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COVER: PJM General Counsel Chris O'Hara speaks at the Members Committee's meeting Jan. 23. (*Page 32*) | *©RTO Insider LLC*

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In this week's issue

FERC/Federal News

Trump Will Need More than Executive Orders for US to Meet Rising Power Demand

By James Downing

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President Donald Trump's executive orders issued just after he took office have already generated plenty of headlines, but on their own, they will not solve the biggest issue facing the power industry — the need to meet rising demand — sources told *RTO Insider* on Jan. 21.

"If we truly want to win the AI race against China, I think that merits a declaration of national emergency, but we can't possibly build enough oil and gas infrastructure in the next couple of years to do it with fossil fuels alone," former FERC Chair Neil Chatterjee (R) said in an interview. "What we should be focusing on is making it easier through this emergency declaration to get every available electron."

In addition to expanding fossil generation, that would include renewable energy, storage and the transmission needed to connect new supplies and loads to the grid, he said.

Electric transmission was not mentioned in the "*Unleashing American Energy*" executive order, and it only came up in the "*Declaring a National Energy Emergency*" order as part of generation. It could benefit from Trump's executive action, Grid Strategies President Rob Gramlich said.

The major tech firms backing AI, many of whose CEOs were in the Capitol rotunda when Trump took office Jan. 20, are going to want to expedite transmission buildout to help meet that demand, Gramlich said in an interview.

Part of the reason that transmission was largely absent from the executive orders is that it became politicized in the past few years, as Democrats came to support its expansion as necessary to deliver on the goals of the Inflation Reduction Act.

"That has created this notion that transmission policy is having red states subsidize blue state policy, and it is going to take some education and experience to overcome that," Chatterjee said.

Why This Matters

Electric transmission was not mentioned in the executive order, but the major tech firms backing AI, many of whose CEOs were at the inaguration, want to expedite the transmission buildout to help meet data center demand.

Republicans are going to get through as many of their policy preferences as they can on their own now that they control the White House and both houses of Congress, Gramlich said. He expects that they will push energy policy through budget reconciliation, a legislative procedure tying bills to budget measures in order to avoid the Senate filibuster. Democrats used this to pass the IRA itself without any Republican support in 2022. (See *Senate Passes Inflation Reduction Act*.)

"I think most permitting reform will need to go through Congress, and I think only a tiny bit could be done through reconciliation, leaving most of it for what would need to be a bipartisan bill," Gramlich said.

He warned not to expect negotiations on permitting reform to pick up immediately where they left off last session because Republicans are going to need to take some time pushing through whatever policies they can without Democrats' votes. Either later this year or next year, momentum could pick up for another attempt at a bipartisan permitting bill. (See *Lame Duck Permitting Push Fails; Manchin Blames House GOP Leaders*.)

The big issue facing infrastructure advancement is bipartisan: Americans of all political persuasions can exhibit "NIMBYism" when it comes to infrastructure, whether it is a pipeline for natural gas or a transmission line for clean energy, Chatterjee said. But the country will need all the electrons possible to meet the rising demand and maintain reliability.

Neither party has wrapped its mind around the surge in demand the electric industry is facing and how important serving it is to win the AI race, which is a national security issue, he said.

"When everyone gets situated, and we start to recognize that electric power is essential to winning the AI race, some of the political obstacles of the last decade and a half, in my view, will start to wear away," Chatterjee said. "And you'll see Democrats recognizing we cannot possibly win the AI race without fossil fuels. And you'll see Republicans recognizing that we cannot possibly win the AI race with fossil fuels alone."

Gramlich agreed with that assessment, adding that many policymakers are stuck on where the grid was a few years ago when the expan-

FERC/Federal News

sion of renewables was the main driver for its expansion.

"But now there's a lot of other generation, and there's a lot of different types of loads, including manufacturing and data centers that are also trying to connect to the grid," Gramlich said. "So, the interests in support of grid expansion have expanded dramatically, and I think we'll see, over the course of this year, the politics come around and incorporate that fact."

Mark Brownstein, the Environmental Defense Fund's senior vice president for the energy transition, took issue with the idea of an "energy emergency" altogether, saying in a statement that the U.S. is already the largest oil and gas producer, with export capacity on pace to double.

"The first-day wave of executive orders does nothing to lower energy costs or improve reliability," Brownstein said. "Instead of rolling back cost-effective, common-sense safeguards that have broad public support, a forward-looking administration would be focused on modernizing our aging electricity grid to meet the growing demand from AI data centers and an increasingly digital economy, prioritizing efficiency and clean electricity."

Erasing Biden's EV Targets

While the industry is dealing with the growth of data center demand now, Trump's executive orders will have some impact on longer-term demand trends, such as for electric vehicles.

Trump's "Unleashing" order states that "it is the policy of the United States ... to eliminate the 'electric vehicle mandate' and promote true consumer choice." There is not any law or rule requiring consumers to purchase EVs, but Republicans branded former President Joe Biden's policies to encourage EV adoption as such.

The order lists several "regulatory barriers" to be removed, such as state emissions waivers and "unfair subsidies and other ill-conceived government-imposed market distortions that favor EVs over other technologies and effectively mandate their purchase by individuals, private businesses and government entities alike by rendering other types of vehicles unaffordable."

R Street Resident Senior Fellow Josiah Neeley said the order could wind up being a blessing in disguise for the industry.

"It seemed unlikely based on the ability of the [Biden] administration to build out necessary accompanying infrastructure, like charging stations," that getting EVs to 50% of national sales by 2030 "was going to be feasible," Neeley said in an interview. "And, so, I think realistically, the administration had set itself on a collision course where it was going to have to do something to alter" its goal.

EVs are going to make up a growing share of new vehicles going forward, but it will be driven by customer demand and that will help turn down the political back and forth around them.

"I think unfortunately in America, everything tends to get very easily politicized, where if one party tries to push EVs, that makes EVs seem uncool," Neeley said. "By contrast, you have [Tesla CEO] Elon [Musk] endorse Trump, and suddenly a bunch of people who used to like Tesla don't like Tesla anymore." ■

FERC/Federal News

Trump Says Data Center Power Plants Will be Expedited

Tells Davos He Has Authority to Fast-track Behind-the-meter Generation

By John Cropley

President Trump presented the World Economic Forum with his desire to power the U.S. AI revolution: behind-the-meter generation co-located with data centers and built rapidly under his National Energy Emergency executive order.

This scenario could avoid the yearslong delays of siting and permitting, he said, and would bypass the transmission grid, which he said is aging and vulnerable to attack.

Trump spoke virtually Jan. 23 to the *annual gathering* of global leaders and decision-makers in Davos, Switzerland.

In response to a question from TotalEnergies CEO Patrick Pouyanne about U.S. LNG exports, Trump segued from fast-tracking LNG facilities to fast-tracking new power generation.

"I'm going to get them the approval," he said. "Under emergency declaration, I can get the approvals done myself without having to go through years of waiting. And the big problem is we need double the energy we currently have in the United States — can you imagine? — for AI to really be as big as we want to have it."

Powering major consumers through on-site generation rather than through the grid is a very old concept, but Trump claimed the idea of doing it with a data center is new.

Trump, a vociferous critic of renewable energy, said new plants could run on whatever fuel the developers like, but he suggested "good clean coal," if only as a backup fuel.

Trump's comments come as the U.S. power sector scrambles to meet what is expected to be a huge increase in power demand from reindustrialization, data center expansion and societal electrification.

Some experts are skeptical the demand will increase as much as the largest projections indicate, but some increase appears inevitable: artificial intelligence is a heavy power draw, and Trump is pushing to make the U.S. a leader in AI.

Why This Matters

The president is moving rapidly to put his economic and energy strategies into place.

The newest projection of AI data center power needs was offered the same day as Trump spoke, when Goldman Sachs Research estimated the facilities' power consumption *would increase more than 160%* from 2023 levels by 2030.

There has been keen interest in powering data centers with nuclear power, thanks to its near-constant output and near-zero emissions.

But Goldman Sachs Research concludes it would be impossible to meet the near-term needs entirely with nuclear. To do so would require 85 to 90 GW of new capacity by 2030, and only a small fraction of that amount is expected to be online by then.

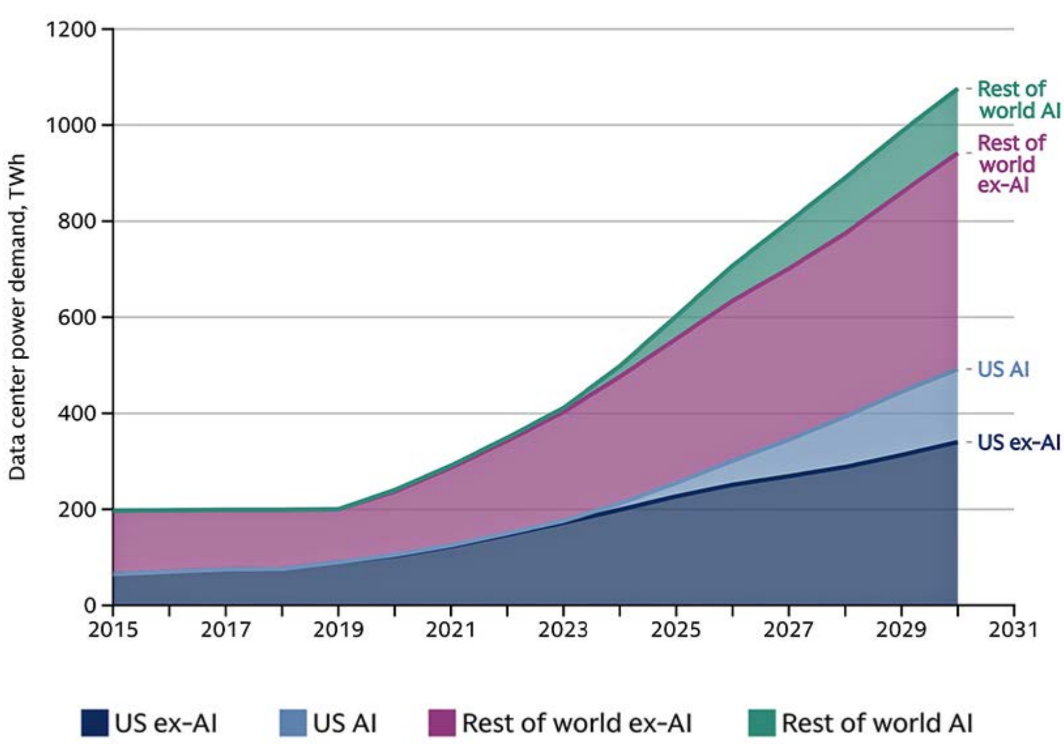
Relying instead on fossil generation would ratchet up greenhouse gas emissions, the report's authors write.

Instead, they suggest a mix of fossil, renewable, storage and nuclear power in the short term.

"Our conversations with renewable developers indicate that wind and solar could serve roughly 80% of a data center's power demand if paired with storage, but some sort of baseload generation is needed to meet the 24/7 demand," said Jim Schneider, a digital infrastructure analyst at Goldman Sachs Research.

The authors also note that future innovations could help reduce Big Data's power needs — from 2015 to 2019, data center workload nearly tripled but electricity consumption was flat, due to increased energy efficiency.

They conclude: "Since 2020, efficiency gains have decelerated, but the team expects more innovations to help lower the power intensity of data centers in future." ■



Goldman Sachs analysts project 2030 data center power demand will be more than 160% higher than 2023 demand. | *Goldman Sachs*

FERC/Federal News

Trump Energy, Interior Cabinet Picks Easily Pass Committee Votes

Democrats Offer Minor Opposition to Burgum, Wright Nominations

By James Downing

The Senate Energy and Natural Resources Committee on Jan. 23 sent the nominations of Douglas Burgum to be interior secretary and Chris Wright to be energy secretary to the floor in bipartisan votes.

"At their nomination hearings last week, the nominees proved that they're committed to implementing President Trump's plan to unleash American energy by ending the policies of climate alarmism and extremism, prepared to streamline permitting and rescind regulations that impose needless burdens on energy production and consequently the American people," ENR Chair Mike Lee (R-Utah) said at the committee's meeting.

Burgum cleared the committee by an 18-to-2 vote, while Wright secured a 15-to-5 vote as more Democrats voted against him. (See *Trump DOE Nominee Seeks to Assuage Senate Democrats*.)

The committee votes yesterday come just a week after Burgum testified before the committee, and eight days after Wright did. (See *Burgum Criticizes 'FERC Queues' for Too Many Renewables*.)

Lee said he hoped the two nominations would move quickly to a vote by the full Senate, and leadership has been pushing through Trump's cabinet nominees, having already secured a unanimous confirmation vote for Secretary of State Marco Rubio on Jan. 20.

Chair Mike Lee (R-Utah) opens up the business meeting to advance President Donald Trump's nominees on Jan. 23. | *Senate Energy and Natural Resources Committee*

What's Next?

Senate leaders, who have been pushing through President Trump's cabinet nominees, say they want the two nominations to move quickly to a vote by the full Senate.

Sen. Ron Wyden (D-Ore.), the ranking member on the Senate Finance Committee, explained he opposed both nominees because of Trump's opposition to clean energy tax credits that both the Finance and ENR committees had worked.

"Rolling back this law is unilaterally disarming America in the face of China," Wyden said. "Because President Trump states he wants to beat the Chinese while seeming to prefer policies that undermine America's greatest advantages, I cannot support nominees that will carry out these policies."

Sen. Maria Cantwell (D-Wash.) said she opposed Wright for more local concerns — cleaning up the old plutonium producing site in *Hanford*, Wash. Wright said cleaning up the site was a top priority, but Cantwell said his commitment to the *Tri-Party Agreement* that has governed the cleanup for decades was "unsatisfactory."

"We get roughly about $2 billion a year in the national budget to clean up Hanford, and we have every energy secretary really pushed by [the White House Office of Management and Budget] to basically try to do cleanup on the short," Cantwell said. "So, I hope maybe between now and the floor, I might get a stronger commitment on the Tri-Party Agreement." ■

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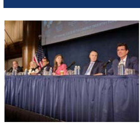

USEA Forum Charts New Focus on 'All-of-the-above' Energy Policies NetZero Insider

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FERC/Federal News

Appeals Court Rules FERC Improperly Awarded RTO Membership Adder

By Devin Leith-Yessian

The 6th U.S. Circuit Court of Appeals *has ruled* that FERC improperly allowed Duke Energy Ohio and FirstEnergy to include the RTO adder in their rates despite participation in an RTO being mandated by Ohio law.

In a December 2022 order, the commission removed the adder from the rates filed by two of American Electric Power's subsidiaries but left it in place for Duke and FirstEnergy (*EL22-34*). The commission differentiated between the three by stating that it previously approved AEP's application for the adder as an independent element, but that Duke's and FirstEnergy's rates were the culmination of settlements that formed the entirety of their rates. (See *FERC Orders Two Ohio Utilities Ineligible for RTO Adder*.)

While FERC argued it could not disentangle the RTO adder from the negotiated rates Duke and FirstEnergy reached in separate proceedings with consumer groups, the 6th Circuit said that in both instances it could be determined that a 50-basis-point adder was included. The commission said it cannot know how the inclusion of the adder interacted with the "precise trade-offs and concessions" in other elements of the settlement.

The court asserted that FERC practice at that time was to grant the adder regardless of the circumstances of a utility, such as whether it was in a state that mandates RTO participation, so the adder likely was not to be a significant factor in negotiations.

"Contrary to FERC's assertion, whether it approved the RTO adder explicitly on a 'single-issue' basis or impliedly as part of a settlement makes little difference to how the three utilities approached rate negotiations," the ruling said.

Judge Karen Nelson Moore partially dissented from the ruling, arguing that modifying elements of a settlement could undermine the preference both FERC and the courts have adopted for resolving issues through agreements over potentially intensive and costly litigation. She said the commission's original solution of eliminating the AEP adders while leaving the Duke and FirstEnergy agreements in place would advance valid policy goals around consumers' rates and promote dispute resolution through settlements.

Why This Matters

The court's ruling solidifies the stance FERC and the courts have taken that the RTO adder can be awarded only to utilities whose participation in RTOs is voluntary.

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"If FERC had accepted OCC's [Ohio Consumers' Counsel] invitation 'to change unilaterally a single aspect of such a comprehensive settlement' … the commission could have signaled to parties that their settlements could become unsettled as a result of later legal developments in which the parties had little say. This in turn would rob the settlement process of the certainty and predictability that incentivize settlements and thereby enhance administrative efficiency in support of the public good," Moore wrote.

Both AEP and the OCC appealed FERC's order to the court, the former requesting that the adder be reinstated and the latter seeking its removal from Duke and FirstEnergy's rates.

The court consolidated that appeal with a separate proceeding Dayton Light and Power (DPL) initiated after FERC rejected its application for the adder in 2021 (*ER20-1068*). The commission determined that DPL was ineligible for the adder on the grounds that Ohio law requires its membership in PJM.

Dayton argued that Section 219 of the Federal Power Act does not condition eligibility for the adder on whether a state makes that decision mandatory and posited that FERC's awarding of the adder preempts state law.

The court disagreed, stating that the adder is an incentive for taking a voluntary act. It also ruled DPL's argument that Section 219 does not have an Order 679 requirement that RTO membership be voluntary constitutes an impermissible collateral attack on Section 219, adopting the "very substantial risk" standard that the commission's interpretation of a rule has shifted. ■

FERC/Federal News

What is and isn't in Trump's National Energy Emergency Order

By K Kaufmann

President Donald Trump's *executive order* declaring a National Energy Emergency talks a lot about energy and energy resources — referring to different fuels, fossil and otherwise — but relatively little about generation, defined as the use of those fuels to produce electricity, according to Keith Martin, co-head of projects for Norton Rose Fulbright.

Electricity is "not the operative part of the executive order," despite the fact that an alleged shortage of electric power across the U.S. is the ostensible reason for its issuance, Martin said in an interview Jan. 21. The order is inconsistent in that respect, he said, "promoting energy defined to exclude electricity. … A more careful draftsman would have connected all the dots."

Signed just after Trump's inauguration Jan. 20, the emergency declaration and some of the other energy-related orders are essentially policy statements aimed at "messaging," Martin said. "They are press releases on fancier paper … directions to the agencies, but they're not specific legal actions."

What's left out of the order is as significant as what's included. While calling for "a reliable, diversified and affordable supply of energy," it omits any mention of solar, wind or storage and makes only passing reference to transmission as part of its definition of generation.

So, what impact, if any, might the declaration and Trump's other energy-related executive orders have? It varies, Martin said.

Trump's order on "*Unleashing American Energy*" calls for an immediate pause on "the disbursement of funds appropriated through the Inflation Reduction Act of 2022 … or the Infrastructure Investment and Jobs Act."

The wording calls for agencies to "review their processes, policies and programs for issuing grants, loans, contracts or other financial disbursements of such appropriated funds for consistency with the law" and Trump's own fossil fuel-leaning energy policies spelled out in the order.

"The Biden administration had been rushing to get to legal commitments for these types of things," Martin said, referring to the Department of Energy's efforts to finalize contracts with a range of grant and loan recipients in the first weeks of January.

According to a final report from the White House, 90% of IRA and IIJA funds available through the end of 2024 have finalized contracts. But, Martin said, "the choice of words — pausing disbursements — suggests that Trump intends to ignore the legal commitments and just block any further disbursements."

