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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Incumbent Utilities Make Case for ROFR Laws in New Report

Group Says 4 Recent Transmission Episodes Show Competitive Process Falls Short

By Amanda Durish Cook

A band of incumbent utilities has collected case studies that they say demonstrate the need to instate or maintain right-of-first-refusal laws for the good of grid expansion.

The Developers Advocating Transmission Advancements (DATA) — comprising Ameren, Eversource Energy, Exelon, ITC Holdings, National Grid USA and Xcel Energy — released a white paper Feb. 5 faulting FERC's Order 1000 and solicitation processes for hindering more effective grid expansion.

Competitive bidding "isn't compatible with what's needed now," ITC Director of Federal Affairs Devin McMackin said in an interview with ***RTO Insider***. "We think it's well established now that the cost benefits of competitive bidding haven't materialized. It creates more litigation than it does transmission."

On the other hand, McMackin said the ROFR is "a model that we know works."

The report, "*Recent Experience with Competitive Transmission Projects and Solicitations*," emphasizes four recent project scenarios from MISO, PJM, CAISO and New England that DATA says put the flaws of competitive processes on display.

The group said a competitive bidding and selection process can fail to take full projects costs into account; fail to "right-size" projects; fail to consider the feasibility of siting and routing proposals; and can come equipped with "illusory" cost caps.

"Order No. 1000 policy has created the incentive for developers to relentlessly argue over the right to build projects, fostering uncertainty that is to the detriment of actual infrastructure development," DATA wrote. It argued that competitive solicitations have not resulted in benefits, instead contributing to a development environment rife with "litigation and administrative challenges, protracted solicitation processes and re-scoping of projects" — all without "demonstrated countervailing benefit to consumers."

Why This Matters

Six incumbent utilities argue that competitive processes are resulting in unrealistic routing proposals, impractical cost commitments, patchwork modifications to projects and protracted litigation. They say federal and state ROFRs are necessary to meet today's grid expansion needs.

The Beverly-Morgan Valley Transmission Project in Iowa | *ITC Midwest*

"There remains no evidence that FERC's competitive transmission policy has improved the process of developing needed transmission infrastructure. Instead, there is an ever growing body of evidence that reform is needed," the group said.

MISO

In MISO, DATA said ongoing uncertainty over Iowa's ROFR law placed 447 miles of planned 345-kV circuits at a temporary standstill. The $2.1 billion worth of lines originate from the RTO's first long-range transmission plan (LRTP) approved in 2022.

At first, MISO automatically assigned the lines to ITC Midwest and MidAmerican Energy, but in late 2023, a state court struck down the law in a case brought by competitive developer LS Power. (See *Iowa ROFR Law Overturned, Throwing Multiple MISO LRTP Projects into Uncertainty*.) Appeals from the incumbents and the Iowa attorney general are pending. After conducting a variance analysis, MISO reaffirmed the lines should continue to be developed by ITC and MidAmerican.

DATA said litigation over Iowa's ROFR could have an "adverse, cascading effect" on MISO's first LRTP projects and delay economic and reliability benefits. Rather than lower costs, Order 1000 has "created the incentive for competitive developers to fight a constant and multifront battle for the opportunity to develop transmission projects, even if the result is to the detriment of actual infrastructure development," it said.

LS Power has also filed a complaint with FERC against MISO for effectively ignoring a preliminary injunction against Indiana's ROFR law. The company argued it is being denied the opportunity to bid on about $1 billion in LRTP projects. (See *LS Power Files Complaint Against MISO over Indiana ROFR*.)

McMackin said once grid planners go through the "arduous" process of assembling a transmission portfolio, the last thing anyone wants is to spend years deciding which developer

FERC/Federal News

should build it.

McMackin said the certainty ROFRs deliver is evident in MISO, where long-range transmission projects in states with such laws move straight to development, while projects in non-ROFR states are ushered through yearslong solicitation processes.

"States without ROFRs won't even get bids out for two years," McMackin said, adding that DATA's "core contention is that ROFR is pro-transmission policy."

PJM

Competitive processes, DATA said, can have planners selecting projects that are not the best in the long term or the most cost-effective.

DATA singled out the $513 million, 500-kV MidAtlantic Resiliency Link (MARL), which PJM awarded to NextEra Energy in Window 3 of its 2022 Regional Transmission Expansion Plan. NextEra was tasked with routing the project through the notoriously difficult-to-site Loudoun County, Va., in the Dominion zone. The company initially used Google Maps to chart an ultimately infeasible corridor and skipped deeper routing analyses. Eventually, Exelon and FirstEnergy assisted with an alternative route and construction on their existing rights of way, and NextEra and PJM agreed to cancel a portion of the project in favor of incumbent utilities building sections. PJM's Board of Managers approved the changes to the project in 2024, at a net increase in costs.

DATA said NextEra's bid on MARL shows how developers can submit "unsophisticated and incomplete proposals" to an "artificially constrained assessment." It said competitive bidders don't instinctively reach out to other utilities for the type of collaboration that might come naturally to incumbent developers.

"Challenges with siting transmission … along the initial MARL route should not have been a surprise to NextEra, or to PJM," DATA wrote. "We will never know if a project collaboratively developed by incumbent utilities in the first instance would have avoided the increased cost or identified a superior, more holistic, more robust solution."

New England

DATA also pointed to the $2.78 billion, 345-kV Aroostook Renewable Gateway project in Northern Maine that the Public Utilities Commission awarded in 2022 and subsequently withdrew because selected developer LS Power announced it would exceed its original fixed-price bid.

The PUC has since initiated a new docket to contemplate an alternative project and developer.

DATA said hard cost caps are ill suited for the "development challenges and commercial realities of electric transmission," which include long lead times, high capital costs and regulatory hurdles, among other cost pressures.

CAISO

Finally, DATA called out two HVDC transmission projects in the San Francisco South Bay region — Newark-to-Northern Receiving Station and Metcalf-to-San Jose B — from CAISO's 2021-2022 transmission plan, also awarded to LS Power.

According to the report, when significant load growth entered the picture and brought hypothetical overloads with the original design, CAISO was forced to modify the Newark project into a 230-kV switchyard and a 230-kV AC circuit. CAISO said it will set apart a San Jose B substation expansion as part of the project for incumbent Pacific Gas and Electric instead of allowing LS Power to build a new station to avoid building duplicative substations on scarce land.

CAISO also must include a new Northern Receiving Station-to-San Jose B circuit that is set to be awarded through bidding later this year.

DATA said CAISO's twisty rescoping and involvement of new developers on the project shows how competitive processes can "lead to fractured and inferior planning outcomes that fail to make project selections accounting for the full costs that will be borne by customers and do not maximize or 'right-size' the value of solutions to meet immediate and future needs."

'Unintended Consequences'

What the case studies "collectively demonstrate is … a full range of unintended consequences," McMackin said. Competitive developers may make "routing choices that might not be compatible with the project with the expectation that it can all be renegotiated later."

As of press time, LS Power did not respond to *RTO Insider*'s request for comment on whether it believes the shift in projects can be construed as misfires, or whether it views its litigation as postponing transmission construction.

The Electricity Transmission Competition Coalition (ETCC) has recently renewed its argument that monopoly incumbents continue to price gouge. It noted that according to the U.S. Bureau of Labor Statistics' *Consumer Price Index Summary* for January, annual electricity price inflation climbed at four times the rate of the average U.S. grocery bill.

ETCC maintains that MISO ratepayers could save several million if all projects in its second, nearly $22 billion LRTP portfolio are competitively bid.

Two months ago, MISO was compelled to conduct a variance analysis on one of the LRTP projects from its first portfolio following a cost increase of more than 2.5 in the project under incumbent Northern Indiana Public Service Co. The planned 345-kV Morrison Ditch-Reynolds-Burr Oak-Leesburg-Hiple line in Illinois and Indiana climbed from an estimated $261 million to $675 million. (See *Cost Overruns on Project in 1st LRTP Prompt MISO Analysis*.)

'Meeting the Moment'

McMackin characterized DATA's members as investor-owned utilities that are supportive of regional transmission. They are "deeply engaged" in building the grids that can "meet the moment" of demand growth from artificial intelligence, electrification and decarbonization.

"Right now, what's best for customers is getting transmission built," McMackin said.

He acknowledged that it is natural that incumbent utilities would want project opportunities.

"I think that's a fair question that goes to motivation," he said. But he said ROFRs have "strong track records of working," having been the default before Order 1000. He argued ROFRs are needed to "reestablish certainty to get infrastructure built expeditiously."

McMackin recognized that getting transmission built is complicated and challenging.

"We do not make the claim that incumbent developers don't encounter the same challenges that non-incumbent developers do, because developing large-scale transmission is hard. And it's hard across the board," McMackin said. However, he said non-incumbent development of projects more routinely results in "cost escalations beyond what's expected."

"Non-incumbent development has a host of issues," he said, adding that he expects the issues to escalate with FERC's Order 1920. "To the extent that there's not ROFR certainty from FERC, there will be more examples."

DATA would like to see FERC reopen the ROFR topic so the group can share the "data we now have about how this process is working," McMackin said. "We need more federal certainty on the issue." ■

FERC/Federal News

FERC Proposes Talks with DOJ on Southern Co. Plant Purchase

By James Downing

FERC on Feb. 10 took the rare step of issuing a Notice of Proposed Communication with the U.S. Department of Justice over Southern Co.'s *application* to purchase a power plant in Alabama (*EC25-27*).

Southern affiliate Alabama Power is trying to buy Tenaska's Lindsay Hill Generating Station, an 895-MW natural gas- and oil-fired power plant, which is currently under a tolling agreement with Mercuria Energy Group through April 30, 2027. Once that lapses, the utility would control its entire output, according to the application filed in early December.

Energy Alabama, Public Citizen and GASP *protested* the application Feb. 7, arguing that the company did not address any market power concerns.

FERC works with DOJ's Antitrust Division often, as they have overlapping jurisdiction on mergers, but the notice is unusual. It simply informed parties to the case notice that FERC staff want to communicate with DOJ officials on the proposed purchase and invited them to raise any objections to such communications. If none are filed, they will go ahead with the communications.

"As a part of the overall regulatory review process for the proposed acquisition of the Lindsay Hill Generating Station, Alabama Power is seeking approval from FERC, and the transaction is subject to review under the Hart-Scott-Rodino Act (as administered by the Department of Justice and the Federal Trade Commission)," Alabama Power spokesperson Anthony Cook said in a statement. "This generating facility is necessary in order to help meet Alabama's growing energy load. We are reviewing the recent comments filed in the FERC proceeding and will respond appropriately."

Alabama Power and Tenaska told FERC that the deal is consistent with its merger policies and has no impact on competition, rates or regulation, nor will it result in any cross-subsidization. Once the tolling agreement ends, the plant's output would be sold under Alabama Power's market-based rate tariff, but the companies argued in the application that no market power issues will occur because of the agreement.

"When the effect of the Mercuria tolling agreement is taken into account, there is no overlap between the combining entities — Alabama Power and its affiliates on the one hand, and [Tenaska] on the other hand — and the proposed transaction results in no change in market concentration," they said.

In their joint protest, Energy Alabama, Public Citizen and GASP argued that FERC needs to anticipate what the market power situation will be in May 2027.

Lindsay Hill Generating Station | *Tenaska*

"The joint applicants' failure to analyze this preordained outcome — which is the stated purpose of the proposed transaction — prevents the commission from evaluating whether the proposed transaction is consistent with the public interest, let alone whether existing mitigation measures remain sufficiently protective," the groups said. "The application further obscures this deficiency by designating the affidavit discussing the horizonal competitive analysis screen privileged and confidential."

It is atypical to keep horizontal market screens confidential in FERC proceedings, and the groups noted that Southern and Tenaska have filed them publicly in other cases. Parties to the case had access to the horizontal market power screen, but any relevant comments in the public version had to be blacked out to abide by confidentiality rules.

The transaction would be the fifth FERC has approved for Alabama Power since 2020, with the commission having already approved 2,500 MW of generation purchases by the utility.

"Acquiring the Lindsay Hill facility would bring that number to over 3,400 MW," the groups said. "When compared to the 12,942 MW of generating capacity that Alabama Power currently owns or controls, this figure cannot be ignored."

The first of those four previous deals involved Alabama Power buying another plant from Tenaska that was under a tolling agreement, and they initially failed to file a market power screen. FERC found that deficient and required them to calculate the impact on market power once the tolling agreement expired.

In the case pending now, the tolling agreement expires a year earlier, meaning the screens will be less speculative, and unlike that earlier Tenaska plant purchase, Alabama Power is not already using the generation for itself. The companies have not asserted that the plant is currently dispatched in Southern's internal power pool, but once the tolling agreement is done, it will add 895 MW to the dominant supplier in that market.

"Alabama Power's systematic acquisition of large generating facilities — and by extension, Southern Co.'s consolidation of generating capacity in the region — is especially concerning given the size of" the company's balancing authority area, which has about 61 GW of capacity, the groups said. ■

FERC/Federal News

US Grid Has Flexible 'Headroom' for Data Center Demand Growth

Duke U. Study Finds 126 GW of Capacity if Data Centers Curtail Peak Electricity Use 1%

By K Kaufmann

A *new study* from Duke University says the existing power system could handle 126 GW of new demand with no additional generation if artificial intelligence data centers can be persuaded to cut their energy use by as little as 1% during times of peak demand.

The "Rethinking Load Growth" report looks at 22 balancing authorities — RTOs, ISOs and large investor-owned utilities — representing 95% of the country's peak load and finds that each could add varying amounts of new load without exceeding its maximum capacity "provided the new load can be temporarily curtailed as needed."

The report defines system curtailment, or flexibility, as a data center's ability to temporarily reduce its power consumption "by using onsite generators, shifting workload to other facilities or reducing operations," thus creating "curtailment-enabled headroom" to add new load.

For example, the study estimates PJM could integrate more than 23 GW of new load with curtailment-enabled headroom based on 1% curtailment. ERCOT could add 14.7 GW, and Southern Co. could add 9.3 GW.

Lower curtailment rates still could provide significant headroom, the study says, with PJM opening up 17.8 GW at 0.5% curtailment and 13.3 GW at 0.25% curtailment.

The length of curtailment periods also would vary, with a 1% curtailment lasting no more than 2.5 hours, while a 0.25% curtailment rate would last only 1.7 hours.

"These results suggest that the U.S. power system's existing headroom … is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year," the report says, framing flexibility as a win-win for all stakeholders.

The U.S. still will need to build new generation and transmission to meet anticipated demand growth, the report says. "[But] flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion and enable greater focus on the highest-value investments in the electric power system."

"The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably and sustainably integrate large loads," the report says. "The unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources."

Data Centers and DR

Authored by researchers at Duke's Nicholas Institute for Energy, Environment and Sustainability, the study grounds its argument for flexibility in the current flashpoints for demand growth. Data centers often have aggressive schedules for going online but may face yearslong interconnection and supply chain delays.

Lead times for ordering transformers have gone from less than a year to two to five years, with prices rising 80%, according to June 2024 figures from the president's National Infrastructure Advisory Council, the report says. Wood Mackenzie has reported that lead times for high-voltage circuit breakers were nearing three years at the end of 2023.

The report notes the growing interest in co-locating data centers with existing or new generation, but says it is not likely to be "a long-term, systemwide solution."

The fact the U.S. grid is designed with headroom to accommodate relatively short periods of peak demand and often is underused provides a further rationale for leveraging this built-in flexibility, the report says. Better use of the system can reduce costs for consumers by "lowering the per-unit cost of electricity — and [reducing] the likelihood that expensive new peaking plants or network expansions may be needed."

The report notes that some grid operators and utilities already are experimenting with flexible interconnection strategies, such as ERCOT's interim treatment of new large loads as "controllable" resources, allowing them to go online in less than two years.

Still another argument for flexibility is the recent release of DeepSeek, the Chinese AI platform that claims to use significantly less energy than U.S. AI. Here, the report says, system flexibility could serve as a hedge for potential demand uncertainty.

But getting data centers to participate in traditional demand response programs — which have long provided system flexibility — has been difficult because of centers' often inflexible, 24/7 demand profiles. Further, traditional DR programs have been designed for "traditional industrial consumers … with different incentives and operational specifications." The report suggests new programs should be developed to align with data centers' needs, including "streamlined participation structures, tailored incentives and metrics that reflect the scale and responsiveness of data centers."

New AI data centers, with "evolving computational loads … are more amenable to load flexibility," the report says. The "training" of AI databases allows for flexible timing and the distribution of workloads across different data centers. An EPRI report cited by the Duke researchers found that "optimizing data center computation and geographic location … to capitalize on lower electric rates during off-peak hours" could provide cost savings of 15% and reduce strain on the grid during high-demand hours.

The report points to three trends that could "create further opportunities for load flexibility now than in the past." First is the construction and interconnection delays that increase costs and timelines for getting new centers online, followed by the growth of clean, distributed technologies that offer lower-cost, behind-the-meter generation.

The third is the growth of hyperscale data centers and their computational loads, "which is lending scale and specialization to more sophisticated data center operators," the report says. "These operators, seeking speed to market, may be more likely to adopt flexibility in return for faster interconnection." ■

Why This Matters

President Donald Trump wants to meet growing data center demand with baseload power, provided primarily by fossil fuels and nuclear. But the Duke University study argues that making data centers flexible grid assets powered by distributed energy resources is a faster and cheaper way to go.

FERC/Federal News

DOE Conditionally Approves Commonwealth LNG to Export

By James Downing

The Department of Energy has approved the first authorization to export liquid natural gas from a new domestic facility since the Biden administration's pause on new approvals.

"Today marks one of many steps that DOE will be taking to assure our future as a reliable energy supplier to the world and resume regular order to our regulatory responsibilities over natural gas exports," Energy Secretary Chris Wright said Dec. 14.

The Commonwealth LNG facility, which will be built in Cameron Parish, La., is owned by Kimmeridge Texas Gas and will be able to export 1.2 Bcfd once it is built.

The project won approval from FERC in 2022, but the case was remanded to it by a federal appeals court. FERC is working on a new, supplemental environmental impact statement, and a final order is expected this summer.

Then-President Joe Biden paused DOE's approval of additional exports in January 2024 so the department could study their impacts. A court overturned the pause over the summer, and Biden's DOE approved exports from a facility built in Mexico in August. (See *DOE Approves 1st LNG Exports Since Biden Administration's Pause*.)

| *Commonwealth LNG*

The department released the study in late 2024; it said exporting more LNG would lead to higher domestic prices for the sake of shipping gas not to just allies, but China with its massive demand for energy. Since the report, China has put tariffs on U.S. LNG exports in response to President Donald Trump's imposition of tariffs on it. (See *DOE Warns About Further Increases of US LNG Exports*.)

"We expect China's imposition of tariffs on U.S. LNG to have a limited effect on U.S. LNG exports," the Energy Information Administration said in its Short-Term Energy Outlook (*STEO*) for February. "With ample demand for LNG globally, we expect that any LNG not purchased by China would be imported elsewhere."

In the conditional *order* approving the exports, DOE found they are likely to yield economic benefits to the U.S., diversify global LNG supplies, and improve energy security for U.S. allies.

DOE has approved a total of 46.88 Bcfd in exports of LNG from the Lower 48 states, with 39 final orders and the conditional order for Commonwealth. DOE expects to issue a final order later in 2025.

