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BPA Markets+ Phase 2 Bill Could Reach $27M — or More

U.S. Army Corps of Engineers

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FERC/FEDERAL PJM

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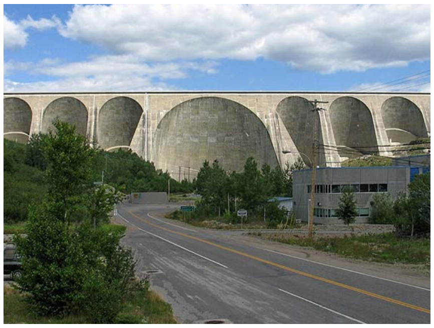
As Policies in Washington Change, Grid Investment Still Needed (p.3)

Now that demand is growing at a pace not seen in decades from data centers, the need to expand the grid goes beyond connecting renewable resources that are far from cities.

NYISO



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NYISO Preparing to Collect Duties on Canadian Electricity Imports (p.29)

NYISO plans to ask FERC to give it the means to collect duties in case President Trump's tariff on Canadian energy imports applies to electricity. Until NYISO develops software to automate calculating, collecting and paying duties, the process would be manual.

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In this week's issue

As Policies in Washington Change, Grid Investment Still Needed

By James Downing

WASHINGTON — Even as President Donald Trump and the new Republican-controlled Congress begin to roll back the clean energy policies of the Biden administration, the grid still needs to expand to meet new demand and become more resilient to extreme weather, state regulators heard last week.

Democrats tried to pass numerous transmission "permitting reform" bills last Congress to help realize the clean power investments in the Inflation Reduction Act, and that has impacted the partisan split on the subject. But now that demand is growing at a pace not seen in decades from data centers, the need to expand the grid goes beyond connecting renewable resources that are far from cities.

"We're trying to solicit as many comments as we possibly can so that we can get this right, because it's going to be threading a needle between the Republicans and the Democrats," Sen. Shelley Moore Capito (R-W.Va.), chair of the Senate Environment and Public Works Committee, said at the National Association of Regulatory Utility Commissioners' Winter Policy Summit. "There's certain things that I might want that I'm going to fight hard for. There's certain things, particularly on the transmission side, that the Democrats want. We're going to try to marry those up and make an effective and long-lasting permitting."

"There's a lot of voices making that connection: that companies are looking for electrons," Clean Energy Buyers Association Senior Director Bryn Baker told reporters Feb. 26 in a webinar on the state of transmission policy under the Trump administration and the new Congress. "And that there are economic advantages to those states and regions that are proactively planning for transmission, and that's fundamental to getting those industries sited and built here."

Why This Matters

Now that demand is growing at a pace not seen in decades from data centers, the need to expand the grid goes beyond connecting renewable resources that are far from cities.

From left: IBEW's Chris Harris, Entergy Texas CEO Eliecer Viamontes, Duke Energy President Harry Sideris, Orange & Rockland CEO Michele O'Connell, Portland General Electric CEO Maria Pope and Southern Co. CEO Chris Womack at NARUC on Feb. 24. | © RTO Insider LLC

Serving the new loads from data centers, which are being built out by some of CEBA's members, will require all kinds of investment in transmission, from interregional lines to reinforcing the existing system with grid-enhancing technologies and advanced conductors.

"I think transmission is kind of under that umbrella of energy infrastructure," Americans for a Clean Energy Grid Executive Director Christina Hayes said on the webinar. "We've heard a lot more clarity under Secretaries [Doug] Burgum and [Chris] Wright [head of the departments of the Interior and Energy, respectively] talking about the importance of the backbone of the grid."

Four years ago, predictions for demand growth were flat in most of the country, and AI was more of a vague concept for science fiction novels than it was a reality both on app stores and in the physical world, she said.

"The growth of data centers and artificial intelligence is driving up energy demand in ways we have not seen in decades, making transmission reform even more critical," Hayes said. "Despite significant discussion about energy policy, we still need more definitive action, especially if we want to meet our projected energy demands."

Even without hyper-scalers driving demand to new levels, the power system needs to be adequately maintained, and Exelon CEO Calvin Butler said that requires some spending. He recalled that before his company bought Pepco, the utility was running about a 6.4% return on equity and was in the fourth quartile for reliability.

"The utility wasn't meeting its obligation to provide strong customer service and strong reliability," Butler told NARUC during a panel on capital markets Feb. 25. "What we have recognized as a company [is that] operations and high customer satisfaction are foundational elements. We have to do that well before we can come to you and talk about our long-term strategy."

By 2021, Exelon had gotten Pepco's ROE up to 9.4% and its reliability improved by 50%, which involved investing in the underlying infrastructure needed for reliable and resilient service, Butler said.

In a panel Feb. 24 at NARUC on mutual assistance during extreme weather events, Southern Co. CEO Chris Womack said his firm was ready to meet demand from new sources thanks to the amount of investments it has made in its system, including new generation.

"With the careful oversight of our state regulators, elected officials, customers and shareholders, we have designed and engineered a remarkably flexible, resilient and affordable system," Womack said. "We recently added new nuclear generation and now can dispatch in the largest nuclear station in America at Plant Vogtle."

The Trump administration's goal is for "energy dominance," which Womack said translates to energy abundance that is important to meeting the new loads coming online in Southern Co.'s utility territories.

"Both energy dominance and energy abundance require a safe and secure energy grid, and thankfully, our nation's power grid is up to that challenge," Womack said. "It is advanced; it's flexible and is integrated in a way that allows us to rely on each other day to day."

Wildfires are becoming more common in Oregon, Portland General Electric CEO Maria Pope said. Devastating fires in California last decade caused its northern neighbor to start considering how the events could impact its utilities back when they were rarer, which proved prescient as Oregon saw more acres burn than any other state or Canadian province in 2024.

Now wildfires are so common, Pope argued that regulators need to insulate utilities from potentially devastating litigation as long as they can prove they followed a set of best practices, which would be similar to legal defenses against medical malpractice.

"Until we have something like that across this country, we're going to continue to have economic hardship on the utilities," Pope said. "Wildfire is an example. Like all the storms we're talking about here, disasters are society-wide problems, and they need a society-wide solution, not just the backstop of a utility and the devastation that that brings the utility's balance sheet." ■

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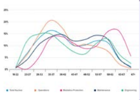
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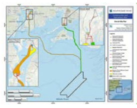
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NARUC Winter Summit Tackles Uncertainty Around Demand Growth

By James Downing

WASHINGTON — Demand growth coupled with an ongoing changeover in supply has dominated the power industry's attention, and it was a major theme at the National Association of Regulatory Utility Commissioners' Winter Policy Summit, held Feb. 23-26.

Those trends have pushed up prices, notably in PJM and its recent capacity auction, but FERC Commissioner David Rosner said all of the RTOs save billions of dollars annually by wringing efficiencies out of the grid.

"The advantage of markets really is their ability to attract capital and attract the lowest-cost resources," Rosner said.

It gets complicated because markets also have to recognize that different resources provide different reliability benefits, and figuring out how to design to markets to address that fact has proven to be a long, iterative process.

"The commission has approved different ways to 'accredit' capacity; that's a fancy word for saying, 'We are compensating resources for their actual contribution towards reliability,'" Rosner said. "And that evolves as the system evolves, and the more smart policies like that that we can have in place that pay for service provided, that just makes sense."

Markets have improved resource performance, and they have placed the risk for bad bets away from customers and toward investors, NYISO CEO Rich Dewey said. But the fleet has changed significantly in the quarter-century since ISOs and RTOs started running parts of the grid.

"You've got to think about valuing the attribute of what these resources bring, and getting that right, so the investment that's necessary matches the value and the performance that you get out of that attribute," Dewey said. "So, markets are in a continuous evolution. You can't just stand it up and then sit back and collect the rewards of harnessing that spirit of competition. We need to continue to work at it."

New York has a goal of getting to net-zero emissions by 2050, but the markets were not set up to address that issue initially, Dewey said. So a big part of the ISO's work has been to get the rules place that attract the kinds of investment that will realize the policy.

From left: Virginia State Corporation Commissioner Kelsey Bagot, American Clean Power's Carrie Zalewski, FERC Commissioner David Rosner, NYISO CEO Rich Dewey, Shell Energy North America CEO Carolyn Comer, and EPSA CEO Todd Snitchler. | *© RTO Insider LLC*

"The challenges, however, seem to be getting bigger," Electric Power Supply Association CEO Todd Snitchler said. "We're going through what I think is a second round of an important opportunity for new investment into restructured markets. But it's not unique to restructured markets. You're seeing this in vertically integrated portions around the country as well, where load growth is growing, and growing meaningfully for the first time in a generation."

All the change is happening at a time with real challenges from the political side, as states that stood up markets in the 1990s now have very different policies, Snitchler said. The focus used to be on least-cost dispatch, which is what the markets were designed for, and now many states want carbon reductions, or other policies that do not always line up with others in the same market.

"It's not an absolute degree of certainty that's needed, but it's a reasonable degree of certainty that's needed," Snitchler said. "And we find ourselves in very uncertain situations presently, which makes investment very difficult at the very time we need investment to be flowing fairly dramatically."

These issues recently came to a head in PJM when its last capacity auction cleared the rest of the market at $270/MW-day after years of lower pricing, a signal for needed new supply, Snitchler said.

"There already is market behavior that is responding to just one price signal," he added. "Now we do have to be thoughtful and understand that a number [of], or several more, high auction clears are probably not politically palatable."

Pennsylvania Gov. Josh Shapiro (D) and PJM have agreed to a deal that will cap prices for the next couple of auctions as the RTO considers additional changes in the capacity market. (See *PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor*.)

All of the changes to markets make it riskier to commit the capital needed to get new generation built, Shell Energy North America CEO Carolyn Comer said.

"The more markets continue to get tweaked, the more uncertainty we see, the harder it is for me to compete for that capital, quite frankly, and that's a problem," Comer said.

Shell has started to invest directly in power plants, so it is watching those rules for its own purposes, she said. It also offers risk-management services for smaller market players. In the past, hedges were commonly offered to such customers for 15 to 20 years, but the pace of change makes that less feasible.

"I do believe it's important to take risk off consumers and move it to the product; that's the whole point of creation of competitive markets," Comer said. "Then I also have to think about making a return on the risk that I'm actually taking. And in order to be able to calculate that return on risk, I need a certain amount of policy certainty."

The changes have led to a number of policies at PJM, especially including price caps and temporary queue jumping, but the ultimate solution to higher prices is to get more resources onto the grid, and that should involve all kinds of generation, American Clean Power Association Vice President Carrie Zalewski said.

"The obvious answer is, let's interconnect stuff," Zalewski said. "Waiting in an interconnection queue is one thing, but not knowing how long you're going to wait, there's a whole other level of uncertainty that creates more issues with supply chain."

Developers can spend so much time waiting for a generator interconnection agreement (GIA) that permits already approved expire. Order 2023 from FERC will help once implemented, but more can be done both before the GIA and after, she added.

Uncertainty on the Demand Side

While suppliers face uncertainty, the issue is increasingly important on the demand side as the grid faces load growth not seen in decades from data centers, reshoring manufacturing and the early days of electrification.

Artificial intelligence is a major source of demand for data centers now, and despite some recent improvements in efficiency from Chinese firm DeepSeek, that is expected to continue to grow, Electric Power Research Institute CEO Arshad Mansoor said.

"There's Jevon's paradox that says things that get more efficient are used more, and that's really what's going to happen," Mansoor said.

The large language models that have dominated AI so far can only train on the information that is on the public internet, which is only about 5 to 6% of the total data in the world. Industries, including energy, are going to start training AIs on their proprietary data to help out in their operations, and that is going to lead to huge new computing demands regardless of how efficient the code is, Mansoor said.

All that growth represents a huge economic opportunity for the country, and meeting it is going to require getting the load forecasts right, PJM Senior Vice President Asim Haque said.

PJM is working closely with its member utilities and increasingly the data centers themselves, while focusing on the areas in its footprint with the highest demand, like Northern Virginia and Columbus, Ohio.

The new load growth is going to require more transmission and generation, but some of the data center customers are focused on speed to market.

"They've got to get to market to a particular point in time," Haque said. "That's why you're seeing some more adventurous efforts outside of directly connecting to the grid — this concept of co-location."

While many data centers are focused on getting to the grid quick, Meta's Etta Lockey said her firm was not interested in shifting costs to other customers and ultimately looks at data center expansion as a net positive.

"We sit at a really generational, hopefully once-in-a-career opportunity to think about some economic growth in this country that could be unprecedented," Lockey said. "And that's the future state that I really want to [home] in on and force us all to kind of think about what that can really look like."

While rates have been on the rise, if the load growth from data centers is handled right, it will lead to more infrastructure, and the overall costs of the system will be spread across a bigger base.

"The end goal should be downward pressure on rates, let's be honest," Southern Co. Vice President of System Planning Clay Rikard said. "This new load is the opportunity to put downward pressure on rates, if we do it right." ■

Solar and Batteries Expected to Lead 2025 Grid Additions

EIA Projects Only 4.4 GW of New Fossil Fuel-fired Power Generation

By John Cropley

The policies of the Biden administration will continue to shape the U.S. power portfolio a while longer, even as the Trump administration tries to make a hard right turn from renewables back to fossil fuels.

The U.S. Energy Information Administration on Feb. 24 said solar and battery storage dominate planned *electric generation capacity additions* to the U.S. grid in 2025, with natural gas providing only 7% of the 63 GW total.

Even the wind turbines that Trump wants to halt are expected to outstrip natural gas, with 7.7 GW of new wind capacity vs 4.4 GW of new gas-fired generation. EIA noted, however, that the data behind its projections was generated in December 2024, a month before Trump began a rapid-fire attempt to limit renewables and boost fossil fuel development.

In total, EIA projects 2025 additions of 32.5 GW of solar, 18.2 GW of storage, 7.7 GW of wind, 4.4 GW of gas and 0.2 GW of all other forms of generation.

That is nearly 63 GW — about 29% higher than the 48.6 GW installed in 2024, which itself was the largest single-year addition since 2002.

The 30 GW of solar added to the grid in 2024 was a record, and EIA expects solar installation to set another record in 2025, with Texas once again accounting for the lion's share of projected new photovoltaic capacity: 11.6 GW.

Likewise, the 10.3 GW of battery storage installed nationwide in 2024 was a record, and EIA expects 2025 installations to far surpass that total. (EIA includes batteries in the generation capacity tally as a secondary source of stored electricity, not as a primary source of electrical generation.)

Wind is expected to bounce back from a slump: The 5.1 GW added in 2024 was the least since 2014. But EIA's 2025 projection of 7.7 GW of new wind power is off by more than 9%, as it includes 715 MW from Revolution Wind, an offshore wind farm that has pushed its completion date back to 2026.

Why This Matters

The Trump administration's focus on fossil fuels is not expected to be reflected in the 2025 mix of electrical capacity additions.

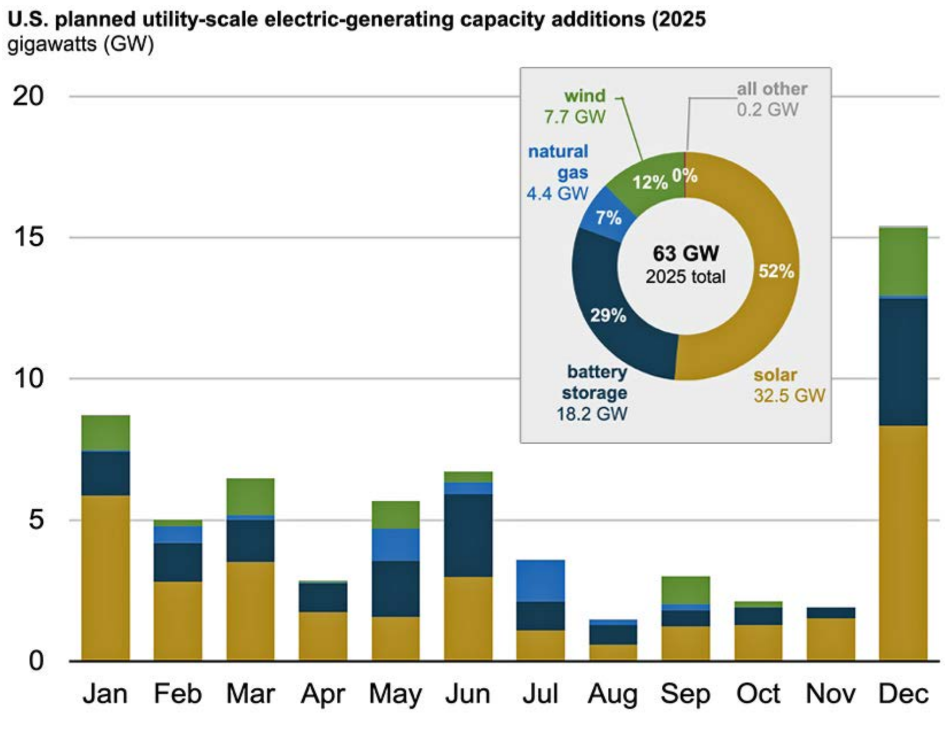
EIA also assumes Vineyard Wind 1 will come online in 2025. The 800-MW facility began construction off the Massachusetts coast in late 2022, with an anticipated 2024 in-service date. But it experienced significant delays and component failures in 2024, and in early 2025, it is well behind schedule, with no anticipated completion date listed on the project website.

