ISSN 2377-8016 : Volume 2024/Issue 43 ▪ October 29, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

MISO

OMS, OPSI Pen 2nd Letter to MISO and PJM to Compel Meaningful Interregional Planning (p.24)

RA Fear and Load Growth at OMS Annual Meeting (p.25)

CAISO/West

Pathways Backers Express Confidence on Calif. Legislation (p.10)

BPA Markets+ Support Intact Despite Exec's Resignation, Agency Says (p.11)

Arizona G&T Cooperatives Announces Pursuit of EDAM Benefits Study (p.12)

ISO-NE

ISO-NE Announces Pause of Order 1920 Compliance Discussions (p.19)

SPP MISO

SPP, MISO Await FERC's Approval of JTIQ Project (p.44)

PJM

Panels Debate PJM Capacity Market Design at OPSI Annual Meeting (p.40)

 |

RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

Editor & Publisher
Rich Heidorn Jr.

Editorial

Senior Vice President
Ken Sands

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Mid-Atlantic Bureau Chief
K Kaufmann

Associate Editor
Shawn McFarland

Copy Editor / Production Editor
Patrick Hopkins

Copy Editor / Production Editor
Greg Boyd

CAISO/West Correspondent
Ayla Burnett

D.C. Correspondent
James Downing

ERCOT/SPP Correspondent
Tom Kleckner

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Vincent Gabrielle

PJM Correspondent
Devin Leith-Yessian

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Senior Vice President
Adam Schaffer

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Holly Rogers

Director, Sales and Customer Engagement
Dan Ingold

Sales Coordinator
Tri Bui

Sales Development Representative
Nicole Hopson

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

USDA Unlocks $3B+ for Rural Electrification Projects

Benefits Flow to Farmers, Seven Rural Electric Cooperatives for Advancement of Clean Energy

By Ayla Burnett

The U.S. Department of Agriculture said Oct. 25 it will issue more than $3 billion to support clean electricity development at seven rural electric cooperatives from South Carolina to Colorado.

The announcement marks "the largest investment in rural electrification since President Franklin Delano Roosevelt signed the Rural Electrification Act into law in 1936," according to a *press release* from the agency.

The funds are available through the USDA's Empowering Rural America (ERA) program, which aims to create jobs and lower electricity costs in nine states. (See *USDA Program Offers $7.3B to 16 Rural Cooperatives*.)

"Since day one of his administration, President Biden has remained committed to ensuring rural communities are directly benefiting from a clean energy economy," USDA Secretary Tom Vilsack said at a Westminster, Colo. press conference. "Through today's announcement, USDA is delivering on this commitment with critical funding from the president's historic Inflation Reduction Act. These projects will strengthen America's energy security while increasing access to affordable and reliable clean energy for people across the nation."

Nearly $2.5 billion is being allocated to Tri-State Generation and Transmission Association to accelerate clean energy projects. Tri-State, which provides wholesale electricity to 41 member cooperatives, plans to use the new ERA funds to purchase 1,040 MW of renewable energy and more than 200 MW of energy storage, as well as to refinance 1,100 MW of previously and newly announced coal-fired generation retirements.

USDA expects the investment to provide multiple benefits, including reducing electricity rates for cooperative customers by 10% by 2034, amassing $430 million in rural consumer benefits over 10 years, reducing carbon emissions by nearly 5.8 million tons annually and creating more than 2,000 jobs.

Why This Matters

The USDA money is earmarked to fund clean energy projects in some areas of the country that have taken a skeptical view of renewables and the need to reduce carbon emissions.

6 Cooperatives Selected for ERA Funds

Nearly $1 billion in ERA funds will flow to six cooperatives, which will leverage investments of $6.4 billion for 1.75 GW of clean energy for rural communities across the country.

The six co-ops all serve rural communities and include Connexus Energy, which operates in Minnesota and South Dakota, Central Electric Power Cooperative in South Carolina, Poudre Valley Rural Electric Association in Colorado, Nebraska Electric Generation, Rayburn Electric Cooperative in Texas and Yampa Valley Electric Association in Colorado.