The EIA expects LNG exports will record highs in 2025, averaging 15 Bcfd, but so will domestic production — hitting almost 105 Bcfd, it said in its most recent STEO.

The outlook also noted that the very cold January contributed to higher natural gas price forecasts this year, adding 65 cents to the EIA's 2025 average price forecast, which hit $3.80/MMBtu.

The Industrial Energy Consumers of America was the only group to protest the application on time, arguing that the additional exports would put upward pressure on domestic natural gas prices, making its members less competitive.

DOE responded that based on forecasts for high domestic production, the additional exports conditionally approved Feb. 14 would not increase prices in the U.S.

"With these decisions in hand, subject to a FERC final order, which we expect in July 2025, and DOE final authorization, Commonwealth anticipates reaching a final investment decision in September 2025, with first LNG production expected in Q1 2029," said Commonwealth CEO Farhad Ahrabi. ■

CAISO/West News

Powerex Paper Sparks Dispute over EDAM 'Design Flaw'

CAISO, PacifiCorp Contest Company's Finding Around Congestion Charges

By Robert Mullin

Why This Matters

The Powerex paper comes just as entities across the West are poised to commit to either CAISO's EDAM or SPP's Markets+.

A new paper from Powerex is likely to reignite the debate between supporters of CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+ just as the competition between the two markets approaches critical junctures.

Chief among them: the pending introduction of legislation in California to allow CAISO to relax its oversight over its Western markets; the Bonneville Power Administration's impending draft decision on a day-ahead market choice; and an expected continuation of participant commitments to both markets.

The *paper*, which Powerex published Feb. 11, contends that EDAM contains a "design flaw" that could saddle non-CAISO participants with $1 billion in unjustifiable charges that would effectively be conveyed as payments to participants operating within the ISO.

Powerex contends that EDAM's treatment of firm transmission rights and congestion would leave the market's non-CAISO participants exposed to charges for constraints occurring outside their systems while not providing them adequate ability to recover or hedge against those costs — what the company calls an "aberration" among organized markets.

"The PacifiCorp, NV Energy and Idaho Power transmission systems are the most exposed to this outcome, including when the utilities use their own transmission systems to deliver their own generation to their own load," Powerex wrote in the paper.

The potential "transfer of value" could have a "wide range of harmful consequences" in those service territories, including: raising costs for retail ratepayers; eliminating incentives for third parties to invest in transmission service; shifting the benefits of non-CAISO transmission expansion projects to ISO customers; and "undermining the proper functioning of other regional programs and markets," such as the Western Resource Adequacy Program and Markets+.

Powerex's assertions prompted a sharp response from CAISO and PacifiCorp, the first utility to commit to joining EDAM and whose recent tariff filing apparently prompted the concern.

"Powerex, a primary funder of Markets+, continues to publish hyperbole and unsupported assertions, with economic impact estimates that defy market logic," CAISO Director of Communications Jayme Ackemann and PacifiCorp spokesperson Omar Granados said in a joint statement to *RTO Insider*.

Ackemann and Granados called the paper "misinformed and inflammatory" and said it represents "an attempt to derail" EDAM "rather than improve it."

Vancouver, Canada-based Powerex is the marketing subsidiary of BC Hydro, the Canadian Crown corporation that provides power for most of British Columbia and operates about 11,680 MW of hydroelectric capacity. Through a trading operation that spans the Western Interconnection, Powerex owns transmission rights on multiple systems throughout the sprawling region.

The company currently participates in CAISO's Western Energy Imbalance Market (WEIM) but has been a key backer of SPP's Markets+ in its competition with EDAM for day-ahead participants and, in that capacity, a vocal critic of CAISO and its EDAM. Powerex recently committed to joining Markets+ and providing a substantial share of funding for Phase 2 implementation stage of the market. (See *Powerex Commits to Funding, Joining SPP's Markets+*.)

On the other hand, PacifiCorp — along with Portland General Electric — is scheduled to begin trading in EDAM next year, while NV Energy and Idaho Power are both heavily leaning in favor of joining the CAISO market.

Parallel Flows

The complexity of Powerex's argument mirrors that of how energy flows on the electricity grid — and how those flows are reflected in the rules and processes of organized wholesale electricity markets.

Powerex notes that under FERC's Open Access Transmission Tariff (OATT) framework of transmission rights, "entities that invest in firm OATT transmission service obtain the right to deliver generation from lower-price locations to load in higher-price locations."

The company also points out that — as in other markets — EDAM will be "layered" on top of that framework, requiring a resource to sell its supply at one locational marginal price, while an end user will pay a different LMP at the point of consumption.

And as in other markets, EDAM electricity deliveries will be subject to a "net financial settlement" that reflects the difference between the prices at the two locations — which can include charges stemming from the congestion on the lines between those points.

The assessment of congestion charges is complicated by the fact that flows of energy associated with a scheduled delivery do not always follow the "contract path" but are often channeled through a neighboring system, producing "parallel" flows on that system.

In EDAM, Powerex contends, this means that a delivery scheduled between PacifiCorp's East and West balancing authority areas, for example, could produce a parallel flow that causes congestion in the CAISO BAA. EDAM would then apply the charge for that congestion to the PacifiCorp transaction.

Powerex contends that EDAM deviates from "all other" U.S. markets because it does not provide "a financial hedge that returns the day-ahead congestion charges on a delivery path back to the entities with firm transmission rights on that delivery path" — as required by FERC.

"Instead, EDAM will allocate congestion revenues based on the modeled locations of congestion 'bottlenecks,'" the paper says.

Powerex says WEIM data show that the "most prevalent" of those bottlenecks occur in CAISO's system.

"Under the EDAM design, this means the California ISO's customers can be expected to receive the vast majority of the flow-based congestion charges collected from activity on other transmission systems throughout the EDAM footprint," the paper says.

Powerex contends that in every electricity market in the U.S. but EDAM, customers using service from one transmission service provider (TSP) are either not liable for the cost of paral-

CAISO/West News

lel flows on other systems, or able to mitigate that cost through specific market mechanisms, such as hedging instruments like financial transmission rights. In the case of Markets+, congestion charges will be returned to the firm rights holder.

"This EDAM market design flaw will have the greatest impact on those adjacent transmission systems outside of California that also provide significant north-to-south and south-to-north connectivity: namely, PacifiCorp, NV Energy and Idaho Power," Powerex wrote. "If each of these utilities join EDAM under its current design, it will be ... [CAISO's] own customers that will collect the vast majority of the locational price difference from activity on the PacifiCorp, NV Energy and Idaho Power transmission systems."

'Completely Meaningless'

Powerex said the issue came to light in January when PacifiCorp filed with FERC its EDAM tariff, which noted the utility could offer its firm transmission customers only a "partial hedge" against congestion charges. That hedging option would reverse only the portion of congestion related to transmission constraints modeled within PacifiCorp's system, "even though the schedules would pay congestion charges that also include parallel flows on other transmission systems," Powerex contended.

In November, Powerex announced that it would cancel a large portion of its transmission rights on the PacifiCorp system in response to the expected OATT changes. (See *Powerex to Cancel Rights on PacifiCorp Tx System over EDAM Changes*.)

Powerex said its experience in the WEIM "shows unambiguously" that the transmission constraints that most often limit physical flows between locations throughout that market are in CAISO.

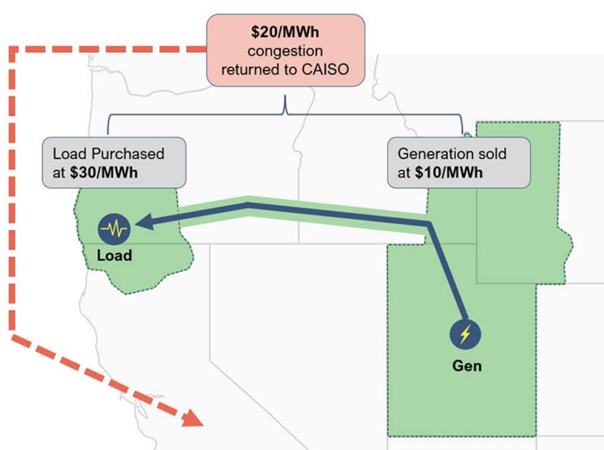
"Since the EDAM design distributes congestion charges based on the location of the constraints that cause LMPs to separate, and data shows these constraints will predominantly be located in ... [CAISO's] transmission system, once EDAM commences, customers that use PacifiCorp transmission service will pay large new congestion charges that will go almost entirely to ... [CAISO's] own customers," Powerex said.

Under one scenario modeled to show heavy solar penetration in the Southwest, Powerex found the "value transfer" from non-CAISO BAAs to CAISO to reach $1 billion annually, a figure not reflected in production cost modeling studies that have repeatedly shown that most Western entities will realize greater economic benefits from participating in EDAM than in Markets+, including a series of studies performed by The Brattle Group.

"All of the EDAM benefits studies to date have completely missed this important market design issue, and given its magnitude, the results of these studies are completely meaningless," Powerex said.

'Feigned Concern'

"Focusing narrowly on one aspect of market design, in isolation, conveys an intentionally distorted picture," CAISO and PacifiCorp said in their joint statement. "As a power marketer, Powerex is simply attempting to force changes to the EDAM market design that have already been approved by FERC for its own economic interest."



This graphic illustrates Powerex's argument about how EDAM flows from one non-CAISO BAA to another (in this case PacifiCorp's East and West BAAs) will result in a price that includes congestion charges incurred inside CAISO. | Powerex

They also contend that, based on the assumed EDAM market footprint, it is "illogical" to estimate that the three cited BAAs would be forced to pay $1 billion in congestion revenues for congestion occurring in CAISO.

"Such claims, which Powerex attempts to cloak in feigned concern for NV Energy, Idaho Power Co. and PacifiCorp customers, are not supported by the analysis from the very entities that are responsible for providing service to those customers," they said.

They said the FERC docket (ER25-951) for PacifiCorp's EDAM tariff is the "appropriate venue" for Powerex to air its concerns about the market.

"While we appreciate Powerex's continued engagement in Western energy market design, its approach continues to be counterproductive," CAISO and PacifiCorp said.

In an email to *RTO Insider*, Brattle Group principal John Tsoukalis said his company's EDAM benefits studies "have repeatedly found results that are consistent with the actual experience in WEIM over the last 10 years": that ISO customers "in fact receive less benefits on a load-ratio-share basis than other market participants due to the fact that CAISO already has a day-ahead market in place."

He said the allocation of congestion revenues "is necessarily simplified in our studies, which means that real-world congestion revenue allocations may differ from our estimates," adding that those revenues are only one metric examined in the studies.

"Of course, it is possible that EDAM implementation might uncover some revenue allocation issues that will need to be addressed, just as PacifiCorp's filing addresses some items that have come up and CAISO stakeholder processes have addressed issues in the past," Tsoukalis told *RTO Insider*.

Tsoukalis additionally contended that Powerex's paper did not provide enough detail to replicate its analysis and "vet its conclusions" and that it failed to cover several aspects of EDAM that will differ from the WEIM, including expectations that:

- EDAM participants will contribute significantly more transmission than they do in WEIM, thereby reducing congestion;
- major new transmission projects under development are likely to "significantly reduce" and change the pattern of congestion; and
- optimized day-ahead unit commitment and dispatch "will further increase the effectiveness of how the existing grid is used."

Tsoukalis also pointed out that EDAM will disaggregate price differences between areas into congestion revenues and "transfer" revenues collected when a transfer constraint results in differentials between two BAAs.

"The [Powerex] memo does not discuss the transfer revenue portion of the EDAM design, which means that EDAM congestion revenues will be more limited than the price differences that [Powerex] uses in its illustrations," he said. ■

CAISO/West News

CAISO EDAM Pioneers Share Implementation Details

'All Becoming Real,' ISO Board Chair Borenstein Says

By Elaine Goodman

With go-live dates for its first two participants looming in May and October of next year, implementation activities for CAISO's Extended Day-Ahead Market are ramping up.

Representatives of PacifiCorp, Portland General Electric and CAISO gave updates on EDAM preparations during a Feb. 12 joint meeting of the CAISO Board of Governors and the Western Energy Markets (WEM) Governing Body.

For PacifiCorp, which has an EDAM go-live date of May 1, 2026, much of the recent focus has been on its Open Access Transmission Tariff filing with FERC.

The company initially filed the tariff in November but decided to withdraw it and submit a *new filing* Jan. 16.

The new OATT incorporates a different methodology for congestion revenue allocation — a subject that gave stakeholders "some serious concerns," according to Robert Eckenrod, PacifiCorp assistant general counsel.

For example, Western Power Trading Forum questioned the tariff's measured-demand approach to allocation and planned to file a FERC protest in January, a representative said in December. (See *CAISO Leaders Look Ahead to 2025 with Confidence*.)

PacifiCorp was able to work around some limits of the methodology from the initial filing, Eckenrod said, and the new methodology is "more granular and more advantageous."

Other than the changes to congestion revenue allocation methodology, the OATT filing is the same as the initial filing. It requested a Feb. 18 due date for comments and a May 16, 2025, decision date.

PGE Activity

Portland General Electric, which has an EDAM go-live date of Oct. 1, 2026, is planning to file its OATT with FERC by the end of March, said Tiffany Emerson, PGE's senior manager of strategy and planning. PGE is working with PacifiCorp to align their tariffs, she said.

As a participant in CAISO's Western Energy Imbalance Market (WEIM), PGE plans to enhance existing systems and frameworks rather than starting from scratch, Emerson said. Testing of system enhancements will begin in December and continue into 2026.

Another focus for PGE is settlements.

"The sheer volume of the transactions that we're going to settle with ... CAISO in the post-go-live EDAM world is just an order of magnitude greater than what we currently do as an EIM participant," Emerson said.

WEM Governing Body member Andrew Campbell said he was encouraged to hear that PGE was working with PacifiCorp on EDAM implementation.

"That's certainly key to success in this process," Campbell said. "The entities as they join are helping the ones who are joining after them."

Why This Matters

PacifiCorp and Portland General Electric will be the first utilities to start trading in EDAM in 2026.

In addition to PacifiCorp and PGE, the Balancing Authority of Northern California signed an EDAM implementation agreement with CAISO in November; the Los Angeles Department of Water and Power formally committed to joining in December. (See *BANC Signs Agreement to Join EDAM; LADWP Gets Board's OK to Join CAISO's EDAM*.)

BANC and LADWP are scheduled to go live with EDAM on May 1, 2027.

CAISO has been conducting EDAM training with PacifiCorp and EDAM and also has publicly posted training material on the WEM website. Computer-based training for EDAM entities is planned for April, according to Heather Kelley, executive director of CAISO's project management office.

CAISO plans to begin integration testing with PacifiCorp this summer.

"We will be revving up our systems, and they're going to be connecting to them, and we'll start to get the market running," Kelley said.

Customer Outreach

Kerstin Rock, managing director of Western market policy and analytics at PacifiCorp, noted that some deadlines for EDAM participation are now merely weeks away. For example, the company plans to complete connectivity testing by June 1.

PacifiCorp is also launching an engagement process for its transmission customers, with a series of workshops starting Feb. 27. Videos of the workshops will be posted on the company's Open Access Same-time Information System.

CAISO Board of Governors Chair Severin Borenstein thanked PacifiCorp for doing the work that will "smooth the pathway" for other EDAM participants.

"It's all becoming real," Borenstein said. ■

PGE distribution lines in Portland, Ore. The company has been working on its implementation plan for joining CAISO's Extended Day-Ahead Market. | © *RTO Insider LLC*

CAISO/West News

BPA Committed to Trump's Energy Goals, Hairston Says

200 Agency Workers Have Resigned Following Trump's Offer

By Henrik Nilsson

Bonneville Power Administration CEO John Hairston said during the agency's quarterly business review Feb. 13 that BPA is committed to President Donald Trump's goal to "unleash American energy dominance," while also revealing that approximately 200 BPA federal employees have accepted the president's deferred resignation offer.

About 6% of BPA's federal workforce have opted into the Office of Personnel Management's (OPM) deferred resignation program, and the agency has rescinded 90 job offers following a hiring freeze on federal employees imposed by Trump on Jan. 20, staff said during the quarterly business review.

About 2.3 million federal employees *received the buyout offer* in a Jan. 28 message titled "Fork in the Road." Employees who accepted the offer would receive a severance package of eight months' pay and benefits through Sept. 30, the end of the federal fiscal year. Employees were directed to respond by Feb. 6.

The offer is one of many actions, including a flurry of executive orders, that Trump has taken since regaining the presidency on Jan. 20, which have directly impacted BPA. Another example is the order on *Unleashing American Energy*.

BPA Administrator Hairston acknowledged that there is "a lot of interest in BPA implementation of President Trump's executive orders, and how those orders are expected to impact our business."

"We see great opportunity in supporting and advancing the administration goals to unleash American energy dominance, and indeed, Bonneville will play a key role in our region as we continue to execute our mission by delivering safe, reliable transmission services," Hairston said.

BPA has taken other actions in light of recent executive orders, including shutting down a culture office under the agency's Diversity, Equity and Inclusion program and requiring workers to return to the office full-time. BPA is also updating its strategic plan to align with the Trump administration's direction, Hairston said.

Veronica Wittig, acting chief financial officer at BPA, said the agency works closely with the Department of Energy to carry out Trump's directives. BPA is *forecasting* negative net revenues of $44 million in the first quarter of 2025, compared with BPA's target of positive $70 million, Wittig said.

"The Q1 forecast was developed based on information at the end of December 2024 and does not reflect the impact of executive order on BPA's financial forecasts," Wittig said.

Additionally, Wittig noted, "there is significant uncertainty at this time of the year with respect to water conditions and market prices, so net revenues picture may change significantly, which may also impact some of our other financial [key performance indicators]."

The call also touched on other BPA initiatives, including the agency's work to offer new long-term power contracts under its provider-of-choice program. BPA hopes to have final contract templates by June with signed contracts by December, according to Hairston.

Hairston also noted the *pause announced last week* on several transmission planning processes spurred by 65 GW of transmission requests.

The agency is also on track to release its day-ahead *market draft policy in March*, followed by a final policy and record of decision in May, Hairston said, referring to BPA's upcoming choice of whether to join SPP's Markets+ or CAISO's Extended Day-Ahead Market.

Additionally, on Jan. 30, BPA broke ground on a new control center located in Vancouver, Wash., which will be fully integrated into BPA's system by 2031, Hairston said.

"It will begin a new era of grid visibility and control for BPA," Hairston said. "The new facility has been intelligently designed to address evolving technology, continuity, safety and security needs. Its design will support the evolution of the bulk power grid over the next 50 years, while providing flexibility for growth and market opportunities." ■

Why This Matters

A 6% loss of staffing at BPA raises questions about how prepared the agency will be to contribute to President Trump's ambition to 'unleash' American energy.

BPA Halts Some Tx Planning Processes Amid Surge of Service Requests

Agency Pauses to Consider Process Changes

By Henrik Nilsson

The Bonneville Power Administration has temporarily paused certain transmission planning processes to consider new "reforms" in light of "exponential growth" of transmission service requests, BPA staff told stakeholders during a workshop Feb. 11.

BPA's 2025 transmission cluster study includes over 65 GW of transmission service requests (TSRs), compared with 5.9 GW in the 2021 study. The requests exceed the total regional load projected for the Pacific Northwest in 2034, Richard Shaheen, BPA's senior vice president of transmission services, said during the workshop.

