean distributed generation.

Requiring the CPUC to review alternatives duplicates work done by CAISO in identifying the need for the project as part of its transmission planning process, supporters said.

The new law comes as the CPUC is updating its General Order 131-D to make the permitting process for transmission projects more efficient and consistent. (See *CPUC Works to Revamp Tx Permitting Rules*.)

Bi-directional Charging Bill

Another bill signed by Newsom could lead to a requirement for electric vehicles to be equipped for bi-directional charging.

Why This Matters

The bills signed by California Gov. Gavin Newsom will affect the electricity grid in a variety of ways because they cover rules for transmission approval, GETs, reliability standards and bi-directional EV charging.

California Gov. Gavin Newsom speaking at a bill-signing ceremony on Sept. 25. | *Office of Gov. Gavin Newsom*

Senate Bill 59, by Sen. Nancy Skinner (D), authorizes the California Energy Commission (CEC) to require any size class of battery EV to be capable of bi-directional charging — if there is a "compelling beneficial" use case for both the EV operator and the electrical grid.

"Bi-directional capabilities in BEVs have the potential to improve customer energy reliability, resiliency and demand management during electric grid stress events while supporting our state's transition to zero-emission transportation," Newsom said in a bill-signing *message*.

The governor's message noted the complexities of aligning BEVs with the bi-directional charging equipment, while factoring in electric rates and potential grid effects.

Another Petrie-Norris bill signed by the governor is *AB 2779*, which promotes the use of grid-enhancing technologies. The bill requires 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.

GETs are a way to expand the capacity of the grid much more quickly than building new transmission, which can take years. They include advanced reconductoring and other technologies.

The governor previously signed SB 1006, by Sen. Steve Padilla (D), which requires utilities to study the feasibility of using GETs. (See *California GETs Bill Gets Newsom's Signature*.)

RA Requirements

Another bill signed into law is Petrie-Norris' *AB 2368*, which addresses electric system reliability.

The bill, sponsored by the Clean Energy Buyers Association, requires the CPUC to adopt a 1-in-10 loss of load expectation (LOLE), or a "similarly robust reliability metric," when setting resource adequacy requirements. (See *Clean Energy Buyers Push Passage of New Calif. Reliability Law*.)

The bill also requires the CPUC to determine whether measures are needed to reduce the costs to ratepayers of a resource adequacy program.

A bill sponsored by the California Nevada Cement Association also received Newsom's signature. *AB 2109*, by Assemblymember Juan Carrillo (D), will exempt large industrial customers from paying their utility a departing load charge if they use waste heat to generate their own power.

The bill will make industrial process heat recovery cost effective and advance the state's efforts to decarbonize manufacturing, CNCA Executive Director Tom Tietz said in an *opinion column*.

Hydrogen Fueling Stations

SB 1418 by Sen. Bob Archuleta (D), which the governor signed, is intended to speed up local government permitting of public hydrogen-fueling stations.

Cities and counties are already required to streamline the permitting process for EV charging stations. SB 1418 will extend that streamlining by requiring cities and counties to adopt an ordinance and checklist for permitting hydrogen-fueling stations.

Archuleta noted in a release that the Department of Energy has awarded up to $1.2 billion to California's hydrogen hub, the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES).

"Success hinges on rapidly scaling up hydrogen-fueling infrastructure and vehicle development," the release said. "California cannot achieve its zero emission goals without success at the local level." ■

CAISO/West News

CAISO Outlines EDAM Access Charge Plan for Its Own BA

Mechanism Designed to Compensate TOs for Lost Revenues After EDAM Launch

By Ayla Burnett

CAISO on Oct. 7 described to stakeholders how it will apply the Extended Day-Ahead Market (EDAM) transmission revenue recovery mechanism to its own balancing authority area.

The mechanism, referred to as the EDAM access charge, will allow transmission owners (TOs) to recover transmission revenue shortfalls attributed to transitioning their assets into the day-ahead market.

The access charge was the only provision of CAISO's initial EDAM tariff proposal that FERC rejected last December, finding the ISO failed to justify the reasons behind the three components constituting the charge. CAISO revised the plan and it was accepted by the commission in June. (See *FERC Approves EDAM Tx Revenue Recovery Plan*.)

During the Oct. 7 meeting, CAISO staff gave an overview of how the access charge could be applied within the ISO through an explanation of the plan's three components for calculating and recovering lost revenue after launch of the EDAM.

The first component allows TOs to recover historical transmission revenues associated with wheeling access charge (WAC) revenues.

"When an EDAM entity joins the EDAM, the intertie point becomes a transfer point between the ISO and that EDAM entity, and there may be an impact on wheeling access charge [WAC] revenues that were historically recovered across that intertie," Milos Bosanac, CAISO regional markets sector manager, said at the meeting. "This component 1 allows for the recovery of those historical WAC revenues at that particular intertie to the extent that there's an impact."

The WAC revenues eligible for recovery under the mechanism will be based on a three-year average of revenues prior to that transfer point becoming an EDAM point, Bosanac explained. The draft tariff revision states that each TO will be responsible for calculating the first component.

CAISO is working through the details of how to apply the EDAM access charge to its balancing authority area. | *© RTO Insider LLC*

Why This Matters

The mechanism will allow CAISO transmission owners to recover transmission revenue shortfalls attributed to transitioning their assets into the EDAM.

Heather Curlee, senior counsel at CAISO, dove into the draft tariff language to implement the access charge in the ISO and provided additional details on the plan's components.

The second component seeks to compensate TOs for costs "associated with forgone transmission sales on eligible existing contracts or [transmission] upgrades" that potentially increase the transfer capability between EDAM areas. Recovery of those costs would again require analyzing the three-year historical average of recovered revenues on a particular EDAM transfer point and comparing it to the overall ratio of the total transmission revenue requirement within the BA.

According to the tariff, a participating TO with existing contracts will calculate the second component, to include revenue shortfalls associated with the release of transmission capacity resulting from expiring existing rights not included in the first component.

The third component centers on compensating CAISO TOs for EDAM wheel-through transfers that provide benefits for other parts of the market footprint.

The draft tariff revisions say that in periods when the total volume of EDAM wheel-through transactions exceeds the total net transfers of the CAISO BA, the ISO will calculate by multiplying its share of the excess volume based on its individual share of transmission revenue requirements in relation to total transmission revenue requirements for the CAISO BA.

CAISO will distribute to gross load in the ISO BA each EDAM access charge allocated to its BA, according to the proposed tariff revision.

The ISO plans to file the draft tariff language with FERC in November. ■

ERCOT News

PUC's Gleeson at Texas Clean Energy Summit: Smooth Tenure Turns 'Interesting'

Demand in Texas Coming from Data Centers, Crypto, not Residential

By Tom Kleckner

SAN ANTONIO — Thomas Gleeson, chair of Texas' Public Utility Commission, has seen it all during his tenure at the PUC.

Named the commission's executive director in 2021 about a month before a winter storm nearly collapsed the ERCOT grid, Gleeson saw the commissioners whittled in numbers from three to two, then one and finally none as they each resigned under withering criticism in the storm's aftermath. The commissioners' numbers have grown to five since then due to legislation passed after storm, with Gleeson appointed as chair in January.

Everything went smoothly for Gleeson and the PUC until Hurricane Beryl caught CenterPoint Energy off-guard in July and then an apparently fraudulent generation project was temporarily included in a grant program for $5 billion in state funds. (See *CenterPoint Energy Still in Eye of the Storm* and *Texas PUC Rejects Possible 'Fraudulent' Loan Application*.)

Dealing with the fallout of those two events has been added to the commission's full plate, which includes finishing a market redesign and working to approve enough transmission to meet Texas' growing industrial demand and deciding whether to use 765-kV facilities in that effort.

"The timeline of my time at the PUC has been quite interesting," Gleeson told attendees during Infocast's Texas Clean Energy summit, held Sept. 24-26.

"Transmission in this state is something that we haven't talked a lot about in recent history, because we've been focused on market design," he said. "I tell the governor and the other elected officials, 'If you want this state to continue to be the economic center for the country and for the globe, you have to invest in infrastructure, water infrastructure, health communication infrastructure, electric infrastructure.' Those things have to be done congruently, because you cannot have one without the other."

Gleeson said demand is increasing in Texas because data centers and crypto miners are being added to the industrial base. ERCOT said earlier this year it expects an additional 150 GW of load by 2030, although not all eventually will be interconnected.

"So, what does that mean? It means a lot of companies, a lot of businesses plan to move here," Gleeson said, noting some of that is crypto mining that "may show up or may not show up."

PUC Chair Thomas Gleeson delivers his keynote address to Infocast's Texas Clean Energy Summit. | *© RTO Insider LLC*

Why This Matters

Demand is growing in Texas because data centers and crypto miners are being added to the industrial base, while residential load remains flat, even with significant population increases.

"The load growth is something no other ISO in this country is seeing," he said. "You hear a lot about the size of our state ... so people automatically assume load growth is happening because people are moving within ERCOT. That's not the truth ... load growth on the residential side actually remains really flat. The increase in load is because of commercial and industrial customers coming here.

"That causes its own set of challenges, right?" Gleeson added. "You have residential customers that are paying a lot of the transmission costs, and those transmission costs are caused by non-residential customers, so I think that'll be another story."

Until then, Gleeson argues, Texas needs an energy expansion, not an energy transition.

"In this state with our load growth, you need an energy expansion," he said, nodding to a slide that included ERCOT's current fuel mix. "These percentages are not nearly as important to me as the underlying data, the total megawatts. I want more of all this to last the summer. If you look and analyze ERCOT data, you'll see that on multiple occasions, solar and batteries saved us. We also need more gas-fired generation because I have days that no one else sees where we are really thin."

Market Participants Pan PCM

Several panelists panned the PUC's proposed performance credit mechanism (PCM), which was selected from among five other potential market designs in 2023.

The PCM has been criticized as favorable to thermal generators. It would reward them with credits based on their performance during a

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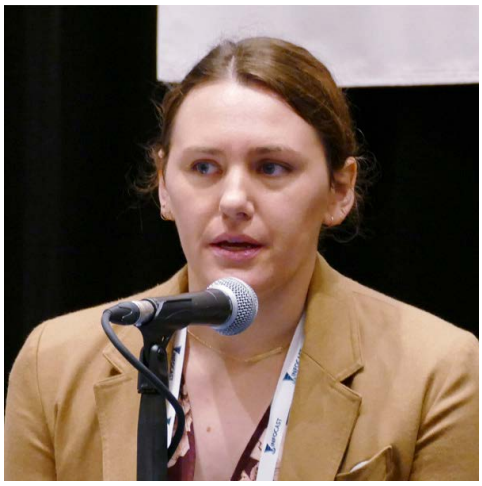
determined number of scarcity hours. Those PCs must be bought by load-serving entities, based on their load during those same hours, or exchanged by LSEs and generators in a voluntary forward market. (See *Texas PUC Submits Reliability Plan to Legislature*.)

"There's been a lot of discussion about who can participate in the PCM," Black Mountain Energy Storage's Kevin Hanson said. "I think it's very important that it has to be technology neutral, that any resource that can deliver those obligations and needs should be able to participate."

Bob Helton, Engie North America's vice president of government and regulatory affairs, pointed out that an early analysis of the PCM included renewables.

"By taking the renewables out of there, it does increase the cost," he said, agreeing the PCM needs to be technology neutral. He also urged patience because it could have a bearish effect on real-time energy pricing. "We don't want to end up with a PCM market with a large percentage of revenue coming through there and overtaking the energy market as a revenue source. We've seen that in capacity markets and other markets," he added.

"I think what's been lost in a lot of the discussions about an energy-only market is that it functions via scarcity," Lightsource's Emily Mullins, on another panel, said. "Scarcity pricing is important because it signals to developers when, where and what type of resource they need to build. However, since Winter Storm Uri, what we've seen is there's snipping at the edges of the energy only market. So, we've ended up in this interesting situation where, by name, we're in an energy-only market, but



Emily Mullins, Lightsource | © *RTO Insider LLC*

we're sort of riding the fence between an energy-only market and the capacity market."

Gleeson, who was the PUC's executive director when it approved the PCM, referred to the design as a "novel approach." He said given that, the PCM should be placed on the back end of other market changes.

"My feeling is, and I think my colleagues share this feeling, is that we have a number of tools at our disposal," he said. "We should try to see if we can meet our reliability goals with those tools before we look to implement something that's new and novel and that we don't really know how it interacts with the rest of our market."

Texas Eyes More Nukes

Constellation Energy's Casey Kelley, vice president of state government affairs in the South, appeared at the conference on the heels of his company's announcement that it plans to reopen Three Mile Island's Unit 1 — not the one involved in a 1979 partial nuclear meltdown — as part of a power purchase agreement with Microsoft. (See *Constellation to Reopen, Rename Three Mile Island Unit 1*.)

Shannon McGriff, executive director of The Energy Professionals Association and moderator of Kelley's panel, said she was with the Constellation executive two days before the announcement.

"So, we know you can keep a secret," she told Kelley.

"I think nuclear is going to be a big topic in Texas this time around, not because anybody's going to build a new AP 1000 [plant] or even [small modular reactors] in the short term, but I do believe there will be conversation about how we set up the framework to make Texas a leader in that space," Kelley said, looking ahead to 2025's legislative session.

He has a supporter in Gleeson, who is waiting on a task force's report on small modular reactors (SMRs) due at the end of the year. Texas leaders hope the work will position the state as a leader in nuclear energy. The state already hosts two nuclear plants and their four reactors; each plant has 5,000 MW of installed capacity.

"My feeling is if you care about net zero emissions and you care about reliability, you have to care about nuclear. I don't think the math works for where people are trying to go [meeting future demand] without adding nuclear power," Gleeson said. "I think increased nuclear has to be a part of our energy future to meet our demand." ■

ERCOT News

Texas Lawmakers, Residents Bash CenterPoint

Lt. Gov. Calls for CEO Jason Wells' Resignation, PUC Accountability

By Tom Kleckner

HOUSTON — Returning to the "scene of the crime," as Houston state Sen. Molly Cook (D) put it, the Texas Public Utility Commission made a rare trip out of Austin for a public hearing as it investigates CenterPoint Energy's heavily criticized response to Hurricane Beryl in July.

The Category 1 storm appeared to catch CenterPoint off-guard and knocked out power to more than 2 million of its customers. The Houston utility was excoriated for its poor communications, an outage map that didn't work and lack of outreach to the community. *At least 40 deaths* have been attributed to the storm, many related to the extreme heat (indexes reached 106 degrees) during the outages that extended into a second week. (See *CenterPoint Energy Still in Eye of the Storm*.)

Texas Lt. Gov. Dan Patrick (R), a Houston-area resident since 1979, was not on the agenda but opened the Oct. 5 *hearing* with 30 minutes of prepared remarks. Saying he had no "personal animus" toward CenterPoint, CEO Jason Wells or anyone on the commission, Patrick suggested the utility needs a new leader and threatened the PUC with using the Senate's subpoena power to conduct its own investigation.

"CenterPoint should have been prepared three and four days after that storm hit Houston, and they were not," Patrick said. "We were at the state level. They were not. Had they been prepared, I believe much of the misery and damage after the fact would have been averted.

"So, it's not personal, Mr. Wells. We've had good discussions, but CenterPoint needs to have a strong leader who will have foresight, not look back in the rearview. 'Oh, we'll fix it now,'" he said. "I believe at this point, the board of CenterPoint should ask for Jason Wells' resignation, or I believe he should submit it."

Patrick noted he returned home from California several days before the storm's July 8 landfall when it became apparent Beryl would hit Texas. A National Weather Service representative backed him up, testifying that the agency had a tropical storm warning in effect July 6 and then expanded it to inland warnings.

"It was a terrible wind event that brought down the trees and power lines and traffic lights. We know all of what happened, but [CenterPoint was] slow," Patrick said. "They were slow in preparation, procrastination and then communication. People didn't know where to turn. No one could get a response. It was the poorest response to citizens and elected officials trying to reach them."

Texas Lt. Gov. Dan Patrick addresses the PUC's commissioners. | © *RTO Insider LLC*

Why This Matters

Despite CenterPoint Energy's pledge to invest $5 billion in the Houston area, Lt. Gov. Dan Patrick is threatening to use state Senate subpoena power to investigate the company's poor performance relating to Hurricane Beryl.

Citing state rules, Patrick said the PUC has the right to audit and review CenterPoint's management and business operations. Consumer advocates have said the utility has been *overcharging customers for years*.

"I expect you to do that audit," he said. "I want to know how much they have been overcharging, if they've been overcharging the customers at CenterPoint, and for how long. We need that answer."

The lieutenant governor also upbraided the PUC for its approval of 2021's *$800 million lease of generators*, some designed to restore power to entire neighborhoods but that weren't used in Beryl's aftermath. The commission approved CenterPoint's cost recovery — about $350 million so far —over an administrative law judge's recommendation.

"If the commission doesn't act on the $800 million, if they don't act on the right cases, if the commission does not act on looking [into whether customers] have been overcharged, then our [state Senate] Business and Commerce Committee will be given subpoena power to get the answers," Patrick said.