Simple-cycle combustion turbines account for about half of the 4.4 GW of new natural gas-fired capacity projected to come online in 2025, and combined-cycle units account for about a third.

EIA said five states — Utah, Louisiana, Nebraska, North Dakota and Tennessee — account for about three-quarters of the expected gas additions, the largest of which are the 840-MW Intermountain Power Project in Utah (where 1,800 MW of coal-fired capacity is being retired) and the 679-MW Magnolia Power in Louisiana.

EIA reports that in 2023, *4.18 trillion kWh of electricity* was generated at utility-scale facilities in the United States — 60% fossil, 21.4% renewable and 18.6% nuclear.

The largest components were natural gas (43.1%), atomic fission (18.6%), coal (16.2%), wind (10.2%), hydropower (5.7%) and photovoltaic solar (3.9%). ■



The U.S. Energy Information Administration is projecting that more than half of utility-scale generation capacity brought online in 2025 will be solar. | *EIA*

Legal Experts Chart Future of Agency Deference After *Loper Bright*

NARUC Panel Explores Impact of 2024 Supreme Court Ruling on FERC Authority

By James Downing

WASHINGTON — Before President Donald Trump's executive orders started raising questions about the authority of FERC and other agencies, courts had already started to chip away at long-standing precedents such as the *Chevron* deference, experts said during a panel at NARUC's Winter Policy Summit.

"*Chevron* has been on the ropes for many, many years," Jonathan Ellis, a partner with McGuireWoods, said during the Feb. 24 panel. "Justice [Antonin] Scalia was once an ardent supporter, and then toward the end of his career soured on the doctrine." (See *Supreme Court Ends Chevron Deference to Administrative Agencies*.)

Before Scalia started to change his tune on the precedent, Ellis clerked for Chief Justice John Roberts, who Ellis said was never a big fan of the doctrine, in which courts usually deferred to decisions by regulatory agencies on issues of their expertise.

In many cases preceding *Loper Bright Enterprises v. Raimondo*, the court had worked around *Chevron*, but the petition for certiorari in that case already asked the court to rule against it or find it did not apply, Ellis said.

"There will always be, I think, out of necessity, some role or deference to regulatory agencies and expertise that they represent," he added.

Georgetown University law professor Howard Shelanski agreed that the tea leaves had not augured well for *Chevron* for quite some time, but noted the issues in the case went to the heart of the constitutionality of Congress delegating authority to agencies.

"For a long time, it was taken as a given by the court that concerns over delegation had been asked and answered," Shelanski said. "And so long as there was some kind of articulable principle that limited the agency — even a very vague one, even a very general one — they had to allow that Congress had the authority to give the agency some scope for interpretation. And that led to the view, if a statute is silent on something, the agency should be able to step in."

Why This Matters

The Supreme Court's 2024 *Loper Bright Enterprises v. Raimondo* ruling leaves many open questions about what authority is retained by federal agencies such as FERC.

'Ambiguous Phrasing'

Overruling *Chevron* means precedent has reverted back to the 1970s, when courts could second guess agency decisions on appeal as a matter of statutory interpretation, he said.

FERC Solicitor Robert Solomon said in his 30-year career he has probably cited the *Chevron* doctrine as much as any lawyer, but over the past 10 years the Supreme Court and lower courts have increasingly avoided using it.

"Courts have gone out of their way to find the absence of ambiguity and no need to defer formally under *Chevron* to the agency," he added.

The Energy Policy Act of 2005 contained what Solomon called "some of the most ambiguous phrasing" he could imagine around when FERC's backstop transmission siting authority kicked in, but the U.S. 4th Circuit Court of Appeals still declined to follow *Chevron* in *Piedmont Environmental Council v. FERC* and sided against the agency, effectively gutting that statute for a decade until Congress passed another law.

"In the Supreme Court demand response case, *FERC v. EPSA* — the greatest case ever decided, the majority found that the FERC's authority to essentially regulate demand response, because it has a direct effect on wholesale prices, was clear and unambiguous," Solomon said, making a joking reference to a case he argued.

But in a dissent in that case, Scalia argued the statute was "clear and unambiguous" against FERC because the agency "was effectively regulating retail sales within the ambit of state authorities," Solomon said.

Even before *Chevron* was struck down, it had proved difficult to determine when courts would apply it, and now FERC's legal team is getting around the issue by using the term "respect" rather than "deference," he said, adding that he's concerned by some of the language courts use when they invoke their authority under Article 3 of the Constitution to resolve all questions of law.

Regardless of court actions, Solomon said FERC still has a responsibility to make well-reasoned decisions based on the record before it. *Loper Bright* will have an impact on interpreting federal law and when it comes to issues where FERC's authority clashes with that of states, the trend has been to let jurisdictions overlap, he said.

"From my perspective, the bigger concern right now isn't whether *Chevron* deference or respect continues to live for our interpretation of federal statutes," Solomon said. "Rather, the current issue is whether we will continue to get *Chevron*-like deference, not when we are interpreting the federal statute, but rather when we are interpreting a federally approved tariff or a contract that similarly involves interpretation by Article 3 courts."

Courts have expertise in interpreting the law, but FERC has continued to argue in court that it has special expertise when it comes to the rates and tariffs that make up the bulk of its work, Solomon contended. And the agency is waiting for a case that will determine whether the courts will defer to its expertise on jurisdictional contracts and tariffs, he added.

"In the eight months or so since [*Loper Bright*] was decided, the courts continue to go out of their way to explain whether or not the decision would have been any different if *Chevron* still applied," Solomon said. "It's actually been quite satisfactory to us. There have been a couple of recent decisions where the court has said not just simply that the agency's interpretation was reasonable or permissible, but rather it was the best or the correct interpretation." ■

BPA Markets+ Phase 2 Bill Could Reach $27M — or More

Funding Agreement Filed by SPP Indicates Range of Potential Costs for Agency

By Robert Mullin

The Bonneville Power Administration will be on the hook for nearly $27 million in funding for the next phase of SPP's Markets+ — and potentially more depending on the market's final footprint, according to a document the RTO filed with FERC on Feb. 21 (ER25-1372).

BPA's funding obligation — and that of other Markets+ funders — appears in a table appended to the end of the *Markets+ Phase 2 Funding Agreement*, which SPP submitted to FERC to gain approval for its plan to obtain third-party financing to cover the $150 million needed for the Phase 2 implementation process for Markets+.

The agreement details the purpose, terms and timelines of the financing and outlines how Markets+ funders will collateralize the loan up front and then ultimately fund its repayment through future market transactions. Funders who back out before the market goes live would still be liable for paying their share.

Why This Matters

The proposed SPP agreement showing BPA's potential share of funding for Phase 2 of Markets+ comes just two weeks before the agency is expected to release its draft decision on joining a day-ahead market.

BPA's Bonneville Dam | *U.S. Army Corps of Engineers*

The agreement contains a few provisions that seem specifically tailored for BPA. For instance, BPA's status as a federal agency prohibits it from posting collateral, so the SPP will instead require BPA to submit a "letter of assurances" committing the agency to cover its obligation.

Another apparent accommodation for BPA is the carve-out Feb. 13 to Aug. 12 as "Stage 1" of Phase 2. During that stage, Markets+ funders will only be obligated to commit to two-thirds of the total spending for Phase 2 — or $100 million. That will allow a funding entity to withdraw from Phase 2 before incurring full charges, a potentially important option for BPA, given that it has committed to funding the market before issuing an official decision on whether to actually join it.

Unclear Liability

But regardless of whether BPA will ultimately be liable for its full share of Phase 2 or only a portion, the Markets+ agreement indicates the agency will likely be obligated to cover more than the $25 million that BPA staff had previously estimated.

The table at the end of the agreement lists the eight entities that have so far publicly committed to funding Phase 2, including BPA, Powerex, Arizona Public Service, Tacoma Power, Grant County Public Utility District (PUD), Chelan County PUD, Salt River Project and Tucson Electric Power.

Absent from the table are two investor-owned utilities known to be leaning in favor of Markets+ — Puget Sound Energy (PSE) and Xcel Energy's Public Service Company of Colorado (PSCo), as well as El Paso Electric (EPE), which last month committed to join the SPP market despite not having participated in its Phase 1 development process. (See *El Paso Electric to Join SPP's Markets+ in 2028*.)

The table shows BPA's "Stage 1" obligation comes to about $26.8 million in a market footprint consisting of the eight committed funders, slightly above — but in line with — BPA's previous estimate for its Phase 2 implementation costs.

But another column for full "Phase 2" obligations, which are calculated off the $150 million Phase 2 total, shows BPA's share increasing to nearly $40.2 million, a figure agency staff did not broach during funding discussions at its most recent day-ahead market stakeholder workshop in late January. (See *BPA Considers Impact of Fees in Day-ahead Market Choice*.)

Industry sources have told *RTO Insider* that the $40.2 million figure is likely an outlier and that its Phase 2 funding exposure should decline once entities such as PSE, PSCo and EPE commit to funding, although those commitments are not guaranteed and the agency's final obligation isn't clear.

BPA expressed confidence that its funding obligation will decrease as other parties sign on to Markets+.

"The $40.19 million represents BPA's total share of the Phase 2 development costs based on the current list of funding participants," agency spokesperson Nick Quinata said in an email. "BPA believes, based on discussions with other Phase 1 participants, that other entities will commit to Phase 2 funding, which will lower each entity's liability."

"Each entity's *pro rata* share will be recalculated to account for any additional entities that execute funding agreements once their internal and/or regulatory processes are complete," SPP COO Antoine Lucas said.

Michael Linn, director of market analytics at the Public Power Council (PPC), which represents the publicly owned utilities comprising BPA's "preference customers," said his group isn't concerned about the $40 million figure.

"PPC expects additional entities will announce their intention to fund Phase 2 over the coming months and BPA's costs will be close to the original anticipated costs," said Linn, whose group has advocated for the agency to choose Markets+ over CAISO's competing Extended Day-Ahead Market (EDAM). (BPA staff have estimated EDAM will require lower startup costs than Markets+ but potentially higher annual costs.)

At least one of those announcements appears to be pending. Earlier in February, PSCo filed with the Colorado Public Utilities Commission for permission to join Markets+. The Colorado utility is expected to pay about $20 million to help fund Phase 2. (See related story, *PSCo Seeks to Join SPP's Markets+*.)

'Mousetrap Situation'

Both Linn and Quinata said the staged funding approach outlined in the Markets+ funding agreement should work to BPA's advantage.

Linn said it would contain the agency's costs as uncommitted entities "work through their internal processes prior to executing the agreement," while Quinata noted it "limits each party's liability should Phase 2 discontinue for any reason."

But Fred Heutte — senior policy associate with the Northwest Energy Coalition, which has urged BPA to join EDAM — cautioned that the timelines established in the agreement effectively bind the agency to joining Markets+ before it issues its draft market decision in early March and its final "letter to the region" on the choice in May.

Speaking with *RTO Insider*, Heutte pointed out that timelines in the agreement require BPA to provide its "letter of assurances" committing to Phase 2 funding by Feb. 28, a week before it issues the draft letter March 6.

"So the timing on this is what's really interesting, because by the time that Bonneville issues the draft letter to the region, they'll already have put the financial commitment on the table. It's not just something they're considering —they're already in the game," making them liable for their full obligation if they pull out after Stage 1, he said.

Heutte laid out a potentially complex scenario in which SPP begins investing in and staffing up for Phase 2 after securing financing this spring, creating an "immediate contingent liability" for the RTO and Markets+ funders such as BPA. Launch of the market in the first half of 2027 would create yet another contingent liability for BPA as it works through its next rate case, because it would then be obligated to begin repaying its portion of the loan whether or not it chooses to participate in the market.

"This is a mousetrap situation. Bonneville's going to say, 'Well, you know, we did what we were asked to do, and now we're kind of in, so we have to stay in,'" he said. "And I have a feeling that, while they are still under a tremendous amount of pressure to have a letter [to the region] say, 'Well, we're not going to decide right now; we're just not going to make a market choice,' which is what we [NWEC] strongly prefer. The financial hook on this letter of assurances is a pretty big one." ■

Feds Pause $1M Pathways Initiative Funding, Group Leader Says

Progress on Pathways Continues Regardless, According to Co-chair

By Henrik Nilsson

The federal government has put on hold nearly $1 million in funding toward the development of a new independent Western "regional organization" (RO) to oversee CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM), the West-Wide Governance Pathways Initiative's Launch Committee said Feb. 27.

The funding status is unknown because of a communication pause from the U.S. Department of Energy, according to a committee presentation.

"Given some of the cuts and uncertainty with the federal government, that funding is currently on hold," Kathleen Staks, executive director of Western Freedom and the Launch Committee's co-chair, said during the stakeholder meeting.

However, the Launch Committee does not expect the uncertainty of federal funding to slow down its work significantly. The current political environment has impacted some partners of the Pathways Initiative, "and we are sensitive to that. But directly for the work that we're doing, we think we're going to be able to continue to move forward," Staks said.

Pathways *received* nearly $1 million from the DOE under former President Joe Biden's *administration in November* to underwrite the committee's efforts to establish an RO to oversee CAISO's WEIM and EDAM.

Why This Matters

Pathways backers will likely need to scramble to find interim sources of new funding after the effort's nearly $1 million grant fell victim to the Trump administration's pause on all federal grants and loans.

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The award was issued through the Pathways Initiative's philanthropy adviser Global Impact, which the group's Launch Committee partnered with earlier in 2024 to secure outside funding for its operations, which so far have been supported by donations — and volunteered staff — from its participants.

President Donald Trump's administration on Jan. 27 *paused* all federal grants and loans, according to a memo issued by the White House's Office and Management and Budget.

"With or without that DOE funding, the RO is going to need additional funding," Staks noted.

Setting up an independent RO comes with several costs, including legal review of various documents, seating a board and ongoing facilitation costs, among other things, she said.

Staks said the committee hopes to have a draft budget to share with stakeholders by spring. She recognized that "all of our work thus far has been funded by a variety of stakeholders, and we are extremely grateful for that support and commitment."

The Launch Committee's success also hinges on the California bill to implement the Pathways "Step 2" plan to transform CAISO's governance. Lawmakers *introduced the bill* in the state Legislature on Feb. 20. The proposed legislation sets conditions under which CAISO and California investor-owned utilities can participate in energy markets governed by an independent RO.

The Launch Committee is also working to finalize corporate documents, including registering as a nonprofit organization and refining the nominating committee process used to seat the RO board. The entire process to establish the RO will be marked by an extensive stakeholder process and negotiations between various parties, Staks noted.

The Pathways bill states that CAISO can join the RO-governed market on or after Jan. 1, 2027, which the Launch Committee believes "will not be too early," according to Staks. ■

Data Center Grid Integration Top Theme at CEC Workshop

Onsite Generation Unlikely the Best Option, Experts Tell Commission

By Elaine Goodman

As some data center operators plan to power their facilities with onsite generation, one researcher suggested it might be better to get electricity from the grid instead.

"At the end of the day, the hyperscalers do not want to be in the business of running a powerhouse on their data center property," said David Porter, vice president of electrification and sustainability at the Electric Power Research Institute. "What they really want long-term is a reliable and resilient power supply. And that doesn't come from any better place than the grid."