"There's been just an exponential growth in the area of transmission service requests," Shaheen said.

"That level of demand has basically strained our existing processes that weren't designed to handle that level of volume, so they literally just crippled under the weight of all of that amount of requests for study," Shaheen added.

BPA first announced the pause in a Feb. 5 email. Specifically, the areas impacted by the pause include the:

- 2025 TSR study and expansion process cluster study;
- TSR evaluation process (for any new TSRs requesting new or modified capacity);
- TSR data exhibit evaluation process;
- Network Integration Transmission Service load and resource forecast evaluation and closeout process.

TSRs requiring network capacity above existing commitments that submitted requests on or after noon Aug. 15, 2024 — the deadline to submit TSRs for consideration in the 2025 cluster study — will see limited impact as BPA assesses the need for planning reforms, according to a staff presentation.

The pause won't impact initiatives deemed critical, like BPA's "evolving grid projects," the Portland area reinforcement study, system assessment and other projects, according to Jeffrey Cook, BPA vice president of transmission asset management and planning.

"This is really just focused on the transmission service request piece that we have in the study," Cook said. He added that "we have to do something different in order to take the next step forward" to deal with the 65 GW of TSRs.

Abbey Nulph, BPA analyst, reiterated that point, saying the pause is a chance for the agency "to not just live with our existing processes and try to find some way to help them limp along through this process, but to take a big step back [to] be able to design the process with the current world and market activity in mind."

When BPA designed the studies, the industry had yet to experience the impact of data center growth or current levels of competitive resource development, Nulph said.

A December report published by WECC *forecast* "staggering" growth in electricity demand in the Western Interconnection over the next decade.

WECC predicted annual demand in the Western Interconnection will grow from 942 TWh in 2025 to 1,134 TWh in 2034. That 20.4% increase is more than four times the 4.5% growth rate from 2013 to 2022 and double the 9.6% growth forecast in 2022 resource plans.

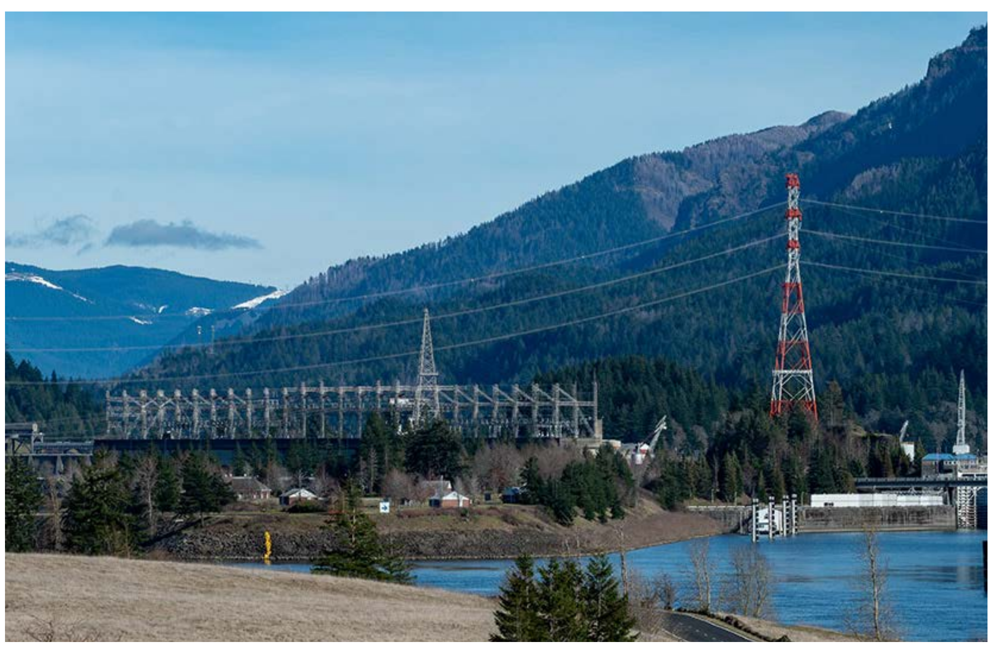
Similarly, the Pacific Northwest Utilities Conference Committee's Northwest regional forecast for 2024 found that electricity demand will *increase* from about 23,700 average MW in 2024 to about 31,100 aMW in 2033, an increase of more than 30% in the next 10 years.

Following stakeholder input, BPA said the plan is to issue a staff proposal in November aimed at improving the processes impacted by the pause.

The pause also comes amid *recent actions* taken by President Donald Trump aimed toward the energy industry at large. Trump recently *paused* a 10% tariff on "energy resources from Canada," along with 25% tariffs on other imports from Canada and from Mexico, for 30 days after last-minute negotiations with the two countries' leaders.

Additionally, Trump, on Feb. 10, imposed a 25% steel tariff on all steel and aluminum imports.

Meanwhile, BPA workers, similar to millions of other federal workers, *received the buyout offer* from the Trump administration in a message titled "Fork in the Road." The administration offered a "deferred resignation" arrangement, promising to provide workers who accepted the offer with a severance package consisting of eight months' pay and benefits through Sept. 30, the end of the federal fiscal year. The offer has been challenged in court. ■



The Bonneville Power Administration has paused certain transmission planning reforms in light of increased demand for new resources and loads. | *Shutterstock*

Pathways 'Step 2' Plan Elicits Praise, Concerns — and Advice

Wyo. Agency Recommends Stakeholders Voice Clear Expectations on Calif. Legislation

By Elaine Goodman

A recent workshop on the West-Wide Governance Pathways Initiative has sparked praise for the proposal as well as concerns, including uneasiness over plans to share staffing between CAISO and a new regional organization that would govern Western electricity markets.

"Shared staffing could lead to undue influence over governance decisions and compromise the impartiality needed for effective oversight and market rule promulgation and implementation," Rob Creager, executive director of the Wyoming Energy Authority, said in a letter to the California Energy Commission.

Even if the arrangement is temporary as part of Pathways Step 2, it could have long-term impacts and "create a precedent for the market operation moving forward," Creager wrote.

The letter was one of several submitted as a follow-up to a CEC *workshop* Jan. 24 on regional electricity markets and coordination, including the Pathways Initiative. (See *CEC Workshop to Focus on Impact of Pathways Initiative* and *Ariz. Commissioner Questions Utility Decisions to Join SPP's Markets+*.)

Pathways proposes to create a new independent "regional organization" (RO) to govern rules for CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM).

The move could alleviate concerns of potential participants who are uncomfortable with markets led by CAISO, whose Board of Governors members are appointed by the California governor.

Pathways backers are now waiting for a bill to be introduced in the California legislature that would allow a change to CAISO's governance with the introduction of the RO.

What's Next

California backers of the Pathways Initiative's Step 2 plan have until Feb. 21 to submit a bill for the state legislature to consider during the 2025 session.

Rob Creager, executive director of the Wyoming Energy Authority, has expressed concerns about a proposed "regional organization" to govern rules for CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market. | *Wyoming Business Council*

The International Brotherhood of Electrical Workers, which opposed previous efforts to "regionalize" CAISO, plans to sponsor the bill, an IBEW representative said in October. The deadline for introducing bills this session is Feb. 21. (See *California Labor, (Possibly) Public Power to Sponsor Pathways Legislation*.)

While the potential legislation has garnered support, including from some past opponents, Creager pointed out it's typical for bills to be revised as they move through the legislature. He recommended that stakeholders clearly state what they want in the bill — as well as what they don't want — "to ensure true political independence of the RO is established and to ensure any market designs and market rules are fair and transparent."

WEA was formed in 2020 when the Wyoming State Energy Office merged with the Wyoming Infrastructure Authority and the Wyoming Pipeline Authority. Creager noted that Wyoming was the largest electricity exporter in the Western Interconnection as of 2023.

EDAM vs. Markets+

While acknowledging the competition between CAISO's Extended Day Ahead Market and SPP's Markets+, Creager said WEA realizes that "with PacifiCorp's long-term participation in the WEIM and first-mover to commit to the EDAM, combined with Black Hills Energy's (dba Cheyenne Light, Fuel & Power) decision to join the WEIM, Wyoming's attention will be more focused on the evolution of CAISO's market offerings with the potential to expand to a RO."

In August, two Black Hills Energy subsidiaries serving parts of Montana, Wyoming and South Dakota announced their move from SPP's Western Energy Imbalance Service (WEIS) to CAISO's WEIM. (See *CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS*.)

Other stakeholders who submitted comment letters to the CEC commended the Pathways Initiative.

Leanne Bober, director of regulatory affairs for the California Community Choice Association, said CalCCA supports Pathways because of its potential to "capture reliability, affordability and environmental benefits of regional coordination."

Pathways continues the incremental approach to regional coordination that has been working well for the region so far, Bober wrote, pointing to CAISO's WEIM and soon-to-be-implemented EDAM as examples.

Shifting energy market governance to an RO with board members from across the West "will promote trust across Western entities, attract a diverse range of potential regional market participants and maximize the potential benefits of a regional market," Bober said.

Adam Smith, director of regulatory relations at Southern California Edison, also wrote in support of Pathways.

"Independent governance is crucial for greater regional market integration," Smith wrote. The Pathways Initiative "has now provided a clear proposal for implementing such governance." ■

CAISO/West News

Brevity Should be Key for Pathways 'Step 2' Bill, Supporters Say

Deadline Approaches for Submitting Calif. Legislation

By Henrik Nilsson

The deadline to submit bills for California's 2025 session is looming, and backers of the West-Wide Governance Pathways Initiative expect legislation without unnecessary fluff that will change CAISO's governance structure and allow a new regional organization (RO) to oversee the ISO's Western energy markets.

California backers of the Pathways Initiative's Step 2 plan have until Feb. 21 to submit a bill for the state legislature's 2025 session. Under Step 2, which requires statutory changes, Pathways would create a new independent RO to govern rules for CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market (EDAM).

Backers of the Pathways Initiative expect legislation that will change CAISO's governance structure. | *NW Energy Coalition*

The Western Energy Markets (WEM) Governing Body and ISO Board of Governors approved Step 1 in August, elevating the Governing Body's authority over CAISO energy markets. (See *CAISO, WEM Boards Approve Pathways 'Step 1' Plan*.)

The anticipated Step 2 legislation comes as entities weigh whether to join SPP's Markets+ or EDAM. The two markets have yet to go online, but both are competing for participants.

EDAM's governance structure has been a concern for stakeholders uncomfortable with markets led by CAISO, whose Board of Governors members are appointed by the California governor. (See *Pathways Step 2 Not Good Enough, Markets+ Backers Say*.)

Pathways Launch Committee member Brian Turner, director of Advanced Energy United's regulatory engagement in the West, expects the Step 2 legislation to address those concerns by preserving states' policy authority. (See *Pathways 'Step 2' Plan Elicits Praise, Concerns — and Advice*.)

"California's clean energy policies, greenhouse gas goals, etc., are preserved and not imposed on other states," Turner told *RTO Insider*. "Other states can make their own decisions and have them be respected under the governance framework that we outlined."

Turner added that states participating in EDAM are "not being asked to give up any of its authority or autonomy on its resource and clean energy policy and other public policy goals."

Ben Otto, energy consultant with NW Energy Coalition, shared Turner's sentiment, saying that a key innovation of the Pathways proposal "is that moving forward with regional governance for EDAM does not depend on California legislation. Rather, the legislation will enable California entities to participate in the regional market and CAISO to contract as an operator."

Otto said he expects the bill to be short and enable CAISO to participate in a regional day-ahead market under certain conditions.

"The conditions match the governance structures, public interest protections, and other elements of the Pathways Initiative proposal," Otto said.

Why This Matters

Passage of a California bill to implement Step 2 of the Pathways Initiative is the vital next step for transferring oversight of CAISO's Western markets to a new, independent 'RO.'

Jan Smutny-Jones, CEO of the Independent Energy Producers Association (IEP) and former board chair at CAISO, similarly said he expects "the legislation to be short and to the point."

"I expect some language on protecting the public interests and respect for the energy polices of the various states. Hard stop," Smutny-Jones said. "This is not a new energy policy, but a bill authorizing how the Western transmission system can be more efficiently operated to the benefit of California and Western ratepayers."

A potential hurdle in the process could be if stakeholders add unrelated energy policies to the bill, said Sara Fitzsimon, policy director at IEP.

"This bill needs to only focus on authorizing the CAISO's participation in an independent RO. Any other language outside achieving that goal should not be included, as it could cause delays in getting this critical language through the legislature," Fitzsimon said.

The anticipated bill also comes as California grapples with wildfires and affordability issues, which could potentially cause delays, according to Leah Rubin Shen, managing director of Advanced Energy United's legislative, political and regulatory engagement in the West.

Though the bill should only enable Step 2, Shen hopes the conversation around markets doesn't end with the bill but rather spurs parties in the West to continue to discuss how to "evolve beyond a day-ahead market" by, for example, building an RTO.

"So, to the extent that this is a step forward, we are hopeful that it is a step that is good in its own right, and also a step that maybe has further steps down the road," Shen said. ■

ERCOT News

ERCOT's Revised CDR Report Met with Doubts

Biannual Report Projects Negative Reserve Margins in 2027

By Tom Kleckner

After a two-month delay, ERCOT on Feb. 13 released its semiannual Capacity, Demand and Reserves *report*, which provides potential future planning reserve margins five years into the future during the high-demand periods of the winter and summer seasons.

According to the report's most dire scenarios, the Texas grid operator may not have enough power to meet that peak demand during next year's summer. However, ERCOT *said* in a statement that the CDR report is a "snapshot of potential supply resource availability and demand" and is not intended to represent expected real-time operations scenarios.

The report was delayed so that revisions to its parameters could be made to "better represent the performance of grid resources and the dynamic nature of the ERCOT grid," the grid operator said.

ERCOT CEO Pablo Vegas appeared before the Texas Public Utility Commission to roll out the report. He told the commissioners that the state's "fast-growing" environment, with large loads able to quickly connect to the grid before the infrastructure is ready, has placed "downward pressure on planning reserves."

"We see that trend continuing in this CDR as well," Vegas said. "Some of the changes that we've made have accelerated or changed the view of those planning reserve margins shrinking, but … the overall trend of a rapidly growing economy, rapidly growing demand as a result of that … the energy economy is working to keep up with that."

The CDR projects PRMs, currently 18.9% for peak load and 10.5% for net peak load (when solar generation drops during the early evening hours when loads are still high), will fall to 8.3% and 21%, respectively, during summer 2027. The 2027/28 winter PRMs also drop into negative territory.

ERCOT CEO Pablo Vegas lays out the grid operator's latest Capacity, Demand and Reserves report. | *Admin Monitor*

ERCOT last year projected demand would reach 150 GW by 2030, fueled by data centers, industrial and petroleum production facilities, and cryptocurrency miners. The CDR projects demand to peak at 140 GW in 2029. The grid operator's current peak is 85.5 GW, set in August 2023.

"It's important to note that all scenarios in this report have a certain level of uncertainty that can alter the long-term resource adequacy outcomes, and these forecasts will change over time based on a variety of factors," ERCOT said in releasing the report.

Skepticism

The release was met with skepticism by several industry insiders.

Stoic Energy's founder, Doug Lewin, jumped on a comment made by Vegas to the PUC that the CDR "doesn't model what the market would typically do."

"Exactly," Lewin said as he moderated a discussion on his Substack feed. "I think this report is largely worthless. Might be worse than worthless because people panic for no good reason."

Pointing to an ERCOT slide with PRMs between 32.4 and 21%, Lewin said it "looks scary, but it's in no way reflective of the reality of the market. So, what's the point?"

The "Texas CDR report is far less important fundamentally than in the past years and is more a political signal in 2025," Julien Dumoulin-Smith, a financial analyst with investment banking and capital markets firm Jefferies, said in an email to his audience.

"The optics of … -2 to -33% reserve margins likely leads to a political response," he said, saying those optics will likely lead to efforts to subsidize generation and potentially less support for data centers.

Dumoulin-Smith said that draft legislation (*Senate Bill 6*) could be "adverse" for power companies. The bill would require a "minimum transmission fee" based on large users' peak load; require disclosure of backup generation; require PUC approval for any data center to buy existing thermal generation's output; and establish a new ancillary service similar to ERCOT's current emergency response service to "competitively procure demand reductions

Why This Matters

Industry insiders say the report has become more of a political document intended to incent legislation that will lead to more thermal generation being built.

ERCOT News

from large load customers" with 24-hour notice.

The changes to the CDR include new load forecasts, as directed by *House Bill 5066*, that come directly from transmission and distribution utilities' projections of new loads. Previously, ERCOT staff only counted loads with signed connection agreements.

It will now use effective load-carrying capabilities (ELCCs) to measure renewable resources' and battery storage's reliability contributions. The ELCC metric is used in most capacity markets, but ERCOT operates an energy-only construct.

The CDR will also illustrate both peak and peak net reserve margins and include demand-side resources such as demand response programs. ERCOT said the potential 9.72 GW of thermal generation in the Texas Energy Fund (TEF) did not meet the rules for inclusion in the base CDR scenario. It said additional scenarios did include the full TEF generation portfolio's potential effect on reserve margins.

"The new parameters and scenarios in the CDR better represent the performance of grid resources and the dynamic nature of the ERCOT grid," ERCOT said.

"The methodology changed significantly and … is extremely suspect. ELCC is a massively flawed metric," Lewin said, noting "centrally planned, administratively determined capacity values" are necessary in capacity markets, but not in an energy-only market.

"That's part of the point of an energy-only market. Markets are far better at determining which resources can meet demand," Lewin said. "Very hard to get good enough data to determine these things administratively. You'll always be behind."