"I want to know about that $800 million. I want to know why it was signed ... I want to know why it was overturned," he continued. "If the PUC allows CenterPoint to get away and try to PR their way through this, that will show the commission is not accountable."

As lieutenant governor, Patrick controls the

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CenterPoint Energy CEO Jason Wells listens to public comments during the PUC hearing. | © RTO Insider LLC

Senate's agenda. Two of the PUC's commissioners, Chairman Thomas Gleeson and Courtney Hjaltman, have not yet been confirmed by that legislative body.

"I know how personal this is to you," Gleeson told Patrick when he wrapped up his comments. "Thank you for your leadership, and I know you'll continue to hold this commission and everyone accountable to make sure we get the right results."

About six hours after the hearing began and some 30 local residents had complained about CenterPoint, Wells took the stand and "personally" apologized to those still present.

"The number of outages [was] too high, the ... outages were too long, and our communications did not meet your expectations," he said. The CEO said CenterPoint has not been overcharging customers and frequently earned less than it could have.

Darin Carroll, CenterPoint's senior vice president of operations, provided an update on the utility's *Greater Houston Resiliency Initiative* to better prepare for the next major storm or hurricane. CenterPoint expects to spend about $550 million during the plan's current phase on 25,000 poles that can withstand extreme winds and undergrounding 400 miles of lines, among other items.

The company plans to invest $5 billion in the Houston system between 2026 and 2028. It will file a long-term plan by Jan. 31.

The PUC also discussed best practices with industry veterans of previous hurricanes, including two former Florida Power & Light employees, and representatives from the Edison Electric Institute and the Southeastern Electric Exchange. Florida has been held up as a positive example of grid hardening following eight major storms in two years.

The commission will continue to take *customer feedback* through Oct. 9. It will file its report and recommendations for changes to Gov. Greg Abbott and the legislature by Dec. 1.

Texas Lt. Gov. Dan Patrick | © RTO Insider LLC

"We heard loud and clear that you expect better from your electric utility, and we plan to use your feedback to ensure Houston-area utilities are prepared the next time extreme weather hits," Gleeson said after the hearing in a *statement*. ■

ERCOT News

Overheard at GCPA's 39th Annual Fall Conference

ERCOT CEO, State Rep Preview 2025 Texas Legislative Session

AUSTIN, Texas — The Gulf Coast Power Association again reported a record attendance — just over 800 — for its annual Fall Conference held Sept. 30 to Oct. 2, with discussions on the industry's future, emerging grid technologies and Texas' 2025 legislative session.

ERCOT CEO Pablo Vegas and state Rep. Todd Hunter (R) — chair of the House State Affairs Committee, which oversees the Texas grid — kicked off the conference with a fireside chat that included their expectations on the 89th Texas Legislature, which convenes Jan. 14.

"Here's the bottom line for all the questions I get every place I go: labor, water, power. I bet I get contacted every two to three weeks by new groups coming to look at Texas," said Hunter, often referred to as "The Man in Black" around the Texas Capitol for his wardrobe choice. "So what's on the legislative agenda? One, I think you will see a push by the legislature to do what we can to increase power resources. Texas, I think, is the fastest growing state. The demands are huge. And what does that mean? Water, labor and power.

"The message from me: What's on the plate is to do everything we can meet the needs."

Vegas said ERCOT works "incredibly closely" with Hunter's committee and that there isn't a "big gap" operationally between what the grid operator has and what it will need for the next few years. The sessions that followed Winter Storm Uri of February 2021, he said, "have set us up for the growth trajectory that's in front of us."

Texas PUC Chair Thomas Gleeson points to an acquaintance in the audience. | © RTO Insider LLC

"One thing that maybe we'll spend a little bit of time on is talking about how to best manage the influx of different types of large loads that are coming to Texas," Vegas said. "That's something that is an evolving and changing dynamic. ... Whether it's data centers; whether it's hydrogen developers; whether it's the electrification that we're seeing out in the Permian [Basin], there's going to be a wide variety of opportunities to work with these customer groups to find ways to help them grow reliably and rapidly, because Texas does have one of the most fertile environments for economic growth. I think we're going to be really well positioned for a constructive legislative session."


Former PUC Chair Pat Wood III moderates a panel with former Commissioners (left to right) Julie Parsley, Paul Hudson, Brandy Marty Marquez and Will McAdams. | © RTO Insider LLC

Moderator Barbara Clemenhagen, GCPA executive director, asked whether ERCOT will continue its post-Uri conservative operations posture in which it sets aside several thousand megawatts each day to respond to tight situations. Vegas responded that as an "energy island," the grid operator can't lean on its neighbors to protect a "flagship competitive market that is studied and looked at very closely around the world."

"This competitive market works, and I believe that it can work in the changing environment that's coming our way," Vegas said. "We have one of the most dynamic set of resources that are providing energy; that can come and go

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and fluctuate their intermittency on the wind and solar side. We need to have a lot of these reserve resources to be able to manage that because we can't lean on anyone else. This is what we have to do in order to ensure we can be reliable on a regular basis. I don't believe consumers or stakeholders are comfortable with living on the edge of a grid that could be an emergency condition on a regular basis."

ERCOT Deals with Uncertainty

Dan Woodfin, ERCOT | © RTO Insider LLC

ERCOT's Dan Woodfin, vice president of system operations, said the pace of change in generator types has been so "tremendous" that the ISO's operators are having to learn a new system every six months.

"Operators like to have rules of thumb about how they operate," he said. "A couple of years ago, we had a lot of wind and a little bit of solar. Last summer, we had more solar and a few batteries. And this year we have more solar and more batteries. And next year, we're going to have twice as much solar, potentially, and a lot more batteries. That means every six months or so, we throw away all our rules of thumb and we're operating a new system."

Woodfin said four issues must be considered in adapting the grid to new technologies: adequacy, uncertainty, variability and stability.

"If you're involved in the ERCOT stakeholder process, you will recognize those things as being the underlying factors behind most of the major debates that have gone on in the last year or so," he said. "Managing the sunrise and sunset ramps is going to become increasingly critical. Now, the increasing number of batteries help manage other resources' variability, but then we have to make sure we're not overly depending on them beyond their inherent limited duration.

"There's also the managing of the uncertainty because some of that we can predict. I'm pretty good at predicting when the sun's going to come up and when the sun's going to go down every day," Woodfin continued. "But as we get more wind and solar, even if we're driving down the percentage error in terms of our forecast, the errors continue to grow with the additional installed capacity. So there's just a lot of variability and uncertainty growing."

PUC Exes Praise SPP

A panel of former Texas regulatory commissioners shared their perspectives on recent shifts in energy policy and offered their thoughts on improving the stakeholder process and communications between ERCOT's Technical Advisory Committee and the Board of Directors.

State Rep. Todd Hunter (left) listens to ERCOT CEO Pablo Vegas during their fireside chat. | © RTO Insider LLC

"What's the right way to kind of think about efficient, inclusive and successful [relationships]?" asked Pat Wood III (1995-2001). He noted recent comments by Public Utility Commission Chair Thomas Gleeson that the interaction between the board and TAC "did not work" for him. (See "Members Discuss Stakeholder Process," *ERCOT Technical Advisory Committee Briefs: Sept. 19, 2024*.)

"There's a disconnect, seemingly, between all these arguments that are happening at TAC and what the board eventually deliberates on," said Will McAdams (2021-2023). "But I believe we don't need to reinvent the wheel. Other ISOs have crossed this Rubicon before."

McAdams offered SPP's Members Committee as an example. The 23-person committee, comprising several different stakeholder segments, debates issues and provides an advisory vote for the board before the directors cast their ballots.

"The Members Committee is a great tool ... and none of this requires statutes, by the way," McAdams said. "I think it could be self-adopted, but ... some type of equivalent organization that may not be empowered to have a binding vote ... where the board will see the arguments from the industrial segment; the industry segment; the utility segment. They'll know exactly what they're getting into with their vote."

"I 100% agree with that," Pedernales Electric Cooperative CEO Julie Parsley (2002-2008) said as Brandy Marty Marquez (2013-2018) nodded her head in agreement.

"SPP has been great because they sit at the table; they argue," Parsley said. "They vote, right? But they're not the controlling vote. They just vote, and then the independent board members vote. [The members are] in front of them. They're not off in some committee room at TAC, so they hear it all, and it's really great."

Marquez, McAdams and Parsley all represented Texas on SPP's Regional State Committee.

DOE's Biddle Spotlights Clean Energy

Leslie Biddle, DOE | © RTO Insider LLC

Bearing what she called "the longest title in the world," Leslie Biddle — the U.S. Department of Energy's deputy under secretary for commercialization and finance — issued a call to action for utilities, regulators and the rest of the industry to "rethink our go-to solutions" for adding new generation.

"So how do we do that in a way that addresses the baseload needs?" she asked her audience. "I'm so excited to be here because we do also need to change the culture; we need to use

ERCOT News

things differently than we have in the last couple decades. For a few decades now, we've been using the same labor to build centralized generation and associated transmission and distribution to meet those long-term human needs. It worked ... but we haven't really had to innovate, and we haven't had to adopt new ways of working, and we will."

Case in point: DOE's latest in a series of liftoffs reports, *Pathways to Commercial Liftoff*. Thanks to the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, the department is positioned to invest billions of dollars in large-scale demonstration and deployment of clean energy technologies it says will be needed to meet rising demand.

Biddle pointed to a slide that listed more than $6 billion in investment for two dozen awards for projects in Texas and Louisiana. They included $1.2 billion to X-energy to develop gas-cooled reactors and another $1.2 billion for a hydrogen hub involving Chevron, ExxonMobil and Air Liquide, among others.

"We expect this all to be built in the next four years," she said. "Our capital goes in currently for the development stage."

DOE says it expects 15 to 20% growth in demand over the next decade and for it to double by 2050, driven by economic development and electrification.

"It'd be hard to say that we aren't surprised about the electricity demand growth over the next decade, when you're telling everyone that they should electrify. That's what happens," Biddle said. "From our perspective, growth is good. It means that we're bringing in more manufacturing jobs, and we're expanding our leadership and innovation and expanding artificial intelligence and expanding access to more efficient clean growth in America. It will require a change in the way we invest and manage our system. Fortunately, we have the technologies and the solutions we need to meet the growing demand."

AI as Savior for Clean Energy?

DOE could find help in reaching its net-zero-emissions goals from an unlikely source, according to several panelists discussing artificial intelligence.

"I'm going to say something slightly controversial, but I feel that AI and the computing power and all of that, even though in some ways it's consuming more ... we need AI to get us to net zero because of the sort of second-by-second optimality that we need," said Erin Boyd, chief digital commercial transformation officer for AES. "All of the data goes into getting more out of our assets and finding better locations and managing demand and supply just down to that sort of microsecond.

"Even though everybody says, 'Oh, AI is driving up energy demand,' it's an interesting problem where I'm not so convinced yet that that's the case. I believe that AI is actually what's going to get us to net zero and a situation where we're actually consuming less, but also consuming energy that's uncertain; that's fickle, that you know can't be managed."

"I'm also very upbeat about the potential for AI," said Venkat Tirupati, ERCOT's vice president of DevOps and grid transformation. "I look at it from two different angles. The first angle is just on grid operations and market operations. There are definitely things that will help us to be more efficient to run markets very well. But if I look at ERCOT as an enterprise, there are a lot of productivity gains that we could get by just embracing AI into the everyday."

PUC's Roth Gets Award

The GCPA honored the PUC's Werner Roth with its emPOWERing Young Professional Award, presented annually to individuals under the age of 40 who have demonstrated excellence in the electric power industry, made unique contributions to the power market's success, and served as a role model and leader for others.

Roth, a senior market economist in the market analysis division, has worked at the commission for more than 10 years. He holds bachelor's and master's degrees in economics and another bachelor's degree in chemical engineering.

"I have often wondered how a young graduate without experience in the electric markets could develop such deep and wide skills for power markets," said Harika Basaran, the division's director. "Then I realized that he did most of it on his own initiative."

Roth thanked the commission's leadership for allowing him to "lean in on a lot of the projects that have focused on a lot of issues in the ERCOT process and, more importantly, have enabled staff to [provide] perspective on those projects." ■

— Tom Kleckner

GCPA Board Chair Beth Garza presents the emPOWERing Young Professional Award to the Texas PUC's Werner Roth. | *© RTO Insider LLC*

ISO-NE News

Long Road Still Ahead for Aroostook Transmission Project

By Jon Lamson

A proposed transmission project to relieve transmission constraints in Maine has received a major boost with the U.S. Department of Energy's announcement of an up-to $425 million investment in the project.

The funding for Avangrid's Aroostook Renewable Gateway stems from DOE's Transmission Facilitation Program, which on Oct. 2 awarded up to $1.5 billion for four projects across the country. (See related story, *DOE Funding 4 Large Tx Projects, Releases National Tx Planning Study*.) The department would serve as an anchor off-taker for the transmission capacity of the projects, with the goal of de-risking development and increasing outside investment.

Northern Maine is not currently interconnected with ISO-NE, limiting the development of renewables in the area despite high *wind speeds* and a large amount of undeveloped land.

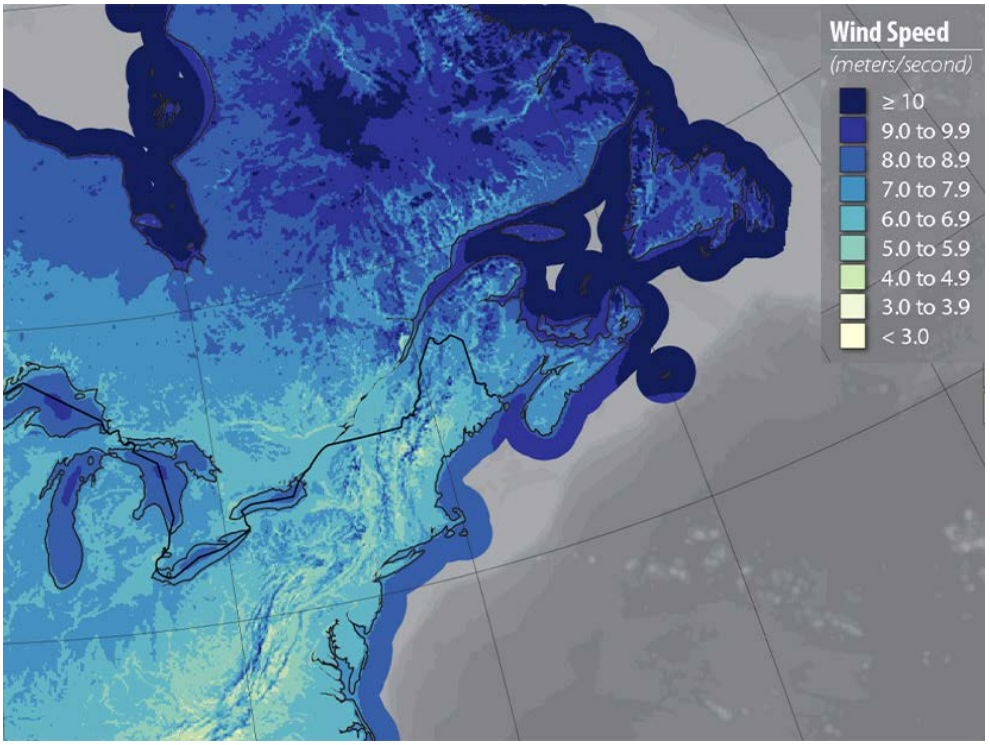
"Unlocking the enormous wind resource in Aroostook County will deliver economic benefits to this important region of the state and is a necessary step toward Maine becoming energy independent by freeing our residents from the stranglehold of expensive and unreliable oil and gas," the Natural Resources Council of Maine said in response to the announcement.

"Transmission line development and the ability to connect clean, affordable energy to the New England power grid is one of the most effective tools available to combat climate change while also enabling a stronger, 21st century economy," Avangrid CEO Pedro Azagra said.

Gov. Janet Mills (D) applauded the Biden administration for the "unprecedented investment" and called the announcement "an exciting step forward and a testament to the tremendous energy opportunity available in Northern Maine."

Why This Matters

While federal support should provide a significant boost to Avangrid's proposal to connect Northern Maine to ISO-NE, there are many obstacles remaining.



Annual average wind speed at 100 meters above surface level | *NREL*

Looming Challenges

To unlock renewable development in the northern part of the state, the Maine Public Utilities Commission is planning separate solicitations of transmission capacity and renewable generation. Avangrid's project would need to be selected by the PUC to proceed with development. The company expects the commission to announce the winning bids in 2025.

Transmission development in New England has faced significant challenges in recent years, and DOE's support of Avangrid's project is no guarantee of success.

The PUC's solicitations come after a previously selected project by LS Power was *terminated* in December by the commission after the company requested an unspecified price adjustment. LS Power said it could *no longer proceed* with the fixed price it bid into the solicitation because of delays associated with negotiating contracts with Massachusetts and pressures from inflation, interest rates and supply chain distributions (2021-00369).