The investment is expected to help reduce and avoid at least 6.4 million tons of greenhouse gases annually, USDA said.

Farmer Benefit Plan

The USDA also announced a new *Farmer Benefit Plan*, which serves as a roadmap for rural electric cooperatives and farmers to raise opportunities for clean energy and collaborate on a community benefit plan. Based on new ERA applications received so far, co-ops are collaborating with 154 local community groups, including 50 farm organizations, to explore local priorities.

Tri-State also is participating in that initiative and will develop a plan aiming to reduce electricity costs for farmers who take part in a smart irrigation program. The goal of the program is to lower pumping load at times of peak demand, which could help reduce future energy demand and offset the need to build new transmission and generation, saving co-op members from future costs.

Tri-State also plans to work with farmers to execute additional energy programs to encourage the most efficient use of electricity and water and will provide free technical support to enable participation.

Including the Oct. 25 announcements, the USDA has unlocked more than $8.3 billion in funding as part of the new ERA program, an investment the agency expects will result in more than $13 billion in financed grants and loans. The plan advances the Biden Administration's Justice40 initiative, which requires 40% of benefits from federal climate, clean energy and affordable and sustainable housing initiatives to flow to disadvantaged communities. USDA estimates one in five Americans will benefit from the newly announced investments. (See *USDA Announces $10.7B for Rural Clean Energy Projects*.)

President Biden announces funding for clean rural electrification through the Inflation Reduction Act at Vernon Electric Cooperative in Westby, Wis. | *The White House*

"All across America, rural electric cooperatives play an important role in delivering reliable sources of energy to rural communities. Under President Biden and Vice President Harris' leadership, we are making significant investments to ensure that those communities are receiving clean, carbon-free energy — which will reduce the pollution in our air and water, create good-paying jobs, and lower families' home energy costs," White House National Climate Advisor Ali Zaidi said.

"By helping rural cooperatives upgrade infrastructure and invest in newer, lower cost clean electricity projects, these investments will benefit rural families and businesses who for too long have faced disproportionately high energy costs due to the challenges of providing electricity in remote communities," he said. ■

FERC/Federal News

ACEG Report Checks in on Regional Planning After Order 1920

By James Downing

Most of the FERC-jurisdictional ISO/RTOs have made progress on transmission planning practices in response to Order 1920, Americans for a Clean Energy Grid said in an Oct. 24 report.

The report, "2024 State of Regional Transmission Planning: An Interim Transmission Planning and Development Report Card" was meant to follow an ACEG report in 2023 that graded grid operators' rules. (See *Transmission Report Card Grades MISO 'B,' Southeast 'F'*.)

"We find that across the country, several regions have initiated steps to reform their long-term regional transmission planning processes," the report said. "Many of those reforms are promising improvements. However, despite the promise, many of these reforms are also in early stages of implementation and it is not clear what the final outcome will be or how it will impact actual transmission development."

Compliance with Order 1920 is required by June 2025, though the report noted this could change as FERC acts on rehearing. FERC gave entities an extra 30 days after issuing a substantive rehearing order for Order 2023 on interconnection reforms. It is also uncertain whether all transmission planning regions around the country will comply with Order 1920 because of court challenges, though parties generally comply with orders even as they are being considered by courts.

"Two regions, the Southwest Power Pool (SPP) and the California Independent System Operator (CAISO), are pursuing reforms to more fully integrate or harmonize transmission planning and generation interconnection processes, which is encouraged but not required by Order No. 1920," the report said.

SPP expects to send FERC its Consolidated Planning Process reforms in coordination with its Order 1920 compliance filing.

"The intent of the CPP is to fully integrate SPP's interconnection and transmission planning process," the report said. "The CPP has the potential to be a significant improvement, and the first of its kind in the country, but the process is still in its early stages, and it is not yet clear what the outcome will be."

SPP has also improved its load and resource forecasting, including the incorporation of extreme weather scenarios.