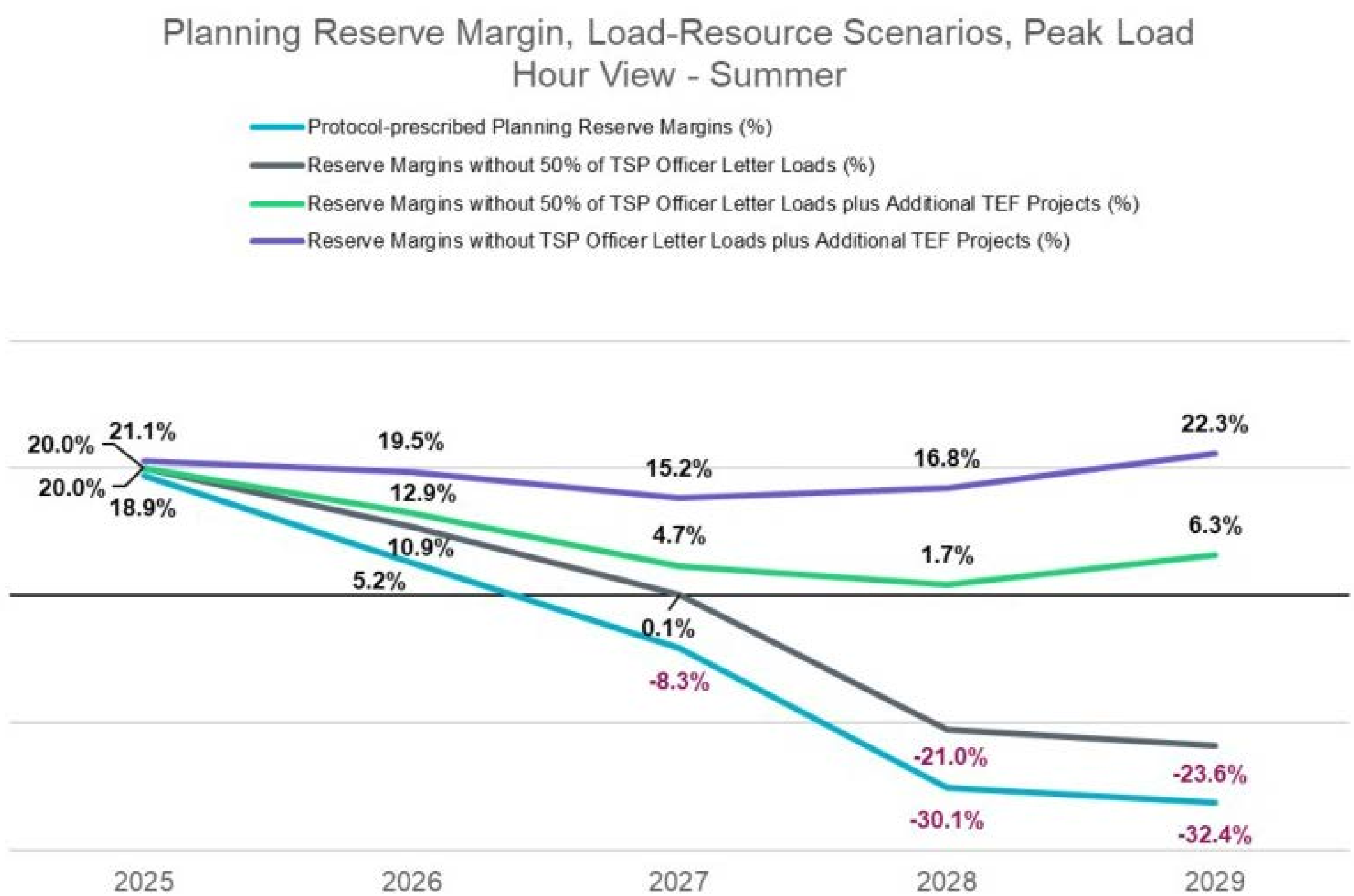
The CDR, originally released at 9:33 a.m. Feb. 13 in a market notice, was revised twice to reflect corrections to formulas in the "load-resource scenarios" tab that affected TEF scenarios.

Dumoulin-Smith said "significant math errors" overstated projected supply in 2029 by about 28 GW, a "substantial delta" on an approximate 100-GW base. The initial report had one reserve margin of 22% that was corrected to 3.9% in the second report and uses a "stale" load forecast from summer 2024, he said.

The analyst said he is "doubtful" many of the TEF projects will be completed without further support. Texas Lt. Gov. Dan Patrick (R), as president of the state Senate, has said he might seek $5 billion in state funds as incentives to build additional natural gas power plants; the TEF's In-ERCOT Generation Loan Program has already been allocated $5 billion for low-interest loans, but the current portfolio will require $5.34 billion in loaned funds.

ERCOT says future economic growth will provide opportunities to improve PRMs. It says potential short-term solutions include expanding DR capabilities and broadening the firm-fuel supply service program. It also says it could further improve energy storage optimization and work with large loads on flexibility capabilities.

"ERCOT looks forward to working on short- and long-term solutions with the Texas Legislature, PUC and stakeholders to continue to strengthen the reliability and resiliency of the Texas power grid," CEO Vegas said. ■



ERCOT's 'scary' slide with negative planning reserve margins in the future. | *ERCOT*

ISO-NE News

Eversource to Boost Grid Investments by $1.9B After Exiting Wind, Water

By Jon Lamson

Eversource Energy executives announced during the company's *year-end earnings* call Feb. 12 its plan to increase investments in its "core electric and natural gas operations" by $1.9 billion in 2025-2028 in the wake of its exit from the offshore wind business and finalizing the sale of its water utility.

"The $1.9 billion increase is primarily driven by higher electric transmission and higher electric distribution investments in Massachusetts," CFO John Moreira said.

The company took a net after-tax loss of $524 million from the sale of its offshore wind business in 2024, which came in the wake of a $1.95 billion loss from offshore wind in 2023. Its pending sale of Aquarion Water to a new Connecticut-owned water authority, *announced* in late January, brought an additional loss of $298 million.

"Proceeds from the [Aquarion] sale will be used to reduce debt, allowing us to reinvest capital into our regulated utilities" in Massachusetts, Connecticut and New Hampshire, Eversource CEO Joe Nolan said.

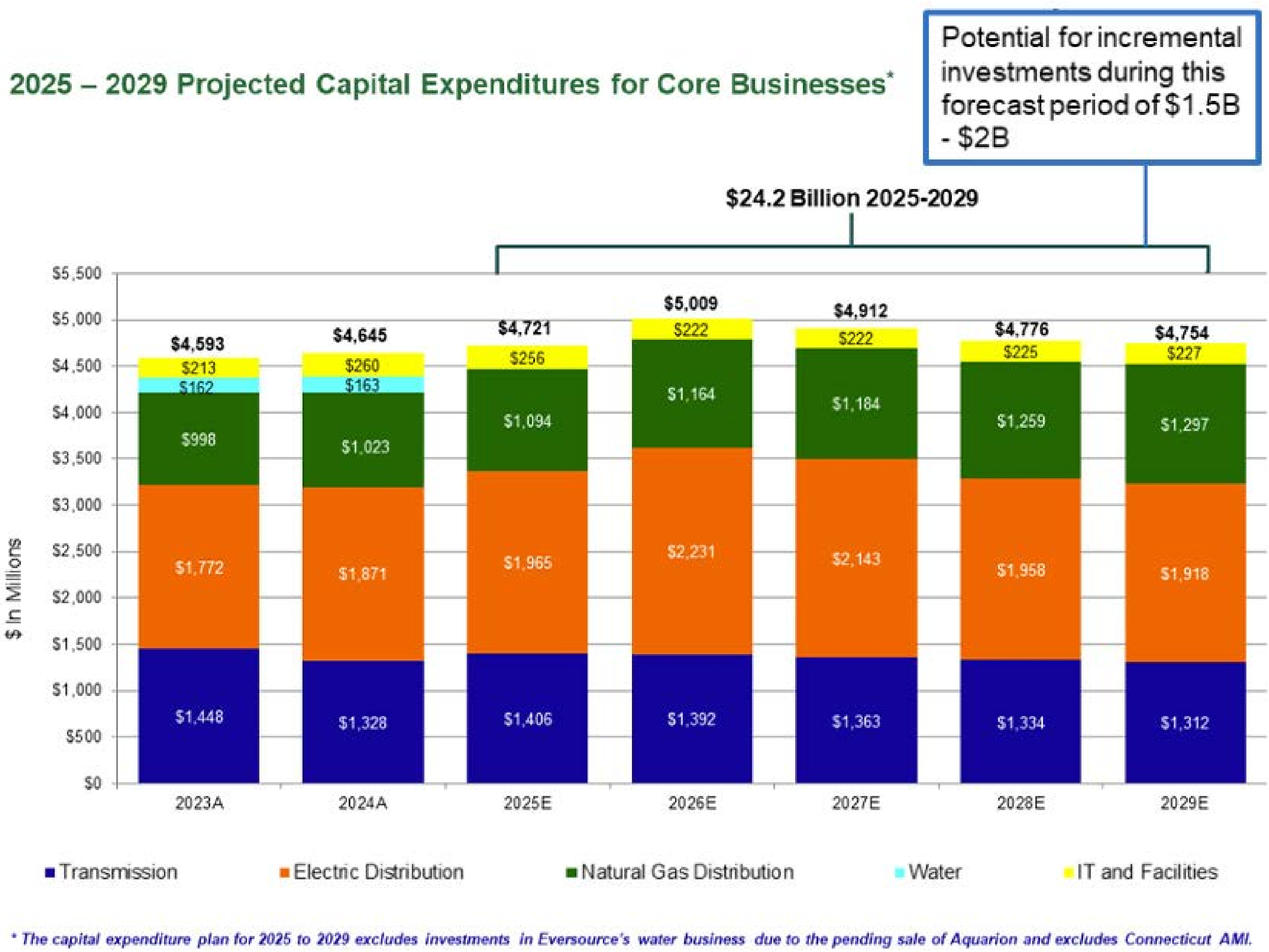
Between 2025 and 2029, the company plans to invest a total of $24.2 billion across its gas and electric businesses, which includes "only those projects that we have clear line of sight on from a regulatory approval perspective," Moreira said. This includes nearly $7 billion in

Why This Matters

Eversource is pivoting to focus its investments on the power grid, but the company remains on the hook for potential cost increases on the Revolution Wind project.

transmission investments, focused on projects to replace aging infrastructure, increase extreme weather resilience and interconnect renewables.

The plan also features more than $10 billion



Eversource five-year investment plan | *Eversource Energy*

ISO-NE News

for electric distribution upgrades, focused on reliability and resilience. This includes $850 million to deploy advanced metering infrastructure (AMI) in Massachusetts, which will "allow customers to increasingly participate in the transformation of energy usage," Moreira said. Eversource's goal is to achieve full AMI deployment by 2029.

Moreira said the company could invest an additional $2 billion in investment over the five-year period, highlighting the deployment of AMI and electric vehicle infrastructure in Connecticut, large-scale solar generation in New Hampshire and upgrades at its LNG facilities.

"The biggest component of that incremental investment opportunity is Connecticut AMI," Nolan said.

The company and the state have struggled to agree on how to fund the deployment of meters for 1.3 million customers, which is expected to cost $766 million. Eversource and Avangrid, which both own utilities in Connecticut, have frequently decried the regulatory climate in the state under the leadership of Public Utilities Regulatory Authority Chair Marissa Gillett. In January, the companies filed a lawsuit alleging that Gillett has abused her authority as the head of the agency.

"PURA's use of unlawful procedures to vest unchecked decision-making authority in a single individual has resulted in an environment of opaque, unpredictable and arbitrary regulatory outcomes," Eversource wrote in a cease-and-desist letter to the agency on Jan. 14.

"We continue to await PURA's action as they consider the final decision" on the AMI meters, Nolan said.

Gov. Ned Lamont (D) has stood by Gillett, who is up for reappointment. He has disputed the utilities' claims that the authority has unlawfully made decisions without holding votes between all three commissioners.

"Stop litigating this in the press," Lamont said in a January news conference. "If you don't like a decision, you can appeal it. I think that is the best way to handle this."

Regarding Massachusetts, Nolan highlighted Eversource's recent acquisition of part of the retired Mystic Generating Station from Constellation Energy.

"Purchasing this site will allow us to transform it into a premier energy interconnection hub that enhances reliability and energy supply diversity for the entire New England region," Nolan said. He noted that the company is still evaluating investment opportunities at the site.

Asked about potential additional delays to Revolution Wind after Ørsted appeared to push the offshore wind project's timeline back at its earnings call earlier in the month, Nolan said that "nothing has changed on Revolution; we continue to make great progress."

While the company sold its stake in the project to Global Infrastructure Partners, it remains on the hook for price adjustments if the project's pre-tax, equity internal rate of return falls below 13%. These adjustments would be applied upon the project's commercial operations date. Eversource also shares partial responsibility for construction cost overruns on the project.

"The 20th turbine is being loaded now at New London. … We feel very good about executing there," Nolan said. ■

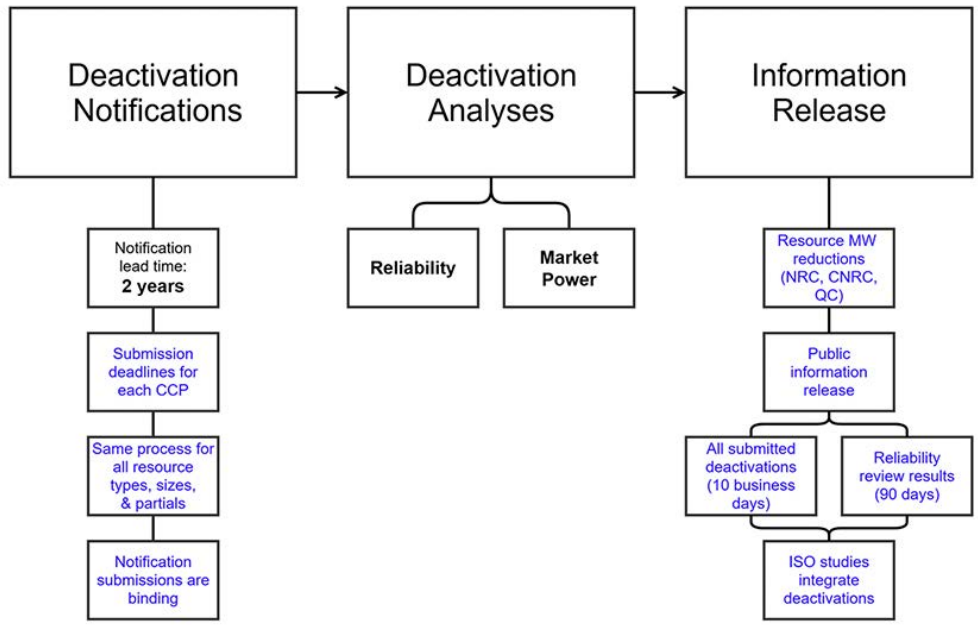
ISO-NE News

NEPOOL Markets Committee Briefs

Resource Retirement Changes

ISO-NE continued discussions with stakeholders on its capacity auction reform project at the NEPOOL Markets Committee (MC) meeting Feb. 11, providing more information on planned changes to the resource retirement process.

The RTO plans to decouple the retirement process from its capacity market as it works to reduce the time between auctions and capacity commitment periods (CCPs). Under current procedures, resources signal their plans to retire through the forward capacity auction process, about four years before their actual retirement.



Deactivation process flow chart | *ISO-NE*

ISO-NE *proposes* to require resources to give a two-year advance notification of their plans to retire for a given CCP. The reduced timeline is intended to give resources more clarity around the economics that motivate retirement decisions, while still providing enough time to conduct market power and reliability analyses, deploy transmission solutions if needed and enable market participants to respond. (See *ISO-NE Introduces Proposed Resource Retirement Changes*.)

While the two-year notification timeline would not provide enough time to develop long lead-time resources, some resources, including batteries and demand response, likely could be developed in this period, said Kevin Coopey, principal analyst at ISO-NE.

"If a market response takes longer than two years, the notification lead time will reduce the gap between when the deactivation occurs and when the market responds," Coopey said.

ISO-NE plans for retirement submissions — including retirement dates — to be binding. This is intended to preserve the market signal sent by retirements and prevent resources from "fishing" for reliability retention contracts, Coopey said. He added that allowing withdrawals could unintentionally create "incentives for resources to 'test' if they can get away with exercising market power with limited repercussions."

The RTO plans to discuss reliability reviews for deactivation requests at the MC in March.

FERC Order 904

ISO-NE opted to delay a planned vote on compliance with FERC *Order 904*, which prohibits transmission providers from compensating generators for reactive power within the standard power factor range.

The standard power factor range is defined as "the power factor range set forth in the generating facility's interconnection agreement when the unit is online and synchronized to the transmission system," FERC wrote in the order.

Prior to the order, the RTO unsuccessfully argued the commission should let it maintain its procedures for compensating reactive resources.

To comply with the order, ISO-NE *proposes* to eliminate its volt ampere reactive capacity cost compensation program. The compliance proposal would not change compensation for resources following ISO-NE dispatch instructions, the RTO noted.

Multiple stakeholders expressed concern that the compliance proposal is too broad and argued the RTO should continue compensating resources for reactive power outside of the standard range. Responding to the concerns, ISO-NE delayed the vote until Feb. 27, when it will hold a joint meeting of the MC and the Transmission Committee.

The compliance filing is due on March 27; ISO-NE proposes for the changes to take effect on June 1. ■

—Jon Lamson

MISO News

Board Orders MISO to Get Answers on IMM's Role in Tx Planning

By Amanda Durish Cook

Board members have directed MISO to seek guidance on the role of the Independent Market Monitor in transmission planning following a year of IMM David Patton criticizing MISO's nearly $22 billion long-range transmission plan (LRTP) portfolio.

MISO's Markets Committee of the Board of Directors voted unanimously on the measure in a special, virtual meeting Feb. 14. The motion from the board instructs MISO's legal department to reach out to FERC for its perspective on whether the IMM should be scrutinizing the RTO's transmission planning. It also directs MISO to communicate to the IMM that it will not pay for work related to transmission planning "until further direction from FERC."

MISO confirmed it received the committee's directions. In a statement to *RTO Insider*, it said it is "working to determine the next steps to effectuate the committee resolution."

MISO IMM David Patton was a vocal opponent of the second LRTP portfolio throughout 2024, repeatedly telling planners they were overstating the benefits of the collection of mostly 765-kV lines and deeming the 20-year future assumptions that transmission needs were established upon unrealistic. Patton argued for a downsized portfolio. (See *MISO IMM Makes Closing Arguments Against $21.8B Long-range Tx Plan* and *$21.8B Long-range Tx Plan Goes to Membership Vote; MISO Resolute, IMM Protesting*.)

While many MISO members have said the IMM should not interfere in transmission planning and should concentrate solely on markets, Patton has said he believes planning is within his scope of work because of how planning and markets "interact with one another."

The board's potential IMM funding freeze comes as MISO is gearing up to update the 20-year scenarios it uses as the basis for long-range planning. MISO has planned a first workshop with stakeholders on the futures Feb. 28. The grid operator plans to retool the futures for the remainder of the year and embark on another LRTP portfolio in 2026. (See *MISO Pauses Long-range Tx Planning in 2025 to go Back to the Futures*.) Patton is likely to disagree with the temporary stop work order, though he ultimately declined to comment on the Markets Committee's motion.

MISO Director H.B. "Trip" Doggett said board members and MISO made a portion of the Feb. 14 meeting public in an effort to be more transparent about the board's activities and budget items related to the IMM.

By the end of 2024, MISO's IMM budget was about $236,000 over an approximate $8 million allotment. Doggett said board members analyzed the overrun extensively and found it ultimately was linked to rooting out demand response schemes in the MISO markets and work dedicated to taming market-to-market congestion between MISO and SPP after a North Dakota data center taxed a transmission constraint.

Doggett said the Monitor's assessments of the LRTP did not contribute to the cost increase. The committee approved the IMM's 2024 budget, including overage, in full.

MISO directors agreed it was time for the board to attempt to clear up the IMM's authority. Director Nancy Lange said it was appropriate to get "clarity on future work related to the LRTP."

"I think it's an important step," Director Robert Lurie agreed.

Some MISO members said they were concerned about the optics of the board's decision.

WPPI Energy's Steve Leovy said while it's fine for the board to want clarification around the IMM's role, the whole "situation has a bad look to it" because the Monitor disagreed with MISO's planning assumptions and benefit calculations. Leovy said he wondered if the board would take such action if the IMM had backed MISO's second LRTP portfolio.

"This has a bit of an appearance of retaliation, in my opinion. … A bit of an attempt to stifle the discussion," Leovy said.

North Dakota Public Service Commissioner Jill Kringstad said her state appreciated the IMM's independent voice during the planning process. WEC Energy Group's Chris Plante, speaking as a representative of MISO's transmission-dependent utilities, also said he found the IMM's perspective helpful, especially as he questioned MISO's processes.