LS Power's project was selected in conjunction with a 1,000-MW wind project by Longroad Energy. According to a study commissioned by LS Power, the projects would have saved Maine ratepayers *nearly $900 million* over the life of the contracts through lower electricity prices.

Following the solicitation, the Massachusetts Department of Energy Resources *found* it would be beneficial for the state's electric utilities to contract for up to 40% of the generation and renewable energy certificates from the wind project and up to 40% of the line's transmission service.

The DOER's authority to participate in the multistate solicitations for transmission expired at the end of 2022, but Massachusetts Gov. Maura Healey (D) included language in a recently introduced budget bill to extend this authority through 2027. (See *Mass. Gov. Healey Includes Permitting Reform in Budget Proposal*.)

"Our region needs to buy more clean power and retain our existing clean resources to ensure reliability and advance our clean energy transition," DOER spokesperson Lauren Diggin said. "Massachusetts will continue to seek out opportunities to partner with other states for our collective benefit."

A spokesperson for Longroad Energy said the company understands why Maine opted to rebid the transmission and generation solicitations, but they said its wind proposal "will be a pivotal investment in Northern Maine and the

ISO-NE News

largest, cheapest source of new clean energy in New England."

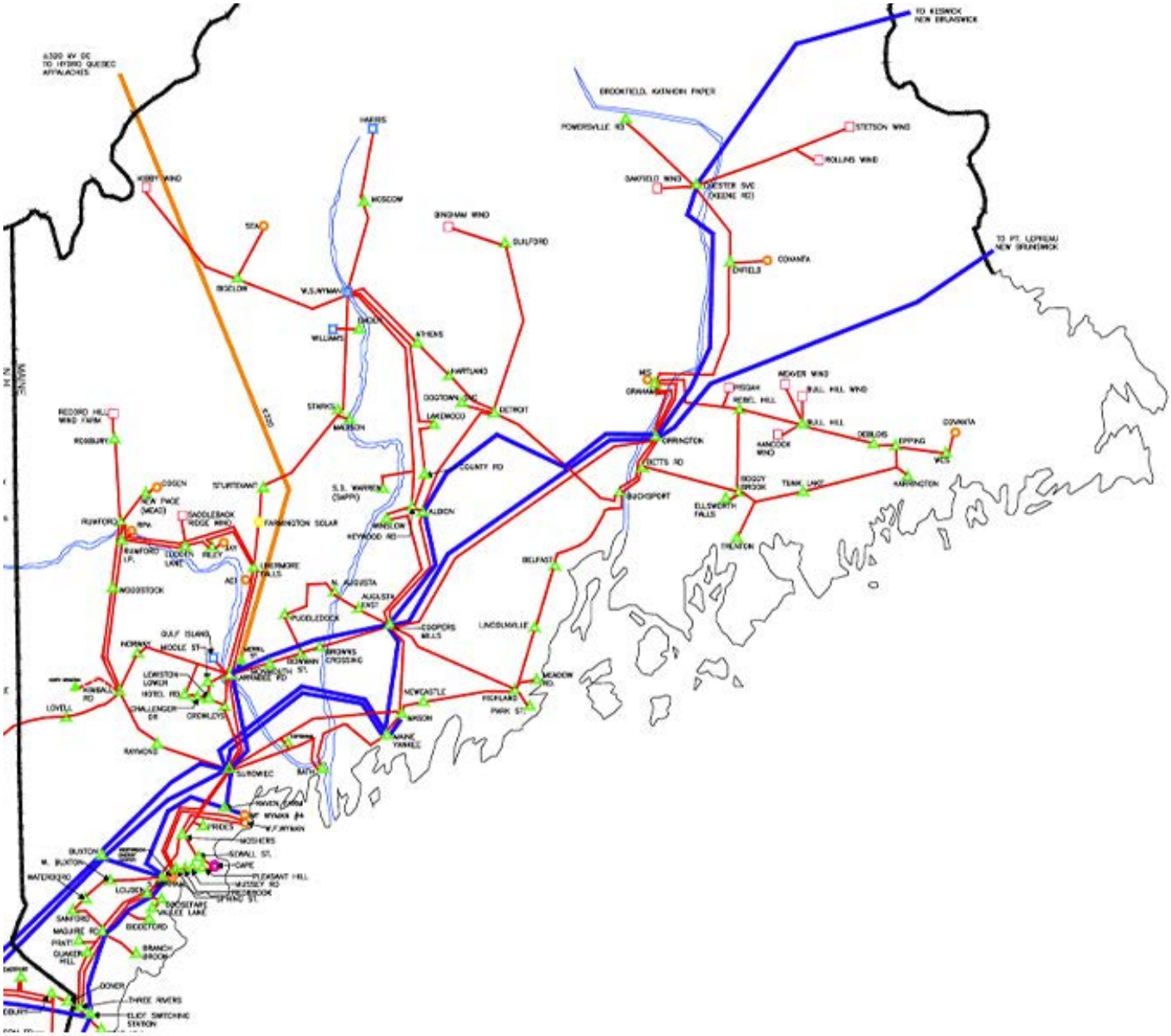
DOE previously agreed to be an off-taker for National Grid's Twin States Clean Energy Link Project, a proposed bidirectional transmission line connecting New England and Quebec via Vermont and New Hampshire. But despite the federal support, National Grid backed out of the project in March. (See *National Grid Backs out of Twin States Clean Energy Link Project*.)

Avangrid's New England Clean Energy Connect (NECEC) project, currently under construction in Eastern Maine, has dealt with significant delays and a roughly *50% cost increase* following legal and political challenges, which were *heavily funded* by incumbent fossil generators. When in service, the NECEC line will allow for the import of Quebec hydropower procured by Massachusetts. (See *Avangrid Details Progress on NECEC Tx Line*.)

Beyond connecting Northern Maine to the rest of ISO-NE, additional work likely looms to ease transmission constraints between Maine and load centers in Southern New England. In its *2050 Transmission Study*, ISO-NE found that the interface between Maine and New Hampshire is likely to face overloads starting in 2035.

Unlocking access to large-scale renewable generation in Northern Maine could put more pressure on these interfaces, while the locations of offshore wind interconnections will also be a major factor in the timing and intensity of potential overloads. (See *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.)

"While the total generation in northern New England is a factor in these overloads, the precise locations of particular generator interconnections in Maine do not affect the probability that the overloads will occur; most of the power generated in this subregion still ultimately flows down through the major lines leading into Massachusetts," the study found. ■



Maine transmission system map | *ISO-NE*

ISO-NE News

RI Siting Board Claims Authority over Storage Permitting

By Jon Lamson

The Rhode Island Energy Facility Siting Board (EFSB) ruled Oct. 3 that it has jurisdiction over large battery storage projects, overruling precedent and giving the board the ability to override local permitting decisions on storage projects if it deems a project has met all the legal requirements (*SB-2024-01*).

In April, the Quonset Development Corp. (QDC) requested that the EFSB declare that a proposed 210-MW battery project is outside the board's jurisdiction, arguing that "the EFSB already has determined that it does not have jurisdiction over battery energy storage systems."

The prior precedent stems from a 2019 EFSB ruling that a 180-MW storage resource is not under the jurisdiction of the board because the state's *Energy Facility Siting Act* does not reference battery storage (*SB-2019-02*).

QDC also argued that EFSB does not have jurisdiction over a substation, tie line and switchyard needed to connect the battery to the transmission system, writing that the 115-kV tie line "is not a transmission line" and is instead "a line that connects a non-generating battery energy storage system for the purpose of storing and discharging electricity."

The EFSB wrote in its ruling that the question of jurisdiction hinges on "whether the project itself or any component thereof falls within the definition of a 'major energy facility,' as defined by the Energy Facility Siting Act."

The definition includes "facilities for the generation of electricity designed or capable of operating at a gross capacity of forty (40) megawatts or more."

While QDC argued that this definition does not apply to battery storage, the EFSB disagreed, highlighting language from ISO-NE and FERC that categorizes battery storage as a type of generation.

"It would be illogical for the state and federal definitions to collide with each other, especially when the energy industry is inherently interstate in nature and Rhode Island is inextricably dependent upon the regional electric system for continuous reliable service," the EFSB wrote.

Regarding the precedent set by its 2019 ruling, the EFSB wrote that it "respects the importance of following the reasoning of prior cases and adhering to settled rules," but added it ultimately is "not bound by its prior decisions and can depart from its own precedents, as long as the agency explains why such a departure is reasonable."

| *Convergent Energy and Power*

The EFSB also highlighted the implications the ruling could have on the state's clean energy goals. This year, Rhode Island set a target of installing 600 MW of storage by the end of 2033; the project at issue in the ruling would meet over a third of this goal. (See *RI Sets 600-MW Energy Storage Target*.)

While no local permits would be required for this project, which would be in an industrial park, local permitting could pose "an insurmountable obstacle" for future battery projects in the absence of EFSB jurisdiction, the board wrote. The EFSB can overrule local permitting decisions for projects under its authority.

The EFSB similarly found that it has jurisdiction over the infrastructure needed to connect the battery facility to the transmission grid.

"Given the numerous FERC cases unambiguously illustrating that generator tie lines are jurisdictional transmission facilities, the claim made by petitioner that the 115-kV Generator Tie Line is not serving a transmission purpose is contradicted by FERC precedent and, therefore, is unsustainable," the EFSB found.

It added that a lack of EFSB jurisdiction over interconnection infrastructure "could have been devastating to the ability of an offshore wind developer in the future to interconnect its project to the transmission system within or through Rhode Island, given the potential for local opposition."

The EFSB said the project developer must submit an application for the battery facility and its associated electric infrastructure. ■

MISO News

Cardinal-Hickory Creek Line Fully Energized 13 Years After MISO Approval

By Amanda Durish Cook

Thirteen years after it was recommended by MISO, the controversial 102-mile, $655 million Cardinal-Hickory Creek line is completely in service.

Co-owners ITC Midwest, American Transmission Co. and Dairyland Power Cooperative announced the completed 345-kV line was flowing power between the Hickory Creek Substation in Dubuque County, Iowa, and the Cardinal Substation in Middleton, Wis., as of Sept. 26. The developers originally anticipated a June 28 full in-service date. The eastern half of the line was energized months ahead of the western half in December 2023 as court battles played out.

Cardinal-Hickory Creek was approved in 2011 as part of MISO's multivalue project portfolio and earned a reputation as the most contentious of the 17-line collection. The line's construction pitted usual environmental bedfellows — conservationists and renewable energy developers — against one another because the line crossed through the Upper Mississippi River Wildlife and Fish Refuge. For years, conservation groups — the National Wildlife Refuge Association, Driftless Area Land Conservancy and Wisconsin Wildlife Federation — argued that the river crossing would scar and fragment wildlife habitat and ruin floodplains.

Cardinal-Hickory Creek's final mile intersecting the refuge was tied up in litigation for months this year as the conservation groups lodged a final lawsuit to halt an ultimately successful land swap between the utilities and the U.S. Fish and Wildlife Service that traded more than *35 acres* in Wisconsin for almost 20 acres of the refuge's Iowa footprint. (See *Cardinal-Hickory Creek Developers Appeal Injunction on Line's Final Mile*.)

Why This Matters

An estimated 160 renewable generation projects were dependent on the line's completion. The lengthy process might foreshadow routing and permitting challenges that future MISO long-range transmission projects could encounter.

Construction on the Cardinal-Hickory Creek transmission line | *American Transmission Co.*

The trio of environmental groups argued that the U.S. Fish and Wildlife Service, U.S. Rural Utilities Service and U.S. Army Corps of Engineers violated federal laws when they approved permits and accepted the land exchange.

In May, the Seventh U.S. Circuit Court of Appeals lifted a Wisconsin federal judge's preliminary injunction issued in March, clearing the way for the final, mile-long connection. The three-judge panel said the federal judge lacked justification for his decision to grant the injunction. Conservation groups tried for a stay; Environmental Law and Policy Center Executive Director Howard Learner, representing the conservation groups, argued the refuge "should not be bulldozed before the conservation groups receive their long-delayed fair day in court."

Dairyland Power Cooperative CEO Brent Ridge characterized line completion as a "victory for energy consumers and the environment."

"As a backbone interconnection, the line will finally serve as the vital link to a long waiting list of regional renewable energy projects. While supporting carbon reduction goals, Cardinal-Hickory Creek also strengthens grid reliability and resilience at a time of great change in the energy industry," Ridge said in a press release.

"Following years of work, including numerous opportunities for public input, extensive regulatory and environmental review, and construction, the entire Cardinal-Hickory Creek line has been placed in service. This allows the project to begin providing numerous economic benefits for electric consumers and environmental benefits for the entire region," ITC Midwest President Dusky Terry added. Terry thanked construction crews in particular for building the line "in full compliance with comprehensive environmental standards."

ATC Senior Vice President of Construction and Maintenance Jared Winters said Cardinal-Hickory Creek will improve reliability, allow access to lower cost energy and offer interconnection points for new renewable resources.

ITC estimates that 160 renewable generation projects representing more than 24.5 GW in

MISO News

Wisconsin, Iowa and other parts of the Upper Midwestern states were dependent on the line's completion.

The developers said they minimized environmental impacts of construction as much as possible, consulting with federal agencies. They said they used wooden construction mats to reduce soil disturbance and sedimentation, did not perform any grading within the refuge and have restored or will restore any impacted natural areas.

Clean Grid Alliance also cheered the announcement and said the line was subjected to "unsuccessful and unnecessary" legal challenges.

"Finally! We can now celebrate the ability to deliver more than 24,000 megawatts of clean, affordable, reliable energy, plus the added benefit of improved grid reliability, all of which is now possible because the Cardinal-Hickory Creek transmission line has been energized," Clean Grid Alliance Executive Director Beth Soholt said in a press release.

Even with the line's energization, the National Wildlife Refuge Association, Driftless Area Land Conservancy and Wisconsin Wildlife Federation remain hopeful in their lawsuit.

Wendy Bloom, senior attorney at the Environmental Law and Policy Center, said a federal court has never found the crossing through the refuge legal. She said the conservation groups maintain ITC, ATC and Dairyland acted unlawfully by clearing protected refuge land after striking the land exchange.

"Despite today's news, we are still awaiting an important decision in our lawsuit in federal court. We are proud to have worked with so many in our community and other committed organizations to oppose construction of this unnecessary line," Jennifer Filipiak, executive director of the Driftless Area Land Conservancy, said in a statement.

The groups also said the east-west transmission line bisects a north-south migratory bird flyway used by hundreds of thousands of birds annually.

Since its multivalue portfolio, MISO has designed two more long-term transmission portfolios: the *first*, $10 billion long-range transmission plan (LRTP) was approved in 2022, and MISO is advancing a second, nearly $22 billion LRTP package for board approval at the end of the year. (See *MISO Affirms Commitment to $21.8B Long-range Tx Plan in Final Workshops*.)

The second LRTP portfolio calls for a 765-kV line crossing the Mississippi River from Wisconsin's Driftless Area into Minnesota, which has led some members to call on MISO to keep the contested Cardinal-Hickory Creek in mind and carefully examine routing assumptions through protected areas. (See "LRTP Mississippi Crossing Raises Specter of Cardinal-Hickory Creek," *MISO Vouches for 2nd, $25B Long-range Tx Portfolio*.) ■

MISO News

EFI Foundation Showcases Minnesota Clean Energy Jobs Sector as Model for Midwest

By Amanda Durish Cook

Minnesota's economy is reaping the benefits of promoting a clean energy workforce, said state regulators, union leaders and utility representatives in a webinar.

EFI Foundation, a D.C.-based nonprofit dedicated to furthering the clean energy transition, held Minnesota up as a success story for other Midwestern states to follow during its Oct. 2 webinar on clean energy workforce development.

"Minnesota is a great example of making some real progress," EFI Foundation CEO and former U.S. Energy Secretary Ernest Moniz said.

Minnesota Department of Commerce Deputy Commissioner for Energy Pete Wyckoff credited the Inflation Reduction Act and the Infrastructure Investment and Jobs Act for greasing the wheels to create quality jobs to build the next-generation workforce in the state.

He said Minnesota is a key player in "building out and rebuilding our manufacturing sector."

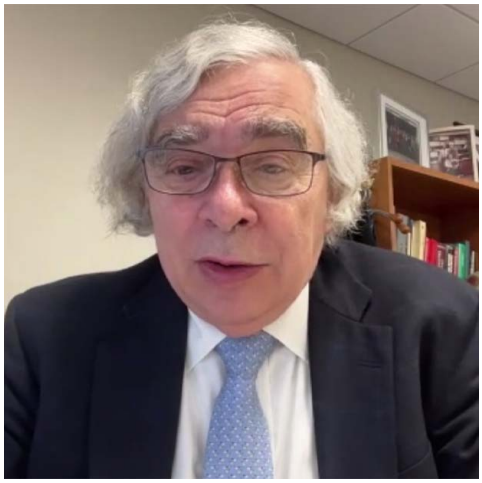
Minnesota Public Utilities Commission Chair Katie Sieben said in the past six to seven years, the commission has gotten better at including community and workers' voices in its dockets and decision-making. She said the commission in some cases has required utilities to file worker transition plans when fossil generation is retired.