CAISO received one of the highest grades in the original report, a B, with the new report noting it is the only organized market that has consistently done proactive long-term, scenario-based planning for a decade. The state's energy and climate goals require major investments in the coming decades with CAISO's latest 20-year transmission outlook calling for $45.8 billion to $63.2 billion in transmission investment to interconnect 165 GW of additional supply.

It has continued to build on that with its 2023-2024 Transmission Plan, which was the result of close coordination between the ISO and state agencies like the PUC and Energy Commission. It recommended 26 projects with a cost estimate of $6 billion.

"The plan builds on the previously established zonal approach, where specific resource zones and related transmission upgrades are identified," the report said. "This coordinated process between CAISO, CPUC and CEC and the resulting identification of resource zones helps better synchronize transmission planning, the interconnection process, and the CPUC's Integrated Resource Planning process and resource procurement by Load Serving Entities."

New York continues to make investments in transmission, with more than $20 billion planned through NYISO and state initiatives. Shortly after the last report, the state's utilities started the Coordinated Grid Planning Process (CGPP), a long-term, scenario-based process to better integrate their local planning

Why This Matters

FERC passed Order 1920, but its true impact will not be felt until the compliance processes are done and the work around planning starts. This report gives an update on what different regions are doing in response to the order and their own needs.

A timeline from the report laying out FERC Order 1920's compliance schedule | *ACEG*

FERC/Federal News

processes with NYISO's regional efforts.

"There is still work to be done to better integrate NYISO's reliability, economic and public policy planning, as well as opportunities to optimize NYISO and the New York Public Service Commission (NYPSC) processes, and it is not yet clear how much of that can be accomplished through the CGPP," the report said.

ISO-NE and PJM are both taking steps to develop and implement improved long-term regional transmission planning.

"ISO-NE is further along with its process," the report said. "The region conducted a state-led, proactive, multi-value transmission study to evaluate transmission needs in 2050 required to meet state law and received tariff approval from FERC for its long-term transmission planning rules that enable the states to move forward with transmission investments in connection with the study."

The states signaled their intent recently to focus new transmission development on unlocking generation in Maine and New Hampshire and to strengthen transfer capacity along the North-South interface. ISO-NE has also initiated the state engagement period that Order 1920 sets up to give state regulators a chance to come up with a cost allocation proposal.

PJM proposed reforms to its long-term regional transmission planning process, which would have included the development of three scenarios and more proactive generation forecasts, but those have been delayed as stakeholders decided the RTO should focus on complying with Order 1920. The reforms were a noted improvement in the new report for PJM, after it got a low grade in the initial version.

In the interim, PJM has seen needs for new transmission grow as load growth is driving new needs, with annual energy use now predicted to rise nearly 40% by 2039 and summer peak by 42 GW, or almost 30%.

MISO got one of the best grades in the previous report – a B – for its transmission planning process that was largely in line with Order 1920 already, but it has asked FERC for a one-year extension on compliance.

Still, the region has stayed the course with its long-range transmission planning (LRTP) initiative and other planning rules.

"For its second tranche, MISO has proposed a $21.8 billion portfolio of 1,800 miles of 765-kV backbone transmission lines and 1,800 miles of 345-kV lines to support the development of the backbone transmission lines," ACEG said.

One lingering concern with MISO is its lack of a planning process in "MISO South," which is largely Entergy's territory, the report said.

ERCOT is the one domestic organized market FERC does not oversee, and in the 2023 report card, it had low grades for transmission planning, as it had not done much proactive planning in recent years.

"The region needs to improve its high-capacity transmission planning, as it is facing some of the most significant load growth in the country and extreme weather will continue to stress a system that is islanded from its neighbors," the report said. "This combination of load growth and extreme weather spurred legislation requiring reforms to transmission planning by the Public Utilities Commission of Texas (PUCT) and ERCOT."