Why This Matters

While calling for "a reliable, diversified and affordable supply of energy," the order omits any mention of solar, wind or storage and makes only passing reference to transmission as part of its definition of generation.

President Donald Trump signs executive orders in the Oval Office on Jan. 20. | *C-SPAN*

Industry analysts ClearView Energy Partners agreed, saying the wording could be interpreted "expansively so that it applies to obligated undisbursed monies as well as those which have yet to be obligated."

The emergency declaration, on the other hand, calls on department and agency heads to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess to facilitate the identification, leasing, siting, production, transportation, refining and generation of domestic energy sources."

DOE's *emergency powers* are limited, under the Federal Power Act Section 202(c), to temporary actions in response to emergency-related power shortages. For example, DOE issued an emergency order Oct. 9, 2024, for Duke Energy Florida to operate some generating plants at low output because of the impacts of Hurricane Milton.

Other sections of the order call for streamlining and accelerating the Fish and Wildlife Service's emergency consultations on projects that might raise concerns about endangered species or critical habitat "in order to ensure an initial determination within 20 days of receipt" and to get to a final decision within 140 days.

Tom Falcone, president of the Large Public Power Council, does not expect immediate changes. "It's early days on a lot of these things," he said, noting that the energy emergency order calls for reviews, assessments and recommendations, as do some of the provisions of the "Unleashing" order. "We read them as general direction with an awful lot of process to come, because each one of those things calls for administrative processes and other processes that are still to come."

FERC/Federal News

'A Period of Power Politics'

Karen Wayland, CEO of the GridWise Alliance, is similarly skeptical of Trump's claims of an energy emergency. "I think managing our energy system requires constant attention, but I don't see anything that constitutes an emergency," she said.

Wayland framed Trump's rhetoric as overreach. "We know where infrastructure constraints are. We know both on the transmission [side] and the pipelines. We know where they are. There's nothing in the presidential authorities that allows him to just say, 'OK, everything has been approved. You can go ahead and go build that.'"

ClearView Energy Partners took a broader view of the current political context for Trump and his executive orders and how they might be implemented. The U.S. and other countries "have entered a period of power politics" in which American presidents first "learn from, and build upon, their predecessors' actions" and appear "increasingly willing to test the outer peripheries of regular order, established norms and American political traditions."

ClearView anticipates legal challenges to Trump's more controversial orders, but should federal courts overturn an order, Trump "might iteratively pursue new tactics to achieve his original objectives."

Like Martin, ClearView sees the emergency declaration as setting direction; "however, it does not appear to immediately change policies that might directly impact supply, demand or price."

Lisa Jacobson, president of the Business Council for Sustainable Energy, sees Trump's orders as an opportunity for bipartisan action in support of clean energy.

The U.S. may not have an energy emergency, "but we clearly have challenges," Jacobson said. "We need to understand and respect them, and if this creates an opportunity to really amplify the urgency of moving us into a better position to modernize and expand our energy infrastructure, I'm going to take that moment."

But Jacobson also argued that the way forward requires "durable" bipartisan legislative action, especially on permitting. "We know there's an appetite for that. Hopefully raising it to the level that the president has done on Day 1 will yet again underscore the fact that for our economy, for our security, for the environment, we need to be able to move much faster with energy infrastructure, and energy infrastructure of all kinds." ■

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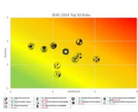
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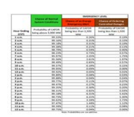
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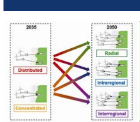
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FERC/Federal News

FERC Drops Consideration of GHG Policy Statement for Gas Infrastructure

By James Downing

FERC on Jan. 24 issued an order terminating its proceeding on the consideration of greenhouse gas emissions in natural gas infrastructure project reviews (*PL21-3*).

"Having thoroughly reviewed that record, we are now withdrawing the draft GHG policy statement and closing that proceeding," FERC said. "We find, based on the record that has been developed, that the issues addressed in that proceeding are, in general, better considered on a case-by-case basis, when raised by parties to those proceedings, as the commission has done following the issuance of the draft."

The proposed policy statement dates back to former Chair Richard Glick's tenure, and opposition to it from former Sen. Joe Manchin (I-W.Va.) helped sink his re-nomination. FERC did not move forward on the draft for the rest of President Joe Biden's term, during which Commissioner Willie Phillips served as chair. (See *Glick's FERC Tenure in Peril as Manchin Balks at Renomination Hearing*.)

FERC had issued the policy statement in February 2022, explaining that it would presume that projects with estimated GHG emissions of at least 100,000 metric tons of carbon dioxide equivalent per year will have a significant impact on climate change — requiring that the commission conduct an environmental impact statement — unless the developer can rebut that presumption with evidence. The policy was strongly opposed by Republican Commissioners James Danly and Mark Christie (the latter of whom became chair Jan. 20).

But a month later, FERC walked back the policy, labeling the statement as a draft and inviting comments on it, on top of the tens of thousands of comments it had already received when it issued its Notice of Inquiry the year before. (See *FERC Backtracks on Gas Policy Updates*.) The commission simultaneously did the same thing with a separate statement that updated its 1999 policy on granting gas pipelines certificates of public convenience and necessity. That docket began with an NOI issued in 2018 and was only mentioned in last week's brief order (PL18-1).

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Why This Matters

A joint concurrence by FERC's three Democratic commissioners — still the majority under President Trump — argued that the commission's case-by-case approvals of gas infrastructure have evolved in response to comments it received in the docket and judicial remands.

All three Democratic commissioners — Phillips, David Rosner and Judy Chang — wrote a joint concurrence, saying that since they have been on FERC, they have followed the law when evaluating applications for natural gas infrastructure.

"The consideration of greenhouse gas emissions in our review of natural gas infrastructure projects has been one of the most challenging issues before the commission for several years," they said. "The extent to which the commission must account for the project's GHG emissions and in turn the impacts on global climate change has been debated and litigated at length before the commission and the courts."

The courts have continued to hand down rulings on cases that implicate FERC's environmental reviews of gas infrastructure, including remanding cases in which they find its analysis lacking, the Democrats said.

While the policy statement is being dropped, the three commissioners said it has provided information that has proven useful for FERC as it developed its current, bipartisan case-by-case approaching to reviewing the climate impacts of natural gas infrastructure.

FERC's approach to GHGs has evolved, and in complying with the National Environmental Policy Act, it estimates reasonably foreseeable emissions attributable to a proposed project; provides a qualitative discussion on potential adverse impacts from those emissions; compares them to state or national levels; and calculates monetized values, the commissioners said. FERC also expects developers to evaluate technically and economically feasible strategies to cut emissions during construction and operation.

"All of our colleagues have joined us on orders using this approach to comply with our NGA and NEPA obligations," the Democrats said. "Critically, the courts have upheld it. If this approach is continued, it will provide more certainty for all parties and stakeholders, fulfill the commission's obligations to consider environmental impacts in its decisions and inform the public regarding the basis for those decisions." ■

CAISO/West News

FERC Approves CAISO's SWIP-North Development Agreement

Proposed Line Playing Role in Utility Decisions for ISO's EDAM

By Robert Mullin

FERC on Jan. 21 approved an agreement between CAISO and LS Power to develop a transmission line that would deliver Idaho wind power into California and could help secure Idaho Power's participation in the ISO's Extended Day-Ahead-Market.

The commission's order covers the Southwest Intertie Project-North (SWIP-North), a 285-mile, 500-kV line being developed by LS Power subsidiary Great Basin Transmission at an estimated cost of $1 billion (*ER25-543*).

The project, which will be jointly funded by CAISO and Idaho Power, will span northern Nevada and southern Idaho and link up with NV Energy's One Nevada (ON) line to the south, providing 2,070 MW of transfer capacity southbound and 1,920 MW northbound.

The development agreement memorializes CAISO's previous agreement to fund about 77% of the project, equal to Great Basin's ownership share, in exchange for operational control of the company's entitlements on the line, which will equate to 1,117.5 MW of southbound capacity and 1,072.5 MW of northbound capacity, with the balance in both directions being allocated to NV Energy.

In addition to facilitating transfers into California, the line offers Idaho wind power resources access to wholesale electricity markets in the Desert Southwest through the Desert Link line connected to the southern end of the ON line.

CAISO's Board of Governors approved the development agreement during an October 2024 meeting despite opposition from some Idaho residents concerned about the path of the line. (See *CAISO Board Approves Moving Forward with SWIP-N Transmission Line*.)

In its filing with FERC, CAISO said it needed to pursue SWIP-North to support the California Public Utilities Commission's resource planning portfolio calling for California load-serving entities to procure 1,000 MW of wind generation from Idaho. The ISO noted the proposed line is the only active project that would help fulfill that objective, making it the most timely and cost-effective option. The project is expected to commence operation in 2028.

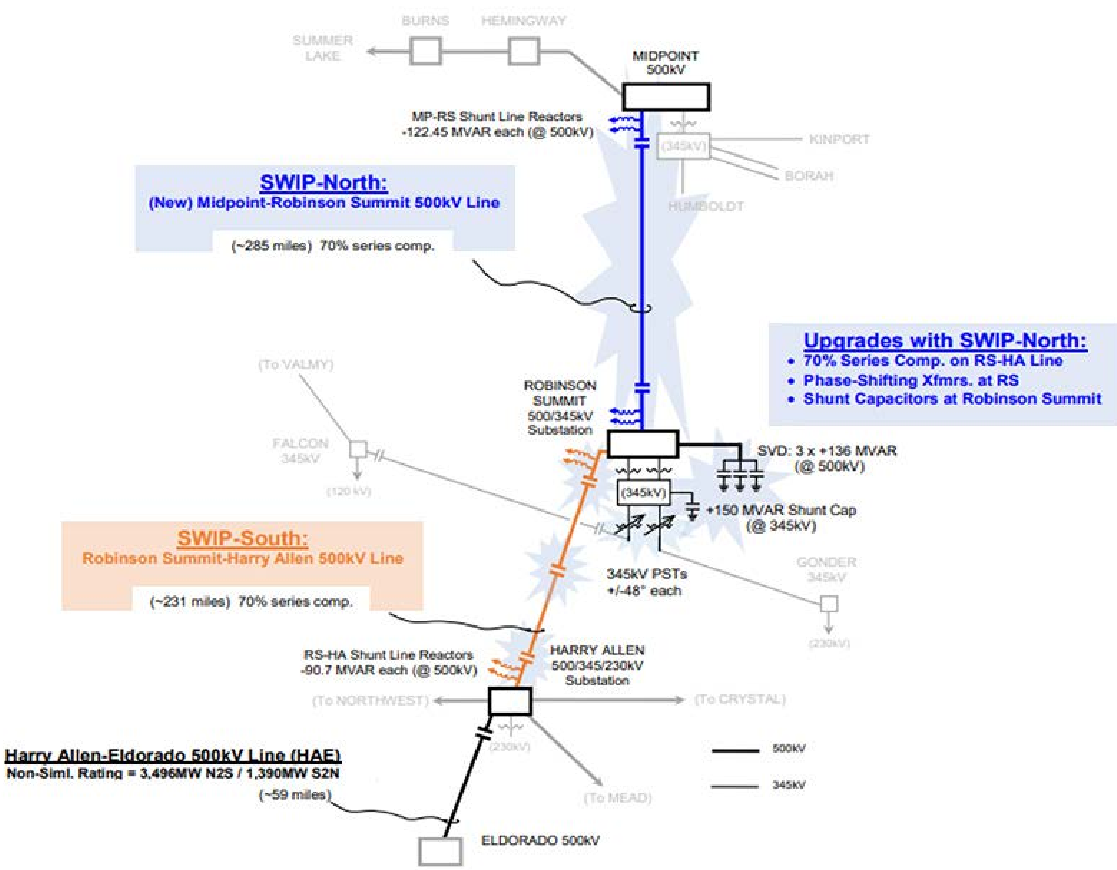
Why This Matters

Development of the SWIP-North transmission line likely will play a key role in Idaho Power getting regulatory approval for joining CAISO's Extended Day-Ahead Market.

CAISO also said SWIP-North would provide additional economic benefits, such as improving California's resource diversity and increasing the ability to reduce congestion costs on the parallel California-Oregon Intertie. The line also will assist California in reducing renewable energy curtailments and exporting its solar surpluses.

CAISO's pursuit of the line likely has played a key role in Idaho Power's leaning in favor of joining CAISO's Extended Day-Ahead Market (EDAM) rather than SPP's Markets+. (See *CAISO's EDAM Scores Key Wins in Contested Northwest*.)

And last year, Ryan Atkins, NV Energy's vice president of resource optimization and resource planning, pointed to SWIP-North and the EDAM's growing transmission footprint when explaining the utility's reason for choosing the CAISO market in comments to the Public Utility Commission of Nevada. (See *Market Footprint Critical for EDAM Decision, NV Energy Says*.) ■



FERC approved CAISO's development agreement for LS Power's SWIP-North transmission project, designed to deliver Idaho wind power into California. | *CAISO*

CAISO/West News

WRAP Members Align on Key Issues to Prioritize

Program Review Committee Votes to Focus on 3 Topics

By Henrik Nilsson

Members of a key Western Resource Adequacy Program (WRAP) stakeholder group voted Jan. 23 to prioritize three topics of concern as the group continues developing the program aimed at addressing resource adequacy and reliability in the West.

WRAP's Program Review Committee (PRC) is "charged with receiving, considering and proposing design changes" to the RA program operated by the Western Power Pool (WPP). The PRC is developing a draft work plan to identify which changes it can develop into concrete proposals.

During the meeting Jan. 23, the committee decided on three topics to prioritize for development this year, including load forecasting, adding language to clarify what qualifies as firm transmission under WRAP and enhancing the WRAP operations program to make it compatible with both SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

Rebecca Sexton, director of reliability programs at WPP | *© RTO Insider LLC*

The prioritized topics have been on most members' minds, and there appeared to be consensus on their importance, Rebecca Sexton, director of reliability programs at WPP, told *RTO Insider*.

Members of a key WRAP committee held its first in-person meeting on Jan. 23. | *Western Power Pool*

What's Next?

The WRAP's Program Review Committee hopes to have its work plan approved by the Western Power Pool board in June.

"There's a lot still to do to come up with the final work plan," Sexton said. "There's a lot more opportunity for stakeholders to weigh in. But for now, seems like a lot of consensus on the order that they determined today."

The PRC hopes to have the work plan endorsed by the WPP Board of Directors by June, but there will be a "rigorous process of review" between now and then, Sexton said.

"So there's a lot of opportunity for the … approach to change," Sexton added. "But I think having not done this before and getting lots of very engaged input, this seems like we're on a path to create something that people will endorse in a couple of months."

The PRC meeting followed WPP board's approval of revisions to WRAP's transition plan in September, including by postponing the program's "binding" phase by one year and reducing penalties for participants who come up short on RA obligations. (See *WPP Board Approves WRAP Transition Plan Changes*.)

The changes were made after WRAP participants urged the board to postpone the start of the program's penalty phase by one year, from summer 2026 to summer 2027, citing "significant headwinds" in securing energy resources in light of supply chain issues, forecasts for faster-than-expected load growth and increasing extreme weather events.

Though the revisions to the transition plan are part of a separate process from those discussed by the PRC, Sexton said much of the work within WRAP task forces tends to overlap.

"It's the way in which we'll hopefully continue to be responsive to stakeholder needs, whether participant or non-participant, and evolve the program with best practices as resource adequacy practices change," Sexton said. ■

CAISO/West News

Data Centers to Drive Calif. Power Demand, Sales

Updated CEC Forecast Shows Outsized Impact from New Facilities

By Elaine Goodman

CAISO peak demand will grow from 48.3 GW in 2024 to about 68 GW in 2040, according to a new forecast that attributes much of the increase to data center load.

The figure is part of the California Energy Commission's annual update to the California Energy Demand forecast. The forecast, which is part of the Integrated Energy Policy Report (IEPR), is considered a cornerstone of the state's energy planning process.

The commission approved the 2024 update Jan. 21.

At the same meeting, the commission welcomed its newest member: Nancy Skinner, who served in the state Senate from 2016 to 2024. Skinner replaces Commissioner Patty Monahan.

The CEC's peak demand projections for 2040 are 66.8 GW in what's known as the planning forecast and 68.5 GW in the local reliability forecast.

That compares to a peak demand recorded in 2023 of 44.53 GW, followed by 48.32 GW in 2024. CAISO's all-time peak demand was 52,061 MW on Sept. 6, 2022, amid a record-breaking heat wave.

The new projections are substantially higher than those made in 2023, when estimated peak demand in 2040 was around 60 GW.

One difference is that the 2024 forecast "improved [the] characterization of the expected growth of data centers," the CEC said in its draft *IEPR update* released in November.

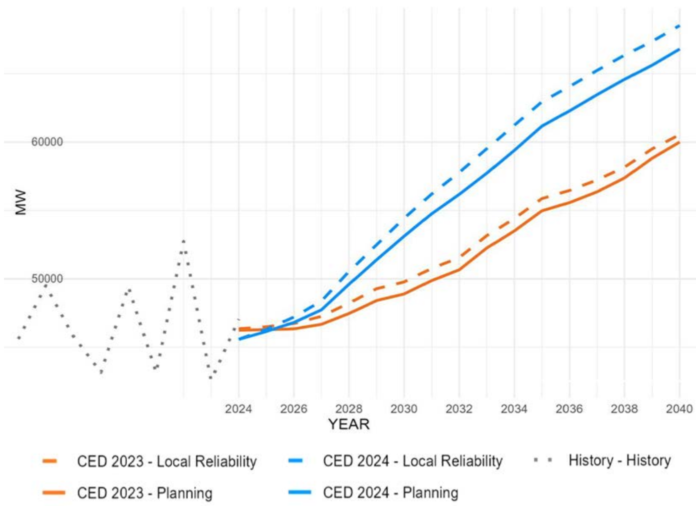
"A significant amount of the peak growth is coming from the additional data center load that we have added this cycle," Nick Fugate, lead forecaster in the CEC's Energy Assessments Division, told commissioners.

Why This Matters

The CEC's updated forecast offers yet another data point showing how profoundly data centers could drive future electricity demand.

Data centers typically run around the clock, including during peak hours, and therefore contribute to peak demand, Fugate said.

The CEC updated its forecasts in December after receiving new information from Pacific Gas and Electric about data center trends. The PG&E update indicated substantially more requested data center capacity compared to figures the utility submitted in September. (See *CEC Ups Data Center Demand Forecast After PG&E Revisions*.)



The California Energy Commission's latest forecast of CAISO peak demand through 2040 has increased significantly compared to the agency's 2023 forecast. | *California Energy Commission*

Sales Forecast

The annual peak demand growth rate in the CEC forecast through 2040 is 2.3% and 2.4% in the planning and local reliability forecasts, respectively.

The growth is even steeper for statewide electricity sales, which see a 3.2% and a 3.3% annual increase through 2040 in the planning and local reliability forecasts, respectively.

Fugate noted that peak load doesn't grow as quickly as electricity sales in the forecast because much of the EV charging that contributes to electricity sales is expected to take place in off-peak hours.