Sieben said state regulators now ask developers if they plan to use local labor in their projects.

"In Minnesota, we want the workers to come from Minnesota. We don't want them to come from Texas and Florida, no offense to those states. … We're asking how we make these

Why This Matters

Some Midwestern states like Minnesota are making more progress on renewable energy. Demonstrating the effectiveness of the workforce transition could help convince other states to accelerate the transition to clean energy.



EFI Foundation CEO Ernest Moniz | *EFI Foundation*

projects Minnesota-based," Sieben said.

Wyckoff also said Minnesota's legislature redesigned its permitting process at the state level. He said he thinks projects now can move faster "without compromising the public input."

"If the federal folks want to know how they can do this, they can give us a call. Sometimes we lead and sometimes we follow," Wyckoff joked.

Sieben said Minnesota sees its infrastructure is aging and needs "intense investment" in transmission to achieve clean energy targets.

Wyckoff said federal funds are key to reducing "energy activation costs" and accessing the cheaper energy that's on the other side of the energy transition.

Siebe noted that federal funds are at play for the reinventing of the Sherburne County Generating Station, where Xcel Energy plans an iron-air battery system pilot and the 710-MW Sherco Solar project, set to become Minnesota's largest solar facility.

Xcel Energy Vice President for Regulatory Policy Bria Shea said her utility contemplated how to take advantage of the significant interconnection rights and existing infrastructure of the coal-fired Sherco plant.

She said the first 260 MW of the expansive solar farm should go into service this week.

Minnesota Power Vice President of Regulatory and Legislative Affairs Jennifer Cady said an energy transition that leaves behind workers is "simply neither just nor sustainable."

Cady said Minnesota Power built *three* solar farms using panels from Heliene's facility in

Jennifer Cady, Minnesota Power | EFI Foundation

Mountain Iron, Minn., to help the state bounce back economically from the pandemic. Cady added that Minnesota Power has contracted with local farmers to use sheep for vegetation management around the panels.

Minnesota Power now has supplier preferences for local companies, Cady said. The company recently announced it plans to build two utility-scale solar projects in northern Minnesota by 2027, one of which will be at the Boswell Energy Center, Minnesota Power's last active coal plant.

"I know new technologies can almost always be disruptive to local jobs," EFI Foundation Distinguished Associate David Foster said. Foster said it's important to showcase that Minnesota's brand of industrial collaboration paired with federal support is driving job creation in the state.

Rick Martagon, executive director at Minnesota building trades apprenticeship preparatory program Building Strong Communities, said the program this year graduated its largest cohort yet at 106 of 125 attendees.

Joe Fowler, business manager at Laborers' International Union of North America (LIUNA), said good relations between laborer organizations and utilities can help ease the disruption of the energy transition.

"It's saying, 'How do we make sure those careers continue?'" he said.

"There are new opportunities to replace the old ones if people are willing to be retrained," he said, adding that the economic benefits of good jobs are multiplied when laborers spend dollars within their communities. ■

MISO News

MISO: Lower Prices, Fewer Outages and Annual Peak in August

MISO reported relatively lower costs and outages in August while it served its annual peak late in the month.

MISO averaged 86 GW load over August, about 1 GW lower than August 2023's average, according to MISO's monthly operations *report*. MISO's 122-GW annual peak arrived in the afternoon on Aug. 26 during a heat wave and a maximum generation warning. (See *Late August Heat Wave Delivers 122-GW MISO Summer Peak*.)

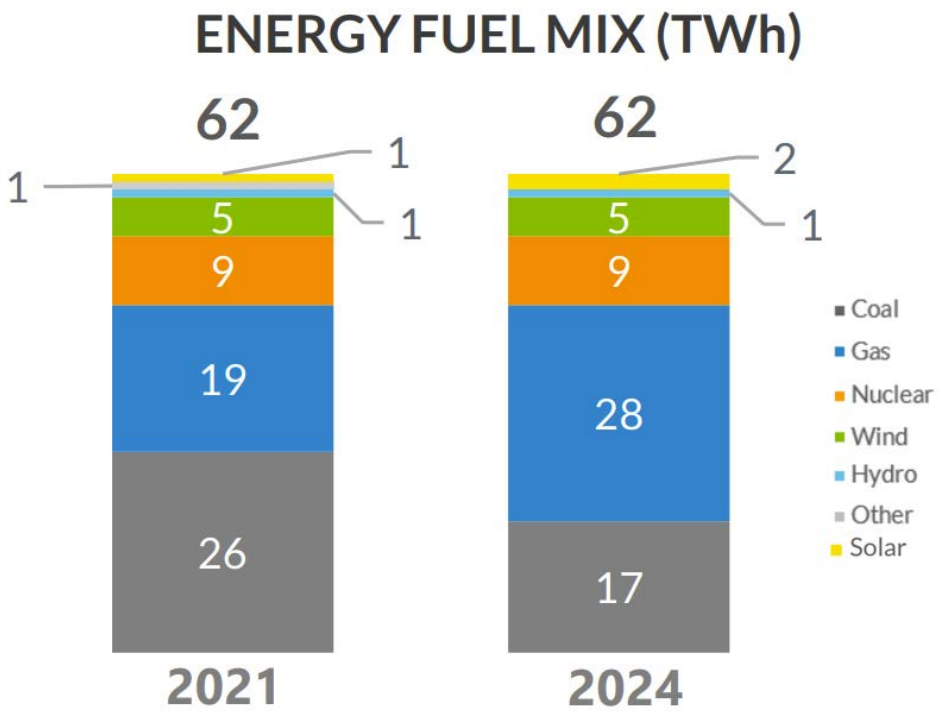
The summertime peak was lower than 2023's 125-GW *peak*, which was set nearly a year to the date earlier during a separate heat wave and maximum generation warning.

Average daily generation outages were down year over year, at 30 GW, an 8 GW improvement over last August.

Real-time locational marginal prices also were down year over year, at $26/MWh from $33/MWh. However, natural gas and coal prices remained static from 2023 at $2/MMBtu. The pricing was a far cry from 2022, when August saw average real-time prices of $87/MWh and $8/MMBtu coal and natural gas prices.

Natural gas delivered the greatest share of terawatt hours this August, at 28 of the month's total 62 TWh. Coal supplied 17 TWh, a stark contrast from the 26 TWh coal managed in August 2021. ■

— *Amanda Durish Cook*



Fuel mix comparison between August 2021 and August 2024 | *MISO*

NYISO News

NYISO Working Group Meeting Briefs

Proposed RS1 Carryover for 2025 Increases

Things got a little testy at the NYISO Budget and Priorities Working Group meeting Oct. 2 when Cheryl Hussey, the ISO's chief financial officer, presented some final *updates* to the proposed 2025 budget.

Hussey said NYISO was proposing to increase the Rate Schedule 1 carryover to $5 million. In September, Hussey explained that the ISO is expecting a surplus this year because of overcollections under RS1, the administrative rate used to recover operating costs from members. (See *NYISO Proposes Increased Budget, Admin Rate for 2025*.)

"That's really the only change to the actual budget itself to date," said Hussey, who went on to explain that this would reduce the budget to $202 million, a $2 million decrease from what she previously presented. This would result in an RS1 surcharge of $1.306/MWh instead of $1.319/MWh. Hussey said that higher projected overcollections were being used to reduce RS1 instead of paying outstanding debt.

"Can you share your analysis that shows that this is actually in the customers' best interest to use this money as a one-time carryover rather than paying down debt?" asked Kevin Lang, a lawyer representing Multiple Intervenors and New York City. "We had pushed for paying down debt years ago because we understood at that point in time that that was really the best use of it. … I don't see any analysis at all. I just see a statement here."

Hussey said the interest rates NYISO was paying on its debt were quite low and that the numbers were just projections but that if NYISO had extra funds they were able to use them to pay down debt early.

"If stakeholders would rather us not have a carryover to reduce next year's budget, that's fine. I've asked for that feedback," Hussey said.

"I'm not asking for that, Cheryl. I'm simply asking for the analysis you guys did," Lang said. "We're paying for all of this. You guys aren't a confidential entity, and you're saying you've done an analysis that shows this is the best use. I'm not saying, 'Don't do it.' I'm simply saying I'd like to see the analysis so we can better understand that."

Hussey said NYISO would need to review its agreements with its banks to see what information she could share.

Lang replied that he had seen more detailed budgets from other grid operators and suggested that if NYISO wasn't willing to share more detailed budgetary information, then perhaps it was time to revisit auditing its management.

"I know you've been completely opposed" to an audit, Lang said. "But the [New York Public Service Commission] has that authority. The FERC has that authority. Maybe it's time that we take a closer look at some of these issues."

Hussey said she was not refusing to share the analysis, but Lang retorted that she had not agreed to provide it, either.

How to Value Transmission Security

The Installed Capacity Working Group meeting Oct. 1 was dominated by a discussion of the different ways that NYISO could *incentivize* transmission security via the markets.

The Market Monitoring Unit and several stakeholders have raised concerns about how transmission security requirements are incorporated into the ICAP market at minimum levels. The worry is that the current market structure does not correctly incentivize or value transmission security, leading to repeated regulatory and public policy interventions to build out the transmission system. (See "Demand Curve Reset and Transmission Security," *NYISO ICAP Working Group Briefs: Sept. 24, 2024*.)

But how to value transmission security is an open question.

"We would have separate requirements, curves and accreditation for resource adequacy and transmission security, priced separately," said Manish Sainani, NYISO market design specialist, outlining the Monitor's proposal.

"You've just described something that's drastically more complicated than having separate requirements and doing a joint solving program," said Mark Younger, principal of Hudson Energy Economics. "It seems what you're proposing is an even bigger kludge than what we have in the market today."

Later in the discussion, NYISO clarified that its presentation was just trying to identify potential options but that none of them had been decided on yet.

"It seems like one of the first things we should try to nail down is the methodologies for calculating TSLs [transmission security limits] and [locational capacity requirements]; that's been underway for a while," said Mike Mager, a lawyer from Couch White representing large energy consumers. "I don't think it makes a ton of sense to change the market for TSLs when we're not even positive what the methodology is for calculating them."

Monitor Pallas LeeVanSchaick said TSLs are having a major impact on the market.

"It's having a big impact today, and it's going to have a bigger impact in the future," he said. "I think our proposal was just trying to make a refinement to the market so that it is having an appropriate impact." ■

— Vincent Gabrielle

NYISO News

NYISO Draft RNA Finds Reliability Need for New York City

Stakeholders Irritated by Draft's Lack of Executive Summary, Tight Comment Deadline

By Vincent Gabrielle

NYISO on Oct. 4 released the first draft of its 2024 *Reliability Needs Assessment (RNA)* showing a capacity deficiency in New York City beginning in 2033 and proposing to declare a reliability need for its zone.

The deficit is driven by a combination of forecast increases in peak demand and the looming retirement of small gas plants in the city, NYISO said. The analysis found that on a peak summer day with expected weather conditions (95 degrees Fahrenheit), the city would be deficient by 17 MW for one hour in 2033, rising to 97 MW for three hours in 2034.

"This is based on the transmission security analysis and the feeding into the transmission security margin," Ross Altman, senior manager of reliability planning for NYISO, told the Electric System Planning Working Group. "This is an actionable reliability need."

The declaration of a reliability need triggers a process in which NYISO solicits solutions, including transmission-based from the local transmission owners, and generation and demand response from market participants. The ISO declared a short-term reliability need for the city last year, finding a potential 446-MW shortfall by 2025. It later decided to keep two natural gas peaker plants, collectively 565 MW, in Brooklyn operational beyond their state-mandated retirement as a solution. (See *NYISO to Keep Gas Peakers Online to Solve NYC Reliability Need*.)

The assessment assumes those units to no longer be available beginning in 2026. The state also recently enacted legislation to retire seven small New York Power Authority gas-fired plants in the city and Long Island worth 517 MW by the end of 2030.

"The reliability need could be met by combinations of solutions, including new generation, retention of planned generation retirements, transmission, energy efficiency, demand response measures or changes in operating protocols," the draft says. "Specifically, scenarios performed in the RNA indicate that the New York City transmission security deficiency could be resolved by resources currently under development but not yet in the base case."

NYISO had reported the possibility of such a deficiency for the city, but it had been overshadowed in meetings by a preliminary finding of a statewide shortfall of as much as 1 GW by 2034. The ISO, however, updated its assumptions about the flexibility of large loads — specifically, cryptocurrency mining and hydrogen-producing facilities — which reduced its loss-of-load expectation to less than 0.1.

Still, the ISO warned in its draft that the LOLE is "extremely close" to the maximum: 0.094. "The tightening margins are a significant concern that ... NYISO will closely monitor and re-evaluate in future [Short-Term Assessments of Reliability] and the next cycle of the Reliability Planning Process."

"We are just under a violation, and a big factor of that is the treatment of large loads," Altman said.

Large Load Flexibility

Several stakeholders questioned how NYISO determined how certain large loads would be flexible and criticized the lack of any data on the topic.

"In your evaluations, did the cryptocurrency load representatives — whatever they are called — give you any idea about how much notice they would need to curtail their load?" asked Mark Younger, of Hudson Energy Economics.

Altman said he did not know and that he did not want to get too detailed on what NYISO discussed with the cryptocurrency companies because such information was "proprietary."

"They provided enough information that [made NYISO] feel they would be flexible, either sensitive to prices or demand response," Altman said. NYISO did not forecast the price of Bitcoin or other cryptocurrencies, he said.

"For other resources, whether it's SCRs [special-case resources] or generators, ... NYISO has tariff provisions and other goals that require submission of information so you guys can track what's going on," said Kevin Lang of Couch White. "This is the only place I can think of where there's absolutely nothing — no reporting requirements, no obligations — ... and yet from the tables you're showing us, if these loads continue to operate during peak periods, we have a very significant problem."

"We are engaged in bilateral discussions and surveying with these large loads in terms of the nature of these large loads and their intention to operate," said Tim Duffy of NYISO, explaining that operating procedures and interconnection studies were also sources of information. "NYISO is really reliant upon transmission owners to gather that data."

"I appreciate the explanation, but I just think, given how critical this is to your assumptions, that there should be something more formalized with these loads," Lang replied.

Tight Deadlines, Annoyed Stakeholders

Stakeholders expressed numerous criticisms of the draft's publications, including the lack of an executive summary: The opening section simply says "Reserved for future drafts."

They were also annoyed that NYISO released the draft on a Friday, with multiple stakeholder meetings scheduled that day, with a deadline for comment the following Monday (Oct. 7).

"I am going to bust your chops," Younger said. "The ISO needs to be rethinking the timeline that they hope that market participants can provide useful feedback on this, given how late it came out and also given that it came out at the same time that many of them are dealing with a critical step in the Demand Curve Reset, a timeline that was well known in advance."

Several sections, including those detailing the New York City reliability need and the narrowly avoided statewide need, were worded confusingly, stakeholders said.

"My personal opinion is that NYISO has bungled some of the communication efforts around recent reliability reports," said Chris Casey, utility regulatory director for the Natural Resources Defense Council. "I think it's important for us to have time to be able to not only understand what the data and findings are, but make sure the narrative matches reality. I don't think we were given time to do that here."

Doreen Saia of Greenberg Traurig requested that NYISO allow more time for discussion at the working group's meeting Oct. 9.

"We are going way too fast on an area that is completely charting new ground," Saia said.

Lang pointed out that NYISO had provided executive summaries on previous RNA reports for 2018, 2020 and 2022.

"You are going way too fast, and you aren't giving market participants sufficient time to understand what's really going on here," Lang said. ■

PJM News

Exelon and Constellation at Loggerheads over Data Center Co-location

By James Downing

The dispute between Exelon and Constellation Energy continued to play out in FERC on Oct. 2, as the latter and others protested a series of filings from the former's utilities seeking to implement new rules for co-locating data centers at power plants in their territories (*ER24-2894*).

"Pepco supports the opportunity for end-use load customers to co-locate where it can be done without threatening reliability. Because the new loads are end-use customers, state law, rather than the [Federal Power Act], determines the retail rate treatment of these arrangements," the Exelon subsidiary said in its proposal, submitted in August along with those of its five sister utilities.

Ahead of the deadline for comments on the proposals, Exelon petitioned FERC on Sept. 30 for an order declaring that PJM's generator interconnection procedures under Order 2003 only apply to end-use generation, not load. (See related story, *Exelon Asks FERC to Weigh in on Co-location Dispute with Constellation*.)

Exelon's utilities argued in their filings that it was important that co-located customers bear their fair share of the costs of transmission service they use and of the interconnection facilities. Even data centers on the generator side of the meter impose similar needs on PJM when it comes to ancillary services and RTO monitoring and administration, they said.