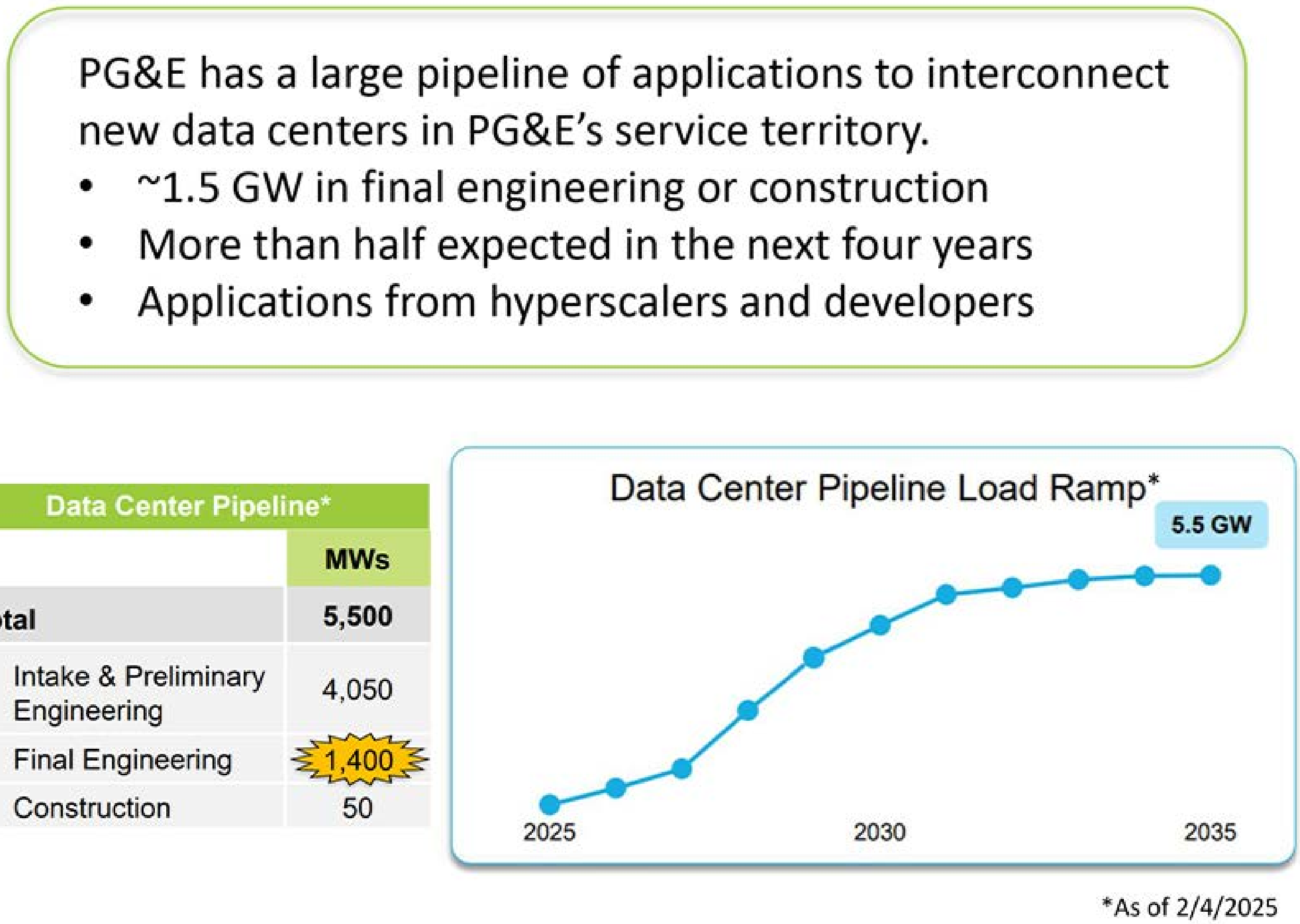
Porter's comments came during a California Energy Commission *workshop* Feb. 26 on California's economic outlook, including data center growth. The workshop is part of the CEC's 2025 Integrated Energy Policy Report (IEPR) process.

Even if a data center had small modular reactors or a combined cycle turbine on site, Porter said, operators would have to contend with maintenance, refueling and repairs.

"And it's not a great equation for anybody that is connected to the grid to have the grid operator provide only backup service in times of extreme need and have to hold capacity back in their planning processes for some of those rare-type conditions," he added.

The Big Picture

Data center operators and grid planners are grappling with how to bring big energy consumers online as quickly as possible without stressing electricity systems.



| PG&E

An issue for data centers is that the energy-intensive facilities can be built relatively quickly but may need to wait for capacity or transmission infrastructure.

Helen Kou, a global research lead on data centers at BloombergNEF, said a standard feature of data centers is a backup generation system for reliability. But grid interconnection issues are now prompting data centers to explore a broader role for onsite generation.

"As data center loads continue to scale, the exact mix of onsite generation, be it natural gas, batteries, renewables or small modular nuclear, really just ends up depending on the project timeline, local regulatory frameworks and the corporate sustainability goals of the data center facility owner," Kou said during the CEC workshop.

Bridging the Gap

Another strategy is the use of "bridge" solutions to meet a data center's energy needs until transmission is available.

That could mean bringing in skid-mounted generation, Porter said, or installing solar-plus-storage to temporarily serve the data center. Even after the data center connects to the grid, the solar-plus-storage could stay in place in front of the meter as a grid resource, he added.

Another hot topic for data centers is their ability to be flexible in their energy use, particularly during grid-constrained hours.

One possibility might be for a data center to tap into its backup generation system at those times, panelists said. That could create air quality issues if backup power comes from diesel generators. But other technology is available.

Panelist Kushal Patel from Energy and Environmental Economics (E3) pointed to a Microsoft data center in San Jose, Calif., that has a backup power microgrid fueled by renewable natural gas. The RNG microgrid also allows Microsoft to participate in PG&E's Base Interruptible Program, which pays customers to reduce electricity use when energy supplies are tight.

"The kind of capability and the kind of resource may be there," Patel said. "Are there the right kind of regulatory incentives, policies in place to be able to maximize that?"

EPRI in October announced an initiative called DCFlex, which will establish flexibility hubs for data centers to try out new strategies that boost operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. (See *EPRI Launches DCFlex Initiative to Help Integrate Data Centers on the Grid*.)

The initiative is bringing together hyperscalers, data center developers, technology providers, utilities, ISOs and RTOs. In February, EPRI *announced* an expansion of the program into Europe.

Peak Load Growth

In its 2024 IEPR, the CEC projected about 3,500 MW of new data center peak load in California by 2040, on top of roughly 1,000 MW in 2024. (See *CEC Ups Data Center Demand Forecast After PG&E Revisions*.) Those estimates will be updated as part of the 2025 IEPR.

Southern California Edison has about 80 MW in existing data center demand and is forecasting an increase to 1,000 MW by 2045, Elliot James Dean, an SCE data science specialist, said during the CEC workshop. Uncertainty in the forecast comes from potential on-site generation, increased energy efficiency, technology advancements and market conditions in the SCE service territory.

The data center pipeline in Pacific Gas and Electric's territory totals 5,500 MW, including almost 1,500 MW in final engineering or construction, according to a workshop presentation.

One key question for utilities is how many inquiries from data centers are "real" versus an information gathering process to compare different regions. Dean said SCE has started assigning a confidence level to each project, based in part on whether it is also making inquiries elsewhere. (See *Data Center Load Uncertainty Tied to Broader Economy, Google Rep Says*.)

"That is not very straightforward," Dean said. "And clear communication from the project is greatly appreciated on that piece for sure." ■

IBR Lessons Can Guide Data Center Challenges, WECC Report Finds

'Flexible, Agile' Regulations Necessary to Meet Growing Demand, According to Study

By Henrik Nilsson

With data centers already causing "major disturbances" on the grid, the industry could learn lessons from the recent growth and implementation of inverter-based resources (IBRs), according to a new Elevate Energy Consulting study.

The *study*, commissioned by WECC, noted that Northern Virginia experienced a large load loss event in July 2024 that resulted in "1,500 MW of data center load switching to backup power. Nearly 60 data centers spread across 25 to 30 substations disconnected from the [bulk power system]. Voltages throughout the area rose significantly and local capacitor banks were removed by operators to bring voltage back within limits."

Meanwhile, WECC expects electricity demand across the Western Interconnection to increase by "an unprecedented 20%" over the next decade. Balancing authorities forecast demand to increase from 942,000 GWh in 2025 to 1,134,000 GWh in 2034, according to the study.

The report found that the rapid expansion of data centers is projected to be the largest contributor to demand growth and will likely impact BPS reliability.

The study noted that the electric power system has not seen this level of growth since the 1950s. Failure to effectively tackle those challenges "may result in unreliable operations of the BPS, an undesired outcome for grid operators and large load operators alike," according to the study.

The situation is similar to the rapid growth and challenges brought by IBRs over the last decade, the study authors wrote.

"It is clear that the path ahead for the industry with these large load interconnections may follow a very similar trajectory as the interconnection of IBRs onto the grid," the study stated. "The experience integrating IBRs can be used as a playbook for mitigating the reliability risks from large loads. The industry must learn from its past with IBRs and act rapidly to address the BPS reliability risks before larger and larger grid disturbances occur and impact the BPS."

For example, while there are standardized procedures for BPS-connected generators governed by FERC, those mandated procedures do not exist for large load interconnections. Specifically, there is a lack of comprehensive data-sharing requirements, study milestones, timelines and other factors, according to the study.

"This may have sufficed when load interconnection requests were orders of magnitude smaller, and the breadth of requests was much lower," the study states. "Today, an agile and well-documented load interconnection process is critical for ensuring BPS reliability and administering a fair, just and equitable interconnection process."

| BLM

Why This Matters

The study performed for WECC suggests that grid planners across the nation can draw on their experience with renewable integration to inform their response to growing data center demand.

FERC Order 2023 and the overhaul of the generator interconnection process driven by the growth of IBRs could provide guidance, the study authors contend. The order shifted the pro forma interconnection rules from a first-come, first-served serial process to a first-ready, first-served cluster study process. It ramped up financial requirements for developers and set penalties for transmission providers that fail to meet deadlines for completing interconnection studies. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

Regulators must adapt quickly while ensuring regulations are "flexible, agile and updated frequently to adapt to the changing technology landscape and complex needs of large load interconnections," according to the study.

"[T]ransmission providers typically do not have adequate interconnection requirements in place for large loads and may be challenged to enforce requirements on interconnection customers," the authors wrote. "As has been observed with IBR risks, ensuring that clear, consistent and applicable interconnection requirements are in place to ensure that adequate data sharing, modeling, studies and operational performance are achieved is a critical aspect for BPS reliability." ■

ERCOT TAC Opens Discussion on Proposed RTC Changes

Staff Face Tight Timeline to Begin Market Trials, Prep for Go-live

By Tom Kleckner

Why This Matters

ERCOT staff and stakeholders are trying to keep the real-time co-optimization plus batteries project on time by reaching consensus on protocol changes now. Market trials to test system interfaces begin in May ahead of a targeted December go-live date.

AUSTIN, Texas — ERCOT staff and the Technical Advisory Committee's leadership teed up for discussion Feb. 27 a pair of protocol revision requests related to the grid operator's real-time co-optimization (RTC) and battery project, set to go live in December.

That gave TAC's members an early opportunity to dive into the two proposed changes (*NPRR1268* and *NPRR1269*) and lay out their concerns before the cadence of meetings quickens and they are brought for approval before the ERCOT Board of Directors in April. Staff hope to resolve those concerns, clearing the way for market trials and implementation.

"We really only have one shot at these in March," said TAC Chair Caitlin Smith, with Jupiter Power, alluding to the committee's only remaining meeting before the board gathers.

"Now is the time to engage as needed," ERCOT's Matt Mereness, chair of the Real-time Co-optimization plus Batteries Task Force, told TAC. "This is why we wanted to get it on the table. We didn't want this to happen next month, when we're under the gun."

Two key upcoming meetings are those of Mereness' task force (March 5) and TAC's Protocol Revision Subcommittee (PRS) (March 12). The PRS is responsible for reviewing and recommending action on formally submitted NPRRs.

TAC would then consider the likely revisions to the proposed changes and any new NPRRs during its March 26 meeting. The board will meet April 7-8, with RTC market trials set to begin in May.

"That's a pretty tight timeline," Smith said. "There's not really time for an extra TAC [meeting] between [March 26] and the board" meeting.

Much of the discussion centered on NPRR1269, staff's effort to codify policy changes that were deferred from the original RTC-related protocols developed in 2020: parameters for ancillary service proxy offers floors; scaling factor values for ramping; and AS demand curves (ASDCs) for use in reliability unit commitment (RUC) studies.

ERCOT's Independent Market Monitor filed *comments* saying proxy offers should be set at fixed values corresponding to the variable cost to provide the service. It said setting ASDC at 95% of the AS plan for a given product — as ERCOT plans to do — "results in proxy prices that are excessively high at times and could lead to reliability and market performance issues."

The IMM also said capping AS' proxy price at $2,000 is arbitrary and "excessively high relative to the cost to provide the service."

Andrew Reimers, the IMM's deputy administrator, said he has brought the Monitor's concerns over the RUC offer floor to several stakeholder meetings.

"We were really hoping that this wasn't implemented with an eye towards making sure that RUC always procured the whole AS plan; that there are going to be plenty of circumstances where we're knowingly going short on the AS plan and printing non-zero prices for non-spin or ECRS [ERCOT contingency reserve service]," Reimers said. "We're accepting the point that RUC is a different kind of tool than the real-time market or the day-ahead market [DAM] and already has kind of different penalty functions in it.

"Now that this is swinging back around to, 'OK, well, if you're going to do that in RUC, then you should also have the same offer floor in DAM,' that's a real problem for us and might be a deal breaker."

Mereness said the task force's consensus is that AS proxy offers distort the market and should be rare exceptions and quickly corrected. The PRS plans to request urgent status for NPRR1269 in March to keep the change on track for regulatory approval ahead of the RTC+B market trials. While the trials begin in May, ERCOT is opening the sandbox for system testing before then.

The IMM is behind NPRR1268, which defines a methodology for disaggregating the operating reserve demand curve (ORDC) and creates "blended" ASDCs.

"We had cliffs on the curves. Now, we have ramps in the curves," Mereness said.

Texas Competitive Power Advocates, a trade association of competitive generators, filed *comments* supporting ERCOT's *suggestion* to add an ASDC floor in RUC that ensures security-constrained economic dispatch (SCED) can procure its AS requirements. The association said that under this construct, market prices will incent the market to self-commit the capacity to meet the AS requirements, rather than have RUC commit them.

Michele Richmond, TCPA's executive director, called in to the meeting to clarify that the association's comments were not intended to set a price floor.

"The [Texas Public Utility Commission] has made it clear through their direction that they want to avoid [operations] watches. They want to consider the conservative operations that ERCOT has been doing," she said. "We want to make sure that whatever amount of ancillary services ERCOT needs to procure in that endeavor are done through the competitive market, through market solutions, and not through out-of-market actions."

After meeting twice on NPRR1268, the RTC+B Task Force is leaning toward a separate revision request with a broader scope for the aggregated ORDC and ASDC issues, Mereness said. He said a broader consensus exists with *NPRR1270*, with stakeholders wanting to remove its original qualification expansion to automatically include all SCED resources for the ECRS and non-spin AS products.

The *RTC process* dispatches energy and ancillary services interchangeably in the real-time market. ERCOT procures AS in the day-ahead market and says it does not typically move the products between resources in real time. The grid operator expects to save $1.6 billion annually in reduced energy costs.

The grid operator has been working on RTC since 2017, when the PUC directed it and the IMM to assess the process's benefits. Work was delayed for several months after the disastrous February 2021 winter storm, known as Winter Storm Uri, that brought the ERCOT grid within minutes of collapsing.

ADER Discussion Moved to WMS

Stakeholders agreed to park continued discussion of an aggregated distributed energy resources (ADER) pilot project to the Wholesale Market Subcommittee.

The hope is that the WMS will be able to resolve issues around direct participation of third-party aggregators in the pilot and flexibility on limits, as well as consumer protection concerns and implications for load-serving entities.

The ADER pilot project is in its second phase and eyeing a third. The PUC voted Feb. 13 to move the project into ERCOT's stakeholder process to determine the best way to move the initiative forward. (See "ADER Project Moved to ERCOT," *2 Companies Withdraw Texas Energy Fund Projects from Consideration*.)

The pilot began in July 2022 and has resulted in *three virtual power plants* participating in the wholesale energy market and providing certain AS. Eight additional ADERs have been approved and are in various stages of registration. Their total capacity, qualified and potential, is 25.7 MW of energy, 11 MW of non-spin reserve service and 8.8 MW of ECRS.

Staff have been working with the ADER Task Force to develop a governing document for Phase 3 and gain board approval in April. Potential changes include a new participation model that would allow ADERs to provide AS as non-controllable load resources (NCLRs) not economically dispatched in real time, and all third-party aggregators as NCLRs when aggregation is larger than 100 kW.

The ADER pilot was originally given a three-year time frame.

Amended NPRR Passes

TAC endorsed a proposed protocol change (*NPRR1190*) that would allow recovery of a "demonstrable financial loss" arising from a manual high dispatch limit override reducing real power output when the output is intended to meet qualified scheduling entities' load obligations.

The measure was amended to include ERCOT comments received Feb. 27. Staff pushed to lower the $10 million threshold to trigger a review proposed by Reliant Energy to $3.5 million, saying the larger threshold, based on historical payment amounts that included Uri, was not appropriate given recent market pricing changes.

Reliant's Bill Barnes said he acknowledged the $10 million threshold was too high and agreed to the reduced amount.

Committee members tabled the NPRR in October 2024 after it was also tabled by the board and remanded back to TAC over concerns of a more equitable and fair treatment of all parties.

The measure passed 26-4, with four members of the consumer group casting no votes.