Electricity sales will increase from about 245 TWh in 2024 to 420 TWh in 2040, under the local reliability forecast. In comparison, the CEC's 2023 forecast predicted only about 350 TWh of electricity sales in 2040.

The CEC's planning forecast makes "mid-range" assumptions and is used for system-level planning, such as resource adequacy.

The local reliability forecast may be used for utility distribution system planning or local area reliability studies in CAISO's transmission planning.

Compared with the planning forecast, it assumes less behind-the-meter solar and storage, less energy efficiency and more electrification, resulting in higher predicted demand. That makes up for some of the uncertainty in forecasting for smaller areas, the CEC said.

Behind-the-meter Solar

Another change to the 2024 energy demand forecast was improved projections of behind-the-meter solar and storage. Historical data was updated based on better interconnection data from several utilities.

The CEC estimated there was 17.2 GW of behind-the-meter solar capacity in California at the end of 2023, including a record-setting 2.5 GW that was interconnected that year.

And behind-the-meter solar capacity factors were updated based on "a large real-world sample," the CEC report said. Capacity factors are the ratio of electricity actually generated by a system to the system's maximum capacity.

The new, lower capacity factors used in the 2024 forecast translated to lower estimates of electricity generation compared to the 2023 forecast.

On the energy storage side, the CEC found roughly 1.5 GW of behind-the-meter storage in the state through 2023, and about 84% of that was interconnected in the last five years.

In other changes made in the 2024 forecast, the CEC used the latest information about zero-emission appliance regulations to update building electrification projections. The forecast also accounted for growth in transportation electrification. ■

WPP Stronger After Modernizing, New Staff Hires, CEO Says

By Henrik Nilsson

TEMPE, Ariz. — The Western Power Pool faced "real potential weaknesses" in 2024 due to staff shortages and outdated financial and accounting systems that needed to be addressed quickly, the organization's leadership said during WPP's annual member meeting in Tempe on Jan. 24.

Following the WPP's Board of Directors approval of a 13% *budget increase* — from approximately $13.4 million to $15.3 million — for the 2024/25 fiscal year, the organization embarked on a hiring spree to improve operational oversight and meet future challenges, WPP CEO Sarah Edmonds said during the meeting.

The new hires include a chief financial officer, board administrator, human resource manager, program management analyst, technical trainer and graphics designer. Edmonds said WPP also modernized its finance and accounting practices by moving from manual spreadsheets to automated systems.

"We do need to keep adding people, but not at the scale of last year," she added. "That was a serious and somewhat urgent investment for some areas of real potential weaknesses that we needed to address quickly."

WPP coordinates six stakeholder-driven programs aimed at improving the power grid in the West, including the Western Resource Adequacy Program (WRAP) and Western Transmission Expansion Coalition (WestTEC). All these programs have experienced growth in scope and regional expansion at a time when WPP's "house wasn't really properly in order," Edmonds said.

Edmonds also acknowledged that WPP historically has not been as transparent as it should be.

However, the efforts to boost staffing and modernize WPP's financial structure have paid off, according to board Chair Bill Drummond. He noted that WPP "has been almost like a startup in many respects. It has scaled up to such an amazing degree."

Why This Matters

The Western Power Pool manages six stakeholder-driven programs, including two dealing with increasingly important issues for the West: the Western Resource Adequacy Program and Western Transmission Expansion Coalition.

Moving into 2025, Drummond said the financial and accounting systems are "in great shape now. Got that where it needs to be."

Edmonds said cybersecurity is the next target area. She noted that's an area not unique to WPP and has also been underinvested in "given the kinds of threats that are out there on the system today. So that's up next, and we'll stay always nimble and vigilant." ■

WPP CEO Sarah Edmonds | © *RTO Insider LLC*

CAISO/West News

FERC Approves CAISO Energy Storage Bid Cost Recovery Changes

Tariff Revisions Seek to Limit Opportunities to Game Market for Excessive Payments

By John Cropley

FERC on Jan. 24 approved CAISO's tariff revisions related to real-time bid cost recovery rules for energy storage resources.

The ISO sought revisions on the grounds that the existing bid cost recovery structure allowed for unwarranted compensation at higher value than actual costs, creating an incentive to bid in a manner that would result in excessive payments (*ER25-576*).

Without the tariff changes, CAISO said, "scheduling coordinators for storage resources may exploit market buy-backs and sell-backs through strategic bidding to inflate bid cost recovery payments even more."

From January 2022 to September 2024, storage resources received bid cost recovery payments totaling $58 million, CASIO told FERC, most of which reflect real-time cost recovery payments.

This is a much higher portion of bid cost recovery payments compared with the portion of energy that they provided to the grid, CAISO said. It said a 2024 report by its Department of Market Monitoring (DMM) found numerous situations where storage resources might receive inappropriate bid cost recovery payments.

CAISO indicated also that storage is a rapidly growing energy sector — battery resources participating in CAISO markets expanded from about 500 MW in 2020 to more than 10,000 MW in October 2024, with 3,500 MW of it in the Western Energy Imbalance Market.

After four months of intense stakeholder engagement, the CAISO Board of Governors and Western Energy Markets Governing Body unanimously approved the changes Nov. 7. (See *Proposal to Refine Bid Cost Recovery for Storage Passes Unanimously.*)

In comments to FERC, DMM said it did not oppose the tariff revisions as a temporary short-term measure because they would limit inappropriate payments and limit the potential for gaming the bid cost recovery rules for batteries.

DMM said it supports CAISO's continued effort to further refine the rules through a new stakeholder initiative, but said these changes by themselves are insufficient because they address only the bid-cost component of the bid cost recovery calculation, which reduces gaming potential but does not address inefficient bidding incentives created by the revenue portion of the calculation.

Rows of battery energy storage units are shown at the Desert Sunlight Solar Farm in Desert Center, Calif. | *Shutterstock*

Why This Matters

CAISO sought revisions on the grounds that the existing bid cost recovery structure allowed for unwarranted compensation at higher value than actual costs.

As such, DMM said, the tariff revisions do not address the core problem: that the payments remove storage resources' exposure to real-time opportunity costs, creating incentives that can lead to inefficiencies and reliability issues. It said it hopes CAISO will promptly propose additional changes that will address this.

In its Jan. 24 order, FERC accepted the proposed changes effective Dec. 1.

It wrote:

- "We find that the revisions can help mitigate the magnitude of unwarranted or inflated bid cost recovery payments to storage resources, especially in real-time."
- "With respect to bid cost recovery related to incremental energy, we find CAISO's proposal to use the lower of a resource's real-time energy bid or proxy (the maximum of a resource's day-ahead LMP, real-time market default energy bid or real-time LMP for that interval) provides a reasonable representation of the operational nature of storage resources."
- "With respect to bid cost recovery related to decremental energy, we find CAISO's proposal to use the greater of a resource's real-time energy bid or (the minimum of) the aforementioned proxies better reflect the costs of providing decremental energy."

FERC also wrote that some of the "core problems" DMM cites are beyond the scope of the proceeding but added that it found CAISO's proposal a reasonable first step to mitigating real-time bid cost recovery payments. And it encouraged the efforts by CAISO, DMM and stakeholders to further refine the tariff. ■

CAISO/West News

Ariz. Commissioner Questions Utility Decisions to Join SPP's Markets+

ACC's Thompson Wants State's Utilities to Give Pathways Initiative More Time

By Robert Mullin

Arizona Corporation Commissioner Kevin Thompson on Jan. 24 said he thinks his state's four major utilities may have erred in committing to joining SPP's Markets+ instead of CAISO's Extended Day-Ahead Market (EDAM).

Thompson shared his views during a California Energy Commission workshop exploring the impacts on California of the West-Wide Governance Pathways Initiative's effort to create an independent "regional organization" (RO) to provide governance to CAISO's EDAM and Western Energy Imbalance Market (WEIM).

In a joint announcement issued last November, Arizona Public Service, Salt River Project, Tucson Electric Power and UniSource Energy Services said they planned to start participating in Markets+ in 2027, citing the potential to realize a combined $100 million in benefits from the market. (See *4 Arizona Utilities Commit to Joining Markets+*.)

Arizona Corporation Commissioner Kevin Thompson speaks Oct. 24 at the joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body in San Diego. | *© RTO Insider LLC*

Speaking during a panel featuring four Western utility commissioners who signed the July 2023 *letter* launching the Pathways Initiative, Thompson said he urged his state's utilities to delay their decisions until developments played out around the initiative's "Step 2" plan, which include an effort this year to pass a bill in California authorizing CAISO to both hand off its oversight of market rules to the proposed RO and participate in the new entity.

"I think Arizona's utilities jumped the ball a little bit," Thompson said. "I think they jumped out there ahead of their skis, and I asked them if they would just allow this to work itself through and see where it ends, because this could be the next best thing since sliced bread. You won't know if you don't see it through."

As a publicly owned utility, SRP is not subject to the jurisdiction of the ACC, while the state's investor-owned utilities have a relatively free hand in deciding on a day-ahead market. APS, SRP and TEP all currently participate in the WEIM but have been firm supporters of the development of Markets+ as an alternative to the EDAM, in large part because of their concerns about CAISO's state-controlled governance framework.

New Mexico Public Regulation Commissioner Pat O'Connell echoed Thompson's comments, saying, "It will be interesting to see if we can overcome this governance issue" and questioned "how well those [Arizona utility] decisions will age."

"As the economic studies suggest, not well," O'Connell said, referring to the series of economic studies published over the last year showing most Western utilities would financially benefit more from a single electricity market that includes California than in a scenario in which the region is divided into two markets.

Among those studies was a Brattle Group analysis showing that New Mexico's utilities would realize greater savings from EDAM even if their larger Arizona neighbors joined Markets+, a finding that prompted Public Service Company of New Mexico (PNM) to commit to the CAISO market. (See *Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+* and *PNM Picks CAISO's EDAM*.)

"One of the things you learn by working in the planning world is that — especially in electricity — it's least-cost if we can share" resources, O'Connell said, referencing his past experience working for utilities, including PNM.

Why This Matters

While Arizona regulators are not likely to block the state's utilities from joining Markets+, Commissioner Thompson's views represent sharp dissent from a key stakeholder.

O'Connell pointed out that New Mexico's potential for developing both wind and solar resources is much larger than its energy demand, which means that "it has a lot to a lot to contribute to California in terms of providing low-cost wind resources."

"All those things were in my head when we gathered together and started talking about, 'How can we create the broadest possible footprint for regional coordination?' And that immediately made sense to me: that that is something worth pursuing," he said.

None of the Arizona utilities responded to a request for comment on the commissioners' statements.

Regardless of the direction the Arizona utilities take, Thompson said he is "committed to staying on" with Pathways, an effort he likened to the drafting of the Declaration of Independence.

While acknowledging Markets+ supporters' concerns that CAISO could have continued outsized influence within the new RO, Thompson expressed hope that Pathways participants can address that when they embark on the effort's "Step 3" process to refine the RO and possibly broaden its authority.

"As the states and the stakeholders continue to work through Step 2 and move to Step 3, I think you're going to see a lot of the details work themselves out," he said.

"This is something that was built from the ground up," he continued. "You know, it would have been too easy to follow a PJM model or the other models in the north and the east. We're not PJM; we're not the east. We're the West, and we're unique in that." ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Why This Matters

One basic issue the ERCOT market design framework document brought up for many is the tension between affordability and reliability, which is a universal concern in the power industry.

Stakeholders Sound off on Market Design Framework

ERCOT's Technical Advisory Committee held its first *meeting* of 2025 on Jan. 22, with the biggest chunk of the meeting devoted to discussing the grid operator's proposed market design framework.

The framework dates back to August 2024, when ERCOT CEO Pablo Vegas presented it to the Board of Directors. It is made up of very broad guidelines to use as the grid operator develops rules and regulations, said Vice President of Commercial Operations Keith Collins.

"What we see is that while reliability is the organization's primary objective, cost should always be considered," Collins said. "So, I think that hopefully will set us up for some of the discussion debate that will happen about what the meaning of this balance is."

ERCOT had already gotten *comments* from six sets of stakeholders on the document, and Collins invited them to reiterate what they wrote at the TAC meeting.

"Our comments are meant to be very generally supportive of the framework and the intent behind the framework, because it can be helpful to have this sort of tool to help socialize and coordinate thinking about market design changes," said Ned Bonskowski of Vistra.

However, Vistra wanted to make sure the policy framework is not resetting all of the work the Texas legislature and Public Utility Commission have put into the markets since the February 2021 winter storm, or even further back, he added.

The PUC shelved the performance credit mechanism in December, and ERCOT is working on implementing the real-time co-optimization (RTC) of energy and ancillary services, which means stakeholders have to look for some new policies to improve the system.

"We want to choose among the best tools that we have available to us and use those tools efficiently," Bonskowski said. "But we also don't want to, for instance, give up on trying to just because we may not have the exact perfect tool that we would like to have for a situation. We should not let the perfect be the enemy of the good."

The Lower Colorado River Authority's Blake Holt saw the document as providing some clarity to those who are not in the "stakeholder trenches" regularly, but he had questions on how the document would influence policy implementation at ERCOT.

"How does ERCOT intend to resolve conflicts between competing attributes and timelines?" Holt said. "For example, [the reliability unit commitment] enhances reliability for the hours utilized. However, excessive use of the tool can lead to wear and tear on a unit and worsen reliability in the future, not to mention the out-of-market action leads to flawed and inefficient price formation."

One basic issue the document brought up for many is the tension between affordability and reliability, which is a universal concern in the power industry.

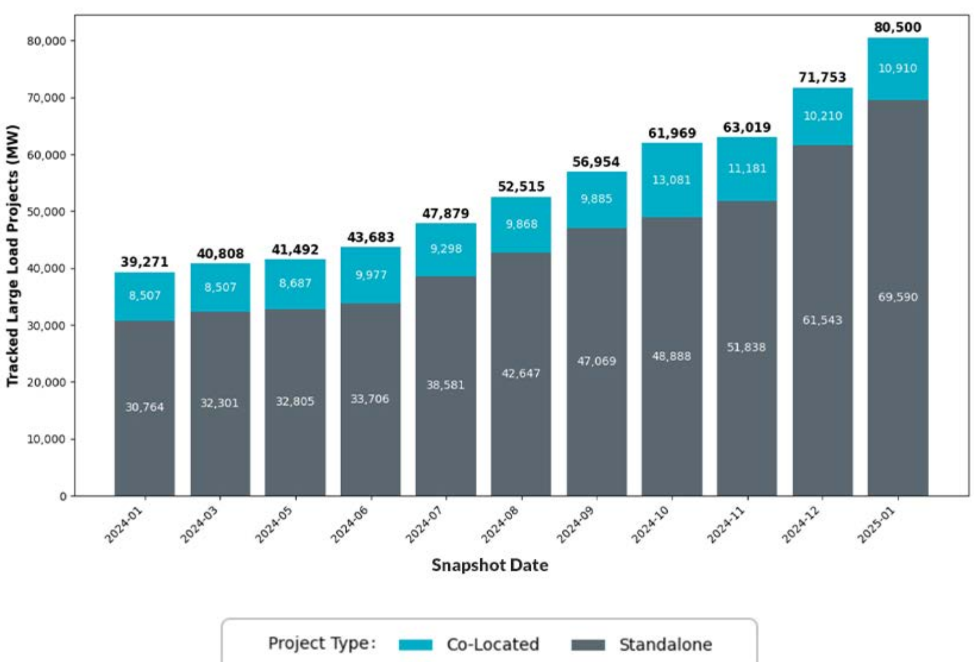
"We recognize there are tradeoffs between the two, and we currently support the stance of conservative operations and understand that operating more reliability or more reliably comes with increased cost," Holt said. "We believe the best way to support this increased cost is through markets in which these operational reserves are currently valued and reflected in as procurement."

Collins agreed that the framework could be useful for people who are not always in stakeholder meetings to use as a way to help wade through the information that is produced at them.

The city of Eastland's Mark Dreyfus questioned the purpose of the document, noting that the stakeholder process implements the nitty gritty details of policy. While they are complicated, many people are involved, and ERCOT's board has the grid operator's whole staff to explain things to them.

"Consumers, as a market segment, have always supported competitive markets, because we know that the competitive market — as reflected in the law, interpreted through the commission rules and into the protocols — is the best way to provide reliability at lowest cost to consumers," Dreyfus said.

The Texas Advanced Energy Business Alliance's Doug Pietrucha said his group agrees that markets are the best way to ensure the right balance between reliability and affordability, but it wants to make sure that technolo-



New large loads planning to connect to ERCOT's system over the past year | *ERCOT*

ERCOT News

gy neutrality is a key part of market design.

"The participation in various services should be based on the attributes that different technologies can provide, and the goal of the service shouldn't be to be designed around the attributes of any one particular technology," Pietrucha said.

Mark Bruce, principal at Cratylus Advisors, questioned the value of the document, noting that policy is determined elsewhere.

"ERCOT doesn't get to make high-level, aspirational policy determinations and documents like this," Bruce said. "All this talk about competitiveness, that issue has been settled since Sept. 1, 1999," referring to the law that restructured Texas' utility industry.

Collins disagreed with that assessment, noting that he has worked around the country in other markets where they do not necessarily wait for FERC for directions.

"You can blaze a path that that can help the commission determine ... a reasonable approach to implementing reliability," Collins said. "It's one thing to say you want a reliable market. Well, how do you want a reliable market? How do you want competitive markets? And what we're seeing here are things that help emphasize how you can achieve that."

Large Load Interconnection Report

In other business, TAC got an update on the number of large loads lined up to connect to the ERCOT grid.

A combination of new standalone projects and those co-located with generation, net of a few cancellations, has ramped up the queue by 17,481 MW since TAC's last meeting in November. With some rule changes anticipated, interconnect requests for loads energizing more than two years in the future have gone up significantly in the last two months, according to an ERCOT report.

ERCOT has added 5,229 MW of large loads from 2022 through 2024, and that could grow to more than 80,500 MW by 2030, the report says. More than 14,000 MW are interested in connecting to the grid this year, though most of that — and most of the 80 GW for 2030 — is under ERCOT review or has yet to submit enough information for the grid operator to even start a review.

Votes on Leadership, Transmission, Rule Changes

The meeting opened up with TAC members voting to give Caitlin Smith of Jupiter Power another year as its chair.

The committee elected a new vice chair, with Martha Henson of Oncor taking that role over after Collin Martin, also of Oncor, stepped down at its last meeting. (See *ERCOT Technical Advisory Committee Briefs: Nov. 20, 2024*.)

TAC voted to recommend three transmission projects from Oncor that are big enough to require approval from the board:

- the Forney 345/138-kV Switch Rebuild Project, which costs $103.5 million, to address reliability issues in Kaufman County and will not require a certificate of convenience and necessity (CCN);
- the Wilmer 345/138-kV Switch Project, which costs $158.2 million, to address reliability issues in Dallas, Kaufman and Ellis counties, which will require a CCN; and
- The Venus Switch to Sam Switch 345-kV Line Project, which costs $118.9 million, to address reliability issues in Ellis and Hill counties and will not require a CCN.

In addition to the three transmission projects, TAC also voted on many rule changes, but the only one that generated debate was NPRR 1250, which is needed for ERCOT to end its renewable portfolio standard implementation practices. Others were put on a *combination ballot* and were unanimously approved.