The changes would require any co-located data centers to pay their share of the cost of transmission services, ancillary services and other PJM charges. Exelon also initially said it would be required to meter the "gross load" of the end-use customer, but it removed that language after an early protest from Natural Resources Defense Council saying that could impact backup generation many customers use.

| Shutterstock

Constellation argued in its protest that any data centers that might connect to its nuclear plants in PJM — and in Exelon utility territories — will not take any service from the grid. They will be separated from the grid by redundant protective relays and other equipment that prevent them from ever taking energy off the grid or relying on other grid services.

"Exelon's request should be rejected for what it is: another attempt by a monopoly utility to preserve and increase its market share at the expense of competition and economic development, including the critical and urgent national security need for artificial intelligence and data centers," Constellation said.

Even with the clarification preserving netting arrangements, Constellation said Exelon's rules are as "clear as mud." The filings leave out details of the services the utilities would provide to "fully isolated co-located loads" and do not explain the rates it would charge them.

They would change the definition of network integration transmission service (NITS) in PJM and require every customer "synchronized" to the grid to become Exelon's transmission customers, Constellation argued. "This would force office buildings, grocery stores and even homes across the Exelon footprint to become transmission customers under the PJM tariff."

Exelon should have made the proposal under FPA Section 206 because only PJM itself can file changes to its rules under Section 205, Constellation said. Even if the changes were filed correctly, the lack of any description or justification of the rules means Exelon has failed to meet its burden of proof, it argued.

"Exelon wants to require its interconnection customers to be its transmission customers, but the commission has always recognized a distinction between the two services, and it should not allow Exelon to eliminate that distinction here through its control over interconnection services," Constellation said. "Nor should the commission usurp a state's authority to determine what is and is not a retail sale."

Why This Matters

A ruling that a co-located load at a power plant can be isolated from the grid could have far-reaching consequences, potentially affecting industrial facilities and possibly even residential customers.

Constellation filed affidavits with its protest from two experts: former PJM Vice President of Planning Steven Herling, and market design expert Roy Shanker.

Herling analyzed the engineering and equipment of co-located load and explained why the load is not relying on grid services.

"Protective relays prevent the load — be it data center, hydrogen electrolyzer or otherwise — from taking electricity off the grid," he said. "Yet Exelon seeks to classify all fully isolated co-located load as network load. Basic engineering confirms that this load is not relying on the grid. Basic cost-causation principles dictate that this load should not pay for services it does not take."

Herling said co-located loads have transformers to measure any flows between the grid, and the behind-the-fence customer can automatically trip circuit breakers if any such flows are detected. That can happen if the nuclear plant trips offline, or lower their output, unexpectedly and would "trip the load from the grid" in 0.05 seconds.

Exelon has protested an existing deal that Talen Energy wanted to expand with a data center at its Susquehanna Nuclear Plant. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

The debate in the Talen proceeding led to FERC scheduling a *technical conference* on the issue for Nov. 1. The issues around data centers are also being taken up by state regulators, with the Virginia State Corporation Commission on Oct. 2 *announcing* a technical conference for December and the Maryland Public Service Commission recently holding a hearing. (See *With Three Mile Island Restart, Debate Continues on Co-located Load in PJM*.)

Data centers are particularly important to the modern economy, and their recent prolifer-

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ation in Northern Virginia shows that only allowing them to connect through the grid can lead to significant delays, Constellation said.

While FERC has rules against generators withholding power, they can sell to any willing customer — including engaging in off-system bilateral sales.

"The commission cannot allow Exelon to exercise monopoly power or force all generators to live and die by RTO market prices," Constellation said.

FERC has worked to correct "the excesses of transmission monopoly" through its 30 years of policies supporting open access, Constellation argued, while Exelon's play is to quash a competitive alternative it believes threatens its bottom line. It is not just data centers; Constellation is using its LaSalle nuclear plant in Illinois to directly power hydrogen electrolyzers under the U.S. Department of Energy's hydrogen hubs program.

The gross metering proposal would be a huge blow to that hydrogen effort, as well as to facilities such as batteries and pumped storage that withdraw more energy from the grid than they inject, Constellation said.

Other Parties Weigh in on the Issues

Exelon's filing drew about a dozen responses from other stakeholders, with Advanced Energy United and the Solar Energy Industries Association urging the commission to either reject them or set them for hearing, so that the issues around co-location can be worked out in a general way.

"These new arrangements raise jurisdictional considerations that require a full analysis of implications based on the unique structure of the arrangement," the organizations said. "The industry and the commission itself are still exploring the electrical, economic and legal implications of these arrangements."

The lack of understanding around the issue could lead to unintended consequences if Exelon's proposal were to go into effect before it is examined in a more general way such as at the technical conference next month, AEU and SEIA said.

Calpine also argued that the issue was too novel to be decided now and that Exelon's proposal could impact industrial facilities and potentially even residential customers.

"The commission's actions here will impact the nation's ability to build vital data infrastructure that is critical for national security and economic development," the company said. "This attempt to circumvent a policy discussion of national significance must be rejected."

Old Dominion Electric Cooperative also wants to see FERC address the issues on a generic, or at least regional, basis — not *ad hoc*, transmission owner by transmission owner. The co-op uses behind-the-meter generation, including in Exelon's territory, and it had urged the commission to reject the initial filing with its language about gross load because that could eliminate the longstanding netting of load it does for customers served by distributed generation.

"ODEC submits that such a piecemeal, TO-by-TO approach to these issues is inefficient and could lead to disparate treatment of co-located load and behind-the-meter generation throughout the PJM region," the co-op said. "For [load-serving entities] like ODEC that have load in several PJM transmission zones, this disparate treatment can have real impacts on ODEC's costs for transmission, ancillary service and PJM administrative charges, as well as ODEC's ability to invest in generation resources and participate in demand response programs."

Voltus, a virtual power plant provider, said that Exelon's filings appear to be an attempt to get around FERC's more general look at the issue with the November conference.

"Exelon provides no quantification of the size or number of facilities that are set to be built with the current tariff in effect, nor the timing of their construction," Voltus said. "Without these details, Voltus does not understand Exelon's need to move so expeditiously."

Public Service Enterprise Group filed a protest arguing that Exelon's proposal threatens New Jersey's solar goals, saying it would harm the 90,000 BTM generation customers in its territory by making their service more expensive, and the same could be said for any qualifying facilities.

"The Exelon companies attempt to carve out from 'all load' BTMG, QFs and retail net metering arrangements," PSEG said. "However, they make no effort to explain or justify why it is just and reasonable and not unduly discriminatory for co-located load to be treated differently than BTMG."

PSEG also made the argument that while the filings claim to only apply to six Exelon utilities, they would modify general terms and conditions of PJM's tariff, and Exelon lacks that authority. BTMG arrangements have been part of PJM's rules for two decades, and Exelon's proposals would threaten that activity, with the RTO's tariff saying the load of a network customer "does not include the load served by operating" BTMG, PSEG argued.

"The central characteristic of a BTMG configuration is that it provides for the delivery of power from the generator to the co-located load 'without using the transmission system,'" PSEG said.

The typical rooftop solar customer on PSEG's system gets an annual bill of $59 from its service charge, but the firm estimated that under Exelon's proposal, that would balloon to $419/year — a 700% increase. PSEG also estimated that it would impact several university campuses with BTMG by raising their network transmission charges by millions of dollars.

Exelon's late revisions would carve out traditional BTMGs, but PSEG said that only compounds the filings' legal flaws.

"As amended, the Exelon filings are unduly discriminatory and preferential in proposing fundamentally different treatment for BTMG arrangements, QFs and retail net metering arrangements on the one hand and co-located load arrangements on the other hand," PSEG said.

Exelon's proposal did win outright support from PJM's Independent Market Monitor, who said in a filing that current proposals for co-located load would provide for "discriminatory treatment" for such customers and impose costs on other consumers.

"Such arrangements between generation owners and co-located loads are not private bilateral arrangements that can ignore the applicable requirements of the PJM" tariff, Monitoring Analytics said. "The core result for co-located load proposals is avoiding the costs assigned to transmission and distribution customers under both state and federal regulation."

The deals would allow large co-located customers to avoid paying transmission and distribution charges, as well as any regulation by state commissions.

"The core assertion underlying such co-located arrangements, that a co-located load at a power plant can be isolated from the grid, is an illusion," the Monitor said. "It is not possible to be off the grid. Both the power plant at which the co-located load is sited and the co-located load itself depend on the grid and cannot exist or function without the grid. In addition, the co-located load will continue to rely on the grid for a range of ancillary services including frequency control, reactive, spinning reserves, reserves in general, black start and PJM administrative functions." ■

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Exelon Asks FERC to Weigh in on Co-location Dispute with Constellation

By James Downing

Exelon on Sept. 30 filed a petition for a declaratory order from FERC on its dispute with Constellation Energy over the latter's effort to co-locate major loads at two of its nuclear plants (*EL24-149*).

The two firms, which used to be one before Exelon spun off its generation and competitive retail businesses into Constellation, have been on opposite sides of the debate on co-location from a purely policy level. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

But Exelon's petition lays out the actual business dispute. Constellation is seeking to co-locate new loads at its Calvert Cliffs Nuclear Power Plant in Maryland and Limerick Nuclear Power Plant in Pennsylvania. Those plants are connected to the grid owned by Exelon's Baltimore Gas & Electric (BGE) and PECO Energy utilities, respectively.

The petition, nor the legal correspondence filed alongside it, do not mention data centers specifically with the modifications, but Exelon argued that Constellation's moves could harm new and existing customers, including data centers. The economics of co-locating data centers at nuclear plants are lucrative, as a deal with Microsoft was enough to get Constellation to reopen the recently retired unit at Three Mile Island, Exelon said.

"Constellation has wrongly claimed that the existing interconnection agreements between the petitioning utilities and predecessors of Constellation (and, in the case of Calvert, PJM) entitle it to connect new end-use load without regard to the purpose and terms of the existing interconnection agreements or to the retail nature of the interconnection and requested services involved," Exelon said in its petition.

Exelon wants FERC to find that PJM's generator interconnection procedures under Order 2003 only apply to end-use generation, not load. FERC should also declare that interconnection of end-use load is a matter of state, not federal jurisdiction, the company argued.

Under the Federal Power Act, FERC is required to respect states' role to regulate retail rates, Exelon said. Order 2003 itself was aimed at ensuring fair competition for generation, and FERC should make clear that it does not apply to end-use customers, it argued.

Exelon also asked FERC to find that a request to reconfigure existing generator interconnections to accommodate the co-located large, new loads would require modification of the relevant interconnection agreements to reflect the new interconnection facilities and the changed nature and purpose of the interconnection. That requires the consent of all the parties to such deals, the company argued, urging FERC to declare that as well.

The company said it supports the efforts of retail customers who chose to co-locate at generators when that can be accomplished safely and reliably and when load pays for its fair share of the costs of the electric grid, as defined by the applicable state and federal rates.

"Fortunately, the standard process of adding end-use load to the system is well understood and can be accomplished quickly while protecting system reliability and other customers," Exelon said. "That process requires only that the load becomes a retail customer of the relevant distribution utility or cooperative, pay rates under existing tariffs, and that the interconnection be studied for safety and reliably."

Changing the interconnection agreements to include large new loads transforms such deals into three-legged arrangements connecting end-use load, generation and the grid, which is significantly different from plugging a generator on its own to the grid, Exelon said.

Both BGE and PECO received requests for such co-locations, and they asked questions that would reflect the standard process for load additions, in which the customer itself or its agent asks the local distribution utility for service and describes the nature of the load and other factors.

Calvert Cliffs Clean Energy Center in Lusby, Md. | *Constellation Energy*

Constellation took exception to those requests, saying the two utilities were not allowed to "condition performance of [interconnection agreement] obligations," Exelon said. Constellation argued it was not required to arrange for retail service for the co-located load deals it is pursuing, according to Exelon.

"By its plain terms, PJM's tariff does not and could not contemplate interconnection of end-use load through the generation interconnection process," Exelon said. "Moreover, in its letter concerning Calvert Cliffs, Constellation has also declared that it may resort to litigation or referrals, including supposed antitrust claims, if BGE does not immediately take steps to provide the service Constellation requests."

The controversy reflects a fundamental disagreement on the law, which includes foundational principles of jurisdiction, in the context of matters of serious import, Exelon argued.

It "respectfully request[ed] that the commission issue declarations that will settle this controversy, which threatens to cloud and undermine the jurisdictional and regulatory division between the states and the federal government embodied in the FPA, and which promises widespread, protracted litigation because requests to modify generator interconnections to accommodate co-located end-use load are becoming increasingly common," Exelon told FERC. "By eliminating any confusion created by Constellation's attempts to shift costs of co-located load at its generator interconnections, the commission can speed the energy transition, ensure reliability and protect all customers." ■

Why This Matters

While FERC is poised to start to collecting information on co-locating large loads with nuclear plants at a technical conference early next month, Exelon's petition asks it to make a number of precedential findings on the subject, including giving states primary jurisdiction over the issue.

PJM News

NJ Offshore Infrastructure Plans Spark Electromagnetic Fears

BPU Solicitation Would Create Coordinated OSW Transmission System

By Hugh Morley

Citing predictions of a 20% rise in New Jersey's electricity demand by 2034, state officials laid out an infrastructure plan to tie offshore wind projects to the grid at a public hearing Oct. 1 amid skepticism about the safety of running high-powered cables through residential areas.

Speakers from the New Jersey Board of Public Utilities (BPU) said at the hearing on the agency's OSW infrastructure solicitation that the state needs extensive support for the dramatic increase in electricity supply to meet demand.

The BPU said coordinated developments to tie three or four projects to the shore, instead of several developments each running their own cables inland, would be more efficient, less disruptive to the community and could save hundreds of millions of dollars. The agency will collect comments on the plan until Oct. 15.

Why This Matters

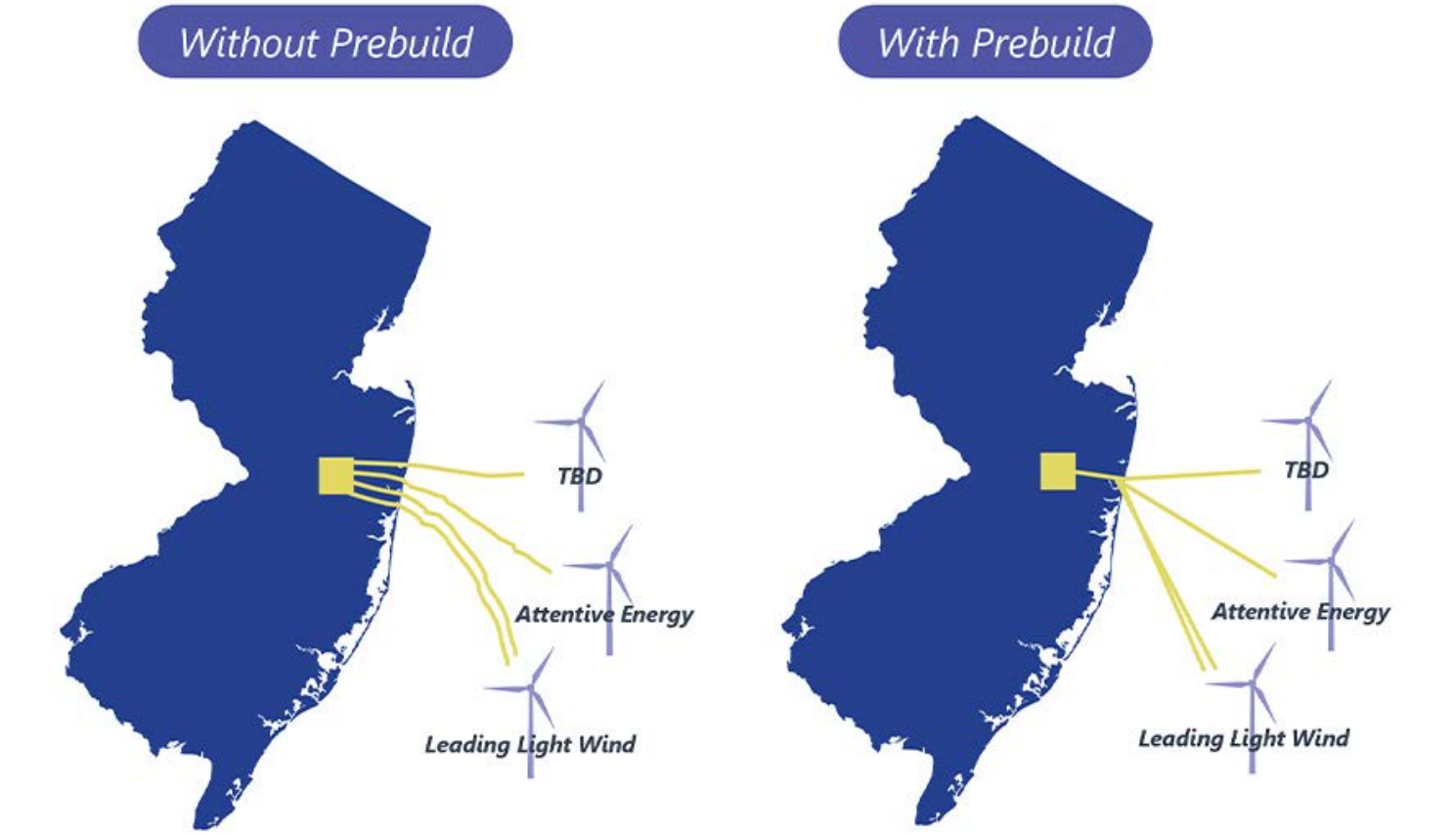
New Jersey counts on offshore wind to help meet the coming demand increase as it now relies on 6,000 MW of power from out-of-state generators, much of which is produced during critical periods by coal plants.