TAC also endorsed a slim consent agenda that included its 2025 *goals and strategic objectives*, a proposed protocol change and a revision to the Verifiable Cost Manual (VCMRR) that would, if approved by the board:

- *NPRR1241*: clarify the hourly standby fee claw backs for firm fuel supply service during a winter weather watch by using a sliding scale approach.
- *VCMRR042*: add seasonal sulfur dioxide and nitrogen oxide prices obtained from indices to calculate emission costs from May through September; annual prices would continue to be used from October through April. ■

TAC members listen to an ERCOT staff presentation. | © RTO Insider LLC

ERCOT Board OKs Mobile Generators in San Antonio

Resources Would be Used Instead of RMR for Aging Gas Units

By Tom Kleckner

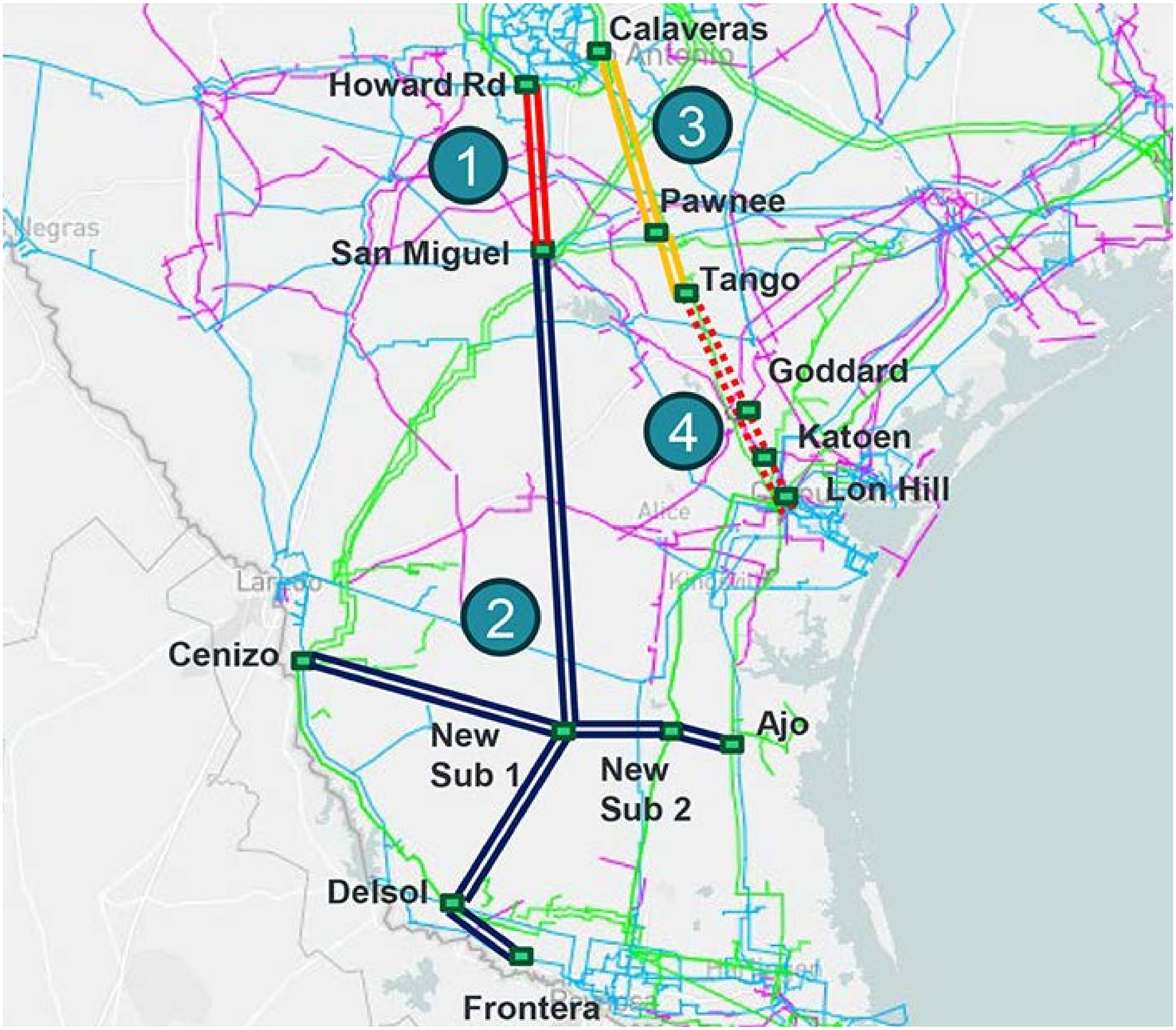
ERCOT's Board of Directors on Feb. 25 approved staff's recommendation to pursue use of 15 mobile generators as an alternative to extending the life of two aging gas-fired units slated for retirement in South Texas.

Staff said during a special board meeting that, based on current cost estimates, LifeCycle Power's generators and their combined capacity of 450 MW will be more cost effective in mitigating the "relevant reliability risks" in the San Antonio area posed by CPS Energy's planned retirement of the three units at its V.H. Braunig plant.

Nathan Bigbee, ERCOT's chief regulatory counsel, said continuing to operate Braunig Units 1 and 2 for two more years beyond their 2025 retirement date is budgeted to cost $59 million, including expected fuel costs and incentive factors or adders. The two units went into service in 1966 and 1968 and have a combined summer maximum rating of 392 MW, according to a CPS update.

In contrast, LifeCycle's generators are projected to cost $54 million, including fuel costs and incentives. They can reach full output in 10 minutes, faster start times than the three Braunig units. ERCOT and CPS signed an *RMR contract* on Feb. 24 for Braunig Unit 3, which has a summer max rating of 400 MW.

The age of units 1 and 2 creates addition-



ERCOT hopes to accelerate these South Texas transmission projects to bring an early resolution to San Antonio's congestion issues. | *ERCOT* al risks in extending them RMR contracts, Bigbee said. He said the budgets for the two units have increased 8% since November.

"These are both 60-year-old units, so they're very old generators," he said. "CPS Energy has told us that these are going to need lengthy outages and expensive inspections and repairs to ensure that they can be safely operated."

The two units would have to be inspected consecutively, potentially pushing the inspections past the high-demand summer season. They would also have to wait until CPS completes its 60-day inspection of Braunig Unit 3, which begins March 3.

"That just shows you that this is subject to a lot of variability," ERCOT General Counsel Chad Seely said.

The generators are leased by Houston utility CenterPoint Energy, which has agreed to release its obligation to LifeCycle for two years without compensation. CenterPoint leased the generators and several smaller ones after the deadly 2021 winter storm, but the large generators have sat unused ever since. (The utility says it plans to resize its generator fleet to address future hurricane outages.)

Why This Matters

ERCOT determined that using 15 mobile generators and their 450 MW combined capacity is less risky and more cost effective than extending the life of two 1960s-era gas units with less capacity.

CPS has said it can interconnect the generators in batches to its substations, starting in June and ending by September. The generators will be registered as generation resources and would be the last resources deployed by ERCOT during actual or anticipated emergency conditions, as are RMR units.

One sticking point is the diesel-fired generators' emissions permitting. Bigbee said the resources might not meet nitrogen oxide gas emissions limits. Staff are working with LifeCycle and the Texas Commission on Environmental Quality to "identify an appropriate solution under the current regulatory framework."

The board's decision also begins a 90-day clock for ERCOT to come up with an exit strategy from operating Braunig and the mobile generators. Staff said that involves accelerating three transmission projects south of San Antonio to alleviate the constraint causing the congestion. Two of the projects are scheduled to come into service in 2027 and a third in 2029.

In the meantime, ERCOT and the market are on the hook for $45.85 million under the terms of Braunig 3's RMR contract. That is the budgeted amount, which ERCOT said is a 33% increase since the first submission from CPS in November.

The RMR contract is ERCOT's first since 2016, when it entered into an agreement with NRG Texas Power over a previously mothballed gas unit near Houston. The RMR contract ended in 2017, thanks partly to transmission facilities that increased imports into the region. (See *ERCOT Ending Greens Bayou RMR May 29*.)

CPS told ERCOT in 2024 that it planned to retire the Braunig units in March 2025. However, ERCOT said the plant's retirement would lead to reliability issues in the San Antonio area until the transmission constraint is resolved. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.) ■

NEPOOL Transmission Committee Briefs

FERC Order 904 Compliance

ISO-NE has revised its compliance proposal for FERC Order 904 to allow generators to be compensated for reactive power outside the standard power factor range, the RTO *told stakeholders* at the NEPOOL Transmission Committee meeting Feb. 27.

Order 904 prohibits compensation for reactive power within the standard power factor range. ISO-NE sought to keep its existing system of reactive power compensation in response to FERC's Notice of Inquiry and Notice of Proposed Rulemaking prior to the final rule, but the commission rejected the RTO's arguments (*RM22-2*).

At a prior meeting of the TC in early February, the RTO proposed to end all compensation for reactive power, while several stakeholders argued for a more limited compliance plan strictly focused on removing compensation for the standard range. The RTO delayed the vote and ultimately accepted the suggestion. (See *NEPOOL Markets Committee Briefs: Feb. 11, 2025*.)

"The revised compliance proposal will eliminate VAR [volt ampere reactive] capacity cost credits to qualified reactive resources within the power factor range of 0.95 leading to 0.95 lagging at continuous rated output but will now continue to compensate for reactive power provided outside this range," said Kory Haag, principal operations analyst at ISO-NE.

ISO-NE estimated that the total annual compensation for reactive power is about $16 million, with $3.4 million for reactive power outside the standard range.

The TC voted to support the proposal, with no opposition and 55 abstentions. Multiple stakeholders expressed concern about the order itself, arguing that it undermines grid reliability.

"We are frustrated by the underlying order but appreciate the steps ISO-NE [has] taken to comply with the order," said Bruce Anderson, general counsel for the New England Power Generators Association. "We also appreciate that ISO-NE took the broadly shared NEPOOL feedback on its original proposal and made changes to that proposal that look to carry out FERC's directives."

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Economic Study Process Improvements

The TC also voted to support updates to ISO-NE's Economic Study process, centered around requests for proposals to address the issues identified during the process.

The updates "incorporate revisions to identifying system efficiency issues and needs by establishing a clear trigger for when to issue an RFP, defining benefit metrics for evaluating RFP responses and streamlining the RFP process into a single stage," said Patrick Boughan, supervisor of economic studies and environmental outlook at ISO-NE.

ISO-NE plans to run a System Efficiency Needs Scenario (SENS) every two or three years, looking at 10 years into the future. SENS tests would be used to identify potential transmission solutions. The RFP process will be triggered if ISO-NE's modeling shows savings of at least $4.3 million from congestion relief.

In *feedback* submitted prior to the meeting, RENEW Northeast criticized the proposal's method of modeling imports, arguing that it "may be artificially reducing the quantity of imports in the model and as a result having the opposite effect of underestimating the benefits of congestion relief."

ISO-NE responded that its modeling approach "is consistent with practices in NYISO, PJM and MISO," adding that valuing imports at the border locational marginal price "is the most logical way to value imports in the modeling context."

RENEW also argued that SENS test should include some projection of capacity market savings and asked the RTO to consider creating a process for smaller solutions that do not meet the $4.3 million savings threshold.

ISO-NE said estimating capacity market savings would introduce a significant amount of uncertainty and added that the cost threshold was calculated based on the cost of projects on the Regional System Plan and asset condition lists. ■

— Jon Lamson

Eversource Outlines Billions in New Boston-area Asset-condition Needs

By Jon Lamson

Presenting to the ISO-NE Planning Advisory Committee on Feb. 26, Eversource Energy *introduced* a new set of asset-condition projects that could cost the region billions over multiple decades.

The company is proposing the staged replacement of its aging network of underground high-pressure fluid-filled (HPFF) transmission lines in Eastern Massachusetts. The company's HPFF lines are reaching the end of their expected lifespan, and leaks from the lines have become larger and more frequent as the lines have aged, Eversource's Chris Soderman said.

"Failures can lead to monthslong outages due to the difficulty of repairs," he said, adding that the company is still working on the environmental cleanup for a leak that occurred Dec. 24, 2023. Most of the 6,000 gallons of dielectric fluid that leaked from the line during the incident flowed into the Charles River, he said.

Eversource outlined its plans to gradually replace its HPFF lines with cross-linked polyethylene (XLPE) technology, which it described as the "preferred technology for new underground transmission line construction."

Soderman said the supply chain for HPFF technology is fragile, and the only remaining HPFF manufacturing plant in the world has signaled its intent to exit the market in the long term.

"If HPFF cable manufacturing were discontinued today, Eversource estimates that spare inventory would be sufficient to maintain existing HPFF lines during the conversion to XLPE — but not over the long term," Soderman said. "The most responsible solution to ensure long-term reliability for customers and protection of the environment is to transition away from HPFF cables as the assets reach [their] end of usable life."

He said the company plans for roughly three to four phases of work to replace its HPFF network, which includes "approximately 179 miles of [pool transmission facility] HPFF circuits."

The company expects the replacements to continue into the 2040s, with the first phase aiming to construct about 35 miles of double-circuit underground duct-bank, which will likely cost "somewhere between $1.5 [billion] and $2 billion," Soderman said. He added that it is too early to make reliable cost projections for later phases of the replacements.

In recent years, the New England states have raised alarm about the rapidly increasing costs of asset-condition projects in the region, prompting some changes to the process of reviewing the projects at the PAC. However, asset-condition projects are under FERC jurisdiction, and the states have limited power to regulate the projects.

The asset-condition project forecast *database* published by the New England Transmission Owners — created at the request of the states in 2024 — outlines $5.8 billion in spending for projects expected to come online between 2024 and 2030. This includes only projects with full cost estimates, and the total cost will increase as additional projects move out of the conceptual stages.

Eversource did not provide an official cost estimate for the HPFF replacement program. Soderman said the first phase of replacements will be broken into 11 individual projects with in-service dates from 2028 to 2033. Eversource plans to provide cost estimates to the PAC in the summer, he said.

Also at the PAC, Joe Dobiac of National Grid detailed a nearly $9 million *cost increase* for a transmission upgrade project in Massachusetts. He attributed the increase to permitting delays, which have pushed the expected in-service date from December 2025 to December 2026.

Rafael Panos of National Grid *presented* a nearly $12 million asset-condition project in Eastern Massachusetts, driven by worn shieldwire assemblies, deteriorated insulation, damaged shieldwire and cracks in a river crossing tower foundation.

Joshua Cefaratti of Avangrid provided an *update* on the final cost of a project to build a flood wall protecting a substation in Connecticut. The project was completed in August 2024 at a cost of $53.9 million, a significant increase over the initial estimate of $16.5 million in 2016. He attributed the price increase to permitting and construction delays and increased labor and materials costs. ■

Why This Matters

The proposed asset condition projects would add to the already-high costs of replacing aging transmission infrastructure in the region.

HPFF cable installation | *Eversource*

Conn. Set to Reappoint Top Regulator amid Utility Legal Challenges

By Jon Lamson

Marissa Gillett, the top regulator at the Connecticut Public Utilities Regulatory Authority (PURA), is poised to be reappointed amid utility lawsuits and outcry about the state's regulatory environment.

Tensions between utilities and regulators have escalated during Gillett's tenure. The utilities have argued that the agency has demonstrated a lack of transparency and threatened their ability to receive a fair return on investments, while Gillett has argued that she is simply holding them accountable to existing laws. (See *The Rocky Road to Performance-based Regulation in Connecticut*.)

In January, Eversource Energy and Avangrid, which own gas and electric utilities in the state, sued the agency in Hartford Superior Court, alleging that Gillett has illegally issued unilateral decisions on "scores of substantive rulings across a wide range of contested and uncontested dockets conducted by PURA over the past five years."

"Certain actors at PURA have undertaken a number of unlawful procedures that have the effect of reducing what the legislature intentionally designed as a multi-member agency to the province of one commissioner," the companies wrote.

Gov. Ned Lamont (D) has stood by Gillett and helped craft a deal to ensure her reappointment on the eve of her confirmation hearing Feb. 20. The administration agreed to appoint state Sen. John Fonfara (D) and former state Rep. Holly Cheeseman (R) to fill the vacancies on PURA's board, which would return the agency to a full complement of five members.

The deal would also transition PURA from a subsidiary of the Department of Energy and Environmental Protection to a quasi-public agency, enabling the administration to circumvent rules preventing it from appointing sitting legislators to executive-level positions.

At a nearly six-hour confirmation *hearing* with the legislature's Executive and Legislative Nominations Committee, Gillett fielded a wide range of questions about her leadership at the agency, energy affordability in the state and utility decarbonization efforts.

She defended PURA against the utilities' allegations in their lawsuit and said she has not made any final rulings without holding a vote with her fellow commissioners.

"We have votes recorded on every final decision of the agency in accordance with law," Gillett said. She pointed to PURA's record in recent court challenges to agency decisions, noting that it has "consistently and repeatedly won when challenged in court — four times at the [Connecticut] Supreme Court."