The legislature passed HB 1500 to end the RPS, which has been effectively moot for more than a decade, as the Texas grid has long had more renewables than was ever required by the standard. ERCOT will still run a voluntary renewable energy credit (REC) trading program but will end the mandatory REC program for RPS compliance.

Vistra's Bonskowski abstained from voting for NPRR 1250 because it did not eliminate several compliance provisions, but he noted that they are going to be dealt with in a future rule change. ■

— James Downing

ERCOT News

ERCOT Fills out Board with 2 New Directors

ERCOT *announced* Jan. 27 that it filled two vacancies on its Board of Directors, bringing it to a full complement of eight independent members.

The Texas grid operator said its Board Selection Committee tabbed Alex Hernandez and Sig Cornelius to serve three-year terms, effective immediately. They replace former Chair Paul Foster and Director Bob Flexon, both of whom left in 2024. (See *ERCOT Board Chair Foster Steps Down*.)

Hernandez is the founder and CEO of Cumulus Data, the first hyperscale data center platform directly connected to carbon-free nuclear power. He brings with him 20 years of experience in business formation, operations, executive leadership and strategic advisory roles, most recently serving as Talen Energy's CEO. Hernandez also served as TerraForm Power's CFO, a board member for the Nuclear Energy Institute's Executive Committee and a managing director at Goldman Sachs.

Alex Hernandez | *Talen Energy*

Sig Cornelius | *Freeport LNG*

He holds bachelor's degrees in economics from both Rice University and the London School of Economics, and an MBA from Columbia University.

Cornelius has spent 45 years in several senior management positions, most recently as president of Freeport LNG Development. Previously, he was with ConocoPhillips, retiring as CFO in 2010.

He has a bachelor's degree from Iowa State University and master's degrees from both Purdue University and Stanford University.

The ERCOT board includes four *ex officio* and nonvoting members to provide an in-person sounding board for member companies: the CEO of ERCOT, the public counsel of the Texas Office of Public Utility Counsel, the chair of the Public Utility Commission and a PUC commissioner designated by the PUC chair.

All board members are from Texas, a change made after the February 2021 winter storm. ■

— Tom Kleckner

ERCOT headquarters in Austin, Texas | © *RTO Insider LLC*

ISO-NE News

ISO-NE Details Evaluation Models for Transmission Solicitation

By Jon Lamson

ISO-NE has *outlined* the transmission and economic models it plans to use to evaluate proposals submitted for the longer-term transmission planning (LTTP) process.

The RTO is developing the first request for proposals for the LTTP process, which is intended to address transmission needs identified in long-term planning studies. FERC approved the new process in July. (See *FERC Approves New Pathway for New England Transmission Projects*.)

At the direction of the New England States Committee on Electricity (NESCOE), the first LTTP solicitation focuses on increasing the transfer capability at two interfaces in Maine and facilitating the interconnection of at least 1,200 MW of onshore wind in the state. (See *ISO-NE to Work on State-backed RFP for Northern Maine Transmission*.)

To help qualified transmission project sponsors (QTPS) develop their proposals, ISO-NE will publish transmission and economic models, said Dan Schwarting, manager of transmission planning at ISO-NE. The models will use the same basic structure as those used by ISO-NE to evaluate projects but will use generic information for generator performance to protect confidentiality.

The economic models outlined at the Planning Advisory Committee meeting Jan. 23 will include a capacity expansion model and a production cost model. The capacity expansion model will determine "the amounts and types of generation needed to adequately serve load over multiple years, given emissions constraints and load growth," Schwarting said. The production cost model will calculate hourly data on generation dispatch, power flow and production cost.

ISO-NE plans to use its version of the models to calculate benefit-to-cost ratios (BCRs) for proposals. These financial benefit calculations will account for production cost and congestion savings, avoided capital costs, avoided transmission investment, reductions of line losses and reductions of unserved energy.

For a project to be selected in the LTTP, the BCR calculation must show that its benefits outweigh its costs. If multiple projects pass this threshold, ISO-NE is not required to select the proposal with the highest BCR and also will consider factors including project scope, permitting challenges and "constructability," Schwarting said.

If no projects pass the threshold, FERC has approved a "supplemental process" in which one or more states could opt to cover the costs that exceed the threshold.

In February, ISO-NE plans to provide additional modeling details to the PAC, including an outline of its modeling of "representative onshore wind projects in northern Maine," and the composite load model the RTO will use for stability simulations.

Schwarting said ISO-NE plans to release a draft RFP to NESCOE and the QTPS to solicit feedback prior to publishing the official RFP in March. He said this limited review process would "strike a balance between feedback and timeliness in issuing the RFP."

Several people asked ISO-NE to expand the opportunity to provide feedback to all stakeholders. Sheila Keane, director of analysis at NESCOE, also expressed an interest in expanding the draft RFP review process.

"As we think about this being the first time through for everyone … it seems like adding in some transparency on the draft RFP might add some value to the process without adding too much time," Keane said.

After issuing the RFP, ISO-NE plans to give transmission developers six months to submit proposals, followed by a yearlong period for ISO-NE to evaluate and select a proposal. Under this timeline, ISO-NE would likely select a solution by September 2026.

"If it is possible to accelerate this timeline we certainly will," Schwarting said.

2024 Economic Study

Also at the PAC meeting, ISO-NE *presented* the final policy scenario results of its 2024 Economic Study, which is intended to evaluate "economic and environmental impacts of New England regional policies, federal policies and various resource technologies on satisfying future resource needs in the region."

The *preliminary results* of the policy scenario, presented in November, found the need to add 58 GW of capacity from a range of zero carbon resources including renewables, energy storage and small modular reactors (SMRs).

The study found that carbon constraints will drive capacity expansion from 2033 to 2039, after which both carbon constraints and load growth will drive resource additions.

Overall, the final results indicate New England will need to add a cumulative capacity of 77,176 MW by 2050. Compared to the preliminary results, the increased need for new capacity reflects a reduced SMR buildout, which increases the amount of capacity required from other resources.

> **What's Next?**
>
> ISO-NE is working with stakeholders to refine the request for the proposals for the new transmission process, which it plans to issue in March.

As the region decarbonizes, SMRs could help fill an essential firm power role and limit the need to overbuild intermittent renewables. ISO-NE has deemed hydrogen generation, carbon capture and storage, and geothermal generation — other potential low-carbon dispatchable resources — to be infeasible solutions for the region due to geological constraints.

The model found that, in 2050, "without additional revenue incentives, SMRs only operate at a 21% capacity factor, but they successfully provide emission free dispatchable generation in the winter to reduce overall system emissions," said Elinor Ross of ISO-NE.

The results also indicate that the cost of additional carbon reductions will increase exponentially as the power system nears full decarbonization in the leadup to 2050.

"Hours of high solar and wind generation are easy to decarbonize at a low cost," said Ross. "The remaining hours left to be decarbonized require energy storage and SMRs, which are more expensive than wind and solar."

Sensitivity analyses also highlighted the significant cost benefits of land-based wind, which was "consistently the most cost effective resource in a levelized cost analysis," said Ross.

Reducing the limitations on onshore wind decreased the overall build costs in the model. In the most extreme sensitivity considered by ISO-NE — which allowed the model to build unlimited land-based wind — the model added more than 44 GW of onshore wind, cutting the overall build costs nearly in half relative to the reference case.

ISO-NE is taking feedback on the policy scenario results and requests for additional sensitivity scenarios through the end of February. ■

ISO-NE News

NEPOOL Reliability Committee Briefs

By Jon Lamson

The NEPOOL Reliability Committee (RC) voted to support *changes* in ISO-NE Planning Procedure 7 (*PP7*) to comply with FERC Order 881. That order is intended to improve transmission line ratings by requiring ambient adjusted ratings for near-term transmission service requests and seasonal ratings for longer-term transmission requests. (See *FERC Orders End to Static Transmission Line Ratings* and *FERC Denies Rehearing, Clarifies Order 881 on Line Ratings*.)

PP7 details ISO-NE's procedures for determining and implementing transmission line ratings.

"The proposed PP7 revisions focus primarily on increasing the number of seasonal ratings from 2 to 12 and providing general guiding principles and requirements in calculating ratings for transmission lines, while allowing each Market Participant to establish their own rating methodology," wrote Michael Drzewianowski, principal engineer of transmission planning for ISO-NE, in a memo before the meeting.

He added that the proposal "is designed to advance the order's objective to account for the natural cooling and heating effects of weather when determining available transmission capacity and to promote and enhance sharing of rating methodologies and ratings data."

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

New England Clean Energy Connect

The RC voted to support two *operating agreements* related to the New England Clean Energy Connect (NECEC) transmission project:

- A transmission operating agreement between ISO-NE and NECEC Transmission giving ISO-NE authority for operational control over the NECEC line
- An interconnection operating agreement between ISO-NE and Hydro-Québec enabling "the coordinated operation of the Québec-to-New England interconnection"

Data and Information Publication

ISO-NE also *outlined* a series of updates to its reporting of operational data and information on capacity scarcity conditions, responding to a series of stakeholder requests.

The RTO implemented several changes in late 2024, including "enhanced notifications of real-time contract curtailments" and a new Next Day Operational Capacity Report.

ISO-NE also is working to create a new "public prospective monthly report" containing total capacity supply obligation data and intends to expand its capacity reporting to include hourly data on capacity surplus. It's considering informational enhancements related to aggregate storage capabilities and real-time tracking of reserves and outages.

Generator Availability Data Collection

The RC also supported a *proposal* for a new planning procedure to govern data collection for the RTO's Generating Availability Data System.

"This procedure will describe the data submission timelines, reporting requirements and validation processes for the required data," said Steven Judd, manager of resource adequacy and accreditation for ISO-NE. He noted that ISO-NE relies on the data to calculate each resource's outage rate and the region's installed capacity requirement.

He clarified methodology used to calculate when wind and solar generators must report events, which differs from the methodology used for conventional generators and is "based on the difference of the plant's [Network Resource] Capability and their Real Time High Operating Limit."

Operating Procedures

Jaren Lutenegger, director of operational performance, training and integration at ISO-NE, detailed some minor *proposed updates* to ISO-NE Operating Procedure (OP) 14, which contains technical requirements for generators.

ISO-NE proposes to clarify its language regarding do-not-exceed dispatch limits for solar and wind generators, and to add fuel types to enable reporting to meet U.S. Energy Information Administration requirements.

Mike Knowland, manager of operations forecast and scheduling for ISO-NE, presented *proposed changes* to OP-21, which governs operational surveys, energy forecasting and energy emergency actions. The proposal is intended to "streamline the surveys and associated processes," and includes updated survey questions and clarifying language regarding energy alerts and emergencies.

The RC voted to support both proposals, along with *clarifying changes* to an OP-23 appendix concerning audits of reactive resources. ■

Why This Matters

FERC Order 881 is intended to improve the accuracy and transparency of transmission line ratings by reflecting real-time weather conditions, aiming to use the grid more efficiently and potentially reduce consumer costs.

Northeast news from our other channels

Prior to Trump Inauguration, Feds Lift Suspension on Vineyard Wind 1

NetZero Insider

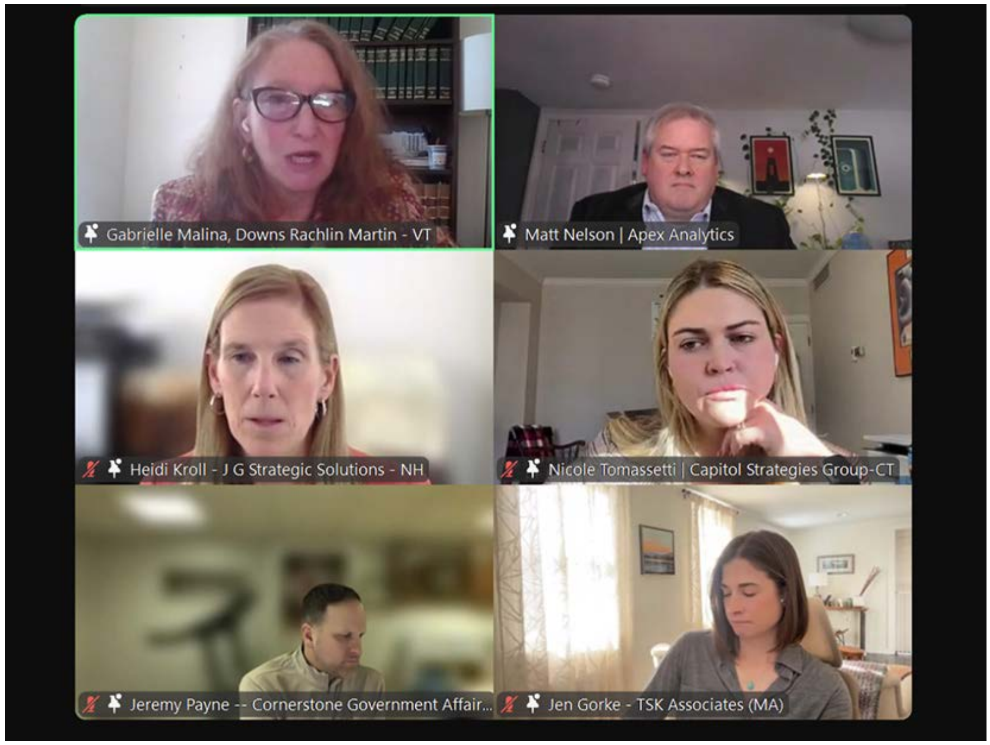
RTO Insider subscribers have access to two stories each month from *NetZero* and *ERO Insider*.

ISO-NE News

New England Lobbyists Preview 2025 State Legislative Sessions

Energy Affordability Continues to be Top Issue Across Region

By Jon Lamson



Clockwise from top left: Gabrielle Malina, Downs Rachlin Martin; Matt Nelson, Apex Analytics; Nicole Tomassetti, Capitol Strategies Group; Jen Gorke, TSK Associates; Jeremy Payne, Cornerstone Government Affairs; Heidi Kroll, J Grimbilas Strategic Solutions | *NECA*

Government affairs experts previewing New England's 2025 legislative sessions during a Jan. 24 webinar held by the Northeast Energy and Commerce Association outlined some key policy overlaps and notable differences among states.

Energy affordability will likely continue to be a major topic for all six states. The region is facing the need for major investments in the coming years to replace aging transmission infrastructure, keep up with load growth and interconnect new renewable resources, which threaten to increase the region's already-high electricity prices.

"The key issue when it comes to energy in Connecticut is affordability," said Nicole Tomassetti, an associate at Capitol Strategies Group.

Increasing electricity prices were a hot topic in the state in 2024, with Republican lawmakers unsuccessfully pushing for a special session to address the issue. Tomassetti noted that affordability concerns caused the state to abstain from selecting any power from the 2024 multi-state offshore wind procurement. (See *Connecticut Closes the Door on 2024 OSW Procurement*.)

But despite high energy prices, Connecticut Democrats performed well in November, achieving veto-proof majorities in the House and Senate.

With Democrat Ned Lamont in the governor's office, "I don't think we expect them to utilize that, but it does illustrate how they've expanded their hold on the legislature," Tomassetti said.

Meanwhile, the public spat between the Connecticut Public Utilities Regulatory Authority and the state's investor-owned utilities continued in 2024, centered around the utilities' rate of return on their investments. (See *The Rocky Road to Performance-based Regulation in Connecticut*.)

Why This Matters

As federal policy turns away from renewable incentives, state policies may become increasingly important to clean energy development.

"Things have been tense, and I think they've gotten tenser in the last couple months between the [electric distribution companies] and the regulator," Tomassetti said.

NH Republicans Tighten Grip

In New Hampshire, Republicans also tightened their grip on all three branches of state government in November, gaining seats in both the House and Senate and maintaining Republican control of the governor's office, replacing outgoing Gov. Chris Sununu with Kelly Ayotte.

With federal funding no longer coming in from the American Rescue Plan Act, balancing the state budget is the "number one priority" for New Hampshire lawmakers, said Heidi Kroll, vice president at J Grimbilas Strategic Solutions. Kroll said state agencies could face budget cuts in the range of 6 to 10%, though specific budget numbers have not been announced.

On energy policy, "affordability and reliability are the two buzzwords that we're hearing most often," Kroll said, adding that lawmakers will likely discuss potential changes to net metering and the state's renewable portfolio standard, which is up for review this year.

Kroll added that she is still waiting to see whether the Ayotte administration will make any notable changes in energy policy from the Sununu administration. Ayotte has called for an "all-of-the-above energy strategy" that includes pursuing small modular reactors and hydrogen power, but has expressed concern about offshore wind in the Gulf of Maine.

Mass., RI Seek to Protect OSW

In contrast to New Hampshire, Massachusetts remains focused on standing up the region's offshore wind industry and will likely be forced to go on the defensive to protect its nascent industry from a hostile Trump administration.

"I can't underscore enough how important offshore wind is to the state's clean energy and climate goals," said Jen Gorke, principal at TSK Associates.

On his first day in office, President Donald Trump paused new leases and permitting approvals for offshore wind projects. (See *Critics Slam Trump's Freeze on New OSW Leases*.) Meanwhile, uncertainty remains around whether the administration will target projects that have already been approved. Vineyard Wind 1, New England Wind, SouthCoast Wind and Revolution Wind all have approved construction and operation plans.

In response to a question at his *confirmation hearing* about offshore wind projects already underway, interior secretary nominee Doug Burgum said projects will be allowed to continue "if they make sense and they're already in law."

"The projects that are under construction, we need to make sure those can continue and are successful," Gorke said, adding that states need to prepare for a "worst-case scenario from the federal government" and work together to prepare to take advantage of the next change in federal administration.

The Massachusetts legislature, which passed major climate and energy bills in 2021, 2022 and 2024, likely will not see another omnibus climate bill this year, Gorke said, adding that "2025 will largely be about implementation."

However, legislators will likely work on smaller-scale efforts related to electricity rates, the state's utility-run energy efficiency program and competitive electricity supply regulations, Gorke said.

Legislators "got really close to a compromise last year" on competitive supply reforms, Gorke said, expressing hope the issue "can be put to bed in a productive way this session."

Rhode Island has similarly focused much of its energy policy on boosting offshore wind, said Matt Jerzyk, legal counsel at William A. Farrell & Associates.

The state has contracted for 400 MW of power from Revolution Wind — with Connecticut on the hook for the project's remaining 304 MW — and recently selected 200 MW from SouthCoast Wind, with Massachusetts selecting the remaining 1,087 MW.

While SouthCoast has received its major federal approvals, it must still win some "ministerial federal approvals," Jerzyk noted.

The project has "a whole host of state approvals to get through, but I think they're still worried about the federal side," he said. The project also has not yet finalized its contracts with the electric utilities in both states.

Vt. Dems Lose Supermajorities, Maine Looks to LTTP

In Vermont, the Republican party gained ground in both the House and Senate, with Democrats losing supermajorities in both chambers. Gov. Phil Scott (R) won reelection by a wide margin.

"There were a lot of veto overrides last year … that has changed now," said Gabrielle Malina, government relations manager at Downs Rachlin Martin. Democratic lawmakers "will have to work more closely with Republicans and with the governor," she added.

Scott and some legislators may seek changes to Vermont's Global Warming Solutions Act, which was passed in 2020 and sets emissions reduction requirements through 2050. The state is *facing a suit* from the Conservation Law Foundation for not taking adequate action to comply with the law's 2025 requirement.