"We're talking about 15,000 GWh of electric demand," said Bob Brabston, BPU executive director, of the expected increase. "That's driven by a host of things, including economic development through port electrification, data centers, the growth in electric vehicles, larger homes and population growth in the state."

The BPU seeks proposals on how to build a corridor linking the Sea Girt National Guard Training Center on the shore, to infrastructure under development at Larrabee Collector Station inland. That station would link to the grid and was approved in an earlier $1.07 billion infrastructure solicitation. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

Four developers have submitted proposals for the second infrastructure solicitation, which the BPU launched in November 2023. The BPU said it expects to pick projects in the coming weeks, with construction expected to start in 2027 and end in 2029. The developers would build duct banks, conduits or pipes through which the cables run, and cable vaults, which are concrete boxes that house the connection point of two long stretches of cable and can serve four offshore projects, with the actual cables installed later.

A series of speakers at the hearing — held at the office of the International Brotherhood of Electrical Workers Local 400 in Wall Township, N.J. — said they were worried about the



Prebuilt infrastructure will allow four different OSW projects to connect to the grid at a single point (right), rather than needing four separate lines with four different onshore connection points (left). | *New Jersey Board of Public Utilities*

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community disruption from laying cables and the safety of having them so close to residences. The BPU said about 450 people signed up to attend live, and an additional 75 registered online. Environmental groups and other OSW supporters held a rally before the event.

Mayor Don Fetzer of Sea Girt and Mayor Mike Mangan, of neighboring Manasquan, said resident concerns were widespread and urged state officials to consider the demands of local communities.

"This is not anything against wind turbines," Fetzer said. "We're not against alternative energy. What we're against is more the process, and how they came into our streets when there are other (possible) areas that we feel are well known."

He said the borough had spoken to the four developers and that officials attended a meeting of 600 people a few weeks ago organized by a group called Stop the High-Risk Power Cables.

From the outside, the cable route landing point "seems like a natural place owned by the state, not a parkland, nothing like that," he said. "And what has always been infuriating to us as a town is it would make a hard north turn after they made the beach and run into Sea Girt proper on our residential streets. And that's been the main focus of our complaints and concerns."

The exact route has yet to be determined, the BPU said.

Changing Strategy

The BPU initially sought offshore infrastructure with the onshore solicitation conducted under FERC Order 1000's State Agreement Approach (SAA). But the BPU changed its plan and decided the offshore infrastructure — known as prebuild infrastructure (PBI) — should be part of the state's third OSW solicitation. The BPU then shifted course again in October 2023 to create a separate infrastructure solicitation, and in February initiated a second SAA. (See *NJ Revamps Third Solicitation OSW Connection Plans*.)

BPU officials said at the hearing that offshore wind is needed to meet the demand increase because New Jersey relies on 6,000 MW of electric power brought in from out-of-state generators. Much of the imported power is produced during critical periods by coal plants, agency officials said.

The BPU since 2019 has completed three OSW project solicitations and approved five projects. It is midway through a fourth solicitation, with a fifth expected to begin early in 2025. Danish developer Ørsted withdrew two of its projects a year ago, while another project approved in the second solicitation, the Atlantic Shores, is now the state's most advanced of three remaining projects.

Underground Drilling

The PBI solicitation seeks proposals to build two 320-kV transmission lines and two 525-kV transmission lines. Duct banks would be buried five feet below ground, BPU officials said. And there would be no trenches or excavation on the beach. Instead, horizontal channels would be drilled 60 feet beneath the beach and pipes inserted, ready to be filled with cables, officials said.

"There's no excavation at the beach," said Nicolas Baldenko, an engineer for consultant Levitan & Associates, which is helping the BPU evaluate the submissions. "Beach landings for cables everywhere around the world, whether it's power or communications, those are always done nowadays via something that's called horizontal directional drilling," he said.

Katharine Perry, BPU's deputy director of offshore wind, said the agency will evaluate the infrastructure projects based on their viability and cost and to ensure "any successful project results in the least disruptive approach."

To that end, "during construction the selected developer would be responsible for ongoing and active communication with local communities to ensure any construction activities follow all requirements to minimize disruptions and maintain the highest safety standards during construction," Perry said.

BPU officials cited several existing examples of similar high-voltage cables in the New York-New Jersey area, most prominently the Neptune Regional Transmission System, a 5,000-kV direct current underground cable that runs from Sayreville, N.J., to Jones Beach on Long Island.

Magnetic Field Fears

Those examples did little to quell residents' fears. Several speakers focused on possible health damage from high-voltage electricity cables running close to their homes and of a proposed route they said would take the cable through an EPA Superfund site formerly occupied by two dry cleaning operations, *White Swan Cleaners/Sun Cleaners*.

"A program of this magnitude and proximity to a developed community is untested and consequential health and safety issues have not been adequately established," said Fred Marziano, a Sea Girt resident. He said the EPA has said, with regard to the Superfund site, that "spreading of the contaminated plume in our groundwater would be very likely if disturbed."

Manasquan resident Lynette Viviani said the cable would pass "30 feet from my living room." She asked "what kind of monitoring" state and federal agencies would do to ensure the Superfund site did not spread pollution.

Glenn Hughes, another Sea Girt resident, said the existing cables cited by the BPU aren't relevant because the voltage on the proposed cables is significantly larger. Moreover, the Neptune cable "does not go through a single residential neighborhood," he said.

No one can say "with any certainty that this is going to be safe," and "nobody living in America should have to live with that risk," Hughes said.

The BPU earlier showed a video in which Benjamin Cotts, an engineer specialist in magnetic fields and cables, minimized the possibility of health impacts from the cables. Cotts, who works for an engineering and scientific consulting firm hired by the BPU, said the cables would carry direct current (DC), and not alternating current (AC), which is most commonly used and studied. Any discussion of electric-magnetic fields relating to AC is "completely irrelevant," he said.

He said, "the cable construction and the burial below ground will effectively block any electric field from the cables," and added that the DC magnetic fields created by the PBI would be too small to harm anyone.

The World Health Organization has determined the acceptable limit for DC magnetic fields is 4 million milliGauss (mG), he said. And "the upper range of the DC magnetic fields from the prebuilt infrastructure is expected to be less than one-half of 1%" of that level, he said.

BOEM Approval

In an unrelated development, BOEM announced on Oct. 1 its *approval* of the construction and operations plans for part of New Jersey's most advanced project, Atlantic Shores South 1 and 2, which are 8.7 miles from the New Jersey shore and together will generate 2.8 GW of power. The company said they will serve 1 million homes.

"Securing these critical approvals enables New Jersey's first offshore wind project to start construction next year and represents meaningful progress in New Jersey achieving 100% clean energy by 2035," said Joris Veldhoven, CEO of Atlantic Shores Offshore Wind. ■

PJM News

Regulators Worry Data Centers Consume Too Much Clean Energy

Webinar Participants Describe Booming Demand Without Enough Resources to go Around

By Elaine Goodman

The growing trend of pairing power-hungry data centers with clean energy resources is sparking mixed feelings among some regulators.

On the one hand, the planned reopening of Three Mile Island Unit 1 will supply Microsoft with energy through a power purchase agreement. It's also likely to supply some energy to the local grid, helping with decarbonization, according to Maryland Public Service Commissioner Michael Richard, who spoke during a WECC webinar on large loads Oct. 2.

But Richard was more concerned about the Susquehanna nuclear power plant in neighboring Pennsylvania, where Talen Energy wants to amend the interconnection service agreement to send some output to a co-located Amazon Web Services data center rather than to PJM. (See *With Three Mile Island Restart, Debate Continues on Co-located Load in PJM*.)

Richard also voiced concern about the possibility of data-center co-location at Calvert Cliffs nuclear plant, which he described as "one of those bedrock, in-state assets that we depend on." Maryland imports about 40% of its electricity, he noted.

"As we drive toward decarbonization and cleaner resources, if we lose what we have, and just end up … importing and enabling the continued operation of coal plants and other fossil plants, that really doesn't advance some of our goals," Richard said.

Richard was more enthusiastic about co-location of data centers with potential wind facilities off the Maryland and Delaware coasts, where he said the centers could help make the economics of offshore wind work.

Why This Matters

With the drive toward decarbonization, the competition for clean resources from large loads like data centers could lead to the continued operation of coal plants and other fossil plants to fulfill other demand.

Co-location of data centers with zero-emissions energy resources such as the Susquehanna nuclear power plant was discussed during a WECC webinar. | *Talen Energy*

Resource Shortage

The *webinar* was part of WECC's "Reliability in the West" discussion series. The focus of the Oct. 2 session was "large load experiences."

Kris Raper, WECC's vice president of external affairs, said the discussion had hit on a challenge that the West, and perhaps the entire nation, is facing.

"We don't have enough resources to meet what is already going on," Raper said, pointing to electrification and efforts to bring clean resources to the grid.

Webinar panelist Glenda Oskar, an economist in the Department of Energy's Office of Policy, said DOE is looking at ways to help new data centers. One possible approach is siting data centers at retired coal plant locations, where existing infrastructure could be used.

DOE also wants to aid in the commercialization of "clean, firm technologies" that could benefit data centers, Oskar said. Those include next-generation geothermal, advanced nuclear and long-duration storage.

Webinar panelist Travis Metcalfe, energy projects manager at Amazon Web Services, said not all data centers are the same.

At some centers, customers might simply be looking for a place to back up their data once a day without using much energy.

"Then you have … AI and machine-learning models, which might be using enormous amounts of electricity," Metcalfe said.

Back-up Generation

Even though Northern Virginia, the world's largest data center market, is just across the Potomac River from Maryland, Richard said he didn't encounter data center issues at the Maryland PSC until recently.

In 2023, a data center developer filed for an exemption from the PSC's certificate of public convenience and necessity (CPCN) requirement for 168 backup diesel generators totaling 504 MW.

Initially, the commission rejected the request. But recognizing the state goal of promoting data center development, the commission later approved a waiver for 25 generators totaling about 70 MW — enough for the first phase of the project, Richard said.

The issue then ended up before the Maryland legislature. A bill requested by the governor (*SB 474/HB 579*) was introduced this year to remove the CPCN requirement for backup power at "critical facilities," which include hospitals, health care facilities and data centers.

The legislature passed the bill, which took effect July 1. ■

PJM News

Electricity Bill Spikes Trigger NJ Legislative Analysis of Generation

Ratepayer Complaints Attributed to Heat Wave, Rate Hikes

By Hugh Morley

Dramatic spikes in New Jersey electricity bills over the summer stemmed from the combined effects of an unprecedented heat wave and recent rate increases, utility executives said at a state Assembly hearing.

Electricity use in June and July shot up by 15 to 20% in some areas over the same period in 2023 in what the New Jersey Board of Public Utilities (BPU) said was the hottest June on record.

The Oct. 2 Assembly hearing also spotlighted the need to better cope with the state's growing need for electricity and how to bring new generation sources online to replace retired fossil fuel sources.

The hearing came as Gov. Phil Murphy (D) pursues an aggressive energy policy centered on electricity and the development of 11 GW of offshore wind capacity. Republican lawmakers argue the state is moving too fast and should embrace a broader energy portfolio.

The Assembly Telecommunications and Utilities Committee convened the hearing in response to widespread customer complaints about the sudden increase in the size of their bills.

"I received countless calls from my constituents because they are seeing what I have been seeing — skyrocketing electric bills," Assemblywoman Andrea Katz said in testimony to the committee. "I heard it from my neighbors, and I saw it on my own electric bill. Utilities like Exelon have seen their stocks up 10% over

Why This Matters

New Jersey has kept electricity demand in check with energy efficiency, but dramatic increases in demand now threaten the reliability of the grid as fossil fuel plants are retiring as quickly as clean energy sources can be built and connected.

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PJM News

the last year, while at the same time, families in New Jersey are paying hundreds of dollars more a month for their electric bills. … And we all need answers."

BPU President Christine Guhl-Sadovy said the "main driver of the increases over the summer was an increase in usage."

Customer use across the four utilities that serve the state — PSEG, Jersey Central Power & Light, Atlantic City Electric (ACE) and Rockland Electric Co. — increased by 12 to 16% over the previous year, which was relatively cool with unusually low use, she said.

In addition, she said, the BPU certified a rate hike that would increase the average customer bill by 5 to 8% due to electricity rates set in the Basic Generation Service (BGS) auction held by the four utility companies.

Multiple Rate Hikes

Brian O. Lipman, director of the New Jersey Division of Rate Counsel, said the rate hike was one of several implemented by utilities that affected customers for whom, given the elevated temperatures, "air conditioning is no longer a luxury, it is life saving."

In testimony, and in a supporting letter to the committee, he said ACE had increased rates nine times since July 2023, and reduced rates four times, for a net overall increase. These included increases for transmission rates, infrastructure improvements, and prices set by the BGS results, which increased electricity supply rates by about $7.56 per month, he said.

Even before the use increase, the average ACE ratepayer was paying about $23.64 more in June 2024 than a year earlier, Lipman said.

Add during the heat wave and "the result is significantly higher bills for ACE customers in the summer of 2024 as compared to the summer of 2023," he said in the letter. "This analysis does not only apply to ACE. I could go through the same analysis for PSE&G, JCP&L and Rockland Electric Co."

Speaking at the hearing, Phil Vavala, ACE's regional president, said the average customer bill increased by 20%, part of which was due to the "pass-through" cost of electricity rates, which are set at the BGS auction.

He said the company works to "empower customers to better manage their energy use." That includes providing customers with programs that "help those who are struggling to meet their energy needs" and to deploy smart meters that enable customers to better monitor their energy use, he said.

Electricity Demand Surge

Several speakers said the spike in customer bills showed the state has to address far larger systemic issues.

"One of the main takeaways that we probably will all share today is that we do need more generation," Guhl-Sadovy said. "We, over the last couple of decades, have not seen a significant demand increase in energy use, in part because we've done a really good job in energy efficiency. And so we've helped to keep that demand flatter. But we have seen energy demand go up, and so we do need more generation."

BPU officials said at an Oct. 1 hearing into the agency's offshore wind infrastructure solicitation that they expect demand for electricity in the state to increase by 15,000 GWh to 93,000 GWh by 2025. (See related story *NJ Offshore Infrastructure Plans Spark Electromagnetic Fears*.)

Jason Stanek, executive director of PJM Interconnection, which serves 13 states, said the region is in the midst of a transition.

"We're seeing a tightening of supply and an increase in demand," he said. "And they're going in opposite directions relatively quickly."

He said the RTO's load forecast released earlier in the year showed trend lines that were "head and shoulders above all prior years." That increase stems in part from the rise in electric vehicle use and the emergence of commercial high-energy users such as data centers and artificial intelligence facilities, he said.

An example of the challenge facing PJM, he said, is that in the 12 months prior to the summer of 2024, the RTO experienced 4,000 MW of generating source retirements, while peak demand rose by 4,000 MW.

"So that's an 8,000-MW difference in just a short period of 12 months," said Stanek, adding that such a sudden increase in demand is difficult for PJM to handle. A shortfall in supply compared to demand can increase the price of electricity. That was demonstrated in the results released in July of the organization's recent *capacity market auction*, which set electricity prices nearly 10 times higher than a year ago, he said.

Stanek urged lawmakers to help PJM, and the region, better handle the ongoing demand surge by avoiding policies that are "designed to push resources off the system before we have an equal and equivalent amount of replacement resources."

At the same time, PJM is working through a backlog of customers waiting to connect new sources to the system, he said. ■

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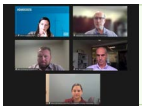


OSW Industry, Advocates See Hope in NE Multistate Procurement

NetZero Insider

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

PJM News

PJM Stakeholders Delay Vote on Generator Deactivation Rules

By Devin Leith-Yessian

The PJM Deactivation Enhancements Senior Task Force (DESTF) has delayed voting on five proposals to rework the RTO's rules for the advance notification generation owners must provide before deactivating units and the compensation structure for resources offered reliability-must-run (RMR) contracts.

Following several major changes to *proposals* presented during the group's Oct. 2 meeting, participants requested additional time to understand where each package stands. An additional DESTF meeting was scheduled for Oct. 17 to open the vote, which will be conducted on the PJM website after the meeting closes. The Independent Market Monitor, Sierra Club and Calpine have each sponsored proposals in the DESTF, while PJM has sponsored two packages, one of which was presented for the first time Oct. 2.