Following the meeting, ITC's Brian Drumm said the Markets Committee's unanimous approval to confirm that the IMM's scope of duties "do not extend to participation in MISO's transmission expansion planning processes will provide important clarity for MISO and its stakeholders going forward."

Drumm pointed out that MISO has *said* before that it believes recommendations related to transmission planning are outside the scope of the Monitor's duties. ■

Why This Matters

Following the IMM's vocal opposition to MISO's long-range transmission portfolio over 2024, MISO board members asked for clarity from FERC on whether it's appropriate for the IMM to weigh in on transmission expansion.

The Markets Committee of the MISO Board of Directors on Dec. 10, 2024, in The Woodlands, Texas | *© RTO Insider LLC*

MISO News

Anti-nuclear Groups Challenge Palisades Reopening

By Amanda Durish Cook

Why This Matters

Anti-nuclear groups, led by Beyond Nuclear, have mounted a challenge to a Palisades restart by challenging a license exemption and admentments Holtec needs from the Nuclear Regulatory Commission.

Anti-nuclear groups have united in an attempt to stop Michigan's Palisades Nuclear Generating Station from being brought back to life.

The coalition — Beyond Nuclear, Don't Waste Michigan, Michigan Safe Energy Future, Nuclear Energy Information Service of Chicago and Three Mile Island Alert of Pennsylvania — argued in front of a trio of administrative law judges from the Nuclear Regulatory Commission's Atomic Safety and Licensing Board Panel that neither the NRC nor owner Holtec is putting enough thought into the restart of the plant.

Holtec aims to bring Palisades back online in October. (See *Holtec Confident on Late 2025 Restart of Palisades Nuclear Plant*.)

To revive Palisades, Holtec needs an exemption on the certifications granted as previous owner Entergy was shutting down the plant. The certifications prohibit operation of the reactor or placement of fuel into the reactor vessel. Additionally, Holtec needs four license amendments that will allow it to refuel the plant and restart operations. The quartet of amendments would alter technical specifications, revise an emergency plan to support the return of operations and update the methodology for studying potential consequences of a main steam line rupture.

Beyond Nuclear and others entered a request for hearing in Holtec's exemption and amendment requests (*50-255*). Oral argument pre-hearings were held virtually Feb. 12.

Coalition attorney Wally Taylor said restarting a reactor in decommissioning status should require "more than just some paper shuffling, as Holtec and the NRC suggest."

Taylor argued that Holtec requires a new operating license, not a license adjustment to reopen Palisades.

Taylor said Holtec and NRC "cobbled together a plan … to try to accomplish a restart" with licensing exemptions and adjustments because there is no regulatory pathway to restarting a closed and decommissioned nuclear reactor. He said Holtec and NRC's "ad-hoc, patchwork" method to relicense a closed nuclear plant runs afoul of the Atomic Energy Act.

According to the coalition, Holtec and the NRC are cherry-picking regulations that will ensure a restart while bypassing a new Updated Final Safety Analysis Report. The group said Holtec has admitted that "current regulations do not specify a particular mechanism for reauthorizing operation of a nuclear power plant after both certifications [regarding decommissioning] are submitted on the docket and before operating license expiration."

"Since there is no dedicated regulatory procedure for restarting a closed reactor, the NRC has no authority to approve the license amendments requested by Holtec," the coalition argued in its October request for hearing.


Palisades Nuclear Generating Station | *Holtec International*

The group said Holtec currently holds an operating license that specifies that fuel is permanently removed from the core while no new fuel is introduced in the reactor. Absent a fresh license, the group argued that Palisades shouldn't be allowed to produce electricity.

The anti-nuclear groups also argue that the NRC is duty-bound to draw up a full environmental impact statement for a Palisades return pursuant to the National Environmental Policy Act. Taylor said NRC staff erred by not ordering one and Holtec erred by not submitting an environmental report.

NRC staff issued a *draft environmental assessment* in mid-January that found no significant impacts; the regulatory body doesn't plan to move to a more intensive environmental impact statement.

Michael Spencer, attorney for NRC staff, argued the coalition's petition is inadmissible because the arguments attack existing regulatory frameworks or are outside of the scope of the case.

Spencer also said the case involves an already constructed plant that safely operated for decades when Entergy voluntarily shut it down before its 2031 license end date. He pointed out that Holtec is attempting to restore a license to a plant that has undergone previous safety and environmental reviews.

Spencer said the case is "not a forum for broader" debates about a Palisades reopening. He said the groups did not limit their arguments to the procedure and attacked the plant's restart.

Continued on page 22

DTE Energy Ups 5-Year Plan to $30B

By Amanda Durish Cook

DTE Energy has announced it will expand its five-year capital expenditure plan to $30 billion, a $5 billion increase in investment.

During a Feb. 13 year-end earnings call, CEO Jerry Norcia said the increase will help the utility improve reliability and transition to a cleaner fleet in accordance with Michigan's 100% clean energy mandate by 2040. Norcia said the plan has the potential for incremental investment above $30 billion depending on "data center opportunities."

"This $5 billion increase is a significant increase to our capital plan and is driven by the need to build out renewables to meet the increased demand from the success of our My Green Power voluntary renewable program and to support Michigan's clean energy legislation, as well as the need to continue to invest to improve reliability for our customers as we continue our efforts to update and modernize our electric grid," Norcia said.

Norcia told shareholders that DTE has "a solid, long-term development pipeline in place, providing clear line of sight on panels, land positions and permitting."

"We have panels secured through mid-2027, land positions that should take us into the 2030s and beyond, and permits secured for the majority of our projects through 2027," COO Joi Harris added.

Norcia said the updated plan includes an additional $3 billion in clean energy investment and $1 billion for improved distribution infrastructure to cut outage rates further.

Harris said DTE was able to reduce outage durations by 70% over 2024. She said the utility over the next five years expects to further reduce power outages by 30% and halve outage time.

In 2022 the Michigan Public Service Commission ordered an *audit* of DTE and Consumers Energy after ratepayer frustration with a "pattern of widespread, lengthy outages from increasingly severe storms."

Norcia said the company's electric arm remains focused on potential demand growth from data centers in its service area. DTE recently signed a nonbinding preliminary agreement with an unnamed company, Norcia said, and if it comes to fruition, it could bring the company's potential new data center load growth to 2.1 GW. DTE already has signed agreements for an artificial intelligence research facility at the University of Michigan and a 1.4-GW Switch data center complex using some of DTE's land.

"We are also in discussions with multiple parties for additional opportunities beyond those that I just described," Norcia said, adding that DTE is supportive of Michigan's new law offering tax breaks to large data centers.

Norcia said that while DTE is sitting on some excess capacity to serve new data center load, the company likely must build new capacity in the near term. He said plans for baseload generation to support the growth would come in the utility's 2026 integrated resource plan.

DTE earned $1.4 billion ($6.83/share) over 2024 despite the warmest winter in more than 60 years, according to the utility. Over 2023, the company brought in $1.2 billion ($5.73/share) in operating earnings. It released an earnings per share guidance range of $7.09 to $7.23 over 2025.

Norcia said 2025 performance will be bolstered by the Michigan PSC granting a $217.4 million increase in electric rates in January. The new rates went into effect Feb. 6. The hike in rates was less than half of the $456.4 million that DTE first requested in early 2024. ■

Anti-nuclear Groups Challenge Palisades Reopening

Continued from page 21

Stan Blanton, an attorney for Holtec, said the groups inappropriately challenge NRC's authority to permit a nuclear plant restart. He said Holtec's plan is to "simply restore Palisades to its pre-decommissioning status."

"There's no question about what regulations need to be followed," Blanton argued, adding that Palisades has an operating license in effect that is applicable to NRC's restart authority.

Blanton said Holtec maintains the restart would not cause a major environmental impact that would require a formal environmental report.

Blanton agreed with an administrative law judge's statement that Holtec's license exemption request can be likened to an officer waving a motorist through a red light.

But the anti-nuclear groups argued that "Holtec's legerdemain, to force all of the safety oversight for Palisades through the tiny eyelet" of a code in the federal regulations, "runs into the laws of chemistry and physics."

The groups contended that Holtec's current path to a Palisades resurrection is a violation of 10 CFR 50.59, titled "Changes, tests and experiments," in the Code of Federal Regulations. They maintained that Holtec should have petitioned the NRC before undertaking significant work at the reactor.

"Without proper layup and very suspect planning for the reopening of Palisades, this aged, degraded reactor almost inevitably will face unforeseen engineering and operational difficulties, hitherto unrecognized safety issues, and the cussedness that accompanies any obsolescent machine or vehicle," the coalition warned in its hearing request.

The anti-nuclear groups' petition included expert testimony from Arnold Gundersen of Fairewinds Associates, who argued that after Entergy terminated the old Palisades operating license, a permit cannot be reissued to Holtec "without Palisades meeting the new, more stringent safety criteria of the 21st century."

Gundersen said since nuclear plants' design basis assumptions are dramatically different than in the mid-1960s, the NRC must compel Holtec to revisit the plant's assumptions. Gunderson said worsening climate change likely would create more frequent "unanticipated scenarios" outside of the design bounds.

Gundersen also said he was concerned about damage from internal vibrations to the plant's steam generator and Entergy disposing of "indispensable" quality assurance records. He said Holtec was moving at a reckless pace, borrowing a phrase from Union Admiral David Farragut as he commanded his fleet to enter Mobile Bay: "Damn the torpedoes. Full speed ahead." ■

NYISO News

NYISO Liaison Subcommittee Briefs

ISO Still Working on Trump Tariff Clarity

NYISO is still working on getting clarification on President Donald Trump's pending 10% tariff on energy imports, Joe Oates, chairman of NYISO's Board of Directors, told the Liaison Subcommittee.

The Board of Directors "has authorized [NYISO] to seek any tariff authority necessary to comply with legal obligations that may be imposed on it," Oates said. "Management is working through these issues internally and with members of the ISO/RTO community," and with FERC. (See *NYISO Assessing Impact of Trump's Canada Tariff on Electricity Market*.)

Oates said the ISO would address the issue in detail with stakeholders Feb. 25.

He also said the ISO had not yet received any guidance from "anyone down in D.C.," as Kevin Lang, representing New York City, put it.

Clean Path

Oates told the subcommittee that the board had approved the changes to the 2025 Project Grant Plan, specifically approving the removal of its initiative to develop market participation rules for internal controllable lines.

This was done because of the New York Power Authority's proposed changes to the Clean Path NY transmission project. (See *NYPA Files Petition with New York PSC to Save Clean Path Project*.)

"We remain ready to support the project in the future once updated details and plans are available," Oates said.

A representative from NYPA thanked the ISO for its continued support of the project.

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

Cybersecurity Updates

Oates said NYISO had successfully completed its triennial critical infrastructure audit by the Northeast Power Coordinating Council. The ISO scored "excellent," and there were no areas of concern.

NYISO also continues to monitor cybersecurity developments with respect to "nation-state threat actors and global attack campaigns." The ISO is implementing "three micro segmentation enforcement environments" within its networks to prevent persistent threats. Oates said this was a key element of the "zero trust" cybersecurity strategy the ISO was implementing.

The subcommittee receiving a classified briefing late in 2024 on *Volt Typhoon*, a Chinese state-sponsored hacking group. The Cybersecurity and Infrastructure Security Agency has continually issued warnings that China has been sponsoring persistent intrusions into critical infrastructure. (See *CISA Leader Reiterates China Cyber Warnings*.) ■

— Vincent Gabrielle

FERC Approves PJM's One-time Fast-track Interconnection Process

Changes to SIS also Approved

By Devin Leith-Yessian

| Shutterstock

FERC on Feb. 11 approved two PJM proposals aimed at allowing some generation projects to speed through its backlogged interconnection queue.

The Reliability Resource Initiative (RRI) is a one-time measure to add up to 50 new projects to a cluster of projects to be studied beginning in April (*ER25-712*), while an expansion of surplus interconnection service (SIS) makes more projects eligible to use underutilized injection capability (*ER25-778*).

FERC noted that the proposals are part of a wider effort at PJM to address a capacity shortfall the RTO has identified toward the end of the decade by allowing new resources that would either contribute to grid reliability or require minimal transmission upgrades to advance through the interconnection process in an expedited manner.

In its "4R report," PJM said it could be short 10 GW of capacity in the 2030/31 delivery year because of rising load growth, generation retirements and slow new entry; in a June 2024 study, that resource adequacy deficiency was moved up by one year. (See "PJM White Paper Expounds Reliability Concerns," *PJM Board Initiates Fast-track Process to Address Reliability*.)

For the RRI, that takes the form of a special application window for Transition Cycle 2 (TC2), created in 2023 as part of PJM's transition to a first-ready, first-served clustered generator interconnection process. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

PJM will allow up to 50 projects to be added to TC2, which is otherwise only open to "legacy" projects that had been sorted into queue windows AG2 and AH1, the latter of which closed in September 2021. If more than 50 applications are received, PJM will use weighted scoring to determine which will proceed:

- 35 points based on the project's unforced capacity (UCAP);
- 20 points for resources with high effective load-carrying capability (ELCC) ratings;
- 10 points for projects sited in the Dominion or BGE zones;
- 10 points for being able to achieve commercial operation between 2028 and 2031;
- 10 points for evidence of permits, siting and equipment procurement supporting a project's in-service date;
- 10 points to projects that are uprates of existing generation or planned projects; and
- 5 points for projects that take advantage of existing transmission headroom.

"This one-time initiative should provide a much-needed on-ramp to the reliability of the PJM system in the short term as we continue to move existing queued projects through our transition cycles," PJM General Counsel Chris O'Hara said in a *statement*. "We now hope to see suppliers take advantage of this unique opportunity."

In a Feb. 12 message to members, PJM said the application window for RRI projects will be open between Feb. 28 and March 14.

'Close Call'

The RRI was approved 3-1, with Commissioner Judy Chang in dissent and Commissioner Lindsay See not participating.

Chang said that while she agreed with PJM's assessment that it has a looming resource adequacy problem, "its proposed solution primarily prioritizes the size of the new interconnecting resources over speed and thus is poorly designed to address those very real challenges."

She said the proposal should have been rejected without prejudice, allowing PJM to file a similar proposal but with more focus on the viability of commercial in-service dates, which she said should have received the greatest weight of all criteria. She also said that granting only 5 points for transmission headroom availability undersells the value that requiring minimal network upgrades can have on being able to quickly progress.

"By expediting projects that are unlikely to directly address PJM's reliability risks in the 2026-2030 time frame, PJM's filing also presents a risk of the worst of both worlds: It compromises the commission's open-access principles with no guarantee it will resolve PJM's reliability issue," Chang wrote.

Commissioners David Rosner and Willie Phillips filed a joint concurrence in which they

PJM News

expressed some reluctance but found that the "one-time, extraordinary measure ... is only needed because of the equally extraordinary circumstances PJM finds itself in today."

The two commissioners said the RRI would not upset the settled expectations of existing projects already in the queue but also criticized PJM's weighting that favors large projects possibly coming at the cost of rapid construction.

This made their approval "a close call," they wrote. "We would have fewer reservations about PJM's RRI proposal had the commercial operation date viability criteria been stronger. We are concerned that PJM's proposal may not enable sufficient 'shovel-ready' resources to interconnect and enter commercial operation in time to prevent the resource adequacy crisis that motivated PJM to develop this proposal in the first place.

"In particular, the proposal does not outright require RRI resources to achieve commercial operation by a date certain (e.g., in service prior to 2030) and assigns only 35 out of 100 points to commercial operation viability criteria."

Response to Protests

Comments on the RRI remained as divided as stakeholders were when PJM broached it with its membership last year. Many renewable energy developers and clean energy associations were opposed, arguing it would allow queue-jumping, mainly to the benefit of large thermal generators, and possibly increase the network upgrade costs for projects that have been in the queue for years.

Other generation developers argued that it would allow uprates and projects that would be built quickly to enter the queue, a perspective shared by consumer advocates and the Organization of PJM States Inc. (OPSI). (See *PJM Stakeholders Wary of Expedited Interconnection Proposal*.)

Invenergy argued that PJM has a track record of discriminating against certain resource classes, which would be continued by the proposal carrying an effective categorical exclusion of wind and solar by prohibiting projects smaller than 10 MW and through the UCAP and ELCC weighting. The Natural Resources Defense Council argued that because UCAP already takes into account resources' ELCC ratings, breaking the latter out into a second component that disadvantages renewables and storage.

Constellation said that splitting ELCC and UCAP into two criteria allows for more diversity in the scoring, making it easier for small, high-impact resources like storage to be included.

Rather than using weighted scores, the Independent Market Monitor said PJM should prohibit projects that don't meet three thresholds: whether a project would be in the correct location to address a reliability issue, possesses the operating characteristics needed to meet that need and would be capable of entering service in time. Rather than using a static number of projects, the Monitor also advocated for a capacity limit for how many projects can be accepted.

"Protesters assert that the RRI proposal allows PJM to put a 'thumb on the scale' in favor of certain resources in a manner that intrudes upon states' jurisdiction over the resource mix within their boundaries. We disagree," FERC said. "The proposal neither mandates nor prohibits the development of any particular generating facility, and it neither authorizes nor requires the adoption of a specific mix of generation resources."

In a statement, Jon Gordon, director of Advanced Energy United, said he agrees bold action is needed to address a possible capacity shortfall, but the RRI would not move that ball forward.

"Unfortunately, the Reliability Resource Initiative is a distraction from the task at hand: restoring confidence in PJM's interconnection process by fully implementing reforms already underway and prioritizing further improvements — such as the surplus interconnection service reforms also approved by FERC," Gordon said. "RRI is a misguided proposal that will disrupt the existing queue process with no guarantee of meeting PJM's identified reliability shortfall. United continues to implore PJM to employ an 'everything all at once' strategy to bring clean energy resources stuck in the interconnection queue online as quickly as possible and ensure PJM resource reliability going forward."

Sierra Club staff attorney Megan Wachspress said PJM is resisting reforms that would allow more renewable projects to be built in its footprint.

"It is deeply disappointing that, despite the problems identified by Commissioner Chang and acknowledged by Commissioners Phillips and Rosner, FERC would greenlight PJM's misguided effort to improve its interconnection process, knowing that adding more toxic gas plants will cause long-term environmental and public health issues across the Mid-Atlantic region," Wachspress said. "Additionally, there's no reason to believe this proposal will even address PJM's short-term capacity problem, since it does not require any of the chosen resources to be online by 2030 or even 2035."

Changes to Surplus Interconnection Service Widen Eligibility

FERC unanimously approved PJM's SIS proposal, though again without Commissioner See's participation.

The changes eliminate a categorical restriction on battery storage taking advantage of SIS; allow the service to be used when the original resource is planned and still in development; and allow projects that consume transmission headroom but do not require network upgrades. It also allows projects that require upgrades to interconnection infrastructure to proceed, a change the commission said is warranted given that developers pay the entirety of those costs and therefore would not impact other interconnection customers.

"PJM's proposal will facilitate the use of existing surplus interconnection capacity by removing certain limitations in the PJM tariff and by making surplus interconnection capacity available sooner in the interconnection process," FERC said.

Aftab Khan, PJM executive vice president of operations, planning and security, said FERC's approval of the proposal will allow it to better take advantage of existing interconnections.

"By taking a less restrictive approach to SIS, PJM will be in a better position to utilize existing system capability and existing interconnections that do not require additional network upgrades," Khan said.