"It's hard to get a read yet whether there will be the political will to change it," Malina said. "I think everybody's pretty worried about the kind of lawsuits we'll see when we get to 2030."

For Maine, Jeremy Payne, principal at Cornerstone Government Affairs, highlighted the potential of the first Longer-Term Transmission Planning (LTTP) solicitation, which is being developed by ISO-NE at the request of the New England States Committee on Electricity (NESCOE). (See *ISO-NE to Work on State-backed RFP for Northern Maine Transmission*.)

The LTTP solicitation is intended to reduce transmission constraints in Maine and enable the interconnection of at least 1,200 MW of onshore wind.

"My hope is that this NESCOE process goes well," Payne said. "If it does, then I think it could be easy to replicate going forward."

He noted that key topics for the state will likely include potential changes to net energy billing, renewable energy solicitations and Gov. Janet Mills' *proposal* to create a cabinet-level Department of Energy Resources. ■

MISO News

MISO IMM Warns of Operational Difficulties with Growing Solar Fleet

By Amanda Durish Cook

CARMEL, Ind. — MISO's Independent Market Monitor said ramping needs north of 10 GW are becoming increasingly common and MISO should expect challenges ahead as its solar fleet expands.

MISO IMM Carrie Milton said in analyzing winter operations data so far, MISO's typical wintertime dual-peaking load pattern in the morning and evening is occurring when MISO's growing solar fleet is unavailable. She said the disparity has become more pronounced as the number of solar panels in the footprint has more than doubled.

MISO set an all-time solar record of 8.272 GW on Jan. 13, where panels accounted for about 10% of total generation. By comparison, January 2024's solar peak was almost 3.3 GW.

On that day, Milton said MISO had a top 17-GW ramping need, with a 9-GW jump occurring in just one hour as not only solar, but wind generation dropped off.

MISO IMM Carrie Milton | *© RTO Insider LLC*

"The good news is MISO managed it very well. You probably didn't even notice it," Milton said at the Jan. 16 Market Subcommittee meeting. She added that routine pricing that day belied the challenges in the operating room.

Milton said such challenges will become a more common feature for MISO control room operators. MISO leadership has said its solar capacity will grow to 12 GW before March. (See *MISO Estimates Solar Fleet will be 12 GW by Winter's End*.)

"We continue to set new records with solar," MISO's John Harmon acknowledged at the Jan. 23 Reliability Subcommittee.

Load Shed Drills Announced

MISO signaled it expects a more fraught operating environment by announcing it will conduct tabletop load shed exercises over 2025, hoping to bring in not only load-serving entities, but also regulators and other stakeholders.

Speaking at a Jan. 23 Reliability Subcommittee meeting, MISO South Manager of Reliability Coordination Jeff Sundvick said MISO's "ever-evolving energy landscape" and "ever-changing weather" is "putting unprecedented stress on our grid." He said MISO would mimic seasonal load shed and extended system loss scenarios in the exercises.

During MISO's Board Week in December, MISO executives confirmed they would pursue large-scale load shedding drills among its membership.

Sundvick said MISO doesn't know some of its members' "specific capabilities for demand reduction." He said MISO hopes to standardize some communication through the drills and "simulate high-pressure scenarios." When MISO issues load shed instructions, it's up to the RTO's local balancing authorities and transmission operators to identify specific loads to shed while prioritizing critical infrastructure.

"We don't want to learn of bottlenecks in the heat of battle. We want to learn about them beforehand," Sundvick said.

MISO Eludes Max Gen Event Thus Far

Recent months have proven little challenge for MISO, which recorded 75-GW average demand and a 95-GW peak in December, a few gigawatts *higher* than December 2023's totals. Peak demand wasn't anywhere near the almost 107-GW peak set in December 2022.

Why This Matters

MISO's solar fleet is poised to hit 12 GW by winter's end. The Independent Market Monitor says that means control room operators will have a rough go with future ramping needs.

Prices rose year over year to an average of \$31/MWh, up from \$25/MWh in December 2023. Natural gas prices inched upward from their stable \$2/MMBtu over most of 2024 to \$3/MMBtu.

MISO also weathered a hard freeze stretching into coastal MISO South using just cold weather alerts and conservative operation instructions Jan. 20 through Jan. 22. The storm dumped a record 10 inches of snow in some parts of New Orleans. MISO also employed a cold weather alert and conservative operations for the South region only to manage a cold front Jan. 6-9. The cold snaps likely produced a winter peak.

Harmon said despite back-to-back winter storms in January, "everything performed as expected from the MISO perspective."

Ahead of the arctic bouts, MISO asked all members to evaluate equipment outage schedules, fuel availability and staffing levels.

MISO operations went off without a hitch in November, bringing lower prices and a lower peak than last year.

The footprint *averaged* a 70-GW average load in November, in line with the previous three years. The month's 81-GW peak load Nov. 21 was smaller than November 2023's 89-GW peak.

Though coal and gas prices were unchanged year-over-year at \$2/MMBtu, the month's average locational marginal price slid to \$23/MWh, lower than November 2023's \$28/MWh.

MISO experienced the lowest generation outages in November in four years, averaging 47 GW daily, a 2-GW reduction over 2023. ■

Generation Developers Ask for Scoring System on MISO Queue Fast Track

By Amanda Durish Cook

| © RTO Insider LLC

Groups of generation owners and developers have asked MISO to adopt a queue fast lane only as a last resort and employ a more limited process that involves scoring criteria to gain entry.

MISO intends to open an express lane in its interconnection queue beginning in June through the end of 2028 for state-designated generation projects that meet resource adequacy targets. The bypass would be meant for projects that can reach commercial operation in three to five years. (See *MISO Tells Board RA Fast Lane in Interconnection Queue is a Must* and *MISO Outlines Plan on Fast-track Queue for Resource Adequacy*.)

However, the Coalition of Midwest Power Producers (COMPP) said MISO should establish a screening process for the fast lane based on project readiness and limit the process to just two accelerated studies — one in 2025 and one in 2026. The two studies should be open to all interconnection customers, independent power producers and load-serving entities alike, COMPP said.

Speaking at a Jan. 22 Planning Advisory Committee meeting, COMPP representative Travis Stewart said MISO's expedited process as proposed creates the possibility of discriminatory treatment in the interconnection queue. This is especially a concern, he said, because designated resource adequacy projects might get first dibs on some of the billions of dollars in freshly constructed transmission capacity MISO has approved in recent years.

Stewart suggested MISO introduce a scoring system to permit projects in the express lane to make sure it's accepting "commercially mature" projects that meet resource adequacy needs. He said project proposals could earn points based on developers' ability to show that projects will serve resource adequacy needs, the completeness of an engineering design and equipment procurement, and that projects have been selected through either regulators or load-serving entities' competitive solicitation. He said the burden to show project need and readiness would be on developers, with MISO to simply "trust and then verify" information from developers and regulators.

Stewart said COMPP's idea, which he dubbed the Alternative Resource Connection Queue, could accept 50 of the highest-scoring projects apiece in 2025 and 2026 to proceed with faster studies aimed at interconnection agreements within 90 days.

"COMPP is concerned that an unchecked, uncapped [express] queue that can continue in perpetuity will likely mimic the 'lane expansion' phenomena in which creating new highway lanes does not improve the flow of traffic but only creates more lanes with more traffic," Stewart said.

Some stakeholders said that asking MISO to institute more evaluation and scoring criteria will inherently slow down and convolute a queue lane designed to be faster.

"We'd rather have some small hurdles set up at the beginning to demonstrate commercial maturity … than have MISO dedicate their engineering expertise to study a project that ultimately doesn't get built," Stewart said, adding that "two weeks of evaluation upfront is better than four months" of ultimately wasted analysis.

NextEra Energy's Erin Murphy, representing a group of MISO generation developers, said MISO's proposal raises fundamental discrimination and undue preference concerns. She agreed with Stewart that a fast lane should be open to independent power producers and load-serving entities alike.

"We are concerned that the most constructable projects and the ones most able to address RA concerns won't get online under this process," Murphy said.

Murphy said while a limited fast track might ultimately prove necessary, MISO should focus first on improving operations of the existing queue to reduce the backlog. She said MISO should increase staffing and allow time for its recently approved queue regulations with FERC to take hold before it establishes specialized processing.

"We're of the firm belief that the volume currently in the queue is more than enough to meet projected resource adequacy needs," Murphy said. She argued that MISO first should take stock of projects already in the queue to ascertain which can meet the footprint's resource adequacy needs. She implied

Why This Matters

MISO said it will respond to generation owners and developers' request that it scale back its fast-track interconnection queue lane and use a scoring system to permit entry to a limited number of project proposals.

MISO News

MISO is establishing a fast lane while disregarding viable projects in the regular queue that already have been vetted.

"There's a heck of a lot of value in the queue that's locked up," Murphy argued.

Murphy said if an imminent resource adequacy gap persists after that, any express lane should come equipped with a scoring system "so the best projects come online in a timely manner." She also said a fast lane option shouldn't "erode" the value of the existing queue.

But WEC Energy Group's Chris Plante said identifying resource adequacy needs is a subjective exercise today.

"It's not as simple as meeting a reserve margin. It used to be that simple," Plante said. He said today's variable requirements in seasons, the sloped demand curve now in place in MISO capacity auctions and more volatile accreditation values year-over-year complicate the picture.

"There's a tremendous amount of uncertainty in determining resource adequacy needs," Plante said.

Murphy agreed and suggested resource adequacy needs could begin with states articulating them and then MISO validating them.

MISO's Andy Witmeier said MISO is delaying its FERC filing into mid-March to consider stakeholders' suggestions. He said MISO would return to the February Planning Advisory Committee to present a final proposal.

However, Witmeier said the point of the fast track is to get projects online quickly as load grows. He said MISO's new queue regulations approved in January 2024 — which include higher fees, automatic withdrawal penalty costs and stricter evidence of land use — will take a few years to bear results.

"We're facing a new phenomenon with spot loads," Witmeier explained.

Witmeier confirmed that projects that elect to drop out of the regular queue to join the fast-tracked queue will face automatic withdrawal penalties.

MISO also plans to collect higher fees from fast-lane developers than in the regular queue. It will start with a $100,000 nonrefundable upfront fee and then a milestone payment of $24,000/MW. Customers in the regular queue pay $8,000/MW.

Clean Grid Alliance's David Sapper argued that MISO's proposal still appears to "violate" FERC's mandate on open access and nondiscriminatory treatment.

Minnesota Public Utilities Commissioner Joe Sullivan said he heard stakeholders offer fair recommendations to MISO.

"I think we have to find a way to treat the existing queue reasonably and fairly," Sullivan said.

Sustainable FERC Project's Natalie McIntire said it seemed MISO wasn't requiring enough proof that projects are ready to embark on construction. She said MISO might consider requiring engineering designs, fuel contracts if applicable and their permitting progress. McIntire said there's "strong stakeholder support" to ensure projects will be able to meet demand in the timeframe MISO needs them.

MISO so far requires details like synchronization and commercial operation dates, interconnection facilities finish dates, generator output, manufacturer and model numbers, fuel type and facility and transformer data. ■

MISO News

6th Circuit Rules Against Michigan Local Clearing Requirement

By Amanda Durish Cook

A federal appeals court has brought Michigan's practice of requiring some amount of locally generated electricity to a standstill, finding that the Michigan Public Service Commission violated the Commerce Clause when designing local clearing requirements.

The 6th U.S. Circuit Court of Appeals decided in a Jan. 16 order that Michigan's local clearing requirement — which requires load-serving entities and alternative energy suppliers alike in the lower peninsula to procure an increasing percentage of their total capacity from within MISO's Zone 7 — is discriminatory and "impermissibly interferes with interstate commerce" (*23-1280*). The appeals court reversed and remanded a district court's earlier finding that the requirement does not discriminate against interstate commerce.

MISO's Zone 7 encompasses the lower peninsula, while the upper peninsula and a portion of Wisconsin are in Zone 2. Michigan relies on MISO's local clearing requirements to establish its own but adds the condition that some capacity comes from in-zone sources.

Energy Michigan, composed of a group of the state's alternative energy suppliers and the Association of Businesses Advocating Tariff Equity (ABATE), an association of industrial and manufacturing entities that use the alternative suppliers, originally sued the Michigan Public Service Commission for its 2017 order establishing the local clearing requirements (U-18197).

Consumers Energy's natural gas Jackson Generating Station | *Consumers Energy*

"Can the state of Michigan require someone selling a product in Michigan to procure that product from the state? Or, phrased in the language of the coin's other side, can Michigan bar in-state retailers from obtaining their merchandise from outside the state? On these issues, negative Commerce Clause jurisprudence is straightforward. Whether the product at issue is milk, or coal-based electricity, the Commerce Clause prohibits such state restrictions unless they clear strict scrutiny's high bar," the court said, drawing on past cases.

The court said the Michigan PSC couldn't make a law that "overtly blocks the flow of interstate commerce at a state's borders."

The Michigan PSC argued that it didn't discriminate because the order's language doesn't mention state boundaries, only MISO's local resource zones. The court called that "not much of a step" because Zone 7 geographically corresponds with Michigan's lower peninsula.

Michigan regulators also argued that the clearing requirement's purpose is to promote resource adequacy, not to protect domestic industry. Energy Michigan and ABATE took a different view of the law, arguing that it's meant to favor utilities in the marketplace and drive out alternative energy suppliers, which are more likely to sell out-of-state electricity. Michigan allows up to 10% of retail electricity sales to be purchased from alternative electric suppliers.

However, the court said the aim of the requirement is irrelevant.

"Even the most benign purpose ... cannot save a facially discriminatory law from strict scrutiny," it said. The court added it judged the percentage requirement the same way it would a requirement dictating 100% of peak demand be procured from Michigan "or even an entire ban on electricity supply derived outside the state's borders."

Finally, the Michigan PSC argued that the Federal Power Act authorized it to enact the local requirement, pointing to a section that removes facilities used for electricity generation from federal jurisdiction. The court responded that "it is difficult to see how this provision authorizes, let alone unambiguously so," Michigan to discriminate against interstate commerce.

Why This Matters

The 6th U.S. Circuit Court of Appeals has reversed and remanded a district court's earlier finding that Michigan's capacity requirement does not discriminate against interstate commerce.

Circuit Judge Danny Boggs dissented from the ruling, saying the case deserves some nuance and is "clearly" beyond the scope of the Commerce Clause because of the players involved. He said the district court erred in its conclusion that public utilities and alternative electric suppliers are similarly situated entities simply because they offer the same commodity.

Boggs argued that unlike the state's utilities, unregulated alternative electric suppliers typically contract with industrial manufacturers and mid-size commercial customers and aren't under an obligation to serve.

"At bottom, eliminating the local clearing requirement would do nothing to further the Commerce Clause's 'fundamental objective of preserving a national market for competition,' and it would undermine the reliability of the state's grid. The majority of Michigan's retail electricity market remains in the hands of the public utilities, who have an unshakable obligation to serve that vital market," Boggs wrote.

Boggs said MISO's local resource zones are not only based on state boundaries but also drawn according to results of MISO's loss of load expectation studies, "the relative strength of transmission interconnections," the electrical boundaries of local balancing authorities and the seams between RTOs.

"Declining to give full weight to the judgment of state and local regulators on a matter of state and local concern is a fraught exercise, particularly considering the intricate area of energy regulation at play here," Boggs wrote. "Geographic proximity to generation improves grid reliability, and without the requirement to secure in-state capacity, Michigan would be at risk of falling short of federal reliability standards." ■

MISO News

Voltus Files Complaint to Hit Brakes on MISO's Stepped-up DR Testing

By Amanda Durish Cook

Voltus has filed a complaint with FERC against MISO, alleging that the RTO's "11th-hour" changes in testing and contract proof requirements ahead of the spring capacity auctions will harm demand response resources and affect rates (*EL25-52*).

In its Jan. 24 complaint, Voltus said MISO is essentially imposing "new terms and conditions" on DR by cracking down on power tests and requiring more detail in contracts. It said the RTO had "moved the goalposts" after testing deadlines passed and with just 45 days to go before the March 1 auction registration deadline.

Voltus asked FERC to deem MISO's stricter testing and contractual requirements unenforceable because they stand to affect rates and had not been filed with FERC for approval. It said that without action, all the 450 MW of load-modifying resources (LMRs) it intends to offer in the 2025/26 capacity auction is at risk of disqualification. The company requested that FERC fast-track its complaint and respond no later than Feb. 14.

Voltus argued that MISO performed an about-face in late December when it announced to market participants via email that "real power tests" would be limited in duration to LMRs' individual stated response times. That means an LMR with a six-hour response time would have a maximum of six hours to demonstrate it could scale back usage. Before then, Voltus said it was MISO's practice to allow DR resources a full day to drop load by at least 50% for real power testing.

But that wasn't the only deviation from MISO's recent testing practices, Voltus told FERC. The RTO announced at the Resource Adequacy Subcommittee's (RASC) meeting Jan. 15 that it would require all LMRs using a firm service level threshold to measure reductions to show in testing that they can cut use to that level and that the reduction be at least 50% of the LMR's registered value. (See *Following DR Exploitation, MISO Announces Stiffer Requirements Before Capacity Auction*.)

Finally, MISO announced that market participants must be able to show that their LMR contracts are active for all seasons their resources offer their services. Contracts themselves must detail response time, how the LMR achieves demand reduction, and specify how many megawatts or to what firm service level end-use customers agree to curtail, the RTO said.

MISO staff said they were forced to double down on existing testing requirements after a handful of companies were caught manipulating the DR market in recent FERC investigations. Staff at the time said MISO's testing requirements are already on the books and that it was merely renewing its enforcement.

Why This Matters

With less than two months to go before MISO's 2025/26 seasonal capacity auctions, Voltus is attempting to halt stricter demand response testing requirements. It argued 'hundreds of megawatts' of demand response are at risk of disqualification because of the RTO's last-minute rule changes.

Voltus itself recently agreed to pay a $18 million civil penalty after FERC investigated the company for reportedly falsifying registrations and overstating capacity from 2016 to 2020. (See *Voltus Agrees to $18M Fine to Settle DR Tariff Violations in MISO*.)

MISO's tariff instructs market participants who wish to register LMRs to conduct real power tests if they have not previously responded to an emergency. The tariff also requires market participants to have "contractual rights" with their resources.

However, Voltus argued that MISO has not defined a "real power test" in its tariff or Business Practices Manuals. The company said it has seen efforts to define DR testing in stakeholder committees repeatedly "fizzle out."

Because MISO and stakeholders have never settled on a definition, the company argued, FERC should act to make sure market participants registering LMRs who relied on the RTO's typical guidance in recent years for the 2025/26 auction are treated fairly.

MISO's late December email came after registration for the 2025/26 planning year had already begun and days before LMRs' testing deadline, Voltus said. And it wasn't until the Jan. 15 RASC meeting — after the LMR testing deadline passed — that MISO announced that it would require aggregators of retail customers demonstrate "contractual control" of their demand resources and resubmit registrations

| DOE

that lack details, it said.

"MISO's beyond-the-11th-hour changes to these requirements will have catastrophic impacts on market participants," Voltus said, adding that it's now impossible for market participants to retest LMRs while still meeting the RTO's original end-of-the-year deadline for testing.