The processes are still in development, and it will take a few years to determine if they lead to major improvements in Texas transmission planning. ■

FERC/Federal News

Changing Dynamics of Clean Energy Transition Debated at Aurora Energy Conference

By James Downing

From left: Lazard's Samuel Scroggins, Vineyard Offshore CEO Alicia Barton, Milbank Partner Allan Marks, Espy Energy Solutions' Nora Mead Brownell and Aurora Energy's Julia Hoos. | © *RTO Insider LLC*

NEW YORK — Despite some recent hiccups with supply chains and higher interest rates, the clean energy transition is set to accelerate with long-term policy support, panelists said Oct. 24 at the Aurora Energy Transition Forum.

The offshore wind industry in the U.S. has had issues with project delays and cancellations and the recent construction accident at Vineyard Wind 1, but the industry has moved projects through the permitting process, and construction is due to pick up soon, Vineyard Offshore CEO Alicia Barton said.

"We've seen setbacks, no doubt about it," Barton said. "When we look ahead, though, over the next — and I'm not talking like the 10 years; I'm talking about 2025 — we are going to see something like 8 GW of projects actively under construction in the United States."

The industry is starting to put steel into the Outer Continental Shelf, but it has already gotten eight to 10 projects through the permitting process, and it will start sending significant power to the grid in two to three years.

"We actually are seeing this industry, I think, at a very different scale," Barton said. "And I think that actually does get lost, even on people that are spending all their time on energy, because you hear so much negative news about offshore wind."

Some projects have had to cancel their initial contracts, but they have been able to sign new ones for higher returns because many of the East Coast states supporting offshore wind need the power, Barton said.

"In New England, increasingly, there is a recognition that offshore wind is the resource that will address long-term winter reliability," she added. "But of course, we need to start showing up sooner ... in terms of the number of years that it has taken thus far to get projects done."

Solar and batteries have come to dominate interconnection queues, but the economic issues of the last few years have impacted them as well, as 2022 and 2023 saw slight price increases because of the supply chain, said Samuel Scroggins, managing director of Lazard's Global Power, Energy & Infrastructure Group, which tracks the levelized cost of energy (LCOE) for different generation technologies in annual reports.

The latest LCOE numbers declined slightly, though the days of regular cost declines are in the past.

"The costs have come down so much for wind and solar in particular that we're at a point now where there needs to be some incremental technology advancement to see continued cost decline," Scroggins said. "The model is relatively straightforward. The inputs are pretty clear."

Bringing down capital expenditure is getting difficult because the industry has already used many of the best sites, so those that remain are not the "nice, flat, square" pieces of land that are easy to develop, he added.

The Inflation Reduction Act has given financers and developers a long enough runway to get projects with 10 years of certainty for tax subsidies, which in the past sunsetted much sooner than that, said Allan Marks, a partner with law firm Milbank. It has spread the money around enough that the policy will likely survive regardless of what happens in the elections Nov. 5.

"If you look at congressional districts, two out of the three jobs created in the manufacturing plants are in red or red-leaning congressional seats," Marks said. "So, there are good reasons why 18 Republican members of Congress wrote a letter to the speaker and said, 'Please do not repeal IRA.'"

While the money will likely still flow from tax credits, the White House switching parties would lead to changes on how the law is implemented with changes at federal agencies, he added.

Nora Mead Brownell, co-founder of consultancy Espy Energy Solutions and a former FERC commissioner, also noted that the IRA's funding of major projects in conservative states gives it staying power, but she also argued that other policies need changes.

"We did not change the regulatory model at the federal and the state level," Brownell said. "We are not rewarding the right things. We have evasive utilities who are terrified of change, who are not introducing their own solutions [and] adding technology efficiency that would give more transparency."

That can change with the rate structure of utilities, with Brownell saying performance-based rates should be widely adopted to encourage utilities.

"We reward great, honking projects that may or may not solve the solution," Brownell said. "We do not reward innovation. We do not allow people to take risks. We do not enforce data to be shared with people who could create those demand response programs, both at the commercial and retail level, that could make a huge difference."

Ideally, more power over the industry would be shifted to the federal level, and states would have more uniform rules because a patchwork makes things harder, she said.

"I think we have to have a larger conversation about, 'Yes, this is going to be expensive, but we're making it more expensive,' and we need to speak in terms that real people can understand," Brownell said.