Responding to questions about the regulatory environment for the state's investor-owned utilities, Gillett said PURA has continued to apply "traditional ratemaking principles" and emphasized that its statute makes clear that the burden of proof in regulatory dockets is on the utilities.

In May 2024, Eversource announced its plans to cut $500 million in planned investments in the state because of the state's "negative regulatory environment." (See *Eversource Announces $500M Cut in Connecticut Investments*.) More recently, Eversource and PURA have disagreed over a potential expedited cost recovery mechanism for deploying advanced metering infrastructure, putting the *estimated* $766 million investment on hold.

"It is the legal obligation of these entities to appropriately invest in the grid," Gillett said. "If a regulated monopoly is not adequately investing in the grid to meet its statutory obligations of maintaining a safe, reliable and affordable grid, the consequence of that is a revocation of their franchise."

Gillett also criticized Eversource for not yet coming in for a rate case during her tenure, noting that it "has not been in for an adjudicated rate case since 2014; there was a settlement in 2018. If there is a question of whether the utility has enough revenue to build out and invest in this state, there is a remedy for that, and that remedy is coming in for a rate case before PURA."

"It is my opinion that it is an unacceptable amount of time for a regulated utility to stay out of receiving scrutiny from not just its regulator, but other stakeholders," she added.

Gillett said the fight between utilities and regulators in Connecticut is being watched throughout the country and could affect utility regulation in other states.

"The work that my colleagues and staff have positioned ourselves to continue … has been viewed at times as existential threats to traditional ways and business models. I think folks should understand that this is being watched and does have larger implications," Gillett said.

Legislators focused much of the hearing on energy affordability in the state, which has some of the *most expensive* electricity rates in the country.

"People are telling us that they are suffering; they are truly having to make a decision between paying their utility bill … and having to give something up in exchange for that," state Sen. Eric Berthel (R) said.

Gillett pointed to a significant recent increase in the public benefits charge for Eversource ratepayers as a key cost driver, which she said was largely from unrecovered costs associated with the power purchase agreement for the Millstone nuclear plant. She said she voted against the 10-month increase in the charge, which will conclude at the end of April, but was overruled by her fellow commissioners.

Environmental justice advocates attending the hearing voiced their support for Gillett, while the committee voted along party lines to support her reappointment. She still must be confirmed by the General Assembly, where Democratic legislators hold large majorities.

Avangrid declined to comment on Gillett's renomination and the agreed-upon changes to PURA's makeup. Eversource wrote in a statement that "the planned changes provide a pathway for a constructive, predictable and transparent regulatory environment that benefits customers through investment and a focus on reliability." ■

ISO-NE Braces for Tariffs on Canadian Electricity

By Jon Lamson

In preparation for potential fees on electricity imports from Canada, ISO-NE requested authorization from FERC on Feb. 28 to collect import duties while simultaneously arguing that the RTO "is not the appropriate entity" to do so (*ER25-1445*).

The Trump administration's monthlong pause of the tariffs on Canadian goods, which include a 10% fee on energy imports, expires today.

Vague language in the original *executive order*, coupled with limited communication from the administration, has created significant uncertainty regarding what is included in the energy carveout, how the tariffs will be applied and whether the tariffs apply to electricity. (See *Uncertainty Remains Around Energy Tariffs amid Last-minute Deals*.)

Along with the 10% energy tariff, President Donald Trump on Feb. 1 imposed tariffs of 25% on all other imports from Canada, as well as those from Mexico.

At a press conference March 3, Trump *said* the tariffs will proceed, with "no room left for Mexico or for Canada" to avoid them.

ISO-NE has *argued* that the tariffs "do not appear to apply to electricity and that, even if they do, ISO New England would not be responsible implementing them."

The RTO noted that the definition referenced by the February order on Canadian imports does not explicitly include electricity. It defines energy or energy resources as "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water and critical minerals."

ISO-NE also pointed to statements from the U.S. International Trade Commission indicating that electricity is exempt from U.S. tariff laws.

| Shutterstock

The RTO's proposal is intended to protect it if the administration does in fact determine it is responsible for the tariffs, which would pose a "significant financial risk to the ISO" if it does not have the means to collect the fees, it said.

It noted that the "failure to have a cost-recovery mechanism in place prior to the effective date of a Canadian import tariff would place the ISO at risk of non-compliance with a federal obligation and, in a worst-case scenario, could force the ISO to seek bankruptcy protection."

If it is unable to pay the duties, the federal government could direct the RTO to suspend imports, which could create "precipitous, adverse consequences" for grid reliability, ISO-NE wrote.

It estimated that a 10% tariff on electricity imports would cost the region about $66 million annually, while a 25% tariff would cost the region about $165 million annually. The RTO noted that Canadian imports have covered about 11% of the region's load over the past five years.

Imports are poised to increase when the New England Clean Energy Connect (NECEC) transmission line comes online, likely by early 2026. The NECEC project includes a long-term contract for the supply of baseload power from Québec to Massachusetts. Hydro-Québec has said it is monitoring the potential effects of the tariffs on its long-term contracts.

To prevent potential fallout for the New England market, ISO-NE proposes a "temporary mechanism" enabling it to collect the tariffs. In the absence of direction from the administration regarding which entities ISO-NE should collect the duties from, the RTO would charge the fees "to the entities selling the assessed electricity into the ISO-administered market."

If the federal government provides more specific information around the responsible entities, ISO-NE would alert its market participants and adopt the requirements, the RTO noted.

The proposal will only take effect if the Trump administration determines ISO-NE is responsible for the tariffs. If the temporary mechanism does take effect, the RTO said it would work with stakeholders to create a "cost-collection mechanism that is specific to the terms and conditions of the import tariff and resulting imposed import duties." The RTO would be required to file the final mechanism within 120 days of the date the temporary mechanism takes effect.

Why This Matters

While uncertainty remains regarding whether the tariffs will apply to electricity, ISO-NE is seeking FERC authorization to prevent outsized market impacts in the region if the RTO is held responsible for imposing the fees.

ISO-NE said its proposal is intended to apply to any other future import duties imposed by the federal government on electricity. The Trump administration has said it may increase the tariffs if Canada retaliates with its own duties on U.S. goods.

Ontario Premier Doug Ford on March 3 said he is prepared to *cut off electricity* exports to the U.S. "with a smile on my face" if the tariffs go into effect.

"They rely on our energy. They need to feel the pain. They want to come at us hard; we're going to come back twice as hard," Ford said.

The RTO requested an expedited review of its order, asking FERC to rule on its filing by the end of March and accept a March 1 effective date for the proposal. It also asked for a shortened comment period ending March 10.

ISO-NE's filing mirrored a proposal submitted by NYISO on the same date. NYISO also argued that the executive order does not appear to apply to electricity but asked FERC to authorize it to collect tariffs if required to do so by the administration. (See related story, *NYISO Preparing to Collect Duties on Canadian Electricity Imports*.) ■

Stakeholders Want More from MISO on Tx Project Cost Containment

RTO Reluctant to Fulfill Request to Step up Measures

By Amanda Durish Cook

CARMEL, Ind. — MISO doesn't think it needs to step up cost monitoring on its ever-larger transmission projects even as some stakeholders call for tighter measures.

Speaking at a Feb. 25 cost allocation working group meeting, MISO's Jeremiah Doner said the RTO doesn't see a need to upend its current variance analysis process, the mechanism it uses to investigate projects that incur cost overruns or other difficulties.

"We think that the current process is designed to sufficiently monitor and track projects," Doner told stakeholders.

MISO's End-Use Customer sector in December asked the RTO and stakeholders to discuss transmission cost containment measures. The request coincided with MISO announcing it would investigate one long-range transmission project from its first portfolio, which experienced a 2.5-times increase in costs. (See *Cost Overruns on Project in 1st LRTP Prompt MISO Analysis*.)

MISO staff perform variance analyses on regionally cost-shared transmission projects that encounter schedule delays, permitting challenges, significant design changes or experience at least a 25% cost increase from original estimates. The studies are also triggered when developers find themselves unable to complete the project or if they default on the terms of their selected developer agreement.

ITC Midwest

After completing the analysis, MISO can either let a project stand, develop a mitigation plan for it, cancel it or assign it to different developers if possible. A committee of MISO employees selected by RTO executives makes calls on how to deal with such projects.

The End-Use Customer sector and the Coalition of MISO Transmission Customers have said that MISO's 25% trigger is too high.

Some stakeholders have suggested MISO lower the current 25% cost-increase limit to around 10%. They have also said the RTO should consult with state regulators to review the cost mitigation measures it prescribes to some developers.

MISO settled on the 25% threshold 10 years ago, Doner said.

"There were stakeholders who wanted the value to be higher, there were stakeholders who wanted the value to be lower," he said.

Zachary Callen, an economic analyst at the Illinois Commerce Commission, asked if MISO has considered notifying stakeholders about projects with up to a 24% cost overrun that might run the risk of a variance analysis.

Doner said MISO thus far hasn't encountered too many projects that have cost overruns that come close to the 25% limit.

"There still is room for some modest enhancements," argued attorney Ken Stark, representing MISO end-use customers. He added that the End-Use Customer sector is willing to come before the working group in April to propose some stiffer requirements to "layer on" to the existing process.

"The world has changed. The portfolios that are coming in aren't exactly cheap," said consultant Kavita Maini, representing MISO industrial customers. She said for a billion dollar transmission project, costs could spill over by $250,000 before MISO commits to examining them.

Why This Matters

Stakeholders are asking MISO to adapt a smaller cost increase threshold than its current 25% before it investigates transmission projects for exceeding cost estimates.

"That's a lot of money. … It seems like this threshold should be much lower," Maini said. She said she believes there's more to do to make the variance analysis more transparent and ensure proper monitoring of projects.

Doner maintained that the process is sufficiently transparent. He said MISO staff uses the publicly available reporting that developers submit to MISO to review projects. However, he acknowledged the RTO can't always share confidential project information.

"We think that the tools are there. We've been able to track costs with projects and make changes, if need be," he said.

Although MISO so far doesn't seem receptive to increased variance analysis activations, Doner said it plans to more clearly provide notice to stakeholders through its public planning committees when it finishes a variance analysis and develops an action plan.

MISO has completed nine variance analyses to date. For most studied projects, the RTO has either drawn up mitigation plans or let projects stand. While the grid operator has never reassigned a project developer through the analysis, it has canceled one 500-kV project because of a new right of first refusal law in Texas. (See *FERC Rejects Last-ditch Effort to Save Tx Project*.) ■

MISO Aims for 4 New Tx Planning Futures in 9 Months

By Amanda Durish Cook


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

MISO expects the revamp of its transmission planning futures will be done by November and will yield an extra scenario dedicated to slow-moving generation construction.

The RTO said load growth from data centers, AI computing and domestic manufacturing makes it clear its current trio of 20-year futures that form the basis of its long-term transmission planning is outdated. It also said it foresees the potential for hydrogen production demand in later years of the futures.

MISO used the three futures it's now retiring to rationalize about $32 billion in transmission investment between its first and second long-range transmission plan (LRTP) portfolios. It plans to use its upcoming revised futures to chart a third LRTP portfolio for MISO Midwest. (See *MISO Pauses Long-range Tx Planning in 2025 to go Back to the Futures*.) MISO established its current futures in 2019 and last updated them in 2022.

"It's critical to do this now because we're at another inflection point," MISO Senior Vice President of Planning Jennifer Curran said during Feb. 28 Futures Redesign Workshop, the first in a series with stakeholders to modernize the futures.

Curran said though MISO has warned several times about inflection points over the years, members' estimated load growth makes the RTO's latest take-notice just as legitimate.

Curran said load growth trajectories are outstripping what's contemplated in the existing futures. She also said MISO plans to add a fourth future to contemplate what happens if generation additions remain sluggish, as they have in recent years, noting that MISO needs to understand "what happens if things don't pick back up really soon."

She said MISO hopes to emerge with a new set of futures within nine months, something she acknowledged would be an uphill battle.

"It's of critical importance to get these updates as soon as we can," she said.

Director of Economic and Policy Planning Christina Drake said MISO decided its members' integrated resource planning, the footprint's load growth, continuing decarbonization and generation retirements will be the "load-bearing walls" of the new set of futures.

MISO's proposed four, 20-year futures include:

A "lower load growth" scenario, in which demand projections don't materialize due to an economic slowdown, and some utilities and states' emissions reductions announcements are unrealized.

A "stated policy" future, in which estimated trends like reindustrialization, data center growth and electrification hold steady while members expand generation and meet their current emissions goals.

A "higher load growth" future, in which supply needs inch beyond today's forecasts driven by high-powered load.

A "supply shift" future, in which MISO said "supply frictions" limit the pace of generation additions and load growth has to be managed through existing generation and demand-side resources.

While the first three futures largely use the logic MISO employed in its existing futures (slow, medium and fast-paced options), Drake said MISO must work through the "finer details" of its new fourth future. MISO also anticipates retirement delays and more demand-side resources in addition to unfulfilled emissions reductions targets.

What's Next?

MISO will continue shaping its proposed 20-year planning scenarios late into 2025, then use them to draw up another long-range transmission plan over 2026.

Across all futures, MISO will apply an age-based retirement assumption to generation if members haven't specified a retirement date. That age-based date will arrive years sooner for coal and gas units in the more progressive "stated policy" and "higher load growth" futures.

This time around, MISO will transition to Energy Exemplar's more sophisticated PLEXOS tool to model generation expansion. It's retiring use of the Electric Power Research Institute's Electric Generation Expansion Analysis System, which MISO said was hitting the limits of the variables it can simulate as the system becomes more complex.

Curran warned the work could feel "uncomfortable" for some stakeholders because change is difficult. She stressed MISO's goal is to land on a range of possibilities and asked that stakeholders not get hung up on modeling precision.

"It can be hard to predict next year, much less 20 years out. I can't say it enough that it's the bounds that are important," she said.

WPPI Energy's Steve Leovy said it was disconcerting MISO seems to be abandoning accuracy to establish its bookends.

Kavita Maini, a consultant representing MISO industrial customers, agreed and asked MISO to "not trade speed for accuracy."

WEC Energy Group's Chris Plante said he was "fearful" MISO would use its search for general bookends to justify omitting sensitivities or robustness testing.

Curran said she expects there will be some variables that won't meaningfully change MISO's transmission expansion needs.

"I guarantee that there are going to be things that we assess as immaterial that stakeholders will disagree with," she said. "I will caution that one person's crazy is another person's reasonable."

MISO also will include energy adequacy assessments as part of its futures. Drake said MISO hopes its adequacy assessment will support its states — which hold resource-planning power — in making informed decisions.

Maini asked if MISO has considered that its members will relax some carbon-cutting endeavors in resource plans due to the Trump administration's standpoints on clean energy. She also asked if MISO has analyzed how trends might change if the Inflation Reduction Act is axed.

Drake said the Inflation Reduction Act might not have as much bearing on planning as some might assume. She said MISO's research to date has found that member plans would predominantly set the futures' course.

"It was basically not as impactful as what was coming through our member plans," Drake said.

MISO plans to discuss other assumptions at upcoming workshops. It plans to hold another Futures Redesign Workshop with stakeholders March 19.

Multiple stakeholders urged MISO to allow them to record and transcribe the workshops so others at their organizations can keep up with futures development. The grid operator prohibits anyone from recording meetings, save for a few self-recorded workshops throughout the year. It has opted not to allow futures workshops in its archives. ■

MISO South Hit Record, 33-GW Winter Peak in Jan. Storm

By Amanda Durish Cook

The MISO South region relied on transfers from the Midwest to handle a record, 33.1-GW winter peak during a Jan. 20-22 storm.

The peak Jan. 22 unseated the previous winter peak of 32.6 GW from Jan. 27, 2024. This year's storm brought near-blizzard conditions to parts of the Gulf South, with 10 inches of snowfall in New Orleans. MISO South's topmost demand remains the 35.2 GW the region realized in late August 2023.

Speaking at a Feb. 24 Entergy Regional State Committee meeting, MISO Independent Market Monitor staffer Robert Sinclair said MISO Midwest assisted the South region with large transfers during the storm.

Sinclair said the Midwestern assist demonstrates the value of the South's membership in MISO. He said footprint-wide, MISO mitigated potential storm impacts through preparation. MISO increased short-term reserve requirements ahead of time, Sinclair said, paving the way for an increase in imports "that helped ease system stress."

Overall, MISO set a 108-GW winter peak Jan. 22, about 1 GW short of its all-time winter peak. The grid operator did not have to resort to emergency measures to power through the arctic blast.

MISO South adviser Tag Short said MISO's entire transmission system held up well throughout the storm.

"[That] gets very dicey, when you have ice on the transmission system," Short said.