The proposal received broad support from developers, who have argued that the RTO has taken a restrictive approach to a process that is meant to allow projects sited at the same point of interconnection as an existing resource.

In a joint filing, the American Clean Power Association, Advanced Energy United, MAREC Action and the Solar Energy Industries Association said the proposal would unlock dozens of gigawatts of capacity that could quickly be deployed to address resource adequacy concerns, while also potentially reducing strain on the interconnection study process.

"Under the current process, most surplus interconnection service requests are deemed invalid, necessitating a new service request and placing the developer at the end of the interconnection queue," the groups said. "PJM's proposal eliminates this restriction." ■

PJM News

Utilities Pushing for Return to Owning Generation in Pennsylvania

By James Downing

PPL is backing legislation this year that would let utilities in Pennsylvania own generation, which would unwind a key part of the state's nearly 30-year experience with restructuring.

The utility holding company, which is based in Pennsylvania and owns utilities there, announced its support for utility-owned generation on an earnings call last summer after capacity prices in PJM spiked. (See *PPL Backs Utility-owned Generation in Pa. After PJM Capacity Price Spike*.)

"In Pennsylvania, specifically, we continue to advocate for a state-focused, no-regrets strategy that addresses impending energy shortfalls and provides the state with additional tools to help protect customers from price volatility and reliability concerns," PPL CEO Vincent Sorgi said during the company's year-end earnings call with analysts Feb. 13. "We believe one way to do this is to allow regulated electric utilities to invest in generation resources up to and including owning and operating generation again. This would complement the competitive market by addressing resource adequacy gaps, rather than relying solely on market forces to deliver a solution."

Sorgi's remarks came after *The Standard-Journal* published an *op-ed* by Christine Martin, president of PPL Electric Utilities, outlining the case for letting utilities back into the generation business without setting up a separate firm that operates generation using only market revenues.

That generated pushback from three former chairs of the Pennsylvania Public Utility Commission — James Cawley (D), Robert Powelson (R) and Glen Thomas (R) — in an *op-ed* published in *The Scranton Times-Tribune*, arguing utility-owned generation would gouge consumers. All three have long supported competitive markets, and Thomas is the president of PJM Power Providers, which represents independent power producers who would have to compete with rate-based generation if the change went through.

The Panda Patriot Power Plant, a natural gas-fired power station located in Clinton Township, Pa. | *Casey Monaghan, CC-BY-SA 2.0, via Wikimedia*

"PPL's policy shift ignores the fortunate position that Pennsylvania now enjoys thanks to competitive markets," the three wrote. "Pennsylvania currently has 70% more power than it needs to meet peak demand. This enviable surplus means Pennsylvania nearly always exports power to neighboring states with generation deficits, no matter how much demand fluctuates."

But Pennsylvania is in PJM, and Cawley noted in an interview that other states in the RTO are falling short on building new generation. That has helped lead to higher prices in the entire market. Pennsylvania has better policies to encourage new generation than neighboring states like New Jersey and Maryland, he added.

"As we say in our op-ed, independent producers will take the risk, and they will meet that demand," Cawley said.

Martin argued just the opposite in her piece.

"We cannot simply wait for the market to 'fix' the issue, especially when that same market is failing to bring new generation capacity online in a timely manner," Martin wrote. "PJM is working on market reforms, and while these are steps in the right direction, they are unlikely to address the immediate crisis facing Pennsylvania and our region."

On the earnings call, Sorgi said the firm expected a bill to be introduced in the legislature this spring or summer that would allow for utilities to own generation. Other options include incentives for utilities to enter into power purchase agreements that go beyond the state's default service auctions, or a "Baseload Energy Fund" that would be modeled on a program in Texas that paid for natural gas plants outside ERCOT's market. (See *PUC Shortlists 17 Projects for Loans from Texas Energy Fund*.)

PPL is not the only utility that does business in Pennsylvania to endorse the idea of utility-owned generation. Exelon CEO Calvin Butler made comments during his own firm's earnings call the same week endorsing the policy shift, saying the rapid load growth forecasted for the PJM region shows that "complementary" approaches to the market are needed to ensure adequate supply.

Why This Matters

Pennsylvania was among the first states to deregulate its electricity industry in the 1990s, allowing consumers to choose the sources of their power.

"It is clear that states are and should be proactively involved in supply solutions that complement the markets," Butler said, "not to mention pursuing policies that enable more demand-side solutions. There is no single answer to meeting the levels of load growth that are anticipated. But instead, a variety of solutions across regulated and merchant participants is necessary."

Cawley served on the PUC for two stints, in 1979-1985 and again in 2005-2015, so he has seen Pennsylvania as a regulated state and a competitive one. He said the change was for the best.

"When I first got into regulation, right after the Three Mile Island accident, there were all these nuclear power plants that were nearing completion, and then we had to decide how much of the cost would be allowed in the rate base," Cawley said. "It's an impossible test. Some construction project that's been going on for 15 years with enormous cost overruns; that's a game the utilities will win every time." Utilities are masters at the accounting game; they know how to recover every cost, he added. But deregulation eliminated that. Competition ensures that customers do not bear the risk for massive cost overruns in generation construction, which was commonplace after Three Mile Island, he said.

Both PPL and Exelon used to be in the generation business, but both spun off their competitive firms, with Talen Energy and Constellation Energy as the results, respectively. Now the utilities are using scare tactics to get back into the generation business, but without the risks facing competitive generators, Cawley argued.

"It's an effort to confuse people, to get legislators afraid that reliability is somehow going to suffer because there won't be enough added generation," Cawley said. "Well, that's certainly nonsense. In Pennsylvania, we have been a net exporter of power for decades, and it's going to stay that way, at least for another 10 years, even if nothing was built." ■

PJM News

Dominion Sees Sharp Rise in Forecast for New Data Center Load

Utility Also Confronts Rising Costs — and Tariff Uncertainty — Around OSW Project

By James Downing

Dominion Energy has seen its forecast for new load from planned data centers in its territory increase by more than 88% over the past six months, the company said during its fourth-quarter earnings call Feb. 12.

Dominion has added about 19 GW of new data center load to its forecast since July, bringing the total to 40.2 GW. The new data centers have a "substation engineering letter of authorization" with the utility, which includes a detailed engineering plan paid for by developers.

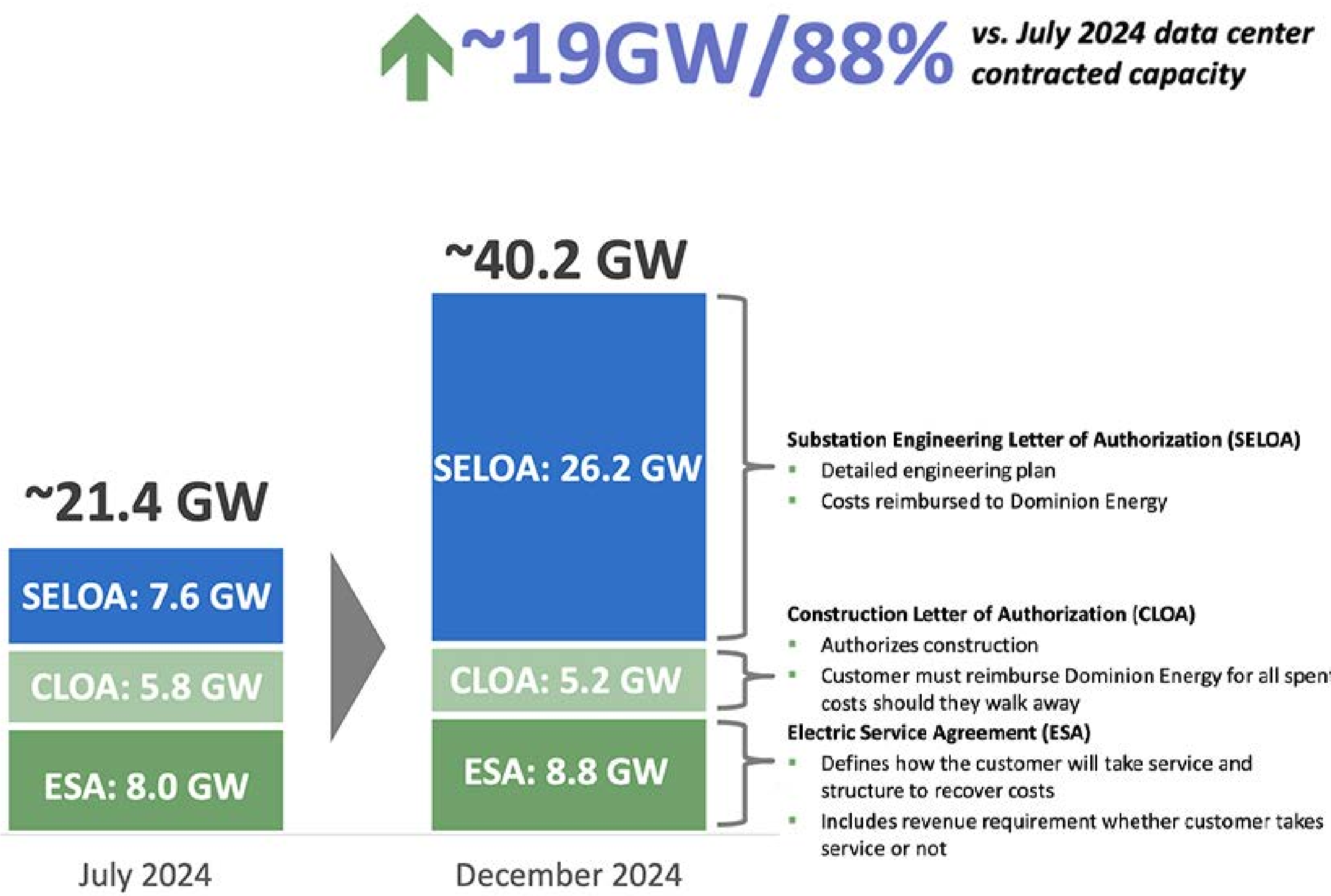
Company executives also told analysts that the load was not included in PJM's most recent forecasts.

"I think it's just important for everyone to understand that the data center demand in Virginia, in northern Virginia and in Loudoun County continues to be very significant," CEO Bob Blue said during the earnings call. "You see that in the numbers there."

Dominion Energy Virginia (DEV) has recently completed two 500-kV lines to serve the state's Data Center Alley, increasing available headroom by 6 GW, he added. While Loudoun County continues to see the most new data centers, Blue said they are now extending

Why This Matters

Dominion continues to see huge growth in data centers despite increased competition from other states and ongoing questions about how much of the projections actually will wind up occurring. It serves part of the largest data center market in the world.



A slide Dominion presented to analysts showing massive growth in the pipeline for potential new data centers in its territory | *Dominion Energy* beyond there, especially down I-95 toward Richmond.

"Since we started tracking, we've connected approximately 450 data centers, representing nearly 9 GW of capacity," Blue said. "Data center sales today represent about 26% of total sales for DEV."

Data centers have wide policy support among political leaders in Virginia, and the Legislature is considering bills to address their rapid growth including *Senate Bill 960*, which focuses on ensuring that the cost of serving the facilities does not increase rates for other electric customers. The bill cleared the Senate. (See *Virginia Legislators Introduce Bills to Deal with Data Center Growth*.)

"These kinds of debates about one customer class subsidizing another customer class have been going on since the beginning of utility regulation, and there are ways always to address that in Virginia, particularly with biennial reviews," Blue said.

Dominion will file its next biennial with Virginia's State Corporation Commission in March, and Blue said he was sure the process would allow the utility to keep meeting new demand without unfairly burdening other customers.

Uncertainty Offshore

A key piece of infrastructure needed to meet the ever-higher demand from data centers is the utility's Coastal Virginia Offshore Wind (CVOW) project, which is facing rising costs due to the need for more transmission infrastructure — in part the result of rising demand for materials. (See *PJM Network Upgrades Boost Cost of Dominion OSW Project 9%*.)

CVOW is 50% complete and on schedule for completion next year, and it is supported by Virginia law with the backing of all of the commonwealth's bipartisan political leaders, Blue said. Offshore wind has faced opposition from the new Trump administration, but Blue said that should not impact the in-progress project.

"This project is consistent with the goal of securing American 'energy dominance,' and is part of a comprehensive 'all-of the-above' energy strategy to affordably meet growing energy needs," Blue said, working in two Republican talking points on energy.

Completion of CVOW still requires about $2.5 billion in components made abroad, mostly in Europe, and it is unclear how much of that could be impacted by tariffs implemented by President Trump, who on Feb. 11 *reinstated* a 25% tariff on steel and increased tariffs on aluminum imports to 25%.

"With respect to potential steel and aluminum tariffs in particular ... generally, these types of tariffs are not intended to apply to most finished products," Blue said. "We would consider the CVOW components to be finished products. That said, we don't have the annexes to accompany the executive order. We can't know what if any of our remaining spend would be potentially subject to tariffs."

Dominion owns the Millstone nuclear plant in Connecticut, which had a 92% capacity factor in 2024 and has most of its capacity under contract through 2029, Blue said. The plant has options for selling power long-term beyond that with Massachusetts legislation authorizing additional procurements of nuclear power — or possibly setting up a co-located data center.

"We feel strongly that any data center option needs to be pursued in a collaborative fashion with stakeholders in Connecticut," Blue said. "At this point, we don't have a timeline for potential announcements." ■

PJM MRC/MC Preview

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to Manual 13: Emergency Operations to establish new wildfire procedures for the RTO and transmission owners to follow ahead of and during fire conditions that could impact transmission.

Issue Tracking: *Wildfire Procedure*

C. Endorse proposed *revisions* to Manual 40: Training and Certification Requirements drafted through the document's periodic review.

Endorsements (9:10-10:10)

Manual 14H: New Service Requests Cycle Process Revisions (9:10-9:30)

PJM's Jonathan Thompson will review proposed *revisions* to Manual 14H detailing the site control requirements for projects in the interconnection queue. Voting on the changes has been deferred twice as some developers seek alternative language to revisions they argue would be overly onerous and require them to hold onto land unnecessary for the completion of their projects. PJM has countered that clear rules are needed that can be applied to all projects in the queue. (See "Stakeholders Endorse Quick-fix Revisions to Site Control Manual Requirements," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

Issue Tracking: *Site Control Modification Clarification*

DR Availability Window (9:30-10:10)

PJM's Pat Bruno is set to review two proposed *packages* to revise the availability window for demand response (DR) resources and how they are modeled in the RTO's effective load carrying capability (ELCC) analysis. The proposals would replace the window with modeling output in all hours, shift the winter peak load (WPL) of each resource to be measured at a set hour, and create an average load profile for DR participants to be used in the ELCC analysis. The two packages differ in which year they would apply to, with the main motion starting implementation in the 2027/28 delivery year and the alternate being effective one year earlier. (See "Expanded Demand Response Modeling Endorsed," *PJM MIC Briefs: Feb. 5, 2025*.)

Issue Tracking: *DR Availability Window*

Members Committee

Endorsements (11:50-12:05)

1. The MC will consider same-day endorsement of the proposed revisions to the DR availability window. Expedited consideration is being sought to allow PJM staff to begin making the changes for the 2026/27 delivery year if the alternative is endorsed by the MRC. ■

— Devin Leith-Yessian

PJM News

Energy Innovation: US Needs New Approach to Grid Reliability

Renewables, Demand-side Resources Cheapest, Fastest Answer to Demand Growth

By K Kaufmann

To build a reliable, affordable and clean electric power system that can meet the challenges of unprecedented demand growth, the U.S. energy industry and the customers it serves will need to shift their thinking about what a reliable system looks like, according to a *new study* from nonprofit think tank Energy Innovation Policy & Technology.

"Grid operators, reliability authorities and utilities are ringing reliability alarm bells, and outdated views on grid reliability are colliding with slow-moving institutions," the report says. New concepts of reliability are needed so that "utilities and grid operators can build new generation faster and more efficiently, while simultaneously deploying strategic demand-side solutions at scale."

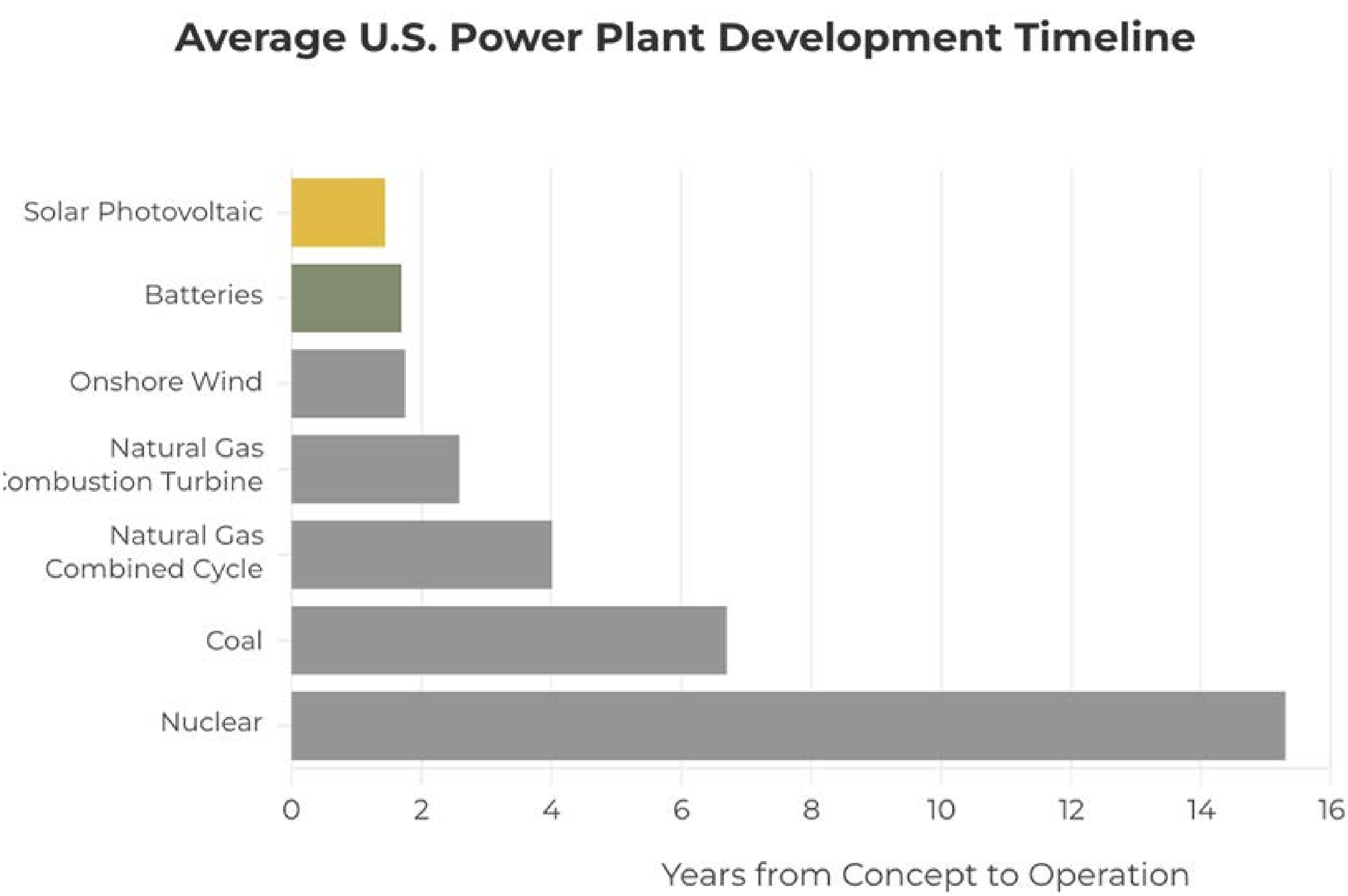
In opposition to President Donald Trump's call to ensure reliability by building new fossil fuel-fired plants, Energy Innovation argues that "reliability is a characteristic of the whole electric system, to which individual resources contribute. Every source of electricity has different characteristics that should complement each other in a balanced portfolio."