The Rapid Growth of Batteries in the 2020s

Just a few years ago, the grid hardly had any storage capacity, but now it makes up about 40% of the queues across the country, with

Continued on page 8

FERC/Federal News

Future of Power Markets Discussed at Aurora Energy Conference

By James Downing

NEW YORK — The Inflation Reduction Act and other policies have made the U.S. into one of the most attractive places to invest in clean energy, but completing the energy transition will require additional advances, panelists said Oct. 24 at the Aurora Energy Transition Forum.

Oliver Kerr, Aurora Energy Research's managing director for North America, asked panelists whether they would pick the U.S. or Europe if they had $1 billion to invest.

"If I had a billion dollars, I would spend $100 million on the best development pipeline that required $2 billion of investment" in the U.S., RWE Clean Energy CEO Andrew Flanagan said. "And I'd invest that other $900 million into that portfolio, and then I'd claw back that additional billion, or $1.1 billion from our colleagues in Germany, or find some other equity source."

Germany-based RWE is not alone, with Sandhya Ganapathy, CEO of EDP Renewables North America (a subsidiary of a Portuguese utility), saying the U.S. represents 45% of the parent firm's investments, the largest share out of the 29 countries in which it is active.

"This is a great, great market to invest, and it's also a great market where I truly believe that market fundamentals work really well," Ganapathy said. "It's not a lot of intervention; it's really set by demand."

There is also still clearly plenty of room to grow, as Europe is up to 35 to 40% renewable energy, while the U.S. is at just half of that. On top of federal policies spurring investments, 28 states have set some kind of mandate for renewables, and there is large and active demand from large corporate buyers, Ganapathy said.

Arguably the two leading states on the energy transition are California and Texas, which have deployed tens of thousands of megawatts using very different regulatory models.

"California, as we know, by state statute, has committed to decarbonizing the power sector by 2045," CAISO CEO Elliot Mainzer said. "I think when you take the fifth-largest economy in the world and put it on that path, every major developer is going to want to have a piece of that, and so that's why we have a 510-GW queue."

Many developers come up against friction in the queue, but the issues around it can mask some realities like the fact that California has deployed 20,000 MW of new supply over the past four years, including 10,000 MW of batteries, he added.

California has a much more planning-based process with its various state agencies taking a bigger role in things than Texas, but part of the fix for that major backlog in the queue was borrowed from the Lone Star State. CAISO's newest recently approved process involves studying which of those 510 GW are actually responding to demand and linking the transmission planning process to the queue, Mainzer said. (See *FERC Approves CAISO Plan to Streamline Interconnection Process*.)

From left: ISO-NE CEO Gordon van Welie, Alpha Generation President Mary Anne Brelinsky, Calpine CEO Thad Hill, Hunt Energy Network CEO Pat Wood and Aurora Energy's Olivier Beaufils. | *© RTO Insider LLC*

CAISO borrowed "very shamelessly" Texas' Competitive Renewable Energy Zone approach, which picked out the best areas for wind and built major transmission lines to connect them to cities, turning the state into the leader in wind capacity, Mainzer said.

"The way the ERCOT market has evolved, it has been very open and made it very easy for both supply and for load to come to the system," CEO Pablo Vegas said. "We've got a light regulatory touch on virtually all facets of the interconnection process, and we're very flexible in the way we manage those interconnection queues. And it's been a benefit that has, I think, gotten us to where we are today, but the old adage of 'what got you to where you are today won't get you where you're going to go' applies very accurately in Texas, as we look forward."

Projections for load growth in ERCOT call for as much as 150 GW to come online; it set its peak record of *85,508 MW* in August 2023. It is far from clear that demand will grow that much, but like in other parts of the country, Texas is seeing demand growth on a scale that has not been witnessed since the years following World War II, Vegas said.

"In order to meet that challenge, we are going to have to think differently," Vegas said. "In Texas, we have not historically planned where load or where supply gets sited. And when you're trying to build transmission, which is going to become the linchpin to the success of this whole strategy, transmission has to know where load and supply is going to be. And so, we're starting to take similar constructs and approaches to what Elliot just described."