Otherwise, Sinclair said voltage and local reliability issues have persisted over the winter in MISO South's load pockets. He explained the region is short on generation in some locations at times, prompting MISO operators to make out-of-market commitments. Sinclair recommended MISO use short-term reserves instead to price the reliability issues and lower revenue sufficiency payments. ■

| Entergy

MISO Approaching LMR/DR Accreditation Based on Availability

By Amanda Durish Cook

CARMEL, Ind. — MISO is nearing an overhaul of its capacity accreditation methods for load-modifying resources (LMRs) and demand response that would be based on whether they can assist during periods of high system risk.

The grid operator plans to accredit LMRs and its emergency DR and behind-the-meter generation depending on their offers during low-margin and risky hours where a capacity advisory, maximum generation alert or warning, or energy emergency is in place. The RTO reasoned that those hours best reflect when it is likely to need those resources.

MISO said it would require DR and LMRs to designate a response time when registering their assets. It plans to dock accreditation when resources report inaccurate availability.

Joshua Schabla, MISO market design economist, said the RTO has "dozens" of DR resources that have never updated availability throughout a planning year.

"We want to accredit a resource based on when it's most needed. That's the crux of this," Schabla told the Resource Adequacy Subcommittee on Feb. 26. He warned that MISO compensates resources that never perform, and he said some resources "look like they exist when they in fact do not."

Why This Matters

MISO is putting finishing touches on a more hard-line accreditation for demand response and load-modifying resources. If those resources aren't available during risky periods, MISO would shave their accreditation values. Staff say the method would weed out demand response that has no intention of performing.

Joshua Schabla, MISO | © RTO Insider LLC

MISO said data from its demand-side resource interface show that about 2 GW of DR is accredited but is never designated as available or self-scheduled.

The RTO plans to rely on the past year as a reference for accreditation. Staff said they are aware that using a single year makes for a more severe accreditation style, but that is by design to send a signal to respond. Last year it mulled using the past three years as a reference but decided that would water down accreditation too much.

Additionally, the RTO plans to split its LMR category into rapid responders with greater responsibility and those with a more lenient availability scheme by the 2028/29 planning year. (See *MISO Closing in on New LMR Accreditation*.) Nimbler LMRs would have a maximum response time of 30 minutes and presumed availability for all maximum generation emergency step 2 events. Slower LMRs would have a maximum six-hour response time and would be called up earlier — sometimes on a voluntary basis — during maximum generation warnings.

The accreditation plan would have an all-or-nothing aspect: MISO plans to assign zero values for the entire duration of an emergency or near-emergency event when resources fail to make any contributions for even one hour.

"It sounds harsh; it sounds mean. But that's the line we've drawn in the sand. … That's the tension we experience between availability and adequacy," Schabla said.

He also said MISO wants to transition to an unlimited number of deployments instead of limiting DR's deployments to a handful of times per season, as is practice now.

However, after a DR resource, BTM generator or the slower LMR type deploys once in a year, they can choose to declare themselves as unavailable in future deployment calls in exchange for reduced accreditation. Schabla said those resources can decide if a deployment is too expensive to carry out. The category of faster LMRs, on the other hand, would not be permitted to designate themselves as unavailable under any circumstances.

MISO staff have stressed that it is imperative that LMRs respond when called upon to retain resource adequacy as the fleet transitions.

"We want to make sure their accreditation is tied to their performance," Zak Joundi, executive director of market innovation, said in front of MISO South regulators Feb. 24. Joundi reminded attendees that LMRs have chosen to register as capacity resources.

As part of its accreditation filing, MISO plans to debut a capacity availability tolerance band for DR resources, in which they would be required to perform between 88 and 112% of their stated load-reduction capability. MISO would cap the tolerance band at no less than 1 MW and no more than 30 MW for underperforming resources. Despite the upper bounds of the tolerance band, DR resources would not be penalized for overperformance.

Some stakeholders have said the tolerance band is too complex to include in the new accreditation method.

"Forecast errors are inevitable, and penalties are not appropriate for LMRs providing good-faith estimates," WPPI Energy's Steve Leovy said. MISO should waive accreditation penalties when LMRs provide "near-real-time demand data" or have used rigorous forecasting methods to estimate their availability, he said. A few tens of megawatts of standard deviation should not make a difference to MISO operations, he argued.

Schabla said LMRs using a firm service level to gauge reductions instead of a megawatt amount would not face accreditation penalties without the tolerance band. He pointed out that LMRs specifying megawatt reductions likewise face performance penalties. MISO's DR resources can use either a firm service level or a megawatt value as the measuring stick for their reductions.

"We believe it's fair to treat all demand response resources the same," Schabla said, stressing that resources should be indicating their availability. He said there are LMRs in MISO who input the same availability information year-round, never adjusting for likely seasonal changes. The RTO expects DR to perform when called on, even if it proves expensive for the resource. Schabla said it is only fair that unresponsive resources take hits to their accreditation when unavailable.

"We're paying you for years in between deployments," he explained, adding that MISO compensates LMRs to respond only in emergency situations.

The RTO has called up LMRs 12 times since 2017, with half of those occurring during winter storms over the last few years.

"These events are very infrequent, and that's to be expected in a system with a one-day-in-10-years reliability standard," Schabla said. ■

NYISO Preparing to Collect Duties on Canadian Electricity Imports

Proposed Tariff Revisions for in Case Trump Tariffs Apply to Electricity

By Vincent Gabrielle

NYISO presented the Installed Capacity Working Group with two *proposals* it plans to file with FERC to give itself the means to collect duties in case President Donald Trump's tariff on Canadian energy imports applies to electricity.

Trump had announced a 10% tariff on "energy resources from Canada" but paused it Feb. 3. While NYISO's current position is that import the tariff does not appear to legally apply to electricity — and it is not necessarily its job to collect the duties if it does — it wants to be prepared on Day 1. (See *NYISO Assessing Impact of Trump's Canada Tariff on Electricity Market*.)

"The goal is to have effective March 4 the tariff infrastructure in order to comply with whatever the government may impose," NYISO General Counsel Robert Fernandez said.

"It seems to me that what we think about whether or not they apply is not relevant because ultimately, it will the wannabe king and his minions who tell us whether it applies or not, and I don't get the impression they're going to consult with you," said Mark Younger of Hudson Energy Economics.

NYISO's primary proposal would allow it to collect duties from real-time scheduled imports originating from "Duty Eligible Proxy" buses that represent interties between New York and Canada. It would create a new Rate Schedule 21 for duty recovery that would be paid to a relevant federal authority and charged to the "financially responsible party" for each subject transaction.

Under this proposal, NYISO would use day-ahead location-based marginal prices to calculate duties. NYISO said that using this method will allow both day-ahead and real-time transactions to reflect the cost of duties in their offers. Using real-time prices would make it impossible for duties to be calculated on day-ahead transactions.

"The day-ahead LBMP represents a financially binding price for electricity sales at the relevant tie and location," said Nathaniel Gilbraith, manager of energy market design for NYISO. "Using real-time prices alone to calculate duties would create a duty cost risk that the day-ahead transactions could not reflect in their offers."

The Daniel-Johnson Dam on the Manicouagan River just north of Baie-Comeau, Quebec | *Bouchecl, CC BY-SA 3.0, via Wikimedia Commons*

Why This Matters

NYISO plans to ask FERC to give it the means to collect duties in case President Trump's tariff on Canadian energy imports applies to electricity. Until NYISO develops software to automate calculating, collecting and paying duties, the process would be manual.

Until NYISO develops software to automate calculating, collecting and paying duties, the process would be manual. The ISO would not collect duties on Canadian energy wheeling in from other control areas.

NYISO's alternate proposal defines subject transactions the same way but would collect the required duties from withdrawals on a ratio-share basis. This is being done to create a duty mechanism that would apply to load in order to maximize the likelihood that NYISO has the legal authority to collect.

"My understanding is that the importer of record pays the collection that pays the tariff and ultimately passes it on to the consumer," Fernandez said. "And that's analogous to what we're saying could happen under the load-ratio-share approach."

Fernandez said this was not the favored approach because it was not as economically efficient. The alternative, which the ISO calls a "backstop," was being filed out of an abundance of caution, he explained.

Younger said he appreciated the steps NYISO was taking to protect the market and added that it should ensure that capacity was also covered by any language filed with FERC.

Ted Murphy, a lawyer for NYISO from law firm Hunton Andrews Kurth, explained that there was historical precedent against import duties being levied against electricity. He said federal customs and tariff enforcement agents did not know how applicable tariffs were to electricity.

“One thing that gives me comfort is that one line in the trade tariffs suggest that intangible things are not subject to tax,” Murphy said. “There are cases saying electricity is intangible. In my mind, capacity as one level of abstraction out from actual electrons crossing the border makes me think that the focus is going to be on energy, not capacity or other products. But nobody knows.”

Chris Casey, with the Natural Resources Defense Council, said that filing a request with FERC to enable compliance with potential import duties made him nervous because no formal ruling on electricity had been made by any relevant authority. Fernandez replied that the ISO had considered going through a more formal process of getting a declared ruling, but the problem was lack of time.

“In a perfect world, these rules would have been developed through the normal shared governance process,” Fernandez said. “But March 4 is next week, and we’ve been looking at this for a couple weeks now, and we simply do not have time to get that ruling.”

Fernandez said that if Customs and Border Protection or the Treasury Department did not give NYISO a definitive ruling by March 4, the import duties would not be collected or remitted to the government. They would set up the accounting necessary to do so only when ordered.

“Dollars will not flow, will not be collected or remitted until we know that we actually have a legal obligation to do that,” Fernandez said. NYISO staff and counsel would consider whether to add capacity to the proposals in a pre-filing conference, he said.

Fernandez went on to say that he expected ISO-NE to file a similar request by the end of the week with FERC but that he did not know where the other ISOs or RTOs stood on this issue. A stakeholder said he was worried that NYISO’s filing would “raise awareness” and cause reinterpretation of existing law.

“Are we making this a self-fulfilling prophecy?” Fernandez reflected. “I don’t know, but I read the newspapers. It’s not like we can stick our heads in the sand and act like ostriches on this and hope it doesn’t happen. On March 4, NYISO needs rules in place so we can comply with the law if it eventually comes to pass.”

When NYISO staff were asked by other stakeholders how much money was at stake for the federal government, they said forecasting that figure was complicated and that they didn’t want to go on record with a dollar figure. ■

Study Finds Considerable 'Grid Flexibility' Potential in New York

Measures Include Managed EV Charging, BTM Solar

By Vincent Gabrielle

A Brattle Group *study* released in February found that New York could achieve 8.5 GW in "grid flexibility" measures by 2040, saving consumers more than $2 billion a year.

The study was commissioned by the New York Department of Public Service as part of its Grid of the Future initiative, which defined grid flexibility as the "ability to shift either demand or supply to meet bulk power system and/or local distribution needs." (See *NY PSC Launches Grid of the Future Proceeding*.)

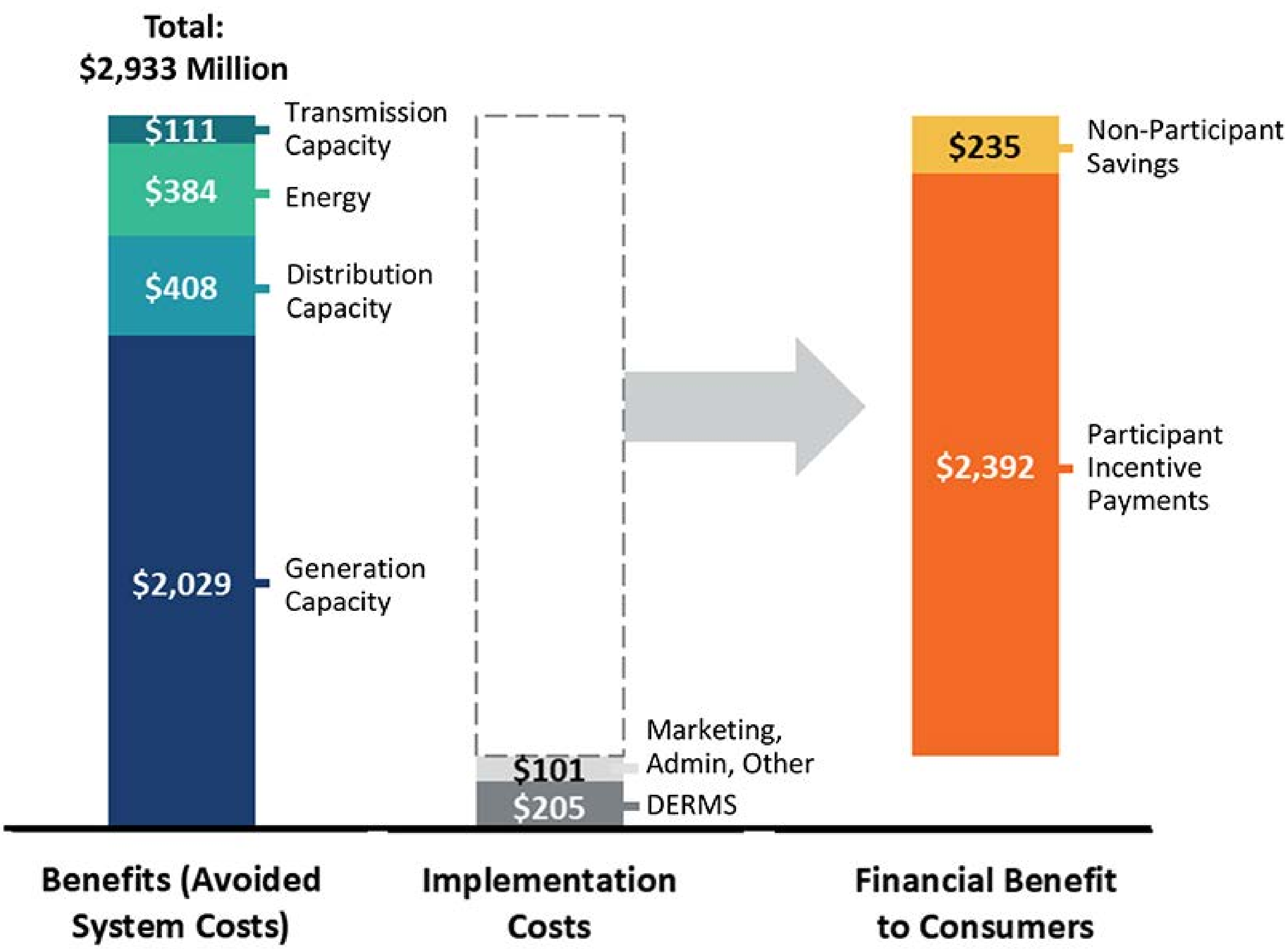
The 8.5-GW figure is roughly 21% of NYISO's forecasted winter peak demand and more than six times the current potential of 1.2 and 1.4 GW in the winter and summer, respectively. Grid flexibility measures could help by "displacing the need" for higher-cost resources, the study says.

"This report has really important implications for regulators, decision-makers and figures in industry," said Amy Heart, senior vice president of public policy at Sunrun. "It sets out what the potential is, and how to get there. It demonstrates that this isn't theoretical."

The study says that implementing grid flexibility improvements could avoid $2.9 billion a year in power system costs by 2040, $2.4 billion of which could be returned to consumers. These cost savings come primarily from reducing how much investment in generation capacity would be needed to maintain reliability. Avoided distribution and energy costs were $408 million and $384 million, respectively.

"Really for the first time this says that there is a unique way for a flexible grid to meet this growing demand," Heart said. "And we have the potential to use these resources and build programs that are cost effective."

Currently New York's grid flexibility primarily comes from NYISO demand response programs — Special Case Resources and Emergency Demand Response — amounting to about 1,300 MW of flexibility. An additional 414 MW of flexibility is facilitated by the Economic Demand Response program, in which



2040 benefits and costs of grid flexibility potential | *Brattle Group* large consumers reduce loads based on price signals in the day-ahead market.

Brattle found that managed electric vehicle charging, heat pump load control and residential behind-the-meter storage all had significant potential for increasing grid flexibility. In a future report, Brattle will examine the potential of thermal energy storage, thermal energy networks, increased efficiency, front-of-meter distributed storage and large loads with microgrids.

"This flexibility study is looking at things that we're either currently doing or really close to doing, moving out of a pilot phase into mass market," said Deb Peck Kelleher, deputy director of the Alliance for Clean Energy New York, highlighting EV charging demand-reduction programs. "I'm glad to see that those programs are working as they were envisioned to work."

Noah Ginsburg, executive director of the New York Solar Energy Industries Association, said he was pleased that the report looked at the grid in a holistic way and that it did a good job identifying both barriers and opportunities for flexibility.

"The moral of the story to me is if we are smart and address these barriers and create the right pricing and regulatory conditions to deploy a lot of these flexible assets, that's just a huge savings opportunity," Ginsburg said.

Barriers Identified

Brattle identified several key barriers to getting grid flexibility measures implemented, with the lowest-hanging fruit being regulatory barriers like zoning, permitting and lack of state goals.