Voltus argued MISO's seemingly new contract specifications are discriminatory because aggregators are now held to a different standard than utilities. While aggregators must submit the more detailed contracts, utilities only must show that customers are enrolled in their DR programs. Voltus argued that MISO did not attempt to explain the disparate treatment.

The company also said it's "unlikely" that contracts between aggregators and their customers "will include all the exact information MISO is now (for the first time) mandating be included."

"As a result of these changes, all of the demand resources Voltus intended to register as LMRs to participate in the [Planning Resource Auction] for the 2025/2026 planning year may be disqualified entirely," Voltus said, explaining that "none" of its customer contracts contains all the data MISO is seeking. It said that as of Jan. 24, it's still waiting for MISO to confirm whether it will accept additional documentation detailing curtailment plans that it has submitted.

"While Voltus has curtailment plans for each of its customers, those curtailment plans are not codified in the contract. Similarly, while some of Voltus' customer contracts specify the [firm service level] to which the customer commits to drop, in many cases that information may be contained elsewhere (e.g., in an email confirmation or other document extraneous to the contract)," Voltus said.

Voltus said that of its 450 MW of LMRs, 112.7 MW are from those that on paper no longer pass MISO's real power testing requirements, either because of new time span limits or the firm service level stipulation. The company said it communicated testing requirements to customers using RTO rules in the last four planning years.

"MISO's 11th-hour change in methodology therefore forced Voltus to choose between two terrible options: (1) not register these demand resources, losing revenues and failing to satisfy its commitments to these customers; or (2) register such demand resources as 'untested,'" the company wrote.

Voltus told FERC it was forced to submit the 112.7 MW as "untested," which it said will increase its potential penalty exposure by $3.16 million per market dispatch and up its collateral requirement by $270,480.

The company predicted that "hundreds of megawatts of demand resources" will be unable to register to participate in MISO's seasonal capacity auctions by the March 1 registration deadline. It warned of "cascading impacts" where aggregators and other market participants will be forced to find replacement capacity or default on bilateral contracts.

Voltus said that while it does not oppose MISO's attempts to strengthen its requirements, the grid operator should not be allowed to "unilaterally impose new requirements on market participants with no basis in the tariff."

MISO told *RTO Insider* via email that it is "reviewing the complaint to determine our response" but declined to comment further. ■

NYISO Presents Preliminary FERC Order 1920 Plan to Stakeholders

By Vincent Gabrielle

NYISO on Jan. 21 presented stakeholders with its preliminary *proposal* for complying with FERC Order 1920, giving a first glimpse into how the ISO may conduct a long-term transmission planning process.

The ISO would repurpose elements of its current Economic Planning and Public Policy planning processes while retaining reliability studies like the Short-Term Assessment of Reliability and Reliability Needs Assessment as separate processes. The System & Resource Outlook would serve as the "core assessment and analysis element" of the new process.

"It's a tough balance," Yachi Lin, director of system planning for NYISO, told the Transmission Planning Advisory Subcommittee. "FERC does give us options on how to comply with Order 1920. We either have a multi-value [process], [with] everything going into one batch, or we decide how to repurpose our current processes, or we develop a new one."

Lin said adding a fourth process specifically for Order 1920 would be overwhelming.

"That's why we landed here," Lin said. "Let's repurpose, leverage, our existing success and experience in economic and public policy planning processes."

NYISO would also adapt its current solution solicitation, evaluation and selection process into the new long-term process. This would incorporate the seven categories of benefits that FERC specified in the order.

Order 1920 also requires a 20-year horizon for transmission planning with cost allocation for projects that ensures that only customers who receive benefits pay for the projects. The order mandates that new grid enhancing technologies and previously passed-over projects be considered.

Why This Matters

FERC Order 1920 is the biggest change to transmission planning in decades. Transmission providers like NYISO have to adapt their planning processes to incorporate FERC's order.

With *Order 1920-A*, FERC gave state governments more of a say in the new long-term processes, granting "relevant state agencies" the opportunity to propose alternative cost-allocation methods for long-term regional transmission facilities. (See *FERC Order 1920-A Wins Approval with Accommodations to States*.)

Several stakeholders asked about why NYISO had only included the Department of Public Service and Long Island Power Authority as "relevant state entities."

"We looked at this issue in connection with a meeting around cost allocation options," said Liz Grisaru, senior adviser for policy at the DPS. "And it appears to us anyway that a 'relevant state entity' is either a state permitting authority or a state entity with the authority to set rates."

One stakeholder pointed out that New York Power Authority sets rates for its communities "all the time," and it was not clear why it was excluded from being a relevant state entity for the purposes of Order 1920. Another stakeholder chimed in that which state entities qualified should be better clarified before "we get too far down the road."

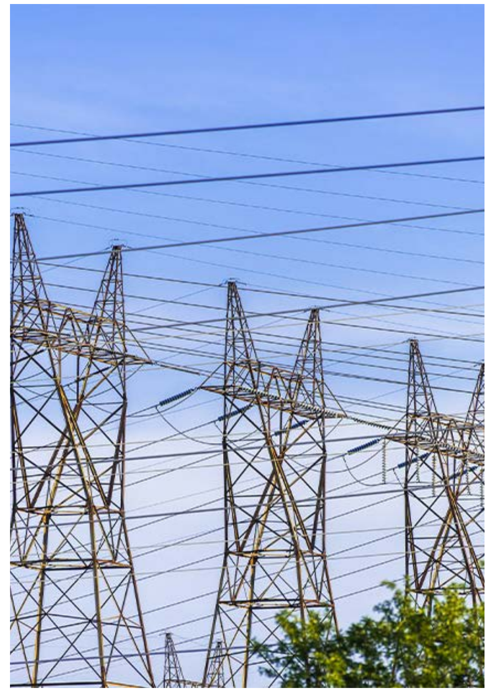
Challenges

The commission required that transmission providers conduct their long-term planning processes every three years. The new process requires NYISO to incorporate more factors, develop more scenarios and include more evaluation metrics than those in the Outlook and Public Policy Transmission Process combined, Lin said.

If the Public Policy and Outlook processes were simply combined without expanding the scope mandated by Order 1920, it would take about four years of NYISO-only work, she said. "We've got to think of ways, creative ways, to try to squeeze the time into three years," she said.

In addition, the New York Public Service Commission will still play a role in the new process. She noted that the involvement of the PSC would add processing time, particularly with the notice and timing rules of the State Administrative Procedure Act.

Lin said some time could be saved by soliciting data from stakeholders and relevant state entities that might affect long-term transmission needs. In effect, this would replace the biennial Public Policy Transmission Need solicitation.



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Chris Casey of the Natural Resources Defense Council said he was worried about the separation of the reliability processes and the new planning process. He said that in the past, the reliability planning assumptions had typically been conservative.

"I guess what I'm worried about is having a separate reliability process identifying a longer-term reliability need and potentially acting on it through that process without understanding if we should be expanding what the solution might be," Casey said.

Lin replied that the objectives of the reliability planning process and the new long-term process were different. Reliability planning is about making sure there's enough energy and capacity. She said that short-term reliability solutions should be used as inputs into the long-term situation.

"There are opportunities to make sure that we link them up together," Lin said. "I do not envision that we will be in a vacuum, only addressing long-term reliability needs without understanding [short-term] reliability."

Lin asked stakeholders and state entities for feedback on the preliminary proposal. NYISO is aiming to submit its compliance filing on regional planning requirements by June 12 and another filing on interregional requirements by Aug. 12. ■

NYISO News

NYISO Begins Capacity Market Structure Review

By Vincent Gabrielle

NYISO on Jan. 22 laid out the timeline for its *Capacity Market Structure Review* project, which will take up the better part of 2025.

Speaking to the Installed Capacity Working Group, Brendan Long, market design specialist for NYISO, said the objectives of the review include identifying current market structures "that will help facilitate New York's evolving grid consistent with policy goals" and exploring potential alternatives. The ISO will solicit feedback from the group throughout the year with the goal of producing a final report in the fourth quarter.

Just like the rest of the U.S., demand for electricity is growing exponentially in New York. The review was called for by stakeholders and the ISO last year to determine whether the capacity market provides adequate resources efficiently and effectively.

According to its schedule, NYISO will propose a priority list of key areas of the market for potential enhancement by the end of the first quarter, propose an initial set of "high-level solutions" in the second quarter and "further analyze and refine" the recommendations in the third.

In response to stakeholder questions, Long said that considering reactive power compensation was on the table and that the review would include evaluating how the market ensures transmission security. The ISO is also going to consider long-duration energy storage compensation structures.

"It's absolutely something we'll consider, and we'll whittle down further as the project progresses," Long said.

One stakeholder pointed out that the project came about because market participants were frustrated with the capacity market; they asked whether identifying the sources of frustration was a priority for the review. Long said NYISO is "definitely going to keep our ears open" for stakeholder feedback and it will play a major role in the direction of the study.

"I think that it's important that part of this project is an articulation of why the current structure is not working," Chris Casey, of the Natural Resources Defense Council, said in agreement with the previous stakeholder. "I think it's important to zoom in on that to know how to fix it. It's more than just collecting the frustrations of the stakeholders. We need to identify and articulate the reasons why this market might not be producing efficient results anymore."

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

What's Next?

NYISO will propose a priority list of key areas of the market for potential enhancement by the end of the first quarter, propose an initial set of "high-level solutions" in the second quarter and "further analyze and refine" the recommendations in the third.

NYISO's structures needed to be harmonized with the state's programs, he said. "I don't think we should come out of this with a structure that pretends that certain revenue sources don't exist or is otherwise blind to state programs because I think that ultimately produces results that are inefficient and costing customers more than they need to pay."

Doreen Saia, chair of the Energy and Natural Resources Practice at Greenberg Traurig, echoed Casey's point, saying any capacity market changes needed to take state policy into consideration.

Saia also asked the ISO to keep in mind that the market structure has been in place for more than a quarter-century and that stakeholders would require "adequate meeting time" to discuss potential changes. This comment came after a November and December where stakeholders had grown frustrated with ISO projects they saw as rushed or incomplete. (See *Large Consumers Vent Frustrations with NYISO's Proposed SCR Changes* and *Winter of NYISO Stakeholders' Discontent over 'Complete' Projects*.)

Several stakeholders, including Casey, urged the ISO to avoid incrementalism and seriously consider the fundamental structure of the market. They said that changes, like new types of resources, might be coming in 10 to 20 years and that any new market structures had to be flexible enough to accommodate them.

"Fundamental changes to the structure, at least looking into them, are in the scope of this project," Long said. "It might not necessarily be prioritized in our list of key areas, but I wanted to clarify that it will definitely be something we're open to hearing feedback." ■

PJM News

PJM in Discussions with Gov. Shapiro on Capacity Price Cap

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM is in discussions with Pennsylvania Gov. Josh Shapiro to work toward a resolution on his complaint to FERC asking it to lower the price cap of the RTO's capacity market, the Members Committee heard Jan. 23 (*EL25-46*).

The discussions also follow a letter Shapiro *wrote* to the PJM Board of Members requesting that it intervene to avoid an "unacceptable" $20.4 billion increase in capacity market prices or the commonwealth may "re-evaluate" its relationship with the RTO. (See *Shapiro Warns of 'Reevaluation' of PJM if Capacity Prices not Addressed*.)

PJM General Counsel Chris O'Hara told the committee that the discussions have included the design of a price cap, as well as the concept of a price floor. He said PJM has also emphasized to the governor that any market changes must consider the need to attract investment in the RTO while also balancing consumer rates.

"We want to make sure you are all aware of these discussions," he told stakeholders.

Responding to questions on whether there is a timeline for PJM to reach a settlement or how the discussions interact with the schedule of the 2026/27 Base Residual Auction, O'Hara said the RTO is moving expeditiously. The auction is scheduled to be conducted in July and in several filings seeking to revise elements of the capacity market, PJM has requested orders by Feb. 21 to ensure it has time to implement the changes.

"We are aware of the auction schedule, and we are moving with haste, but there is no date certain," he said.

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned if it was appropriate for PJM to be discussing market rules with a nonmember, particularly when the changes could affect all market participants. O'Hara responded that PJM will continue to have discussions with membership as well.

Why This Matters

Since Pennsylvania Gov. Josh Shapiro's complaint was filed, the governors of Maryland, Delaware, Illinois and New Jersey also have sent letters to PJM and FERC urging action.

Shapiro requested that the auction's price cap be reset to 1.5 times the net cost of new entry (CONE); the status quo is the greater of gross CONE or 1.75 times net CONE. On Jan. 21, FERC granted a joint motion that Shapiro and PJM filed asking for a one-week extension on the RTO's deadline to respond.

"The requested extension will allow the joint parties to engage in discussions concerning the complaint before any answers are filed," they said in their motion.

PJM *responded* to Shapiro's letter on Jan. 16, saying it has yet to take a position on the substance of his complaint.

"We share your concern for consumer cost increases resulting from the region's supply/demand challenge," PJM wrote. "We are simultaneously concerned about market changes that could serve to thwart new generation entry. This new entry is needed to preserve system reliability and ultimately reduce costs for consumers. PJM is very willing to have discussions about how these two concerns can simultaneously be addressed."

Since Shapiro's complaint was filed, the governors of Maryland, Delaware, Illinois and New Jersey have also sent letters to PJM and FERC urging action.

"As one of the original members of PJM, New Jersey has long worked in partnership with PJM to pioneer new and innovative approaches to provide our residents with reliable and affordable power, most recently exemplified with our work together on the State Agreement Approach," Gov. Phil Murphy said in a Jan. 21 *letter* to the RTO. "That long partnership has become frayed in recent years as PJM continues to take actions that are incongruent with our energy policy and the best interests of our residents. I am calling on you to help repair that partnership and work with New Jersey and other interested states to resolve this matter."

In his own *letter*, Maryland Gov. Wes Moore argued that a lower price cap is needed to prevent a growing affordability problem from worsening in the next capacity auction.

"I strongly urge you to make the requested adjustments to help contain costs to Maryland households, as well as households throughout PJM, particularly in light of the fact that the previous suite of changes to risk modeling and capacity accreditation developed under PJM's Critical Issue Fast Path contributed to the results of the last auction," he wrote.

PJM General Counsel Chris O'Hara speaks at the Members Committee's meeting Jan. 23. | *© RTO Insider LLC*

On Jan. 17, Illinois Gov. JB Pritzker and former Delaware Gov. Bethany Hall-Long (whose term ended Jan. 21) joined Murphy and Moore in a *letter* to FERC arguing that the temporary change would contain auction prices, as barriers to new entry prevent resources from responding to high prices and a large number of rule changes are being considered by the commission.

"The proposed temporary modification to the price cap ensures that prices do not reach unjust and unreasonable levels despite the structural limitations in today's marketplace preventing a pronounced market response to elevated prices," they wrote. "This measure is also warranted given the unusually large number of emergency reforms PJM has proposed for the upcoming 2026/2027 auction, as well as the significant changes implemented in the 2025/2026 auction." ■

PJM Sets Record Winter Peak Load

By Devin Leith-Yessian

PJM set a record winter peak load of 145 GW around 8:15 a.m. Jan. 22, surpassing its previous seasonal peak of 143.7 GW, set in February 2015.

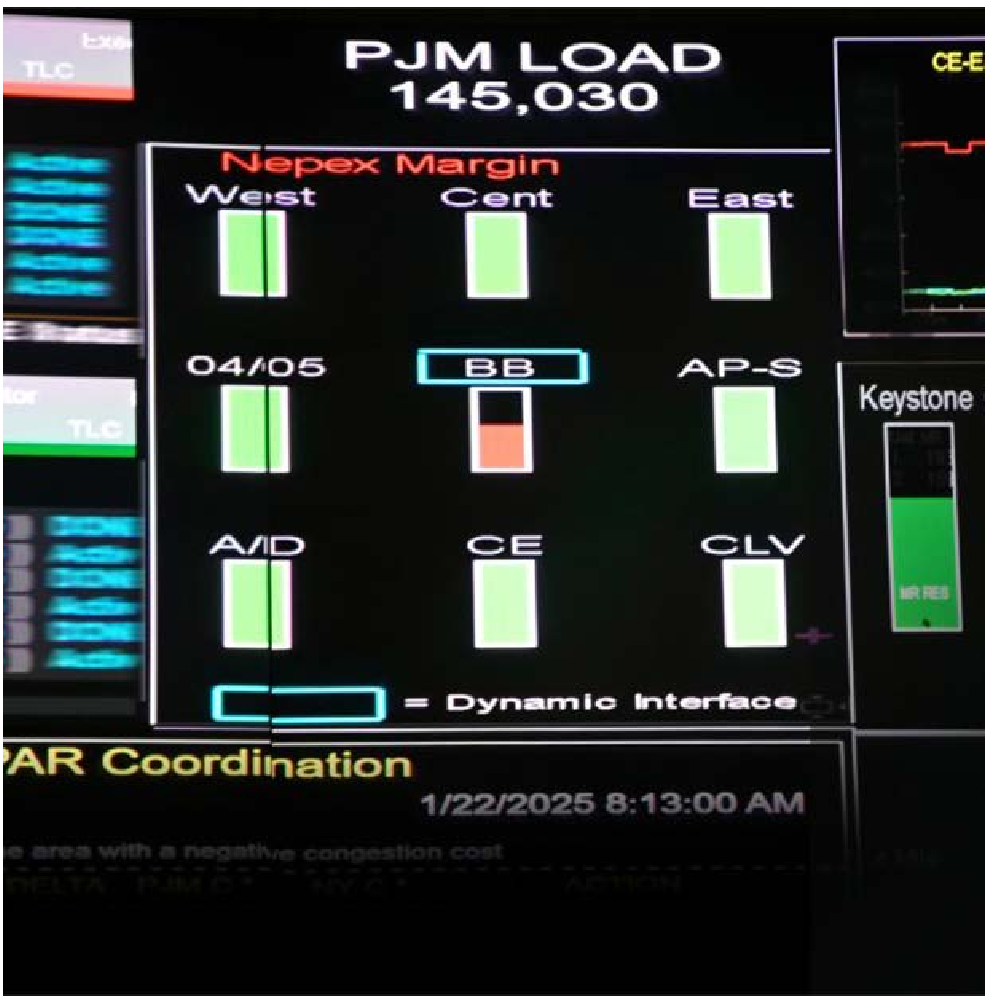
In an *announcement* of the record peak, Senior Vice President of Operations Mike Bryson said actions the RTO and its members took ahead of the cold snap got the system through strained conditions the night of Jan. 21 and the following morning. That includes maximum generation and low voltage alerts, a load management alert, a maintenance outage recall, conservative operations and a cold weather alert.

"We also worked closely with member companies to help resolve any cold-weather issues before the deep freeze set in," Bryson said. "All of those steps served to help PJM and our members get ready for the cold weather. They have performed remarkably thus far, and I am grateful for their efforts."

Exports added an additional 8 GW on top of the Jan. 22 peak and were as high as 9 GW during other times. The maximum generation alert put neighboring regions on alert that exports may need to be curtailed, PJM said. Bryson added that interchange is bidirectional, and PJM has relied on its neighbors in the past.

The preliminary load data PJM shared should be considered approximate figures calculated from raw telemetry data, PJM cautioned in the release.