The most significant changes were made to the Monitor's proposal to create an expedited interconnection process for projects that would alleviate transmission violations prompted by a generation deactivation, with the goal of allowing generation to present an alternative to transmission projects and RMR contracts. New language was added that would model the expected output of RMR units in the capacity supply stack — counting them toward meeting the reliability requirement without mandating that they offer into Base Residual Auctions (BRAs) and take on Capacity Performance (CP) obligations.

Monitor Joe Bowring has argued that not including RMR resources in the supply stack is inconsistent with PJM's practice of modeling their output when calculating the capacity emergency transfer objective (CETO) and limit (CETL) for different delivery areas. Under the Monitor's proposal, RMR resources would not be included in the day-ahead or real-time energy markets nor ancillary services unless required to maintain transmission reliability or resource adequacy. (See *PIO Complaint Faults PJM Treatment of Deactivating Generation*.)

Anti-toggling rules were also added to the Monitor's package, stating that if a RMR unit ultimately decides not to deactivate after the contract term has begun, it would be required to refund capital recovery for improvements and maintenance to the appropriate load-serving entity.

The compensation rate in the Monitor's package was adjusted to be based on short-run marginal costs (SRMC) rather than megawatt-hours, and an applicable adder of 10% of the deactivation avoidable cost rate was also added. Actual revenues would be the market revenues the RMR resource receives, such as energy and ancillary service payments, minus the SRMC for the unit.

A limit to the duration of RMR contracts was proposed by the Monitor, capping them at five years with a possible three-year extension. Any requests for an extension would have to be presented to the PJM membership at least a year in advance, where practical, so stakeholders can explore alternative solutions to resolving the underlying transmission violations.

PJM's Package A pointed to the IMM's language defining the compensation rate and would allow generation owners to choose between the Monitor's net revenue compensation approach or the status quo cost-of-service option.

All five proposals would require generation owners to provide PJM with at least one year's notice ahead of their desired deactivation date, while the RTO's proposals contain exceptions for units that must retire to comply with government policies and catastrophic failures. PJM also added language granting exemptions for the requirement that resources must offer into capacity auctions for years when the unit would be granted deactivation.

The Monitor's proposal includes exceptions for failures and a "clear regulatory order to retire," which is mirrored by the Calpine package. The Sierra Club would allow early deactivation, within the one-year notification period, if PJM determines that there would be no reliability issues created by the retirement, along with catastrophic failures and policies that would make the resource uneconomic.

PJM also introduced a new Package D aimed at compromising with some of the changes made to the Monitor's proposal. It would remove the $2 million limit on project investment costs recoverable through the default compensation rate and rework the default avoidable cost credit (DACC) calculation when it is used for determining compensation. Other components are based on Package A.

David "Scarp" Scarpignato, of Calpine, said it would be inappropriate to move to a vote immediately after major changes were presented to proposals that could change stakeholders' voting positions. Several changes would also need to be made to the Calpine proposal, which contained references to the original IMM and PJM packages for some components.

Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

Calpine's proposal would preserve the status quo compensation rate with a 20% applicable adder and adopt the Monitor's components on actual revenues, RMR term limits and requiring RMR agreements to be public. The company copies PJM's language on notification timelines. Calpine's anti-toggling rules would require an RMR unit that reverses its retirement during the RMR term to refund LSEs for payments toward capital improvements. The requirement would also be effective for units that return to serve two years after deactivation.

The Sierra Club proposal largely mirrors the Monitor's language, but it would subject RMR units to CP penalties for underperformance with an annual stop-loss set at the BRA clearing price per megawatt.

Package sponsors discussed both notifying other parties with proposals of any significant changes ahead of the Oct. 17 meeting and replacing cross-package references with specific language to avoid repeat conflicts. There were also requests for PJM to draft a document or presentation that details the differences between each proposal. ■

SPP News

Brattle Study Likely to Fuel Debate over EDAM, Markets+

Paper Compares Key Features, Finds More Benefits in CAISO Offering

By Robert Mullin

A new white paper by The Brattle Group offers a point-by-point comparison of CAISO's Extended Day-Ahead Market and SPP's Markets+ that leans in favor of EDAM but stops short of endorsing either market.

The *paper*, published Oct. 1, will likely further fuel the ongoing and contentious debate between supporters of the two markets.

It examines and compares seven design features in each market, including transmission optimization, fast-start pricing, real-time unit commitment (RTUC), procurement of imbalance and flexibility reserves, seams optimization, greenhouse gas pricing and congestion revenue allocation — all of which have been the subject of controversy between the two sides.

"Many stakeholders in the [Western Interconnection] have suggested that certain market design elements, available in one market but not the other, will have material impacts on market outcomes and customer costs," the paper says. "We aim to compare specific elements of the two market designs and, where possible, provide evidence that sheds light on where one market's design is more likely to improve customer outcomes than the other."

Brattle produced the study on behalf of PacifiCorp, which in April became the first utility to sign an EDAM implementation agreement with CAISO. A separate Brattle study, released in September, found PacifiCorp could earn up to $359 million a year in net benefits from participating in the ISO's day-ahead market, nearly double a previous estimate. (See *Updated EDAM Study Shows Doubling of PacifiCorp Benefits*.)

"As we look at the future of the West and the next stage of market evolution, it's clear that the logical next step is the EDAM," Mike Wilding, vice president for energy supply management at PacifiCorp, said in a statement. "We have to strategically harness as much of the existing transmission and resource diversity of the West as we can, in order to benefit our customers, while maximizing the investments that will meet the evolving needs of the region into the future."

While resource diversity wasn't a focus of the Oct. 1 analysis, the paper's introduction emphasized Brattle's finding from previous EDAM benefit studies performed for Western utilities: that the biggest driver of benefits in a day-ahead market will be creating the largest possible footprint containing the greatest diversity of load and resources — a point repeatedly argued by key EDAM supporters.

"While some of the design differences between Markets+ and EDAM will impact market outcomes and overall market efficiency, they are unlikely to have a material effect on customer savings," the paper says. "Various analyses of customer benefits from market participation indicate that the largest drivers of customer savings will be ... the diversity of load and generation resources available in the markets, and the connectivity between participating members, which all lead to increased economic trading and lower curtailments in the market." (See *Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+* and *NV Energy to Reap More from EDAM than Markets+, Report Shows*.)

Flow-based vs. Contract Path

The core of the paper starts with an examination of a market feature that a core group of Markets+ funders addressed in their most recent "issue alert" covering market seams: transmission optimization. (See *Markets+ 'Equitable' Solution to Seams Issues, Backers Say*.)

In their Sept. 17 *alert*, the Markets+ backers contend that, unlike the SPP market, EDAM doesn't rely on a "full" flow-based approach for optimizing transmission use.

"As a result, EDAM transfers between [balancing authority areas] and between [transmission service providers] will continue to be subject to contract-path scheduling limits used under the [open access transmission tariff] framework (and currently employed in WEIM [the Western Energy Imbalance Market])," the alert says.

The Brattle paper attempts to deconstruct that contention, arguing that both markets will be required to recognize contract path limitations because of "the complex nature of transmission rights" in the West, where the operation of transmission systems is largely decentralized because of the absence of an RTO.

"This is consistent with both markets' tariff language filed with the Federal Energy Regulatory Commission, which indicate that both markets plan to recognize contract-path transmission constraints where appropriate," Brattle says, noting that FERC would have likely directed either market operator to include contract path constraints in their market-clearing processes if they'd proposed "purely" flow-based optimization.

Why This Matters

The Brattle comparative study comes at a time when supporters of both EDAM and Markets+ are ramping up their efforts to influence utilities still undecided about which day-ahead market to join.

"Ignoring contract path rights in regional market clearing engines can result in commitment and dispatch decisions that create negative outcomes for neighboring entities," Brattle writes. "For example, a market dispatch solution using a transmission asset beyond the contracted capacity can create congestion on the asset and impair the utilization of other parties' transmission rights."

Brattle cited the controversy surrounding MISO's integration of Entergy's sprawling service territory (now MISO South) as a cautionary example of the consequences of ignoring contract path limitations in market dispatch. In that situation, MISO initially dispatched energy between its North and South regions without considering those limitations, which created parallel flows on neighboring systems and prompted SPP to "file a complaint with the FERC stating that 'significant intentional, unscheduled incremental power flows are crossing SPP's system without any corresponding reservation, service agreement or compensation.'"

Western stakeholders concerned about the impact of contract path limitations would be best served by the entire region joining the same market, Brattle said.

"This would bring all the physical transmission assets under the control of a single market operator, thereby reducing the need for contract path constraints. Moving towards a joint transmission tariff or a full regional transmission organization would further reduce, and possibly eliminate, the need for contract path constraints altogether," the paper says.

SPP News

Fast-start Pricing

In another section, the Brattle paper plays down the importance of one market feature that Markets+ supporters have argued is an important benefit of the SPP market but notably absent from CAISO's markets: fast-start pricing (FSP).

"Some stakeholders have presented analyses suggesting that FSP has a substantial impact on market prices and revenues collected by generation resources that can come online quickly ('fast-start resources')," Brattle writes. "However, evidence from several U.S. markets, including SPP, indicates that FSP has a very minimal impact on market prices, impacts relatively few hours, and does not materially increase the market revenues of fast-start resources."

The paper points to discrete analyses performed by the market monitors for ISO-NE, MISO and SPP that showed "the overall frequency and magnitude of the price impacts of FSP [in each market] were very small."

For example, a MISO study covering 2016 showed FSP affected only 7.7% of real-time clearing intervals and increased real-time prices by just 1 cent/MWh, while an SPP study for 2022 found FSP increased fast-start resources' day-ahead energy revenues by about 1.5% and real-time revenues by about 0.5%.

Additionally, Brattle says, PJM's Monitor "has also indicated that FSP potentially undermines the objective of reducing production cost, and its implementation in the PJM market has distorted efficiency."

Brattle also questioned the validity of a 2022 *study* conducted by consulting firm Energy GPS for Canada-based energy trader Powerex and the Portland, Ore.-based Public Power Council (both key Markets+ supporters). The study found that if CAISO markets had used FSP over 2017-2020, prices would have increased by $15 to $23/MWh and generators would have collected an additional $1.2 billion to $2 billion in market revenues.

"The analysis informing [the Energy GPS] white paper calculated ... fast-start units' impacts on energy prices as the difference between the marginal cost of starting and running peaking units and the average energy price at regional pricing hubs (NP15 and SP15 in CAISO, plus the Southwest and Northwest regions)," Brattle said. "The study did not simulate a counterfactual market commitment and dispatch solution for the CAISO market to validate this impact, which falls short of the analytical rigor of the analysis conducted by the independent market monitors for the MISO, SPP and ISO-NE markets."

Jeff Spires, director of power at Powerex, said his "first impression" was that Brattle's assessments of FSP was "flawed in multiple areas."

"Brattle mischaracterizes the methodology used by Energy GPS to assess the impact of fast-start pricing in the west and misrepresents the results of their analysis," Spires told *RTO Insider* in an email, adding that the paper "selectively refers to certain historical data from eastern markets to support its conclusion, while failing to include other more recent metrics demonstrating a significant impact of fast-start pricing in eastern markets, including PJM and MISO."

Asked if he could supply those metrics, Spires said the Markets+ funders are compiling the information and will share it when it's ready.

Michael Linn, director of market analytics at the PPC, said the Brattle paper "misrepresents" the results of the Energy GPS study, and that the $15-$23/MWh range represented market prices "for the evening peak hours, typically the highest priced hours in the West when fast-start units are most often dispatched."

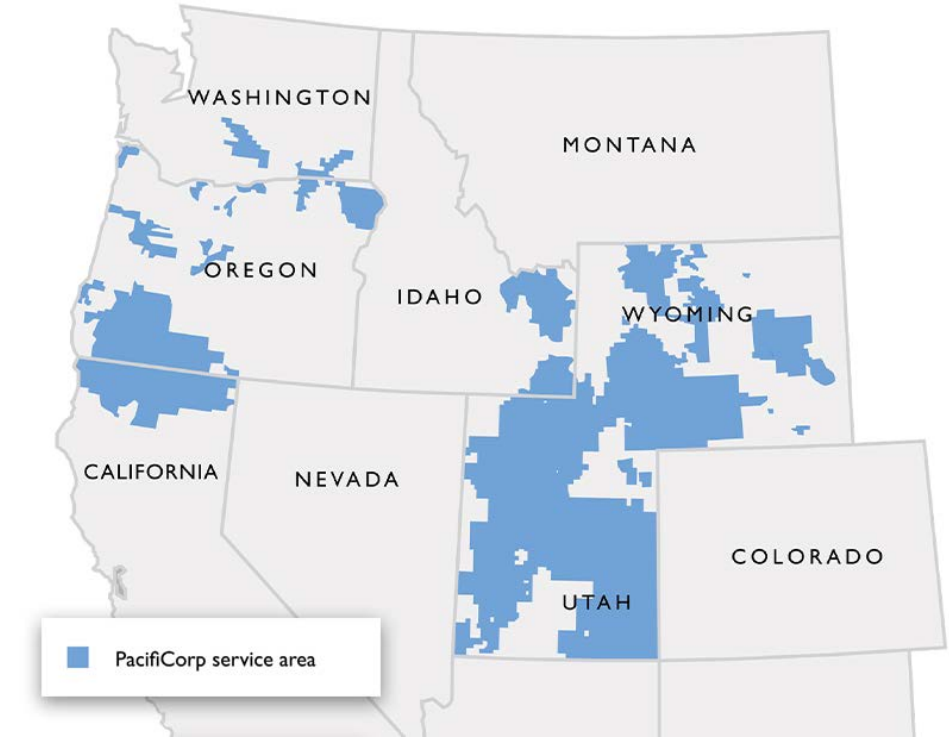
"The Brattle study takes these numbers and compares them to multi-month averages in other studies. The Energy GPS study included an apples-to-apples estimate of average fast-start price impacts that show prices increases by $2 to $4/MWh in Northern California, $4 to $9/MWh in Southern California over the study period, and lower impacts in the Pacific Northwest and Southwest," Linn wrote.

Linn said also that "while the Energy GPS study did not perform a counterfactual analysis, the study relied on publicly available data on actual historical fast-start unit dispatch and fuel costs, providing a useful and practical approach based on real-world data."

Linn criticized the Brattle report for "narrowly" focusing on "a few criticisms" of FSP and ignoring the "overwhelming evidence" of the benefits of the practice, "most recently echoed by the Western EIM Governing Body expert." In May, that expert, Susan Pope, told the Western Energy Markets Governing Body that FSP could fix certain "price anomalies" in CAISO markets better than existing mechanisms for compensating fast-ramping resources. (See *WEIM Expert Calls for Fast-start Pricing to Address 'Anomalies'*.)

'Look Ahead'

The Brattle paper commends CAISO's markets for using a market-clearing engine that relies



Brattle produced the EDAM/Markets+ comparative study on behalf of PacifiCorp. The six-state utility was the first Western entity to commit to the EDAM. | *PacifiCorp*

SPP News

on a four-hour "look ahead" period "that enables it to optimize real-time unit commitment decisions for generation resources in the market that can cycle on and off in four hours across the entire market footprint."

In contrast, Brattle says, the market-clearing engine that SPP uses for its Western Energy Imbalance Service (WEIS) does not include a similar look ahead or perform RTUC, and the Markets+ tariff doesn't indicate that practice will be adopted in the newer market.

"These additional features of the WEIM optimization will allow it to find lower-cost and more operationally responsive solutions relative to the Markets+ real-time clearing that will not perform unit commitment and relies on manual real-time unit commitment decisions," the paper says.

Brattle notes the look ahead feature provides an advantage only real-time optimization, but does not affect day-ahead operations, "where both EDAM and Markets+ optimize unit commitment and day-ahead dispatch."

In an email to *RTO Insider*, SPP spokesperson Meghan Sever said the WEIS design is "not relevant to a comparison of Markets+ and EDAM."

"WEIS is a separate service provided under a different tariff than Markets+," Sever wrote. "The study assumes Markets+ will not include real-time unit commitment, although it is clearly defined in the Markets+ tariff filing currently being reviewed by FERC."

"We do not say that there is no real-time unit commitment, but rather that the real-time market clearing engine does not perform that function," John Tsoukalis, a principal with Brattle and the report's lead author, said in an email.

Tsoukalis said the section of the Markets+ tariff that lists the outcomes of the "Real-Time Balancing Market" does not include unit commitment, while another section describes unit commitment as being an outcome of the reliability unit commitment process.

Markets+ Wins on Seams

The Brattle study also takes a more favorable view of EDAM's GHG pricing mechanism, which it says benefits from 10 years of operational experience in CAISO and the WEIM, and the ISO's process for allocating congestion revenues in its markets.

But Brattle gives Markets+ higher marks for seams optimization, noting that the SPP market will require all participants along a market seam to offer buy and sell bids for import and exports at the seam — the practice of "intertie trading" — while in EDAM, intertie trading will only be activated if market members choose to do so and at the CAISO balancing authority area border.