Examples include the increasing number of grids around the world that provide reliable service with major amounts of solar, wind and storage online, it says.

"For instance, large grids in the Midwest, Texas and California regularly operate using more than 70% renewable energy, and … Iowa and South Dakota generated roughly 60% of all their electricity in 2023 from wind power," the report says. "In Hawaii, South Australia and Denmark, grids are already operating using

Why This Matters

Republicans and some RTOs like PJM want to speed up permitting and construction of 'baseload' natural gas plants, while the clean energy industry is arguing that swift deployment of renewables and demand-side resources will be faster, cheaper and just as reliable.



| SEIA

PJM News

100% renewable power for days at a time.

"Notably, though, these jurisdictions have adjusted their planning and operating practices to integrate higher penetrations of renewable energy and battery storage without compromising reliability."

The Energy Innovation report is intended to be a primer for U.S. regulators and policymakers to demystify the often-daunting technical details of "grounding reliability discussions in meaningful solutions … while also discussing the challenges in achieving a 100% clean electricity grid."

Caught between the high speed of data center buildout and the much slower regulatory speed of project permitting and interconnection, the industry is at "an inflection point where the pressures are growing," Sara Baldwin, Energy Innovation's senior director of electrification policy and co-author of the report, said in an interview with *RTO Insider*. "So, the lag that is created in slow decision-making is actually exacerbating the challenges. It's creating more of an energy emergency. … Excuses are standing in the way.

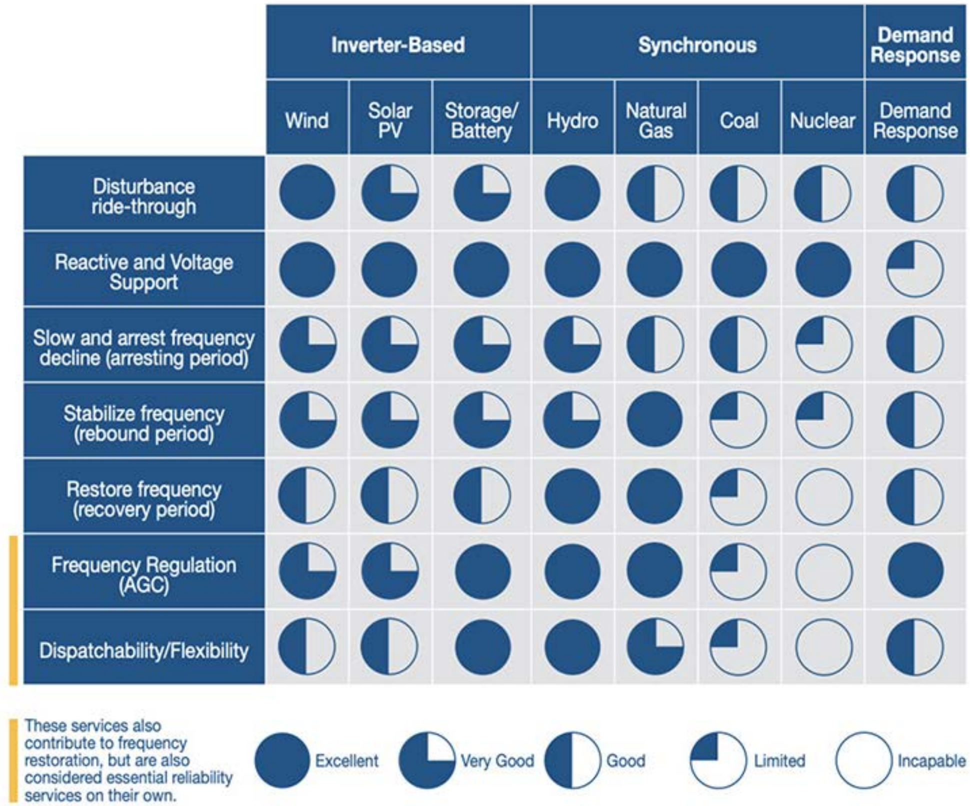
"We're actually not confronting technical challenges as much as we're confronting human challenges," Baldwin said. "And in some ways, human challenges are harder because human beings want to have full control over all the decision-making that falls underneath their jurisdiction and in their purview."

An example is the traditional thinking about the need for system inertia, provided by spinning turbines and typically powered by fossil fuels or hydropower, often cited by industry leaders arguing for more baseload power.

Specifically, they say, inertia can help to keep frequency levels on the grid stable in the event of stress on the system or disturbances caused by extreme weather.

Report co-author Michelle Solomon, Energy Innovation's manager for electricity policy, countered that "traditional inertia isn't actually something that you need to run the grid. Traditional inertia is part of this broader frequency response set of services, and actually, in many cases, inverter-based resources can respond faster … and provide what's called synthetic inertia."

The report notes that "while inertia slows frequency decline, it is not capable of restoring frequency back to its nominal level. Instead, services like fast frequency response, which can both slow the rate of frequency decline and help restore frequency are needed. …



Grid services provided by inverter-based and synchronous resources | *Milligan Grid Solutions*

"Inverter-based resources (IBRs) can ramp up and down much more quickly than a conventional power plant, making them more responsive to changing grid conditions," the report says. "IBRs can provide nearly instantaneous fast frequency response."

Can IBRs Deliver?

But the report also acknowledges that a significant gap exists between what IBRs are technically capable of doing and industry confidence in their ability to deliver when needed in real-life situations.

"Developers must be disciplined to program their resources to ride through a voltage event [even] if such a setting should compromise their asset or their operating revenues," the report says. Similarly, utilities and grid operators need to "quantify and understand how IBRs respond during a grid emergency" and ensure appropriate compensation in cases where they "provide a superior response."

For Mark Lauby, senior vice president and chief engineer at NERC, such recommendations contain a lot of "ifs" and potential threats to reliability. While he agreed that the future of the U.S. grid lies in a portfolio of diverse resources, including IBRs, "they haven't been proven. We haven't got a lot of them on the system."

New and traditional technologies have "got to work together, not against each other," Lauby said in an interview with *RTO Insider*.

"Batteries can move very quickly as long as they are charged … and inverter-based resources can mimic some of the things like inertia on the system, but they have got to be able to run on the battery," he said. "The battery better be charged, and if you have long-term events, where you've kind of exhausted your battery storage, now you don't have energy and, by the way, you don't have essential livelihood services."

Lauby also said that while management of demand-side resources can be effective for shaving peak demand, which can be predicted and prepared for, stress on the grid is now coming at less predictable times and locations.

IBRs could build more uncertainty into electric systems, on top of the essential variability of wind and solar, he said. For example, a dayslong drop in wind could take thousands of megawatts off the grid.

NERC is working on a range of standards intended to build industry confidence in the

PJM News

reliability of IBRs and other new technologies, he said.

Natural Gas Won't

The Energy Innovation report comes at a pivotal moment in industry and public debates over the most effective short-term strategies for meeting data centers' ravenous appetite for electricity, which could make up 12% of U.S. energy demand by 2028. (See *Berkeley Lab: Data Centers Could Need 12% of US Power by 2028*.)

The Trump administration and congressional Republicans are advocating for regulatory changes to allow faster permitting, interconnection and construction of natural gas plants, which they are promoting as baseload power that will keep the lights on and cut consumers' bills.

For example, in a *speech* on the House floor Feb. 13, Rep. Julie Fedorchak (R-N.D.) announced her plans to form an AI and Energy Working Group that would target increasing baseload power on the grid.

"The rapid, forced transition to intermittent power sources — paired with the retirement of reliable baseload generators — has left our electric grid increasingly vulnerable to outages," Fedorchak said.

On Feb. 11, FERC approved PJM's Reliability Resource Initiative, a one-time measure aimed at adding extra capacity to the RTO's system by allowing generation that meets certain criteria to essentially jump its notoriously backlogged interconnection queue. (See related story *FERC Approves PJM's One-time Fast-track Interconnection Process*.)

Renewable developers opposed the initiative, saying it is designed to allow large natural gas plants to get online ahead of the approximately *286 GW* of projects, mostly wind, solar and storage, that have been waiting for years for PJM to work through its queue backlog.

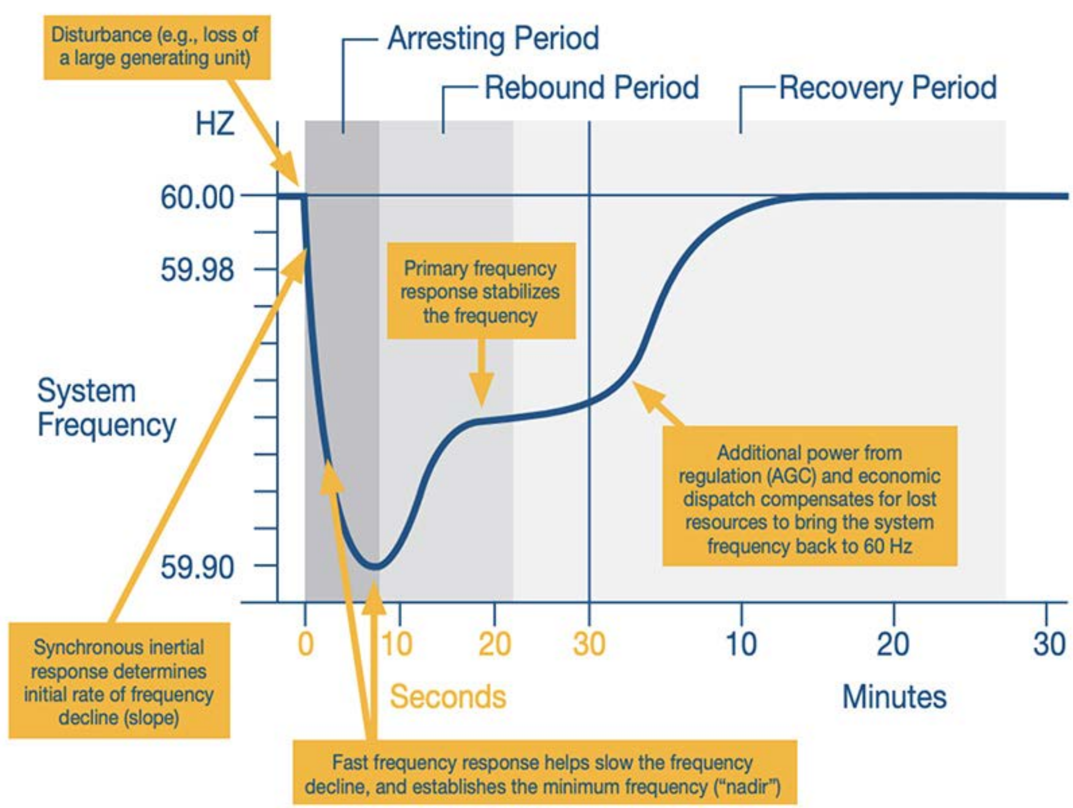
On the other side, the Solar Energy Industries Association has been attempting to pivot the public dialogue on demand growth to include solar, storage and other renewables as "the fastest technologies to develop and deploy. Not only are they much simpler to engineer, their supply chains are more robust than natural gas (which currently faces a bottleneck in gas turbine blades)," SEIA said in a Feb. 4 *blog post*. Natural gas plants can also be 2.5 times more expensive to build, it said.

The Energy Innovation report joins a recent study from Duke University in arguing for aggressive deployment of demand-side resources that can open up capacity on the grid versus inherently slow and costly fossil fuel generation. (See related story *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

"While strategic new generation and transmission solutions are needed to meet growing demand, these large investments will show up on customers' electric bills for decades to come and could increase emissions without helping affordability or sufficiently improving reliability," the report says.

"But aggressive investments in demand-side solutions are a cost-effective, least-regrets way to manage growth in the near term, while unlocking their full potential over the long term." Similarly, getting solar, wind and storage online quickly will buy time for the development of dispatchable, zero-carbon generation that could replace fossil fuels, the report says.

Pointing to the 2,600 GW of mostly renewable projects in RTO and ISO interconnection queues, Solomon said, "Because wind and solar and batteries are already in the process of being built, [they] can come online in a matter of a year and a half. … The gas plants they are looking at building are not coming online until 2030. Natural gas isn't the solution that's going to deliver." ■



An illustrative example of grid services working together to stabilize frequency | *Milligan Grid Solutions*

SPP News

SPP Secures Funding to Begin Markets+ Phase 2

Commitments from 8 Entities Allow RTO to Start Implementation Work

By Tom Kleckner and Henrik Nilsson

SPP said Feb. 14 it has received enough commitments to support the funding necessary for Markets+'s second developmental phase, the buildout of market systems that will begin in the second quarter of this year.

The grid operator said it has received signed Phase 2 funding agreements from eight interested participants in its proposed day-ahead service offering, including Arizona Public Service, Bonneville Power Administration, Chelan County (Wash.) Public Utility District (PUD), Grant County (Wash.) PUD, Powerex, Salt River Project, Tacoma Power and Tucson Electric Power.

Powerex, the marketing and trading arm of Vancouver, British Columbia-based BC Hydro, and Chelan PUD announced their Phase 2 funding commitments in January. (See *Powerex Commits to Funding, Joining SPP's Markets+* and *Chelan PUD Commits to SPP Markets+ Phase 2 Funding*.)

SPP noted in a statement that the entities operate a diverse mix of generating resources and serve more than 216,000,000 MWh in the Western Interconnection's Desert Southwest, Pacific Northwest and Mountain West regions.

"The continued engagement and support of Markets+ by Western entities has certainly driven this day-ahead market one step closer to reality during this critical time for our industry," SPP CEO Barbara Sugg said in the statement.

SPP said it will finance the projected $150 million in implementation costs, recovering them through the Markets+ operations. Staff said they have not distributed other funding agreements and do not yet have a full list of Phase 2 participants.

BPA transmission lines near The Dalles Dam. The agency estimates it will pay about $26.6 million to help fund Phase 2 of Markets+. | © *RTO Insider*

"There may be more coming," SPP spokesperson Meghan Sever told *RTO Insider*.

The RTO said it will post exact financial commitments for Phase 2 funding on Feb. 17. Funding obligations will be based on the participants' load share.

Powerex and BPA were the *leading funders of Phase 1*, meeting obligated 20.2% and 15.2% shares, respectively, for the phase's $9.7 million in costs. Powerex was charged $1.96 million and BPA $1.47 million.

Public Service Co. of Colorado was the only other participant with a share above 10%, being charged 12.3% of Phase 1's cost, about $1.19 million. PSCo has not yet returned to SPP a financial commitment agreement for the next phase.

Funding shares for all Phase 2 participants have increased due to the withdrawal of some entities from Markets+ development.

The grid operator gave interested Phase 2 financial backers a Feb. 14 deadline to submit executed funding agreements, a two-month extension from its original December target. It said the agreements are vital to meeting the Markets+ launch date of 2027.

FERC approved the Markets+ tariff on Jan. 16. (See *SPP Markets+ Tariff Wins FERC Approval*.)

BPA Looking at $26.6M Commitment

During Phase 2, stakeholders and SPP staff will work together to develop the systems needed to operate the market and conduct market trials and parallel operations.

BPA spokesperson Doug Johnson told *RTO Insider* the agency's "initial commitment could be up to $26.6 million depending on the final number of Phase 2 funding participants." The federal agency said it still plans a March release of its draft day-ahead market policy. It will issue a final decision in May.

BPA and SPP have differed over whether the Phase 2 funding is an actual commitment to join Markets+. In a December letter, a group of U.S. senators referenced an SPP statement that asserted, "[implementation] activities cannot begin until prospective market participants execute Phase 2 funding agreements, essentially committing to join Markets+." (See *BPA Has not Made 'Business Case' for Markets+, NW Senators Say*.)

Why This Matters

SPP has received Phase 2 funding agreements from eight participants in its proposed Markets+ day-ahead service, with more expected. That gives SPP enough support to finance building out and testing the market systems for a 2027 launch.

In response, BPA Administrator John Hairston rebuffed the assertion, saying "Phase 2 funding is not a commitment to joining Markets+; it is a commitment to continue funding development of the market."

Hairston also noted that BPA will provide $25,000 toward the West-Wide Governance Pathways Initiative's effort to bring independent governance to CAISO's markets, SPP's competitor in the West. (See *In Letter to Senators, BPA Tempers Markets+ Leaning*.)

SPP has maintained it simply wants to give Western entities a choice in markets. Its COO, Antoine Lucas, told *RTO Insider* during an October interview that the debate over day-ahead markets appears to be focused on pressuring entities into a market selection, "rather than work directly with those Western entities to truly understand what their issues and concerns are, and also work to try and accommodate them and address those issues so they want to choose to be within that market." (See *SPP Sees Bias in Brattle Western Market Studies, Exec Says*.)

The RTO included comments in its news release from several Phase 2 participants who expressed their support of Markets+.

Chelan PUD's Janet Jaspers said SPP's market "offers consensus-driven, stakeholder-led governance" and an "equitable market design" that leverages the Western Resource Adequacy Program.

"We look forward to bringing the benefits of Markets+ participation to our customers and the western region," Salt River Project's Josh Robertson added. ■

SPP News

Tacoma Power to Join SPP's Markets+

Municipal Utility is 2nd Northwest Entity to Commit to RTO's Western Market

By Robert Mullin

Tacoma Power has signed an agreement to join SPP's Markets+, making the Washington utility the second Pacific Northwest entity to commit to participating in the market in the past month.

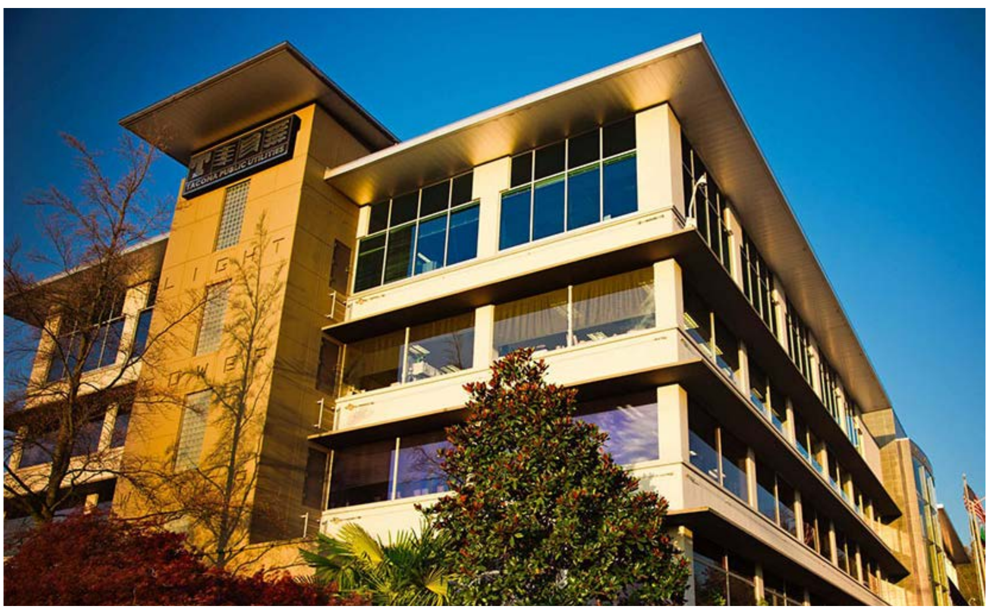
The Feb. 13 announcement comes as little surprise, given that Tacoma has been among the Western entities contributing to the series of "issue alerts" published since last summer favorably comparing Markets+ with CAISO's Extended Day-Ahead Market. (See *Pathways Step 2 Not Good Enough, Markets+ Backers Say*.)