This hampers adoption by consumers and does not incentivize utilities to incorporate grid flexibility into their projections. The study also notes that New York's cost-benefit analysis framework may undervalue flexibility initiatives, leading to the deprioritzation of some technologies.

Brattle is saying, "'Hey, just make this simple and effective and easy for customers to navigate, to sign up and to bring these resources to the table,'" Heart said. "These are the sort of tangible actions that we can get everyone together and hammer out."

Tariff complexity prevents consumers from understanding or evaluating potential benefits from established compensation mechanisms. Utility tariffs also lack support for bidirectional distributed energy resources, like chargers and batteries, which depresses adoption. Retail rates also are not designed for customers to take advantage of grid flexibility.

Ginsburg said that local building codes compound other regulatory problems. He noted that in most of the Consolidated Edison footprint in New York City, residential battery storage is banned for fire safety reasons.

"This isn't a matter of getting batteries built; it's a matter of fairness," Ginsburg said. "Frankly, New York City and Con Ed ratepayers are funding a lot of the statewide incentive programs that the city of New York doesn't allow them to access."

Now that Brattle had identified the barriers, it was now on DPS to pick a pathway to advance, Ginsburg said. He said he hoped this would lead to improved rate design and compensation for distributed storage programs both behind and in front of the meter.

Peck Kelleher said the biggest challenge for DPS would be coordinating across all of its various proceedings and initiatives revolving around grid modernization.

"It was great work that was published by the Brattle Group," Peck Kelleher said. "But how to take that data and inject it into each of the separate proceedings and keep them going in the same direction" will be a challenge.

Realistic?

"I think all power systems have unexploited flexibility and that something can, and should, be done," said Francisco de Leon, a professor of electrical engineering at New York University. "I don't think flexibility is the final answer to electric energy challenges of the future because its full-blown implementation (as described in the report) is very expensive."

While de Leon said he was not opposed to the idea of increasing grid flexibility, the report was being "overly optimistic" about grid flexibility. He said the expected cost of generation in the report was far too high for the state to bear politically.

"Using the numbers in the report, the cost of marginal generation of electricity is expected to increase from $40 to $70/kW-year to over $200," de Leon wrote in an email. "Would you like your electricity bill to increase by three to five times?"

Brattle says its analysis "found that overall net costs may be small relative to the size of the state's economy and will be offset by the health and societal benefits. Nevertheless, managing power system costs will be crucial to delivering an affordable transition for New Yorkers."

But de Leon said to expect a change of state government if the price of generation goes up that high as a result of decarbonization. With the current federal government not investing in renewables, and likely consumer unwillingness to deal with such steep price increases, decarbonization by 2040 was extremely unlikely, he said.

While load shifting could be "low-hanging fruit," de Leon was also pessimistic about HVAC upgrades serving as a cost-effective way to reduce demand. He said that the cost of acquiring and installing new heat pumps makes retrofitting cost "thousands of dollars per room," which is difficult to sell to homeowners and "impossible" to sell to renters.

"We should not pass on the opportunity of heat pumps for new construction," de Leon wrote. "But in my opinion the cost to retrofit old buildings is very large."

Demand for electricity is going to grow in New York, whether from AI centers or electrification or manufacturing; no matter what the cause, people still want ways to manage their electricity, Heart said.

"The question becomes how are we going to squeeze as much juice out of these resources that are in people's homes and businesses to help keep those costs low," Heart said.

She pointed to the distributed resource deployment in Massachusetts, where consumers can enroll in smart thermostat, solar and battery programs that compensate them for injecting power into the grid. (See *Mass. DPU Approves 1st Round of Utility Grid Modernization Plans*.)

"They have a very successful program," Heart said. "While we encourage experimenting, we've done pilot programs; you don't have to start from scratch. You can take this framework." ■

PSEG Sees Surge in Large Load Inquiries

Proposals Include AI, Data Centers, EV Connection Projects

By Hugh R. Morley

Public Service Enterprise Group saw an "over-12-fold" increase in mature leads and inquiries from customers exploring "large load and data center projects" over the past year, CEO Ralph LaRossa said in the utility's fourth-quarter earnings call Feb. 25.

The suggestion of a potentially expensive surge in demand comes after several quarters in which LaRossa has touted the utility's South Jersey nuclear generators — Hope Creek and Salem — as primed to accommodate the needs of data centers and artificial intelligence developers. Company officials have suggested they are an important part of the utility's future expansion and of helping the state boost its economy. (See *Data Center Opportunity is Strong, Expanding, PSEG CEO Says*.)

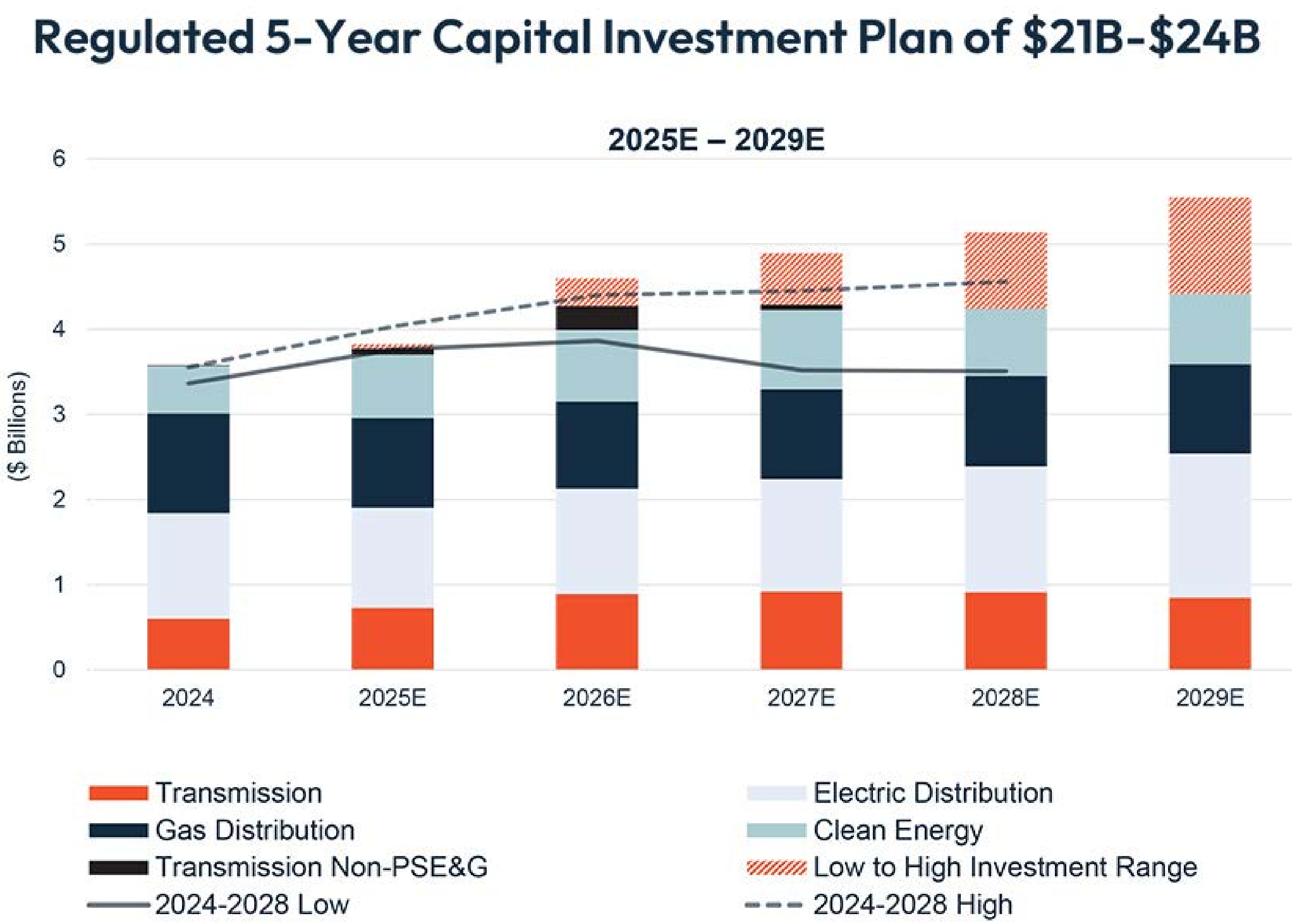
The volume of inquiries totaled 4,700 MW in the last year, compared to about 400 MW in 2023, LaRossa said. The average size of the leads in 2024 was 100 MW, and the customer inquiries even included some "large electric vehicle interconnections," he said.

"Approximately 25% of the 4,700 MW of new business leads have been incorporated into PJM's 2025 system peak load forecast," he noted.

NJ Wind Port

Responding to an analyst's question, utility executives rebuffed suggestions that the utility's ability to develop such projects would be affected by recent FERC rulings.

The commission Feb. 20 voted to launch a review of issues associated with the co-location of large loads such as AI-enabled data center at generating centers in PJM. (See *FERC Launches Rulemaking on Thorny Issues Involving Data Center Co-*



| PSEG

location.) The inquiry was triggered in part by the number of such proceedings that emerged in the RTO's territory. (See *Constellation Complaint Seeks Formal Data Center Co-location Rules*.)

The ruling gave PJM and its transmission owners 30 days to answer a series of questions about whether the RTO's tariff needs updating to accommodate co-location arrangements.

"We continue to have discussions with multiple parties for various elements of what we're talking about, and that interest remains strong," CFO Daniel Cregg said.

"It would have been great to have complete answers throughout everything from what FERC said," Cregg added. "I don't know that we necessarily expected that, and we've got to wait for some [details]. But I think directionally, what they said was favorable for the flexibility to do what you want to do, and those details have yet to be written, so we'll continue to see what happens there."

LaRossa said he hoped for more "clarity" from FERC on the issue in the future but added that "it's not stopping anything."

New Jersey has spent more than $500 million to develop the New Jersey Wind Port adjacent to PSEG's nuclear plants, off the Delaware River, with a goal of serving the state's nascent offshore wind sector. However, state wind projects have largely stalled amid economic and supply chain difficulties, as well as opposition from the Trump administration. (See *NJ Abandons 4th OSW Solicitation*.)

LaRossa noted that the New Jersey Economic Development Authority announced recently that it is looking for alternative uses for the port.

"That's one thing that we just want to point out," he said. "And we know that there's some interest, from the governor's standpoint and from New Jersey's standpoint, to continue for us to look to pursue these opportunities."

The sheer volume of inquiries shows that "there's interest from the industry in New Jersey" and that the state's effort to market itself to large load clients "has been working," LaRossa said.

Fall in Earnings

Cregg said the utility plans to invest $3.8 billion in 2025 in regulated investments on "infrastructure modernization, energy efficiency and meeting growing demand and electrification initiatives."

That expenditure is part of an expanded five-year regulated capital investment plan of $21 billion to $24 billion between 2025 and 2029, an increase from the previous planned $18 billion to $21 billion, he said.

PSEG's fourth-quarter results for 2024 fell from $546 million ($1.10/share) in 2023 to $286 million ($0.57/share). Non-GAAP operating earnings for the quarter were $421 million ($0.84/share), compared with $271 million ($0.54/share) in the same period last year.

Full-year 2024 earnings were also lower than those of 2023. The company reported net income of $1.772 billion ($3.54/share), compared with $2.563 billion ($5.13/share). Non-GAAP operating earnings were $1.839 billion ($3.68/share), compared with $1.742 billion ($3.48/share). ■

PJM Board Approves $6B in Grid Upgrades

By Devin Leith-Yessian

The PJM Board of Managers on Feb. 26 approved a $6 billion package of grid upgrades that includes expanding the 765-kV backbone east to meet rising demand, particularly in Northern Virginia's Data Center Alley.

PJM's recommended slate of projects includes Window 1 of the 2024 Regional Transmission Expansion Plan, as well as a doubling of the cost estimate for grid reinforcements needed to allow the deactivation of Talen Energy's Brandon Shore generator outside Baltimore from $738.83 million to $1.5 billion. (See "RTEP Changes Include Doubling of Tx Costs for Brandon Shores Deactivation," *PJM TEAC Briefs: Feb. 4, 2025*.)

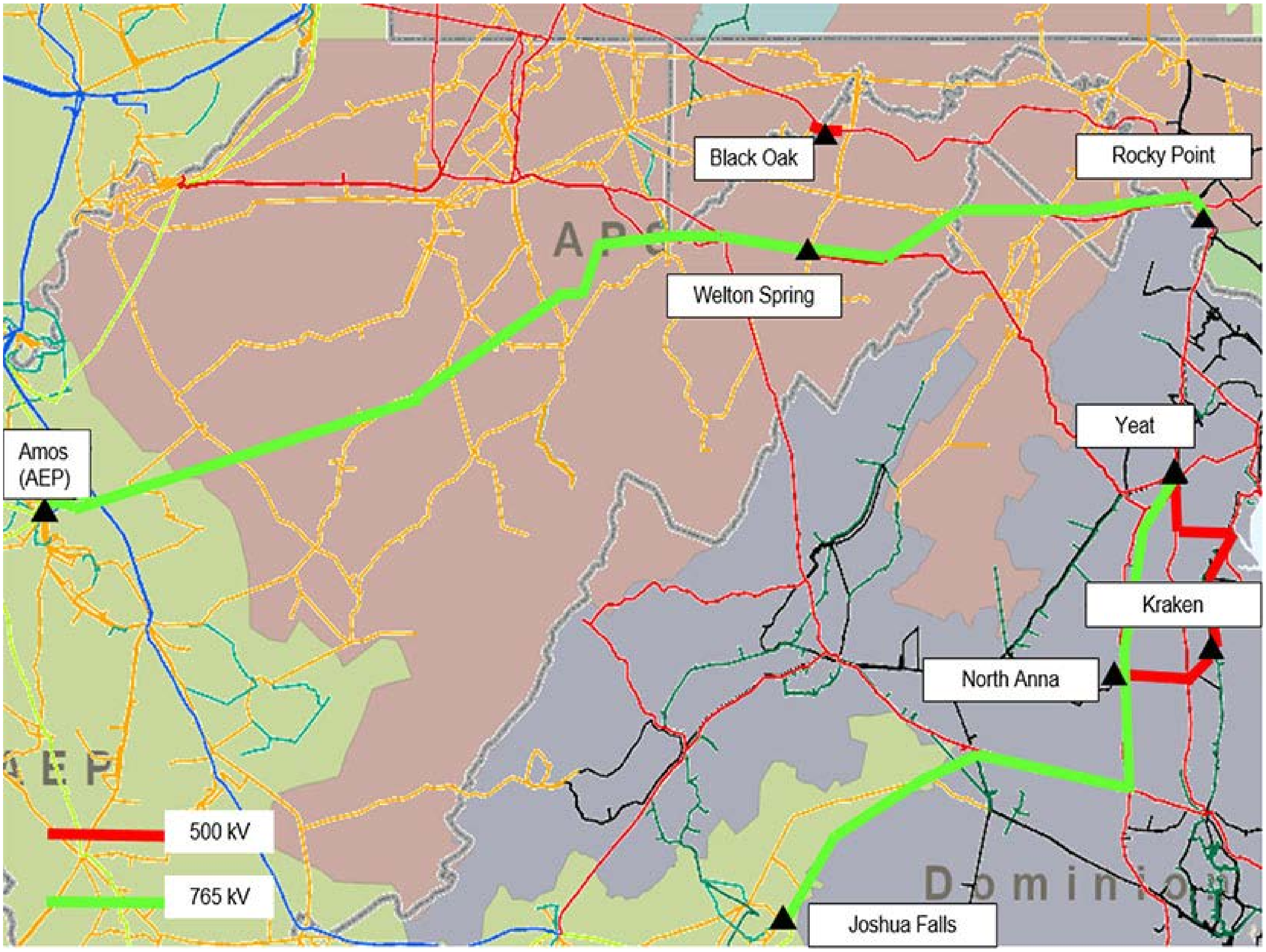
"A strong, efficient transmission system enables economic growth and ensures reliability for consumers across the PJM region," PJM's Executive Vice President of Operations, Planning and Security Aftab Khan said in an *announcement* of the approval. "These projects are especially critical to reliably meet the increasing demand for electricity and leverage new generation resources."

The expansion of the 765-kV network, which accounts for the bulk of the cost, would proceed in two regions: one to the north running from the John Amos substation in West Virginia to the Doubs substation in Maryland, and a second to the south linking the existing network looped into Joshua Falls in Amherst, Va., to a new substation, named Yeat, in Fauquier County to the north.

Why This Matters

PJM is pursuing the grid upgrades because its modeling showed increasing load and the need to correct reliability violations. Consumer advocates say the ever-escalating costs are absorbed by ratepayers.