"Verified metered loads are provided by electric distribution companies and represent the best-quality level of load within their zones, with adjustments to data occurring up to 90 days after the actual date," it said.



PJM saw a record winter peak approaching 145 GW of load on the morning of Jan. 22. | *PJM*

Why This Matters

Winter storms have become an increasing focus in PJM's risk modeling, in part due to accelerating demand. Most of the demand increase is associated with large load additions such as data centers and chip manufacturing facilities.

High demand is expected to continue as long as temperatures remain unusually cold.

In an *announcement* of the alerts Jan. 21, PJM noted that the conservative operations declaration had been established in the wake of the December 2022 Winter Storm Elliott to provide operators with more flexibility in committing reserves or reducing power flows on certain facilities. It said PJM was working with gas generators to ensure their resources were dispatchable ahead of the onset of cold weather and the MLK Jr. Day holiday weekend.

The RTO also lauded the performance of its generation fleet during a cold weather alert issued between Jan. 8 and 10. PJM's Kevin Hatch told the Operating Committee that generation owners started their units early to ensure they could be dispatched if needed and maintenance was rescheduled to ensure availability. Forced outages increased by 2 GW as the temperatures fell, which Hatch said was an improvement over the 7 GW increase in outages seen during the January 2024 Winter Storm Gerri. (See "System Performing Well During Cold Weather Advisory," *PJM OC Briefs: Jan. 9, 2025*.)

Winter storms have become an increasing focus in PJM's risk modeling, with the season holding 87.8% of the expected unserved energy risk according to figures the RTO will *present* to the Markets and Reliability Committee on Jan. 23. Accelerating demand is noted in the preliminary 2025 Load Forecast, which estimates winter peaks will increase by 2.4% annually, up from 1.8% the year prior. Most of that increase is associated with large load additions, such as data centers and chip manufacturing facilities, which make up 11.8% of the increase in winter loads between the 2024 and preliminary 2025 forecasts for the 2030/31 delivery year. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Changes to Generator Deactivation Requirements

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee and Members Committee endorsed a *proposal* to rework the RTO's rules around generation deactivations, including a longer notification period, changes to components of the deactivation avoidable cost credit and adding transparency to the process. (See "First Read on Extended Notification Requirement for Deactivating Generation, Changes to Compensation," *PJM MRC/MC Briefs: Dec. 18, 2024*.)

PJM's Chantal Hendrzak speaks during the Markets and Reliability Committee meeting Jan. 23. | *© RTO Insider LLC*

The proposal would increase the advance notice a generation owner must provide PJM ahead of bringing a unit offline from three months to one year. The status quo deadlines for owners to file for exemptions from the requirement that they offer their resources into the capacity market if they intend to deactivate would remain unchanged. The PJM proposal was supported by the Deactivation Enhancement Senior Task Force (DESTF) in October 2024, winning out over alternatives from the Independent Market Monitor and Calpine, as well as a separate proposal by the RTO.

The longer gap was sought to provide PJM with more time to conduct studies to identify any transmission violations that may be caused by a unit going offline and to make it more feasible for other resources or market participants to mitigate those issues rather than relying on costly reliability-must-run (RMR) agreements.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the longer deadline, paired with a compressed Base Residual Auction (BRA) schedule, would prevent generation owners from being able to tell if their resources would be able to provide capacity in a delivery year before making the decision to deactivate. Given accelerating load growth and generation retirements, he said the proposal could imperil PJM's efforts to maintain resource adequacy.

"We believe that runs counter to the reliability of the system," he said.

The proposal would also increase the deadlines for all resources, Sotkiewicz argued, when only a few require RMR agreements.

PJM Executive Vice President of Market Services and Strategy Stu Bresler said the submission of a deactivation notification does not prevent a generation owner from offering that unit into the capacity market and withdrawing the request if it clears. He acknowledged, however, that there could be staffing issues associated with that dynamic.

Sotkiewicz responded that there are financing and debt issues associated with the determination to bring a unit offline that complicate the ability to undo the decision. It would also increase the administrative burden for PJM staff if resources are submitting and withdrawing deactivation notices that must be studied.

"That's not helping PJM because you're ripsawing the system around in terms of planning," he said.

The proposal would also revise one of the two compensation mechanisms for resources operating on RMR agreements: the deactivation avoidable cost credit. It would remove the $2 million limit on project investments that can be recompensed, limit the annual adder on those investments to 10%, and remove a trigger that causes the credit to be paid through the daily deficiency rate rather than the deactivation avoidable cost rate (DACR) when the DACR and multiplier is greater than the deficiency rate.

The changes to transparency would increase the amount of information published around responses to deactivation notifications, market power determinations, details of RMR agreements and the estimated RMR revenue allocation zonal rate. PJM's Chantal Hendrzak said stakeholders have requested more transparency to understand the going-forward costs of RMR agreements.

Susan Bruce, representing the PJM Industrial Customer Coalition, said the proposal is an improvement from a consumer perspective, albeit a minor one. She said the ICC is supporting the changes in a goodwill gesture with the hope that deeper changes to how RMR agreements are utilized will be pursued in the second phase of the DESTF's work. The end product of those efforts should consider both the permanent design of the capacity market, with three-year forward auctions, and the current reality where auctions are held months in advance of their corresponding delivery year.

"There is a need for thinking about some of those issues, both within the world that we live in now, where we are dealing with things in a whack-a-mole fashion and an accelerated auction timeline. But we also need to think about a time when we have a three-year forward" market, she said. "There is a place here for pragmatism, as well as creating certainty for this fragmented piece."

Monitor Joe Bowring argued that PJM's proposal would not adequately address issues with RMR compensation; would not require RMR resources to document their actual costs; did not require a review of the need for and level of those costs; and should have required the notice be provided one year ahead of the BRA corresponding to the delivery year in which the unit would retire.

Bowring said that under the normal capacity market timing, retiring resources have had to provide notice more than three years ahead of the relevant delivery year. The proposal also lacks provisions for addressing circumstances where RMR units underperform and would fail to address the inclusion of RMR resources in capacity auctions, he argued.

Widened Scope for ELCC Issue Charge Approved

Stakeholders endorsed adding a key work activity (KWA) to an *issue charge* focused on how PJM's effective load-carrying capability (ELCC) framework feeds into resource accreditation and the amount of capacity it may offer.

The additional KWA seeks to "explore potential reforms that may provide greater certainty in ELCC accreditation and/or allow market participants to better manage potential changes in ELCC accreditation between the time of the BRA and the final ELCC values determined for a delivery year."

The paragraph added to the issue charge was revised during the meeting to include other relevant planning parameters to allow the work to also consider impacts to the stability of financial transmission rights.

The discussion was sparked by rising load growth in the preliminary 2025 Load Forecast, particularly in the winter, leading PJM to consider revising the ELCC values of resources participating in the third 2025/26 Incremental Auction, as well as the installed reserve margin (IRM) and forecast pool requirement (FPR) for the auction.

Mike Cocco, of Old Dominion Electric Cooperative, said the change is warranted to address the risk capacity providers face if their accreditation shifts after the BRA, forcing them to buy capacity in the IAs or face deficiency charges.

E-Cubed's Sotkiewicz said the issue demonstrates that PJM needs to stop moving items through the stakeholder process without doing the analysis and full stakeholder discussion, because there have repeatedly been unintended consequences. "We need to think things through very clearly, and we are not learning the lesson," he said.

The overall issue charge also seeks to provide capacity sellers with more certainty around how changes to their resources will affect accreditation and improve the investment signals sent by accreditation. Other KWAs include education about the historical data included in ELCC, key design principles and criteria for accreditation, alternative methods and inputs that can be used in the marginal ELCC framework, and developing proposals to revise ELCC.

The issue charge aims to have governing document revisions filed with FERC in the first quarter so the changes can be implemented for the 2026/27 BRA, scheduled for July. The work is being conducted by PJM's ELCC Senior Task Force, which is also considering a handful of issue charges brought by LS Power to evaluate the transparency and functionality of the framework. (See "Discussions on CETL Shifted to ELCC Task Force," *PJM MRC/MC Briefs: Dec. 18, 2024*.)

Revised Incremental Auction Parameters Endorsed

The committee endorsed *revised* ELCC ratings and a lower FPR value for the third 2025/26 IA, reflecting a shifting resource mix and performance data pushing risk toward the winter.

The endorsement is advisory to the PJM Board of Managers' decision on whether to approve the figures.

Most resource types saw their ratings stay flat or within 1% of the ratings used during the BRA, but offshore and onshore wind saw theirs increase by 3% and 2%, respectively. Storage ratings decreased most sharply for four-hour batteries, with the impact muted the longer the duration, and landfill gas intermittent generation decreased by 3%.

The available installed capacity decreased from 191,693 MW to 188,920 MW, causing the FPR proposed for the IA to fall from 0.9387 to 0.938. The IRM and capacity benefit of ties would remain the same.

The class rating changes were in line with a shift toward winter risk, which accounts for 87.8% of expected unserved energy (EUE) risk under the proposal, up from 86.9% in the BRA. The changes were less substantial than values PJM had presented to the Planning Committee earlier in January, as the RTO decided not to continue using preliminary data from the 2025 Load Forecast in the proposal. The original values saw 96.2% of EUE risk concentrated in the winter, driving sharper changes in ratings and auction parameters.

PJM's Andrew Gledhill told the MRC that the 2025 Load Forecast would be used for the capacity emergency transfer objective and reliability requirement, but not the ELCC class ratings. (See "Stakeholders Discuss Revised IRM and FPR Values for 3rd Incremental Auction," *PJM PC/TEAC Briefs: Jan. 7, 2025*.)

PJM CEO Manu Asthana said there are improvements to be made to how ELCC models extreme weather and performance data. While load forecasting tends to look at 50/50 cases, it's the 90/10 case that is driving the risk modeling, particularly the January 1994 cold wave. He said PJM is looking at spending more time considering how the edges of the data are reflected in its modeling.

E-Cubed's Sotkiewicz said that raises questions of whether reliability risks are being driven by historical data or PJM's selection of which data to include. He also argued that the impact of the load forecast on accreditation has created a dynamic where demand is determining the amount of available supply, running contrary to economic principles. "If our accreditation is affected by the load forecast ... then this is a modeling that is not working," he said.

Sophia Dossin, of Middle River Power, said there is a broader gap around being able to hedge capacity market risk, particularly around the prospect of changing accreditation.

Performance Strong During Record Winter Peak

PJM Director Operations Planning Dave Souder said there was excellent coordination between the RTO and its transmission and generation members as it set a new winter

PJM News

peak load of 145 GW on Jan. 22 as a winter storm brought freezing temperatures across the footprint. (See related story, *PJM Sets Record Winter Peak Load*.)

Several emergency procedures and alerts were announced ahead of the storm, including maximum generation and load management alerts, some of which remained in place until the end of the storm Jan. 23. Souder said two other days exceeded 140 GW during the storm, and it was possible that two of the top five winter peaks were set that week.

Based on unit start-up requirements, low ambient operating temperature limits and historical performance, Souder said about 50 GW of resources were determined to be at risk going into the storm, leading PJM to preschedule resources and avoid cycling them on and off.

Rebecca Stadelmeyer, of Gabel Associates, said the lack of coordination between the electric and gas sectors was on display during this storm and must continue to be a focus of stakeholder efforts. She noted that scheduling fuel over long holiday weekends was one of the core focuses of efforts following the December 2022 Winter Storm Elliott, and generators reported significant losses over the Martin Luther King Jr. Day weekend after procuring packages of fuel that ultimately was not consumed. (See "Stakeholders Endorse Revised Proposal to Align Energy, Gas Schedules," *PJM MRC/MC Briefs: June 27, 2024*.)

"It doesn't seem to be changing anytime soon," she said of the gas industry's rules for fuel procurement.

PJM Senior Vice President of Operations Mike Bryson said it's an issue the RTO must "wrestle with" because the long weekends remain a challenge for dispatchers and generators.

PJM's Bresler said emergency procedures continue to not be fully reflected in market prices, which is part of the issues being addressed by the Reserve Certainty Senior Task Force.

Other Committee Business

Stakeholders deferred action on *revisions* to Manual 14H: New Service Requests Cycle Process that PJM said would clarify the site control requirements for projects in the interconnection queue. The RTO has argued that the language is necessary to create a clear set of rules to apply to all generation projects, but developers have argued that the proposal is too onerous and would require holding onto unneeded land to comply. (See "Vote on Site Control Requirements Deferred," *PJM MRC/MC Briefs: Dec. 18, 2024*.)

PJM's Kevin Hatch presented a first read on *revisions* to Manual 13: Emergency Operations to establish a new procedure for wildfires. Staff meteorologists would evaluate and discuss wildfire risks with transmission and generation owners, conduct future and real-time studies to identify transmission assets that may need to be taken out of service and coordinate with TOs to cancel future transmission maintenance and bring offline assets back into operation as needed. TOs would be responsible for monitoring red flag warnings and high risk conditions, notifying PJM of lines that may need to be de-energized, and re-evaluate the ratings of any facilities impacted by wildfires.

PJM's Ben Miller presented *revisions* to Manual 40: Training and Certification drafted through the document's periodic review. The proposal would update references to reflect organizational changes and clarify how members should respond to PJM data verification requests. It is set to go for an endorsement vote on Feb. 20.

Members Committee

Stakeholders Endorse Process for Proposals Rejected by FERC

The MC endorsed *revisions* to Manual 34: PJM Stakeholder Process to create a pathway for considering how to proceed after FERC rejects a member-endorsed proposal.

The language states that within 90 days of FERC rejecting a filing, PJM may present the order to a senior standing committee and recommend next steps. The presentation may be made on the RTO's own initiative or following a stakeholder request. The discussion may include changes to the proposal that could be made, restarting the stakeholder process or following a new path. ■

— Devin Leith-Yessian

SPP News

SPP Markets+ Tariff a 'Home Run', Staff Says

By Henrik Nilsson

FERC approved SPP's tariff for Markets+ with minor modifications in what the RTO's staff described as a "home run" during the Markets+ Participant Executive Committee's meeting Jan. 21.

The commission's approval Jan. 16 marked a significant milestone likely to ramp up competition with CAISO's Extended Day-Ahead Market. The order came with two conditions, including a requirement that SPP make a compliance filing within 30 days. (See *SPP Markets+ Tariff Wins FERC Approval*.)

Paul Suskie, SPP's executive vice president of regulatory policy and general counsel, noted during the executive committee's meeting that the compliance filing requires SPP to add six sentences to the tariff and delete one.

"I'm going to repeat that: addition of six sentences and the deletion of one, out of a 650-page tariff," Suskie said. "Pretty significant accomplishment."

Specifically, FERC asked for modifications to sections in the tariff dealing with transmission availability and transmission opt-out mechanism, duration and communication of opt-outs, Markets+ transmission contributor and mitigation methodology for resource aggregation, according to Suskie.

"Then last was a deletion of a duplicate that we acknowledged was an unintended duplicate in the filing," Suskie said.

SPP and the SPP Market Monitor also must file informational progress reports to FERC every six months to provide updates on market developments.

Suskie said after reading and rereading the order, "I give it a home run with 10 feet to spare. So, a great success."

SPP Director Steve Wright said the FERC approval is "a really big moment" and that consumers will be better off as a result.

"Because what has happened here is choice has been created, and when there is choice, there is competition," Wright said. "And we've already seen the impacts of the competitive element that Markets+ has offered in the West just over the course of the last 18 months."

The commission said it expects Markets+ will provide its participants with "important economic and reliability benefits" and help them manage the impact of "increasing levels of variable energy resources, load growth and extreme weather events in the region."

Why This Matters

FERC's conditional approval of the tariff opens the door for backers of Markets+ to commit resources to Phase 2 planning.

The order comes nearly six months after the commission *issued the RTO a deficiency letter* outlining 16 problems it needed to address in the tariff, which it filed last March after an intensive stakeholder process.

The decision indicates that SPP sufficiently addressed most of those deficiencies, with FERC asking the RTO to provide clarity where the tariff "lacks specificity on key points," as Commissioner Judy Chang noted in a concurrence, such as in protocols covering "market and resource dispatch mechanics to account for state greenhouse gas programs and the ability for resources to be aggregated when participating" in the market.

SPP anticipates executing Phase 2 funding agreements soon. FERC must approve the agreements, after which SPP can go to the bank and obtain the financing necessary to fund Phase 2. The process may take up to two months, SPP staff said. ■

This map shows the balancing authority areas that participated in Phase 1 of developing SPP's Markets+. NV Energy in Nevada has committed to joining CAISO's EDAM and will not be participating in Phase 2. | *SPP*

SPP headquarters in Little Rock, Ark. | *WER Architects Planners*

SPP News

Powerex Commits to Funding, Joining SPP's Markets+

Announcement Continues String of Good News for SPP's Western Effort

By Robert Mullin

Powerex said Jan. 21 that it will fund the next phase of SPP's Markets+ and "re-affirmed" its commitment to joining the Western real-time and day-ahead offering, a move the company signaled as early as November 2023 — before the start of the extensive stakeholder process to develop the market.

The announcement by Powerex, the marketing and trading arm of Vancouver, British Columbia-based BC Hydro, comes on the heels of another positive development for SPP in its competition for participants with CAISO's Extended Day-Ahead Market (EDAM)/Western Energy Imbalance Market (WEIM): FERC's approval of the Markets+ tariff. (See *SPP Markets+ Tariff Wins FERC Approval*.)

"Powerex has greatly appreciated the collaboration of a diverse group of stakeholders who have invested countless hours over multiple years, with SPP providing facilitation and market expertise to aid in this effort," Powerex CEO Tom Bechard said in a *statement*. "The end result is a fair, robust and durable initial market design built upon an inclusive and independent governance structure from the outset."

The announcement also follows by two months the first formal commitments to Markets+ by Arizona's four largest utilities, including Arizona Public Service, Salt River Project, Tucson Electric Power and UniSource Energy Services. (See *4 Arizona Utilities Commit to Joining Markets*.)

"We are pleased to hear of Powerex's commitment to join Markets+ phase two, and we look forward to continued collaboration with Powerex and other entities as we work together to build a Western market that will reduce costs for members, improve reliability and help members reach their renewable integration goals," Antoine Lucas, SPP vice president of markets and incoming COO, said in an email to *RTO Insider*.

What's Next?

While significant from a funding perspective, Powerex's commitment to Markets+ has never been in question. The most important day-ahead market decision will be that by the Bonneville Power Administration, which is expected to issue a draft decision in March and a final one in May.

BC Hydro's Mica Dam | *Powerex*

FERC's Jan. 16 decision approving the tariff opened the door for Markets+ backers to begin making formal participation commitments and provide the $150 million investment needed to fund the market's Phase 2 implementation stage.

According to an SPP *spreadsheet* posted to the RTO's site Oct. 24, 2024, Powerex will be the single largest funder of Phase 2, responsible for 23.2% under the most likely market footprint scenario, equating to around $34.8 million.

"Our share of Phase 2 is not yet finalized and will depend on who ultimately signs on," Jeff Spires, director of power at Powerex, said in an email, adding that 23.2% "seems like a reasonable estimate based on participation in Phase 1."

"SPP is using a funding mechanism for Phase 2 similar to Phase 1 for determining each participant's share of the Phase 2 implementation costs," Lucas said.