ERCOT is doing that less formally, making assumptions as to where demand is likely to show up on the grid based on where resources are and linking the two with transmission. None of that activity is required by rules, but the hope is that the market will follow suit and plan accordingly.

"It'll be the fastest way to get there, and it will be the most efficient way to build the transmission infrastructure, but the market will respond to that," Vegas said.

ISO-NE CEO Gordon van Welie said the transition involves four pillars, but one of them is much less discussed: ensuring the system has enough stored energy in fuel tanks or other long-term options to make it through times when renewable supply is low and demand is high, especially during winter.

FERC/Federal News

"We've assumed that problem away," van Welie said. "Actually, if you go back 25 years ago when we started the market construct, we just assumed that everyone was going to have a reliable fuel supply."

The clean energy supply in New England is being driven by state mandates, while the issues around resource adequacy and reliability services is driven by the wholesale market. The states have said they do not want to take back authority for resource adequacy, van Welie said.

"They want the kudos from signing the contracts with the green stuff, and they want to leave the problem of how you pay for all that fossil stuff to the ISO and FERC, right?" he added. "So that's the sort of political dynamic that's going on there. But in this regard, I agree with [FERC] Commissioner [Mark] Christie, which is the states can't just walk away from resource adequacy."

The states have to get behind a market that can support resource adequacy over the long term, because otherwise it will be chaos, with the markets having to be redesigned every three or four years, van Welie said.

One of New England's longstanding issues is ensuring reliability at the end of the pipeline network during harsh winter weather, which has bedeviled the market at the opposite end of many of those pipelines: Texas. Unlike the Northeast, Texas has plenty of natural gas supply, but it has had its worst reliability issues during the winters, Hunt Energy Network CEO Pat Wood said.

"Gas has two mistresses in the middle of a cold day, and it's gas customers who keep their homes warm through natural gas and now 62% of Texans who keep their home warm through electric heat," Wood said. "And that very tight period of time is where you've got the problem."

Texas cannot count on its growing solar resources before the sun rises on a cold winter morning and when wind is also not producing at those times, and the market is not sending a strong price signal that resource adequacy is required in such times, Wood said. After Winter Storm Uri, the price cap was cut back from $9,000/MWh to $5,000/MWh.

The dispatchable reliability reserve service (DRRS), a proposal from the Texas Industrial Energy Consumers working its way through ERCOT's processes, could help send the right kind of price signals to get needed generation built, Wood said.

While Texas and New England both face winter reliability issues, Calpine CEO Thad Hill, whose firm is active in both markets, noted they have very different causes.

"In the east, we've got a fundamental capacity shortage," Hill said. "In ERCOT, we had a breakdown of preparation."

Part of that breakdown ahead of Winter Storm Uri came from new oil and gas production capacity that had come online in the Permian Basin since ERCOT's previous winter reliability problems in 2011, he added. Oil and gas production older than that performed better, while the new Permian capacity was often supplied by the grid and stopped producing when it lost power, exacerbating shortages in both gas and electricity.

While PJM had its hiccups in winters past, historically it has had very healthy reserve margins. But its recent capacity auction saw prices shoot up as those narrowed, which has sparked controversy. (See *PJM Capacity Prices Spike 10-fold in 2025/2026 Auction*.)

Hill noted that in the past when capacity prices have spiked, his firm and other suppliers have responded with new supply, and he expects that to happen again. ■

Changing Dynamics of Clean Energy Transition Debated at Aurora Energy Conference

Continued from page 6

significant deployments in CAISO and ERCOT, Jupiter Power CEO Andy Bowman said.

"It's become the kind of firm dispatch that we have traditionally looked for natural gas plants to provide," Bowman said. "And I think the growth opportunity for storage increasingly is not as some kind of ancillary renewable technology; it is for firm clean power. Firm clean power that can be dispatched very quickly. Firm green power that can provide a lot of valuable grid services."