The northern corridor would use a mix of greenfield and existing rights of way between Joshua Falls and the Welton Spring substation, which would be up-



Network upgrades planned as part of the first window of the 2024 Regional Transmission Expansion Plan (RTEP) | *PJM* graded with a new 765-kV switchyard, four 250-MVAR shunt reactors and a 500-MVAR synchronous compensator (STATCOM). The line would continue to Doubs mainly following existing ROW and then to a new Rocky Point substation sited nearby. The new facility would be looped into the 500-kV Doubs-Goose Creek, Doubs-Aspen and Woodside-Goose Creek lines and would feature 765- and 500-kV yards; two 765/500-kV transformers; two 765-kV and two 500-kV, 250-MVAR capacitor banks; and a 500-MVAR STATCOM. Upgrades would also be made to the Joshua Falls, Doubs and Black Oak substations.

PJM's analysis *report* accompanying the recommended projects states that the proposals to upgrade the corridor between John Amos and Rocky Point to 765 kV was selected to provide scalability and flexibility to address load growths and changes in the resource mix beyond the RTEP horizon. A newly implemented 15-year analysis found anticipated violations that would be resolved by the proposal. The work was assigned to American Electric Power, FirstEnergy and Trans-Allegheny Interstate Line Co. (TrAILCo), the latter of which is a FirstEnergy subsidiary. It is expected to cost $1.9 billion, with a required in-service date in June 2029 and projected in-service date in December 2029.

The southern Joshua Falls-Yeat line would mainly follow existing ROW, with some greenfield components. Yeat would be cut into the 500-kV Bristers-Ox, 500-kV Meadowbrook-Vint Hill and 230-kV Vint Hill-Elk Run lines. The component is estimated to cost $1.1 billion and go into service in June 2029.

The work between Joshua Falls and Yeat also includes the proposed 500-kV "Kraken Loop" branching off the North Anna substation to a new Kraken facility to the northeast and turning back northwest to Yeat. Existing lines between North Anna and the Ladysmith substation would be upgraded to 500 kV, and new lines mainly following existing ROW would be built to Kraken, which would be outfitted with two 1,440-MVA, 500/230-kV transformers. The corridor would continue to Yeat with a mix of greenfield and existing ROW. Upgrades would be made to the North Anna, Ladysmith and Elmont substations.

The RTEP report states that the loop will address load growth expected to the east of North Anna, while also resolving stability and operational constraints. Ties to the 230-kV network around Kraken would be deferred until they are needed and likely pursued through the supplemental planning process. The loop was assigned to Dominion Energy at an estimated cost of $704 million and an in-service date in June 2029.

Several additional project components across the PJM region were included in the RTEP window. An additional $672 million Transource project was selected to upgrade 230-kV and 115-kV infrastructure across the Dominion's footprint, which was assigned the construction as the incumbent transmission owner. The package includes a new 230-kV Elmont-Ladysmith line using existing structures between the two substations; a new 230-kV Raines-Cloud line; and rebuilding two 230-kV lines between the Marsh Run and Remington CT substations.

A $217 million package was approved in the ATSI region to rebuild the 32-mile, 138-kV Greenfield-Beaver line and sections of the Hayes-Avery, Avery-Shinrock and 138-kV Greenfield-Lakeview lines. A $262 million project would reconfigure the 765-kV Maliszewski substation and reconductor the 10.2 miles of the 345-kV Maliszewski-Corridor line and 4.75 miles of the 345-kV Bokes Creek-Marysville line.

Advanced Energy United Policy Director Jon Gordon said the RTEP process fails to consider regional impacts and alternatives to transmission for solving needs identified. He also argued that projects submitted by TOs are planned in isolation and not competitively bid.

"PJM continues with its business-as-usual buildout of local transmission 'reliability' projects that are not part of any kind of comprehensive regional infrastructure planning process. The PJM board just approved $6.7 billion of these transmission projects for this year, up from $5.1 billion in 2024. The five-year cost for these projects is approaching $40 billion," Gordon said. "These costs are passed through directly to ratepayers and are part of the ever-escalating retail electric rate problem that PJM seems to have little concern for." ■

PSCo Seeks to Join SPP's Markets+

Xcel Energy Subsidiary Cites Governance, Costs as Reason for Decision

By Henrik Nilsson

Xcel Energy subsidiary Public Service Company of Colorado (PSCo) has asked the Colorado Public Utilities Commission for permission to join SPP's Markets+, saying the market option would not lock "the company into other markets which have suboptimal policies for customers and Colorado's state goals."

In a Feb. 14 *filing*, PSCo requested that the commission find it is in the public's interest that the utility join SPP's Markets+ while also asking for approval of modifications to the electric commodity adjustment tariff to recover costs associated with its market decision.

Specifically, PSCo seeks recovery of approximately $2 million in Phase 1 funding fees. The company also seeks recovery of costs associated with Phase 2 of Markets+, including approximately $14 million in administrative fees during the first five years of market operations and about $13 million to $15 million in technology upgrades, according to the filing.

Gerald Deaver, a commission adviser sitting in for CPUC Chair Eric Blank during a Feb. 21 Markets+ State Committee, said, "PSCo indicates in the filing that it would enter into the Phase 2 agreement as quickly as it could after a commission order approves their participation."

PSCo "has evaluated several alternatives to Markets+, including the SPP RTO expansion and CAISO EDAM," the filing stated. "The company's analysis concluded that, at this time, participation in Markets+ provides the best option to retain the benefits of market participation while not prematurely locking the company into other markets which have suboptimal policies for customers and Colorado's state goals."

Xcel Energy subsidiary Public Service Company of Colorado (PSCo) has asked the Colorado Public Utilities Commission for permission to join SPP's Markets+. | *SPP*

The company said it favors Markets+ for several reasons, including its governance structure, benefits "overall and in relation to costs relative to the other markets studied, including EDAM," and Markets+'s greenhouse gas emissions tracking and accounting system.

PSCo also said "Markets+ is the only organized day-ahead market proposal for the West that will have a fully impartial and independent market operator, providing confidence that all market operator actions will be for the benefit of all participants and stakeholders."

Markets+ supporters have repeatedly touted the benefits of the market's independent governance in comparison with CAISO's state-backed governance, an issue supporters of the ISO's EDAM and Western Energy Imbalance Market have been attempting to address through the West-Wide Governance Pathways Initiative. (See *Pathways 'Step 2' Bill Sets Conditions for EDAM Governance*.)

"Over the past 10 years, through the successful implementation of the Western Energy Imbalance Market, regional coordination has proven an essential tool in maintaining grid reliability and lowering costs for electricity consumers in California and across the West," CAISO spokesperson Jayme Ackemann said. "We look forward to continuing that work as we move [toward] the launch of the Extended Day-Ahead Market in 2026, which will build upon the benefits of the WEIM for all participants."

In an email, Xcel spokesperson Tyler Bryant told *RTO Insider* that the company has been involved in the development of Markets+ since 2022. Bryant said the company believes joining Markets+ is in the public interest based on CPUC's criteria.

Antoine Lucas, SPP vice president of Markets, said the RTO is pleased with the application and the company's continued participation in Markets+.

"SPP values their unique voice as an entity representing the Mountain West region and the specific needs of Xcel customers, and we look forward to their engagement in phase two of Markets+ development," Lucas said.

> **The Big Picture**
>
> PSCo's decision would put Markets+ at the border with SPP's own RTO.

'Thoroughly Intermeshed'

But not everyone is thrilled with the decision.

In an interview with *RTO Insider*, Brian Turner, director of Advanced Energy United, contended that the application lacked sufficient analysis of climate change impacts and the purported costs and benefits to Colorado ratepayers.

Turner also said the decision will *create market seams* within Colorado. He noted that Colorado-based Tri-State Generation and Transmission — which sells energy to utilities all around the Centennial State — has *indicated* it will join SPP's full RTO as that entity expands into the West.

Meanwhile, the utilities that buy power from Tri-State have each indicated they will join different markets, some going with Markets+, others committing to SPP RTO, and others joining no market, Turner said.

The transmission systems of Xcel and Tri-State "are thoroughly intermeshed," according to Turner.

"The seams between Xcel, going with Markets+, and Tri-State, going with SPP RTO and [Tri-State] having its own issue with seams with individual co-ops, is going to be a very major issue here, and one that should be raised to Colorado policymakers and is not," Turner said.

"I fear the Colorado utilities, and therefore, policymakers, and therefore, ratepayers, are headed down a road to a very limited market with lots of costs and reliability risks from the seams and the limited market that they've set themselves up with, basically driving down a dead-end road," Turner said. ■

Tom Kleckner contributed to this story.

Company Briefs

NRG to Build Natural Gas Plants to Supply Data Centers

NRG Energy last week announced plans to build four new natural gas power plants to supply data centers.

NRG said it plans to build 5.4 GW of natural gas combined-cycle power plants primarily to serve data centers in the ERCOT and PJM markets. The first 1.2 GW are expected to begin operations in 2029.

NRG also said it plans to build three gas-fired plants totaling 1.5 GW in the Houston area.

More: *Houston Chronicle*

EDF Withdraws from Atlantic Shores Wind Project

French energy giant EDF announced it has withdrawn from its stake in the Atlantic Shores wind project off New Jersey.

Its partner, Shell, also withdrew from the 200-turbine, 1,510-MW project in January. Following Shell's decision, the New Jersey Board of Public Utilities decided not to proceed with a new solicitation that would have allowed Atlantic Shores to submit an updated bid.

More: *WorkBoat*

Air Products Drops Green Hydrogen Projects in 3 States

Air Products officials announced the company is canceling projects in New York, California and Texas.

The company said the cancellation of the $500 million green hydrogen facility in New York was "based on recent regulatory developments rendering existing hydroelectric power supply ineligible for the Clean Hydrogen Production Tax Credit, as well as slower than expected development of a hydrogen mobility market in the region."

Air Products' board of directors and CEO recently conducted a review of numerous projects, making the decision to cease operations to record a pre-tax charge not to exceed $3.1 billion in its fiscal 2025 second quarter.

More: *North County Now*

First Solar Q4 Sales Up

First Solar last week reported net sales for the fourth quarter were $1.5 billion, up $0.6 billion from the prior quarter.

Meanwhile, net sales for the full year were $4.2 billion compared to $3.3 billion in the prior year. Looking ahead, sales are forecast to be about 32% higher than in 2024.

More: *pv magazine*

Federal Briefs

NOAA Suffers Mass Layoffs

The Trump administration last week informed hundreds of probationary employees in the National Oceanic and Atmospheric Administration that they were fired. The firings were expected to cost more than 800 people their jobs.

Most of the employees were responsible for producing weather forecasts, maintaining radar systems, gathering data from satellites and monitoring commercial fisheries. Several hundred more staff members were also expected to leave as part of the resignation program.

More: *The Washington Post*; *The New York Times*

Congress Votes to Overturn Rule Implementing Methane Fee

The House last week voted 220-206-1 to overturn a Biden-era rule implementing a program that charges oil and gas companies for excess methane emissions. The Senate voted 52-47 the next day to repeal the rule.

Overturning the rule does not necessarily eliminate the program, which was written into law in the 2022 Inflation Reduction Act. Fully overturning the rule appears to require additional legislation, and Republicans are expected to try to repeal it as part of their broader legislative package. Under the law, companies that emit methane at levels equivalent to 25,000 metric tons of carbon dioxide each year must pay for their excess emissions.

More: *The Hill*; *The Washington Post*

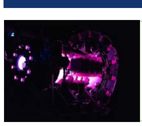
EIA: US Coal Retirements to Double in 2025

U.S. power generators plan to remove about 8.1 GW of coal-fired capacity this year, which would roughly double the amount that was retired in 2024, according to the Energy Information Administration.

Coal retirements slowed last year to 4 GW, a sharp decrease from the 9.8 GW retired annually over the past decade, the EIA said. The country's electricity supply from coal, which was once the primary source, has dropped to about 16%.

More: *Reuters*

West news from our other channels



Wash. Bill Seeks to Attract Fusion Energy Developers

NetZero Insider

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

State Briefs

ARIZONA

House Approves Bill to Require Utility Wildfire Prevention Plans

The House of Representatives last week voted 35-25 to approve a bill that would require utilities to create wildfire prevention plans.

The bill would require utilities to prepare wildfire mitigation plans to proactively prevent wildfires and decrease any damages that may occur. Those strategies include inspection procedures for wildfire risks, procedures for de-energizing power lines, community outreach and public awareness efforts, and new steps on how power companies will monitor compliance with their plans.

The bill now heads to the Senate.

More: *Arizona Capitol Times*

COLORADO

House Passes Bill to List Nuclear as 'Clean Energy'

The House of Representatives last week voted 43-18 to pass a bill that would add nuclear power to the state's list of "clean energy" resources.

The state's definition of "clean energy" determines which projects are eligible for clean energy financing at the county and city levels and determines which resources may be used by a utility to meet the state's 2050 clean energy target.

The bill now heads to the Senate.

More: *Colorado Politics*

DELAWARE

NRG Closes State's Last Coal Plant

NRG announced it officially closed the coal-fired Indian River Power Plant on Feb. 23.

Originally scheduled for decommission in 2022, the plant was kept operational while transmission upgrades were conducted to the grid until 2026. Now the plant will close 22 months early.

More: *WBOC*

LOUISIANA

Meta Announces Plans for $10B AI Data Center

Meta recently announced plans to build a $10 billion AI data center in Richland Parish.

To power the massive data center, Entergy is investing $6 billion in infrastructure, including a 10,000-acre solar farm, three natural gas turbines and 100 miles of new transmission lines.

The facility, which is projected to be the largest of more than 20 Meta data centers worldwide, is expected to be operational by 2030.

More: *WVUE*

NEVADA

NV Energy Seeks 9% Rate Increase

NV Energy is seeking approval from the Public Utilities Commission for a $215 million rate increase in Southern Nevada.

The increase would raise residential rates by 9%.

The utility is also asking to increase shareholder return on equity from 9.5% to 10.25% and save low-income residents about $20/month by eliminating the basic service charge.

More: *Nevada Current*

NEW MEXICO

House Passes Low-income Rates Bill

The House of Representatives last week voted 42-25 to pass legislation that would pave the way for low-income rates for investor-owned utility customers.

The bill would let utilities submit applications to the Public Regulation Commission for low-income rates. The legislation does not create a low-income rate but instead allows utilities to craft a rate or develop a program that is brought to the PRC for approval.

More: *New Mexico Political Report*

SOUTH DAKOTA

Lawmakers Endorse Eminent Domain Hurdles, Enviro Studies for Carbon Pipelines

Lawmakers have advanced legislation that would make it more difficult for carbon dioxide pipeline companies to use eminent domain and would subject their projects to required environmental impact statements.

A bill to ban eminent domain for carbon pipelines passed the House last month and is awaiting action in the Senate. Meanwhile, another bill approved by the Senate would retain eminent domain as an option but would require entities using it to first attend mediation with the affected landowner and to have a state permit before commencing eminent domain proceedings.

Elsewhere, the House Commerce and Energy Committee voted 9-4 to send a bill to the House floor that would require an environmental impact statement for CO_2 pipelines. The bill would require utility regulators to prepare or require the preparation of statements before approving a permit.

More: *South Dakota Searchlight*

PUC Approves Massive Wind Farm

The Public Utilities Commission last week approved a 260-MW wind farm.

The $621 million project will consist of 68 turbines on 46 square miles of privately owned land in Deuel County.

More than 50 conditions were included in the permit, addressing cooperation with local agricultural operations, daily time limits on construction, protection of threatened or endangered species, noise levels and more.

More: *South Dakota Searchlight*

TEXAS

Shell Sells Residential Portfolio to NRG Energy

Shell last week confirmed it has sold its residential book of customers in the ERCOT market to NRG Energy.

No other details of the transaction were released.

More: *Houston Chronicle*

VERMONT

Lawmakers Signal Pause of Clean Heat Standard

Lawmakers last week indicated they will likely not continue to pursue development of a Clean Heat Standard.

The discussions come a month after a report was released saying the standard would cost $1 billion over 10 years and raise heating fuel 58 cents/gallon to reduce carbon emissions in the thermal sector.

Lawmakers are also discussing a change to the Global Warming Solutions Act, a law that created carbon emission reduction deadlines, if the Clean Heat Standard is abandoned.

More: *WPTZ*

VIRGINIA

Lawmakers Approve Rate Relief for Appalachian Power Customers

The House and Senate voted unanimously to approve a bill that would provide relief to Appalachian Power ratepayers.

Appalachian would be prohibited from raising rates during the winter months, while there would also be moratoriums on late fees for residential customers.

The bills must be signed by Gov. Glenn Youngkin.

More: *Roanoke Times*

SCC Approves Dominion LNG Storage Facility

The State Corporation Commission last week approved Dominion Energy's plans to construct a liquified natural gas storage facility.

The 25 million gallon facility, capable of storing up to 2 billion cubic feet, would be for the utility's 1,358-MW Brunswick and 1,588-MW Greensville power stations.

Construction is expected to begin this year and be completed by the end of 2027.

More: *Inside Climate News*