The Bonneville Power Administration, which has not finalized its funding commitment, would be the second-largest contributor, at about $25 million, or 17.4%. The federal power agency recently said it "is actively working with SPP and all other Markets+ participants on finalizing Phase 2 funding agreements."

In its statement, Powerex noted that a market footprint that includes much of the Northwest (BPA was not explicitly mentioned), the Arizona utilities and — likely — Xcel Energy-Colorado "will have substantial resource and load diversity, enhancing the benefits for all participants."

"This expected diversity includes an extensive hydro fleet in the Northwest, growing solar supply in the Southwest as well as expanding wind resources in the Northwest, Southwest and Rockies western subregions," the company said. "The Markets+ footprint will also have both winter-peaking and summer-peaking utilities, further enhancing the opportunities for mutually beneficial trade."

Powerex said it also is "actively pursuing investments in transmission expansion efforts"

SPP News

to help support connectivity across Markets+.

Markets+ Supporter, EDAM Critic

In nearly equal measure, Powerex has been one of Markets+'s most ardent supporters and one of CAISO's harshest critics, having previously stated it had no intention of joining EDAM under any circumstances.

The company has been a consistent critic of CAISO's state-backed governance structure and an outspoken skeptic of the ISO's dual roles as operator of and participant in the EDAM/WEIM, contending that CAISO market practices don't provide equal treatment to non-California participants — all complaints CAISO and EDAM supporters in the Northwest have contested.

In that capacity, Powerex has been a key contributor to the series of "issue alerts" Markets+ backers have been publishing since summer 2024 to compare key features of Markets+ and EDAM, covering such issues as governance, market operations, market design and market seams.

In its Jan. 21 statement, Powerex said it "evaluated its decision to fund and join Markets+ based on three equally important pillars: independent governance, an impartial market operator and sound market design. These three pillars are critical to ensure equitable outcomes for all participants and ratepayers across the market's footprint."

Powerex was one of the first entities to weigh in on the debate over CAISO's response as WEIM operator during the January 2024 cold snap in the Northwest, which pushed a handful of the region's balancing authority areas to the brink of rolling blackouts in the face of power supply shortages.

The company criticized how CAISO distributed the high transmission congestion revenue rents resulting from the event, questioned California's role in supplying its northern neighbors and even offered a recommendation that the Northwest use existing transmission to increase import capability directly from the Southwest and Rocky Mountain regions to circumvent flowing power through CAISO's territory. (See *Powerex Report Expands NW Cold Snap Debate*.)

The persistent debate around the cold snap prompted CAISO to respond eventually with its own rebuttal. (See *CAISO Seeks to Dispel CRR 'Myths' Around January Cold Snap*.)

More recently, Powerex published its own analysis questioning the soundness of a Brattle Group comparative study that found Northwest utilities as a whole would financially benefit more from participating in EDAM than in Markets+, which elicited a *response* from Brattle. (See *Powerex Contests Brattle's EDAM/Markets+ Comparative Study*.)

In June 2024, clean energy industry group Renewable Northwest released a study contending that Powerex was backing Markets+ because the company would benefit more financially from a West divided into multiple markets than a single market that included California. The study was conducted by Grid Strategies. (See *Group Claims Powerex Backing Markets+ to Benefit from Divided West*.)

At the time, Spires told *RTO Insider* the intent of the study "appears to be to distract from the essential governance and market design elements that differentiate the two day-ahead market options."

With Powerex's announcement, the attention of participants in Western electricity market developments will return to BPA, which says it will issue a draft day-ahead market decision in March and a final decision in May. ■

SPP News

Chelan PUD Commits to SPP Markets+ Phase 2 Funding

Decision Closely Follows that of Market's Biggest Funder, Powerex

By Robert Mullin

SPP's Markets+ notched another in a string of successes Jan. 22 after the Chelan County Public Utility District in Washington said it will pay its $1 million to $2 million share of funding for the market's Phase 2 implementation stage.

The announcement by the Wenatchee-based publicly owned utility (POU) came just a day after the biggest Markets+ funder, Powerex, committed to joining the market and providing its funding share, estimated to be about $34.8 million. (See related story, *Powerex Commits to Funding, Joining SPP's Markets+*.)

Powerex's move followed FERC's Jan. 16 approval of the Markets+ tariff, which opens the door for other such moves by backers of the market. (See *SPP Markets+ Tariff Wins FERC Approval*.)

Chelan spokesperson Rachel Hansen said the PUD's announcement covered only funding for Phase 2 and did not constitute a commitment to participating in the market.

"Joining the market will be a separate decision," Hansen told *RTO Insider* in an email.

In a statement accompanying the announcement, Chelan General Manager Kirk Hudson echoed a point the Bonneville Power Administration has made in defending its intention to contribute its own $25 million share of Markets+ funding before a participation commitment: that the investment is necessary to ensure that Western utilities have a viable alternative to CAISO's Extended Day-Ahead Market (EDAM).

"It's in our customer-owners' interest to ensure that a day-ahead and real-time market option exists that features independent governance, encourages investment in resource adequacy and appropriately values hydropower," Hudson said.

And like BPA, Hudson referred to the fact that Northwest utilities will inevitably face a need to participate in an organized day-ahead market.

"The success of wholesale power markets is critical to keeping rates low for Chelan PUD's customer-owners. All around us, we see changes to the region's electric system that will affect how utilities buy and sell power, including a shift to organized electricity markets," he said.

Chelan County PUD's headquarters in Wenatchee, Wash. | *TCF Architecture*

Why This Matters

FERC's Jan. 16 approval of the Markets+ tariff opened the door for backers of the market like Powerex and Chelan PUD to commit to funding Phase 2.

Chelan is not a participant in CAISO's real-time Western Energy Imbalance Market.

According to a *spreadsheet* posted on SPP's website on Oct. 24, 2024, Chelan would be responsible for funding 0.7% of the estimated $150 million cost for Phase 2, based on the most likely Markets+ footprint scenario. SPP has told *RTO Insider* that it is using a funding mechanism similar to that of Phase 1 to calculate each participant's share of the Phase 2 implementation costs.

As competition between Markets+ and EDAM has ramped up over the past year and a half, Chelan has been solidly aligned with the majority of BPA's base of POU "preference" customers who have urged the agency to join Markets+ and asked federal officials to respect its independence in making a day-ahead market decision. (See *Public Utilities Urge DOE to Respect BPA's Day-ahead Decision Process*.)

And along with Powerex and a handful of other utilities in the Northwest and Southwest, Chelan has been a consistent contributor to the series of "issue alerts" published by Markets+ backers that have favorably compared features of the SPP market with those of the EDAM.

Despite its status as a BPA preference customer, Chelan manages its own balancing authority area in Central Washington, operates 300 miles of transmission and controls a combined nameplate capacity of 2,037 MW from the Rocky Reach, Rock Island and Lake Chelan hydroelectric dams.

The utility serves about 49,000 customers in a territory covering nearly 3,000 square miles. ■

SPP News

Western Regulators Clarifying Their Role in Markets+

By Tom Kleckner

Arizona Corporation Commissioner Nick Myers, chair of the Markets+ State Committee, said Jan. 24 that he is drafting a response to FERC's requested compliance filing to clarify some of the key points raised in the commission's approval of the day-ahead market's tariff (ER24-1658).

Myers, vice chair of the ACC, told the MSC that his letter will explain the regulatory group's structure and how it will be funded by SPP. The MSC comprises regulators from most Western states who provide their perspective on Markets+'s development and operations.

"I think this reply would be more of an informal response, as it is a point of clarification other than actual comments, but open to feedback from you all," Myers told the MSC. "I do think having as many as MSC members as possible behind that would be beneficial and helpful and also just keeps everyone on the same page with where these discussions are at moving forward."

FERC conditionally approved the market's tariff Jan. 16. The commission found the tariff was still "insufficiently clear" on some points and directed a compliance filing that is due Feb. 15. (See *SPP Markets+ Tariff Wins FERC Approval*.)

Commissioner Mark Christie (now chair) and Commissioner David Rosner filed a joint concurrence to FERC's order, expressing their concern with governance and ensuring "robust" state involvement in the market's development. They urged SPP to ensure that the MSC, and its Regional State Committee in the Eastern Interconnection, have the ability to provide adequate independent staff support and the means to maintain dedicated staff, similar to the structures of the Organization of PJM States Inc. and Organization of MISO States.

The *Western Interstate Energy Board* currently serves as the MSC's staff support. WIEB's Gia Anguiano, who supports the MSC, said SPP staff will visit Christie and Rosner in D.C. this week to discuss their concurrence in a "little bit more detail." She said there have also been discussions to have the two commissioners participate in an MSC meeting.

"[We] really want to get to the root of their concerns around [their concurrence] and see what we can do to further address it," Anguiano said.

FERC Commissioner Judy Chang issued a separate concurrence that noted the tariff leaves some uncertainties about key market design details, such as transmission capability rules, greenhouse gas pricing and potential seams issues, between Markets+ and CAISO's competing Extended Day-ahead Market.

"I think the biggest point in Commissioner Chang's concurrence is just really to make sure that the market is operating at its greatest potential and for the consumer's benefit," Anguiano said.

SPP has said the compliance filing will require adding six sentences to and deleting one from the 650-page tariff. (See related story *SPP Markets+ Tariff a 'Home run', Staff Says*.) ■

Arizona Corporation Commissioner Nick Myers pauses during a December 2024 trip to D.C. to discuss Markets+ and other Western issues. | *Nick Myers via X*

SPP News

El Paso Electric to Join SPP's Markets+ in 2028

Texas-based Utility Did Not Participate in Phase 1 of Market's Development

By Tom Kleckner

El Paso Electric says it will join SPP's regional day-ahead *Markets+* service offering in a "strategic move … tailored" to meet expected customer load growth and evolving needs.

In a Jan. 24 *press release*, the Texas utility said it made the decision following an "extensive" evaluation process and its participation in CAISO's Western Energy Imbalance Market. It said SPP's experience as an RTO and its "proven track record of expanding renewable energy resources" make it a trusted partner.

EPE plans to make the transition in 2028, a year after Markets+'s expected launch. The utility did not participate in the first phase of the market's development and is the first new organization to join during Phase 2. It will sign the same Phase 2 funding agreement as current participants, SPP said.

The RTO's staff and more than 30 Western entities are working on the market's second phase of development following FERC's approval of the tariff Jan. 16. (See *SPP Markets+ Tariff Wins FERC Approval*.)

Why This Matters

El Paso Electric's decision makes it the first utility to join Markets+ during the second phase of its development. It was a member of CAISO's Western Energy Imbalance Market, but chose SPP's market because of the RTO's "proven track record of expanding renewable energy resources."

SPP COO Antoine Lucas said he was excited to hear of EPE's decision.

"We look forward to welcoming them as a market participant," Lucas said in a statement.

"Markets+ will provide utilities across the region, including EPE, access to a diverse pool of energy resources, enabling a more efficient and reliable energy grid," the company said in its release.

It said joining the market will result in increased reliability, cost savings and clean energy integration, supporting its commitment to sustainability and clean energy goals and maintaining affordability for customers.

EPE said its decision came after two years of collaboration and planning with stakeholders across the region.

A Brattle Group market study released last August estimated EPE would see projected benefits of $19.1 million a year in EDAM, compared with $9.1 million for Markets+. (See *Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+*.)

The utility sits outside ERCOT in the Western Interconnection and is receiving reliability coordinator functions from SPP's *Western RC Services*. It serves about 460,000 customers in 10,000 square miles of Texas and New Mexico, including the major cities of El Paso and Las Cruces, N.M. ■

El Paso Electric's Sunland Park power plant | *Shutterstock*

Company Briefs

EV Startup Canoo Files for Bankruptcy

Canoo on Jan. 17 said it would file for Chapter 7 bankruptcy and cease operations, effective immediately.

Canoo said it had been unable to obtain funding from the Department of Energy's Loan Program Office and its recent discussions to acquire capital from "foreign sources" also failed.

More: *Car and Driver*

Prysmian Group Pulls Plug on OSW Cable Plant

The Prysmian Group announced it has canceled its plans for a $300 million offshore wind cable plant in Massachusetts.

The group spent nearly three years obtaining all the necessary state and local permits but ultimately decided to walk away from the project just days before Donald Trump, who has vowed to shut down the offshore wind industry in the U.S., took office. However, Prysmian did not mention Trump in a statement confirming its decision to not exercise an option to purchase land at Brayton Point and instead chalked the decision up to its efforts to align capacity to produce subsea cable with demand for its product.

More: *CommonWealth Beacon*

Senechal Named New CEO, President of NOVEC

The Northern Virginia Electric Cooperative's (NOVEC) Board of Directors last week named Kristen Senechal as its next president and CEO, effective April 2.

Senechal is currently the executive vice president of transmission and chief operating officer at Lower Colorado River Authority in Texas. She joined the authority in 2017 after nine years at CenterPoint Energy in Houston.

Senechal will succeed David Schleicher, who will retire on April 1.

More: *Potomac Local News*

Federal Briefs

EIA: Wholesale, Retail Electricity Prices to Rise in 2025

U.S. wholesale power prices are expected to be slightly higher on average in 2025 in most regions outside of Texas and the Northwest, according to the EIA's Short-Term Energy Outlook.

The forecast expects the 11 wholesale prices it tracks to average $40/MWh in 2025, up 7% from 2024. It also expects the average residential prices to be 2% higher than the 2024 average, though after accounting for inflation, prices may remain relatively unchanged.

The only two regions expected to have lower than average prices are ERCOT ($30/MWh) and the Northwest ($55/MWh).

More: *EIA*

DOJ Asked to Investigate Texas' Handling of Harvey Recovery Funds

The U.S. Department of Housing and Urban Development (HUD) has asked the Justice Department to take action against the Texas General Land Office (GLO) after finding it had violated the Fair Housing Act by discriminating against Black and Hispanic residents when it designed a competition to allocate Hurricane Harvey relief money.

HUD's review of the GLO's funding process revealed the state agency had engaged in a pattern of "discriminatory actions based on race and national origin," wrote Ayelet Weiss, assistant general counsel for HUD's Office of Fair Housing Enforcement, in a letter to the Justice Department. The GLO originally awarded no money to Houston or Harris County.

More: *Houston Chronicle*

BLM Seeks Public Input for Idaho Renewable Projects

The Bureau of Land Management is seeking public input on two renewable projects in Idaho proposed by Arevia Power.

The proposed projects are for a 400-MW Snake River Energy Solar facility and a 500-MW Taurus Wind facility. The facilities will share a 550-MW battery storage facility and a transmission line.

An informational forum will be held Jan. 28. The public may submit their input by email until Feb. 7.

More: *pv magazine*

State Briefs

CALIFORNIA

Gov. Newsom Calls for Investigation of Moss Landing Fire

Gov. Gavin Newsom is calling for an investigation into a fire that occurred at Vistra Energy's Moss Landing Energy Storage Facility two weeks ago.

The fire was the latest in a string of incidents at Moss Landing. In September 2021, a purported software programming error caused a heat suppression system to activate and douse three 100-MW racks of batteries. A second, nearly identical issue involving the early detection safety system occurred in February 2022 in the 100-MW Phase II building next door.

The PUC's Safety and Enforcement Division was scheduled to meet with Vistra last week.

More: *Renewable Energy World*

GEORGIA

PSC Approves New Rule for Data Centers

The Public Service Commission last week approved a rule that allows Georgia Power to charge new data centers in a manner that works to protect ratepayers from cost-shifting.

The rule states that any new customers using more than 100 MW can be billed using terms and conditions beyond those used for standard customers to address risks associated with large-load users. The data centers would also pay for costs from upstream generation, transmission and distribution as construction on the data centers progresses.

In addition, any new Georgia Power contract with a company that fits the 100-MW usage category must be submitted to the PSC for review.

More: *WXIA*

IOWA

NextEra Starts Process to Reopen Duane Arnold Nuclear Plant

NextEra Energy Resources said it has filed a request with the Nuclear Regulatory Commission to potentially restore the Duane Arnold Energy Center's operating license.

The 50-year-old facility, which NextEra has owned since 2005, was decommissioned in 2020 amid the rise of wind and solar energy production. Now, the demand for electricity has the company eyeing a restart by the end of 2028.

More: *The Gazette*

KENTUCKY

Devs Plan to Build State's First 'Hyperscale' Data Center

PowerHouse Data Centers and Poe Companies of Louisville have announced plans to build the state's first "hyperscale" data center in Louisville.

The companies said they plan to build a 150-acre data center campus that is expected to use about 130 MW in 2026 when the center becomes operational. That total could eventually grow to 400 MW.

More: *WDRB*

MICHIGAN

PSC Approves DTE Energy Rate Increase

The Public Service Commission last week approved a $217.4 million rate increase for DTE Energy.

The hike, which will go into effect Feb. 6, will raise the typical residential bill by about $4.61/month.

More: *Detroit Free Press*

MINNESOTA

PUC Approves Northland Reliability Project Tx Line

The Public Utilities Commission last week approved a certificate of need and route permit for a 180-mile high-voltage transmission line.

Minnesota Power and Great River Energy jointly plan to build the Northland Reliability Project, which could cost more than $1 billion.

The utilities say the new line is needed to help maintain a reliable grid as they transition away from fossil fuels to renewable energy.

More: *MPR News*

NEVADA

Solar Facility Shutting Down Two-thirds of Plant

The 386-MW Ivanpah Solar Electric Generating Facility will shut down two-thirds of its capacity after Pacific Gas and Electric terminated its power purchase agreement with NRG Energy.

PG&E contracted with NRG, who operates the plant, to provide energy to customers in 2009, and the agreement was planned to run until 2039. However, PG&E decided to end the agreement with plant owners Solar Partners to save ratepayers money, PG&E said.

The California Public Utilities Commission must approve the termination agreement.

More: *Las Vegas Review-Journal*

OHIO

Former FirstEnergy Execs Indicted on RICO Charges

A federal grand jury has indicted former FirstEnergy executives Charles E. Jones, 69, and Michael Dowling, 60, on one count of participating in a racketeering (RICO) conspiracy.

From 2015 until 2020, when he was fired, Jones worked as a senior executive, including president and CEO. During that time, authorities say Jones earned around $65 million, with about $60 million coming from performance-based compensation connected partly to company stock prices. Dowling worked as senior vice president, and his compensation was also tied, in part, to stock prices. Both were indicted last year on state charges.

According to the Southern District of Ohio, the two are accused of using "bribery, money laundering and obstruction to increase the company's stock price and enrich themselves."

More: *WEWS*

Power Siting Board Approves Solar Farm, Rejects Others

The Power Siting Board has approved a 100-MW solar project in Clermont County.

The Clear Mountain Energy Center will proceed on 1,226 acres and will be paired with a 52-MW battery system.

Meanwhile, the board rejected the 250-MW Richwood Solar project and the 70-MW Circleville Solar project due to heavy opposition.

More: *Cleveland.com*

UTAH

PacifiCorp Extends Life of Coal-powered Plants

According to PacifiCorp's long-term regional resource plan, both coal-fired plants in the state will not be retired before 2045.

In the 2023 version of PacifiCorp's Integrated Resource Plan, coal units at Hunter had an assumed end in 2042, while its Huntington units were scheduled to be retired in 2036. The company attributed the shift to "changes that have happened recently in regulatory requirements at the state and federal levels."

More: *Utah News Dispatch*