Years ago the price for batteries was $4,000/kW, which made them irrelevant, but by 2019 that came down to $400/kW, said Spearmint CEO Andrew Waranch. With tax subsidies and plenty of financing available, the price of a 100-MW, two-hour battery in Texas is down to just $10 million.

"I've always said that batteries will be as prevalent as cell phone towers," Waranch said. "They will be everywhere. They'll be on every corner. Because even if they're big or they're small, they're affordable. And when you look at how they compete with other assets, relative to CTs [combustion turbines], they're cheaper, faster, cleaner and stronger and a lot quicker to build."

So far, batteries have had major impacts in California and Texas, Bowman said.

"California, as with just about every new energy technology, leads the way," he said. "Texas comes in close behind, surpasses them, and I think we'll be doing that shortly with batteries."

But with how quickly the grid is changing and how disruptive batteries have become, Bowman expects energy storage assets will start to grow in every market eventually. Jupiter is working in MISO, ISO-NE, NYISO and PJM on changes that will help grow and integrate batteries into their systems.

Spearmint is building 1,200 MW of batteries in ERCOT, but its largest development portfolio is in MISO because it and SPP have the most acute needs for the technology now.

"If they're telling you that they're unsolvable in a few years from now, you usually want to listen," Waranch said. "But at the same time, in between 1997 and 2002, we did build 225 GW of gas in five years, and so you can solve problems with building quickly."

The supply-and-demand picture is always important, but EnCap Investments Managing Partner Kellie Metcalf said that to really roll out the technology, the right market designs are needed.

"That's what's so good about California: The resource adequacy charge is huge," Metcalf said. "In ERCOT, it's been the ancillary services and the volatility top to bottom that [cause] revenue."

MISO does not have anything like those revenue streams, and other markets like ISO-NE have clean peak programs, but that is still in its early days, she added.

While MISO is not quite ready to see major investments in batteries because it lacks any real construct that can make storage profitable, Waranch argued that that could be solved quickly. "Even if they don't have a construct yet, when the need arises and they are deficient, they will have to create a construct that works." ■

FERC/Federal News

Tx Supporters Check in on Order 1920 Compliance Efforts

ACEG Webinar Examines Progress at RTOs/ISOs

By James Downing

With the Order 1920 compliance window already halfway closed and an order on rehearing expected in the next couple of months, Americans for a Clean Energy Grid (ACEG) hosted a webinar Oct. 28 examining progress on the measure so far.

The group worked with Grid Strategies to release an update to its regional transmission report card, which showed all U.S. organized markets have recently been looking at changes to their planning practices. (See related story *ACEG Report Checks in on Regional Planning After Order 1920*.)

The original report, which predated Order 1920, attempted to examine best practices in planning. With Order 1920 compliance efforts underway, it was time for an update, said Rob Gramlich, president of Grid Strategies and co-author of both reports.

"There's some signs of improvement," Gramlich said. "CAISO and MISO continue to proceed with what they're doing, which is, you know, largely close to Order 1920 and the best practices."

CAISO and MISO received the best grades in the initial report, and other markets have all made improvements, though the report said areas outside organized markets — the Southeast and most of the West — have done little in terms of region-wide transmission planning, he added.

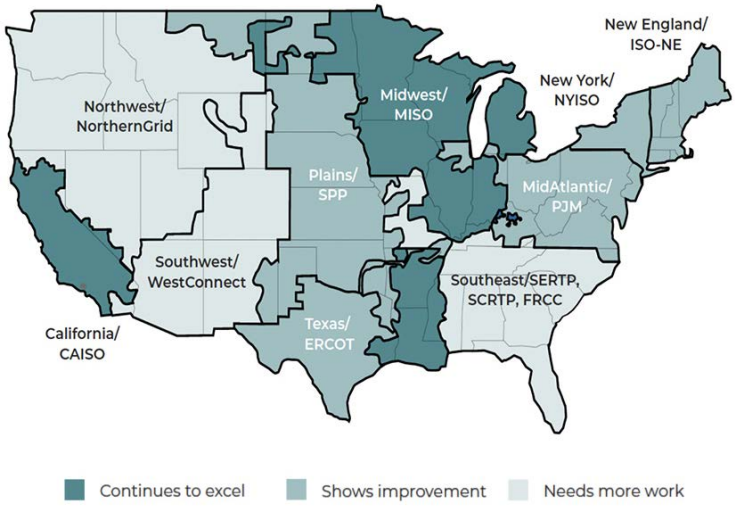
Compliance filings are due next summer, but some regions are already starting to work on them. For example, several regions have already launched their state engagement periods, which give six months for state regulators to craft a regional cost allocation methodology, said ACEG Executive Director Christina Hayes.