The municipal utility has also been counted among the majority of the Bonneville Power Administration's base of publicly owned utility "preference" customers urging the federal power marketing administration to sign on to the SPP effort.

"A diverse group of electric utilities came together with a common goal: to build an energy market that will benefit our customers by optimizing how utilities in the West buy and sell electricity," Chris Robinson, Tacoma Power's general manager, said in a statement. "We've accomplished this with a durable and independent governance structure that will provide the right value for hydropower and will ensure the benefits continue flowing to our customers far into the future."

Tacoma's Public Utility Board approved the utility's commitment to Markets+ last November, according to the statement.

"Tacoma Power will continue to participate in ongoing market development over the next two years. This will create the systems that will enable Markets+ to operate while Tacoma and other utilities complete the internal onboarding steps necessary to integrate market operations," the utility said.



Tacoma Power's headquarters in Tacoma, Wash. | *Tacoma Public Utilities*

Why This Matters

Tacoma Power's commitment represents a continued expansion of the Northwest footprint of Markets+ ahead of the Bonneville Power Administration's draft decision on a day-ahead market choice.

According to a *spreadsheet* posted to SPP's website last October, Tacoma would be responsible for a 1.7% share of the funding for the Phase 2 implementation phase of Markets+, equating to more than $4.8 million.

Tacoma Power serves more than 180,000 electric customers in the city of Tacoma and nearby communities, as well providing power to the U.S. military's Joint Base Lewis-McChord. The utility owns about 643 MW of hydroelectric generation, which account for more than 80% of its nearly carbon-free resource mix. It also operates 2,386 miles of transmission and distribution lines.

The utility's announcement follows a similar one by Powerex, the largest Markets+ funder, which in January said it had committed to joining and paying its share of Phase 2 funding. (See *Powerex Commits to Funding, Joining SPP's Markets+*.)

Last month, Chelan County Public Utility District, another publicly owned utility in Washington, committed to funding Phase 2 but said it still had not decided to join the market. (See *Chelan PUD Commits to SPP Markets+ Phase 2 Funding*.) ■

Company News

AEP to Increase Investment in Face of Data Center Growth

By Tom Kleckner

American Electric Power told financial analysts during its fourth-quarter earnings conference call Feb. 13 that the company is evaluating $10 billion of potential incremental investment because of increasing interest from data centers and other large loads looking to build in its 11-state service territory.

"The tech companies are fast movers, and AEP will be there to support them with whatever technology solution they want to deploy, but we need to ensure that we are protected and compensated," CEO Bill Fehrman told analysts.

The Columbus, Ohio-based company announced a record $54 billion capital plan in the fall that will last through 2029. Fehrman said AEP expects 20 GW of new load by the end of the decade, much of it in Ohio and Texas.

The utility added 450 MW in its home state in December. It expects an additional 4.7 GW of data center load to come online by year-end.

"We are investing in tailored solutions for new individual large loads to meet their requirements and timelines while mitigating rate impacts to existing customers," Fehrman said.

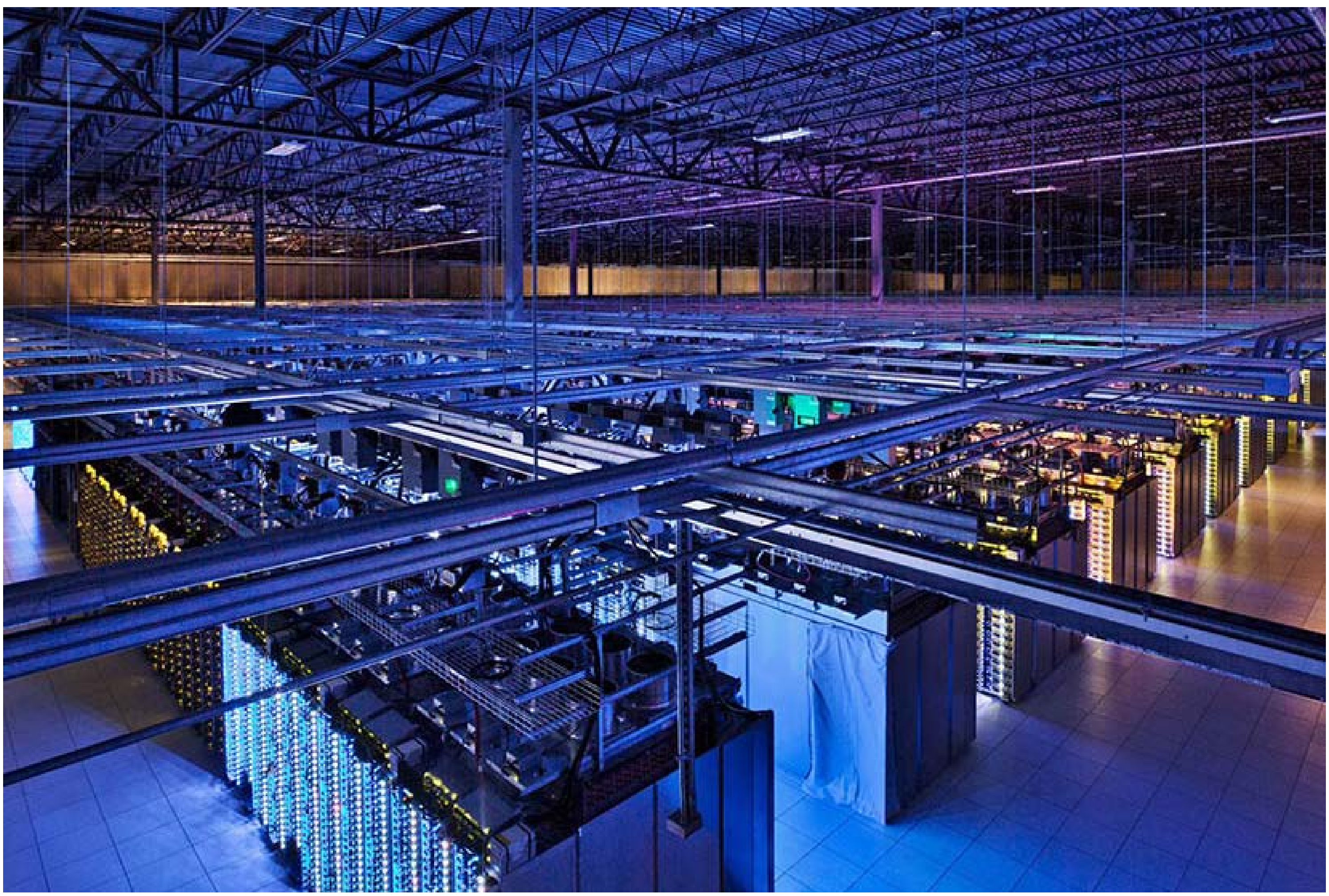
AEP has already filed for approval of 2.3 GW of natural gas generation in its Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Co. service territories. It also has active requests for new generation proposals in Appalachian Power, Indiana Michigan Power and PSO to meet demand.

The company is waiting on a ruling from the Public Utilities Commission of Ohio over proposed tariffs for new large-scale data centers that would require them to pay 85% of their projected energy use each month to cover the cost of infrastructure. AEP filed a settlement agreement with PUCO in October.

"Clearly, we're going to make sure that this doesn't fall on the shoulders of our existing customers, and make sure that the appropriate parties who are driving the incremental cost will pay for the incremental cost," Fehrman said. "As a company, we're going to drive ourselves to be the biggest and the best energy infrastructure company in this country. It's in our name. We're American Electric Power. We're going to power America."

AEP *reported* year-end earnings of $2.97 billion ($5.60/share), an increase from 2023's performance of $2.21 billion ($4.26/share). For the quarter, earnings were $664 million ($1.25/share), compared to last year's fourth quarter of $336 million ($0.64/share).

The company's share price closed at $100.99 on Feb. 13, off $1.36 from its previous close. ■



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Company News

Duke Spending Big to Meet Increasing Load Growth in the Late 2020s

By James Downing

| Duke Energy

Duke Energy's leadership changed the guard during its first-quarter earnings call Feb. 13 as retiring CEO Lynn Good and her replacement, Harry Sideris, split the presentation.

Good announced her retirement effective April 1 early in 2025. (See *Duke Names Harry Sideris as Company's Next CEO*.)

Last year was defined largely by Hurricanes Helene and Milton, which hit Duke's territory. Good thanked the communities it serves for their support and understanding as the utility restored service after the storms. Duke plans to spend $83 billion in the next five years to meet the growing needs of its utilities.

"This capital represents infrastructure spending driven by growing jurisdictions and underpinned by robust regulatory processes such as integrated resource plans and approved grid investment spending," Good said. "With the continuation of our 5 to 7% [earnings per share] growth rate through 2029, with the potential to earn higher in the range as the years progress, Duke Energy enters the back part of this decade in a position of strength, and we're excited about the future."

Good said Sideris and the incoming chair of the board of directors, Ted Craver (formerly Edison International's CEO), are up to the task of leading the utility.

"I assume this new role at a pivotal point for our company and industry," Sideris said. "We share the new administration's commitment to ensuring the availability of reliable and affordable energy to meet our country's aspirations for technology leadership and economic growth. These priorities align with our business strategy, and we look forward to working with President Trump, both parties in Congress and our states to build, operate and protect the critical infrastructure needed to deliver on these goals."

The needs to meet growing demand and replace aging infrastructure mean the firm plans to invest billions of dollars in new generation and the grid, with Sideris saying the firm had a "decade of record infrastructure build."

A key source of the new demand for Duke's utilities is going to be data centers. Sideris said that while Chinese artificial intelligence company DeepSeek's efficient model might have made headlines and cut into chipmaker Nvidia's stock, the hyperscale data center developers the utility has worked with already expected efficiency advances.

"They're full-speed ahead," Sideris said. "They're looking at the fact that these efficiencies may actually increase the demand for AI. So, we have not seen any pullback in anything they're planning on. In fact, we've seen a lot more discussions with accelerating some of their work."

Many of the near-term data centers being built in Duke's territory are not for AI but rather the growth in demand for cloud services, Good said.

"Then as we move later into the plan, that's where some of the generative AI data centers are coming in, and that's when we see the larger load growth," Sideris said.

This year and next, Duke expects 1.5 to 2% load growth across all of its utilities, jumping to 3 to 4% in 2027 and staying there through 2029. Its core market of the Carolinas should experience slightly higher growth, with 2% this year and next heading to 4 to 5% for the rest of the 2020s.

Duke plans to build about 5 GW of new natural gas-fired generation by the end of 2029, mostly in North Carolina, with just one of five plants located in Indiana. The firm plans to start procuring 1.5 GW of solar per year in North Carolina and an additional 900 MW of solar in Florida by 2027.

The utility also will add storage in the coming years, and it could add small modular reactors by the mid-2030s. Of the $83 billion, Duke plans to spend $37 billion on its transmission and distribution systems. ■

Company Briefs

Energy Transfer, CloudBurst Sign Natural Gas Supply Agreement

U.S. pipeline operator Energy Transfer announced it has entered into a long-term natural gas supply agreement with CloudBurst Data Centers for its development in Central Texas.

Energy Transfer will provide up to 450,000 MMBtu/day of natural gas through its Oasis Pipeline to CloudBurst's campus outside of San Marcos, Texas. The supply will generate up to nearly 1.2 GW of power for at least 10 years.

More: *Reuters*

Toyota EV Battery Factory Ready to Begin Production

Toyota announced that Toyota Battery Manufacturing North Carolina, the automaker's first in-house battery manufacturing plant outside Japan, is ready to begin production and will start shipping batteries for North American EVs in April.

The nearly $14 billion battery facility will produce batteries for hybrid electric vehicles, plug-in hybrid electric vehicles and battery electric vehicles. Production will be increased in phases, with line launches planned through 2030.

More: *Assembly Magazine*

Denbury Fined for Menacing Federal Inspectors

The Pipeline and Hazardous Materials Safety Administration has proposed a $2.4 million fine against pipeline company Denbury and its contractor, Republic Testing Laboratories, for taunting, pushing and blocking inspectors from doing their jobs while examining a carbon dioxide pipeline in Texas.

PHMSA's report details six incidents from Aug. 30 to Dec. 7, 2023, that it says violated federal law at the facility. The report also says Denbury refused to provide data and prevented inspectors from photographing readings on equipment.

More: *Louisiana Illuminator*

Clean Hydrogen Startup Syzygy Announces Layoffs

Syzygy Plasmonics said it would slash more than half of its staff by the end of March.

The company, which has raised more than $100 million in funding and received backing from Mitsubishi Heavy Industries America, notified the state of Texas that it plans to lay off 68 employees beginning March 31. The layoffs are "a result of the company's current financial outlook," CEO Trevor Best said.

Syzygy develops photoreactors that use light rather than combustion to power chemical reactions.

More: *Houston Chronicle*

Federal Briefs

IEA Raises Energy Consumption Predictions

The International Energy Agency last week raised its predictions for the world's rising electricity demand, pegging the growth at almost 4% a year until 2027, up from its previous forecast of 3.4% a year.

The consuming of more electricity will be led by China, where demand grew by 7% last year and could grow by 6% a year over the next three years. Rising demand in the U.S. is expected to add the equivalent of California's current power consumption to the national total by 2027.

More: *The Guardian*

SEC Moves to Kill Climate Disclosure Rule

Mark Uyeda, the acting chair of the Securities and Exchange Commission, last week announced he was directing the commission's legal team to inform a federal appellate court that the regulator was pausing a rule that requires publicly traded companies to provide investors with information about the impact of their businesses on climate and the environment.

The decision to tell the U.S. Court of Appeals for the Eighth Circuit to pause any further proceedings in the matter is an indication the regulator may eventually move to rescind the rule or modify it.

More: *The New York Times*

Separate from DOGE, TVA Offers Buyout to Workers

The Tennessee Valley Authority is offering a voluntary buyout program that will give qualifying employees five days of pay for every full year of service to reduce the utility's workforce and cut costs.

The offer was announced internally last year and applies across the company, TVA spokesperson Scott Brooks said. It is unrelated to the buyout offered to federal employees by the Trump administration.

TVA had 11,312 employees in 2024, up from 10,901 the year before, according to its latest annual financial report.

More: *Knoxville News Sentinel*

National/Federal news from our other channels

Type One, TVA to Cooperate on Fusion Plant

NetZero Insider

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

State Briefs

REGIONAL

$3B Natural Gas Pipeline Expansion Planned for Southeast

Kinder Morgan and Southern Natural Gas last week announced their proposed $3 billion natural gas expansion project called the South System Expansion 4 Project.

The project, which would deliver over a billion cubic feet of natural gas daily, would stretch nearly 300 miles across Georgia, Alabama and Mississippi. The companies are splitting the cost.

Construction is expected to start in 2027.

More: *WJCL*

CALIFORNIA

Edison International Faces Shareholder Lawsuit over LA Wildfires

Edison International, the parent company of Southern California Edison, has been sued for allegedly defrauding shareholders before the recent Los Angeles-area wildfires by assuring them it could shut down power lines to reduce the risk of catastrophic damage.

Shareholders said Edison made materially false and misleading statements for nearly four years before the fire by assuring its utility unit used a power shutoff program to "proactively de-energize power lines" to reduce wildfire risks during "extreme weather events." The shareholders said reports claim Edison had not de-energized the lines, while lawsuits blamed the company's equipment for starting the Eaton fire.

The lawsuit seeks unspecified damages for shareholders.

More: *Reuters*

Lawmaker Proposes Law to Limit Rate Increases for Investor-owned Utilities

Sen. Aisha Wahab last week introduced a bill that would prohibit investor-owned utilities from proposing more than one rate increase per year.

The bill would also cap any rate increase to no more than the Consumer Price Index, which is a measure of the average change over time in the prices consumers generally pay for goods and services.

The Public Utilities Commission approved six rate increases for PG&E in 2024, which later announced it made a record $2.47 billion in profits.

More: *KCRA*

ILLINOIS

Madigan Convicted of Bribery Conspiracy

Former House Speaker **Michael Madigan** was convicted last week on 10 counts relating to a nearly decadelong bribery conspiracy involving ComEd.

The jury also convicted Madigan of a plot to install ex-Ald. Danny Solis on a state board in exchange for Solis' help securing private business for Madigan's law firm. However, the jury acquitted Madigan of attempted extortion and other crimes involving Solis and an apartment project, as well as failing to agree on finding Madigan guilty of a broad racketeering conspiracy.

The most serious counts carry a maximum of 20 years in prison for the 82-year-old. No sentencing hearing has been set.

More: *Chicago Sun-Times*

IOWA

House Advances Bills Aimed Against CO2 Pipelines

A House subcommittee last week advanced bills aimed at curtailing carbon sequestration pipelines.

One bill would allow landowners to seek declaratory judgment, or a legally binding explanation of their rights, from a district court if their property were subject to an eminent domain claim in an application before the Utilities Commission. Another bill would limit permits to liquified CO_2 pipelines to 25 years and prohibit the UC from renewing those permits.

More: *Iowa Capital Dispatch*

MARYLAND

Constellation to Upgrade Calvert Cliffs Nuclear Plant

Constellation Energy last week said it will spend $100 million to upgrade equipment and electrical systems at its Calvert Cliffs nuclear power plant.

The company is upgrading the plant with the hopes of renewing its operating licenses. The current licenses for its two reactors expire in 2034 and 2036. The upgrades are expected to increase production by 10%.

More: *The Baltimore Banner*

MICHIGAN

PSC Approves DTE's Application for Cold Creek Solar Project

The Public Service Commission has approved DTE Electric's application for its 100-MW Cold Creek Solar Park Project.

The project will provide power to Ford Motor Co. through DTE's voluntary green pricing program.

Commercial operation is expected in late 2026.

More: *WTVB*

MINNESOTA

PUC Approves Xcel Gas Rate Increase

The Public Utilities Commission last week approved an 8.17% rate increase for Xcel Energy natural gas customers, effective July 1.

The PUC approved the deal between Xcel and officials, which was down from an original request of 9.6%. The increase will add about $4.20/month to the average household.

More: *The Minnesota Star Tribune*

PENNSYLVANIA

Senate Votes to Pull State from RGGI

The state Senate has passed a bill that would pull the state out of the Regional Greenhouse Gas Initiative.

The bill formally repeals Pennsylvania's participation in RGGI, ensuring that any decision to impose electricity taxes or emissions programs must go through the legislative process rather than being enacted unilaterally by the executive branch.

The bill now moves to the House of Representatives.

More: *PA Senate Republicans*