"The automatic inclusion of intertie trading at the Markets+ seam is likely to deliver benefits to market participants, and similar broad availability of intertie trading would be an improvement to the EDAM design," Brattle wrote.

'Independent Evaluation,' or 'Limited'

Asked why PacifiCorp commissioned the study, spokesperson Omar Granados said the utility was seeking "to offer an independent evaluation of the market design, including the design differences between EDAM and Markets+. This information will be useful for potential future market enhancements and will help inform decision-making if the Western Energy Imbalance Market participants split their participation between two day-ahead markets."

For its part, Brattle said it hoped the paper provides "helpful takeaways for stakeholders in both markets on where the respective designs can be improved in the future, and help the region focus its efforts on developing the markets to enhance the overall efficiency and outcomes for customers."

CAISO and SPP offered predictably different takes on the study.

"We appreciate Brattle's publication of the comparative design paper between Markets+ and EDAM," CAISO spokesperson Anne Gonzales told *RTO Insider*. "The assessment aligns with our perspective that EDAM provides significant reliability and economic value to customers across the West as designed, with the largest seamless footprint possible providing for significant load and resources diversity as well as transmission connectivity, all key factors in enabling those benefits."

SPP's Sever said the RTO hadn't been invited to participate in the study and was still reviewing the results.

"Beyond our assessment of the study's conclusions, SPP also notes that its scope is limited and ignores a number of factors that stand to distinguish it from other options. Production cost studies don't tell the entire story," she said. "Apart from the unique Markets+ design elements that will benefit all Western entities, participants will benefit from an independent and transparent governance and robust stakeholder process that values all participants equally." ■

SPP News

FERC Issues Deficiency Letter for SPP's RTO West Tariff

By Tom Kleckner

FERC has issued a deficiency letter over SPP's proposed revisions to its tariff, bylaws and membership agreements intended to facilitate nine western entities' RTO membership as transmission owners.

In an Oct. 3 letter, the commission said SPP's filings are deficient and that it needs more information to process them. It asked the grid operator to submit its responses by Nov. 4 (*ER24-2184, ER24-2185*).

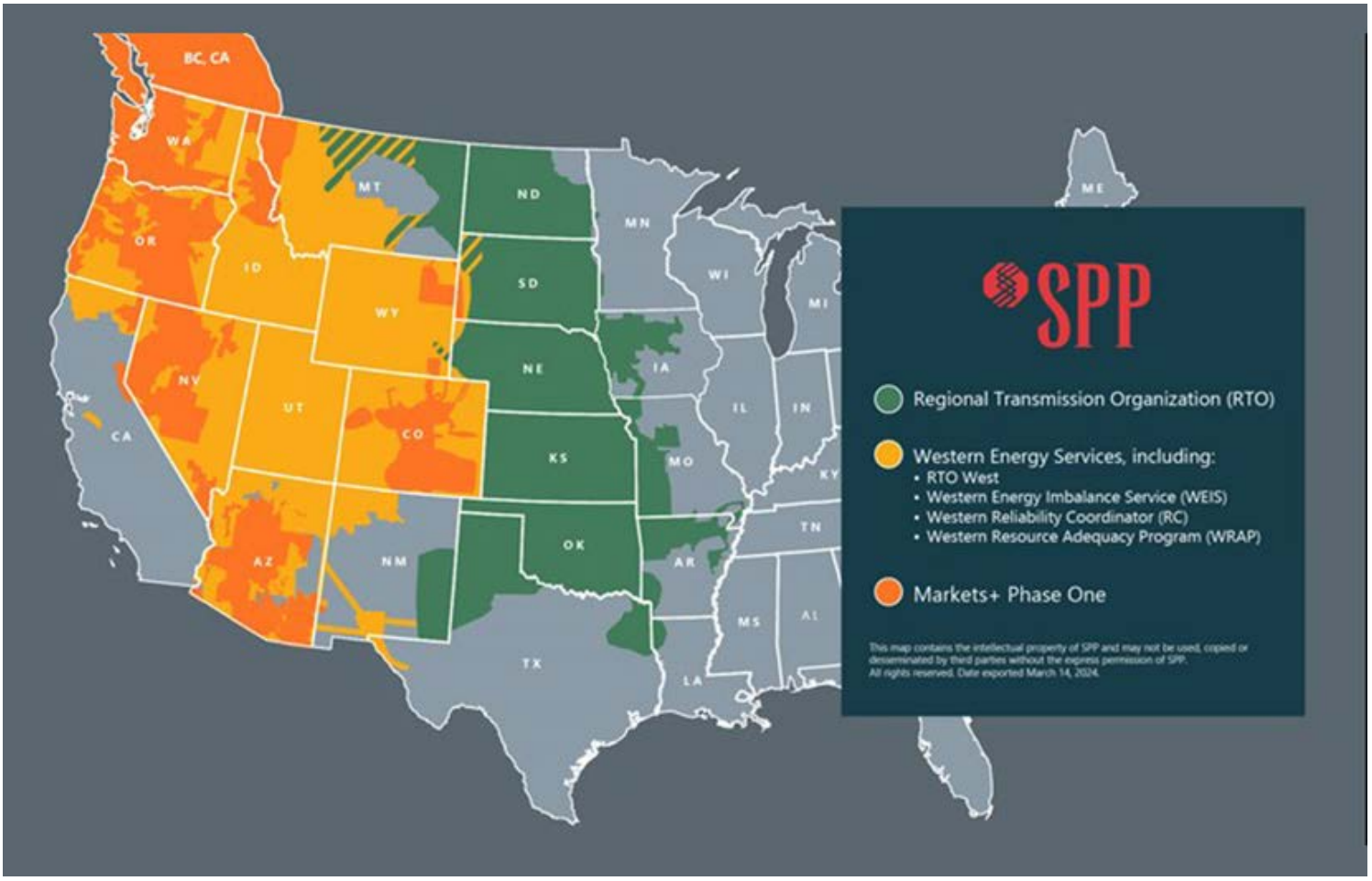
FERC asked for more information on:

- Any existing tariff provisions that will facilitate the transition of the new members' transmission service request queues into SPP's current service-study processes.
- The proposed tariff's provision that the Western Area Power Administration-Colorado River Storage Project's replacement energy is "necessitated by WAPA-CRSP's inability to deliver sufficient energy from reservoir projects under the control of the U.S. Bureau of Reclamation in the marketing area of WAPA-CRSP for reasons such as persistent drought or environmental constraints."
- New metered boundaries and the need to establish a second balancing area authority that will be incorporated into SPP's markets.
- How separate reference buses in the market's two balancing authority areas will accurately model the marginal cost of serving load in each BAA, including the cost of congestion.
- How LMPs on both sides of the West DC ties will inform how SPP optimizes the interties' usage.
- Which rate(s) under the tariff revisions would apply to point-to-point transmission service where the load is located within a BAA external to the SPP Region but not interconnected to SPP's eastern or western market.

SPP filed the tariff for its *western RTO expansion* in June as it seeks to become the first grid operator with markets in both the Western and Eastern Interconnections. It says its RTO West will provide more than $200 million in annual benefits to its members. (See *SPP Files to Incorporate Western Entities into RTO*.)

RTO West is scheduled to go live in April 2026.

FERC also filed a deficiency letter for SPP's Markets+ tariff, another of the RTO's *western services*. Saying deficiency letters are part of a "routine process, SPP staff responded to the letter in September and asked for an order by Nov. 20. (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.) ■



SPP's existing and proposed Western Interconnection markets. | *SPP*

Company Briefs

Constellation Seeks Taxpayer Backing to Restart Three Mile Island

Constellation Energy, the owner of the shuttered Three Mile Island nuclear plant, is pursuing a $1.6 billion federal loan guarantee to help finance its plan to restart the facility and sell the electricity to Microsoft.

The taxpayer-backed loan could give Microsoft and Constellation a major boost in their unprecedented bid to steer all the power from a U.S. nuclear plant to a single company. A loan guarantee would allow Constellation to shift much of the risk of reopening Three Mile Island to taxpayers. The federal government, in this case, would pledge to cover up to $1.6 billion if there is a default.

Constellation plans to restart Three Mile Island by 2028.

More: *The Washington Post*

Dominion Energy Announces Sale of Public Service Co. of North Carolina

Dominion Energy last week announced closure of the sale of its natural gas utility, Public Service Company of North Carolina, to Enbridge for $3.2 billion.

This is the last of three separate transactions as part of an agreement Dominion and Enbridge announced Sept. 5, 2023, whereby Dominion would sell its Ohio-, Utah- and North Carolina-based gas utilities for about $14 billion.

Public Service Company of North Carolina serves about 600,000 customers.

More: *Dominion Energy*

Virginia Natural Gas Taps New CEO

Virginia Natural Gas last week announced Shannon O. Pierce will be the company's new CEO.

Pierce will succeed Robert Duvall after he retires in April.

Pierce started out as a lawyer for McGuireWoods in Richmond and joined Southern Gas, Virginia Natural Gas' parent company, in 2004.

More: *Virginia Business*

Federal Briefs

SCOTUS Declines to Block Methane, Mercury Regulations

The U.S. Supreme Court last week left in place two Biden administration environmental regulations aimed at reducing industry emissions of methane and mercury.

The high court denied petitions brought by Republican states and energy industry groups seeking a stay of the Mercury and Air Toxics Standard while the D.C. Circuit Court of Appeals weighs the merits of legal challenges to the rule. The states challenging the rule called the new standards "impossible to meet" and said they amounted to an "attack" on the industry. The court is still considering challenges to a third EPA rule aimed at curbing planet-warming pollution from coal-fired plants.

The rules will have a direct effect on the Colstrip coal plant in Montana. NorthWestern Energy, one of Colstrip's six co-owners, previously indicated the rules could make the plant's operation "uneconomic" due to needed upgrades.

More: *The Associated Press*, *Montana Free Press*

Siemens to Pay $104M in DOJ Trade Secret Probe

Siemens Energy AG has agreed to pay $104 million to resolve a criminal investigation into misappropriating confidential information from competitors to win a bidding process.

The Justice Department accused Siemens of "illicitly obtaining" confidential information from competitors General Electric and Mitsubishi Heavy Industries "to obtain an unfair competitive advantage" in a bidding process involving a gas turbine plant project. Siemens, which didn't receive credit for voluntarily reporting, pleaded guilty, according to a federal court filing.

Siemens is scheduled to be sentenced Dec. 5. The company also agreed to three years of organizational probation.

More: *BNN Bloomberg*

NRC: Palisades Nuclear Plant Corrosion Exceeds Estimates

The Nuclear Regulatory Commission last week said Holtec, the company that wants to reopen the Palisades nuclear reactor in Michigan, found corrosion cracking in steam generators "far exceeded" estimates.

A summary of an early September call between the NRC and Holtec said indications of stress corrosion cracking in tubes in both of Palisades' steam generators "far exceeded estimates based on previous operating history." It found 1,163 steam generator tubes had indications of the stress cracking.

Holtec spokesperson Patrick O'Brien said the return of Palisades is still on schedule and the company wants to fix, and not replace, the steam generators.

More: *Reuters*

National/Federal news from our other channels

Waiting for 45V, US Green Hydrogen Projects Frozen — NetZero Insider

IBR Ride-through Standard Passes Industry Ballot — ERO Insider

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State Briefs

ALABAMA

Alabama Power, EPA Settle Over Coal Ash Pond

Alabama Power last week said it reached a settlement with the EPA over concerns about millions of pounds of coal ash dumped in unlined ditches near Mobile.

The settlement requires the utility to increase monitoring of its coal ash ponds by adding groundwater monitoring wells and updating its emergency action plan to account for severe weather.

Plant Barry is 597 acres and holds almost 22 million cubic yards of coal ash. The company further stated that testing has shown no impact on the Mobile River.

More: *Alabama.com*

Solar Fee Lawsuit Moves Forward in Federal Court

U.S. District Judge Myron Thompson last week denied a motion to dismiss a case that challenges the fees levied on people who install solar panels on their homes and will allow the case to move forward.

The plaintiffs in the case argued the Public Service Commission violated federal energy laws by allowing Alabama Power to charge fees to people who use solar panels. Alabama Power and the PSC had asked for the case to be dismissed, arguing the court did not have jurisdiction and the plaintiffs did not make a claim for which relief can be granted.

Thompson ruled against the defendants, arguing the court does have standing to adjudicate claims made under the Public Utility Regulatory Policies Act.

More: *Alabama.com*

CALIFORNIA

Imperial County Approves Solar Project

The Imperial County Board of Supervisors last week approved the VEGA SES 6 Solar and Battery Storage Project.

The project, which spans around 320 acres, will deliver 80 MW of solar energy paired with 160 MW of battery storage.

More: *Calexico Chronicle*

COLORADO

PUC: Need More Time to Consider Xcel Energy's Wildfire Plan

The Public Utilities Commission last week pushed back a deadline to approve Xcel Energy's $1.9 billion wildfire mitigation plan, saying the proposal could create new risks if it is not thoroughly reviewed.

The plan lays out how Xcel will notify customers when it preemptively shuts off power to reduce wildfire risks. The commission now has until August 2025 to rule on the proposal.

Xcel Energy is currently facing at least 300 lawsuits for its alleged role in sparking the Marshall fire and additional lawsuits that blame its equipment for sparking Texas' largest wildfire.

More: *CPR News*

ILLINOIS

Madigan Judge Refuses to Toss Counts After SCOTUS Ruling on Bribery

U.S. District Judge John Blakey last week declined to dismiss several criminal counts against former House Speaker **Michael Madigan** in the wake of a Supreme Court decision that limited bribery laws.

The Supreme Court found in June that a bribery law key to Madigan's prosecution does not also criminalize after-the-fact rewards known as "gratuities." Madigan's defense attorneys argued weeks later that prosecutors had failed to allege a "quid pro quo" that would be required to prove bribery under the high court's standard.

Prosecutors plan to pursue a so-called "stream of benefits" theory, explained in an appellate court ruling from the prosecution of ex-Gov. George Ryan. In it, the court wrote the corruption there "was more like a meal plan in which you don't pay for each item on the menu. Rather, there is a cost that you pay, an ongoing cost, and you get your meals." Blakey ruled the approach theoretically satisfies the requirement prosecutors have to prove a "quid pro quo."

More: *Chicago Sun-Times*

MARYLAND

Lawsuit Seeks to Derail New Consumer Protection Law

The Retail Energy Advancement League and Green Mountain Energy last week filed suit in U.S. District Court in Baltimore, saying the state's new guardrails on energy companies that compete with utilities violate the firms' First Amendment rights and act as an impediment to the state's clean energy mandates.

The 37-page suit asserts that the law's constraints on energy companies' ability to market themselves is a violation of their First Amendment rights — and impedes their ability to tout the clean energy they may be purchasing. The suit names the state attorney general's office and the Public Service Commission, which will implement parts of the new law on the electricity marketplace, as defendants.

Maryland laws require the state to create a 100% clean energy standard by 2035, while reaching zero carbon emissions by 2045.

More: *Maryland Matters*

NEW JERSEY

BOEM Approves OSW Farm

The Bureau of Ocean Energy Management last week gave its approval for an offshore wind farm that would be built between Atlantic City and Long Beach Island.

BOEM approved Atlantic Shores' plan to construct and operate the facility, which would generate 2,800 MW from 197 turbines.

The project still requires a review by the U.S. Army Corps of Engineers and several state permits.

More: *The Associated Press*

NORTH CAROLINA

Biden Approves More Federal Aid After Hurricane Helene

President Joe Biden last week announced additional aid for the state as it recovers from Hurricane Helene.

Biden said he accepted Gov. Roy Cooper's request for a 100% federal cost share for

debris removal and emergency protective measures for six months. The funding will cover work addressing the impacts from debris flow, flooding and removing fallen trees.

Biden also directed the Department of Defense to deploy 1,000 soldiers to assist North Carolina's National Guard.

More: *NC Newsline*

WEST VIRGINIA

PSC Staff Slams Appalachian Power Outage Performance

Public Service Commission staff last week said Appalachian Power and Wheeling Power's reliability was "unreasonable" and urged the PSC to deny their request for more lenient targets in metrics measuring the duration and frequency of outages.

Staff noted the American Electric Power subsidiaries have routinely failed to meet minimum reliability targets, and their performance negatively impacts reliability compared to other states. Staff also said it is ready to launch an investigation into Appalachian Power and Wheeling Power.

As staff made its recommendations, customers of both companies were still dealing with outages stemming from Hurricane Helene.

More: *Charleston Gazette-Mail*

WISCONSIN

WPS, We Energies Announce Renewable Energy Projects

Wisconsin Public Service and We Energies have announced plans to build nearly 800 MW of new solar, wind and battery storage in the state.

The projects would add 500 MW of solar and 180 MW of wind power to the grid, along with 100 MW of new battery storage.

More: *WLUK*

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FERC Rejects Mabee's 2021 Supply Chain Complaint — ERO Insider

Re-ballot Underway for IBR Ride-through Standard — ERO Insider

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