SPP launched that process Oct. 28 and its Regional State Committee was poised to vote on whether it would be the venue for those cost allocation discussions, said Christy Walsh, a senior attorney at the Natural Resources Defense Council. Walsh watches the organized markets for NRDC and its Sustainable FERC Project, and she noted a similar attitude among many of them.

"They say: 'We know there's need for regional transmission — it brings reliability and affordability benefits, but we're doing it right,'" Walsh said.

WIRES Executive Director Larry Gasteiger said he sees some of that messaging from the RTOs/ISOs, but contended they still have many issues to deal with.

"What I really think is happening is they are saying we are working hard on trying to address these concerns. We think we're meeting them in some respects," he added. "I think there's an acknowledgement that there can be some improvements, but I'm also hearing it against the background where they're trying to get a heck of a lot of other things done at the same time."



A map produced by Grid Strategies and ACEG showing transmission planning regions' recent reform progress. | *Grid Strategies / ACEG*

Why This Matters

Supporters of new interregional transmission are hoping that successful implementation for FERC Order 1920 will finally spur development of new projects.

MISO got good grades on its ACEG report card, but it has asked for a year delay in complying with Order 1920 to avoid disturbing its ongoing planning processes. (See *MISO to Request Year Deferral on FERC Order 1920*.)

ISO-NE got a most-improved nod from Gramlich because of its recent work with member states around transmission planning, but it recently put a pause on Order 1920 compliance due to uncertainty around the rule's fate. (*ISO-NE Announces Pause of Order 1920 Compliance Discussions*.)

Rehearing Order Imminent

In general, major FERC orders have not undergone significant changes on rehearing, but that might not be the case with 1920, Gasteiger said.

"There were some stark differences right from the get-go on this rule, and I don't know with three new commissioners how that's going to play out," he said. "My guess is not huge changes, but I think the potential for more significant changes is greater here than in the past."

FERC is expected to issue a rehearing order in the next couple months because it has asked the 4th U.S. Circuit Court of Appeals to hold off on its review of the order until January, Walsh said. Gramlich agreed that a rehearing order was likely to come out soon.

Another looming area of uncertainty is the elections, as a change in the White House would mean a change in FERC chairs and eventually a shift to a Republican majority on the commission.

"To the extent some regions are not racing [toward] compliance, I do think the industry will get some more clarity in the next couple of months about some things, and hopefully at that point they'll be moving forward quickly," Gramlich said. ■

CAISO/West News

Pathways Backers Express Confidence on Calif. Legislation

Supporters Poised to Engage with Legislative Staff on Bill Needed to Alter CAISO Governance

By Robert Mullin

SAN DIEGO — Key backers of the West-Wide Governance Pathways Initiative told state energy officials Oct. 24 they're confident California lawmakers next year will pass a bill needed to relax state oversight on CAISO's markets and establish the "regional organization" (RO) envisioned by the initiative.

"I think we're feeling pretty optimistic, given the coalition that we have through the [Pathways] Launch Committee," committee Co-Chair Kathleen Staks, executive director of Western Freedom, said during a panel discussion at the fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB).

That coalition includes labor, public power entities and environmental groups, Staks said, each of which opposed previous efforts to pass legislation to bring independent governance to CAISO. She noted that Pathways supporters in California have begun discussions with legislative staff who likely would contribute to crafting the bill, which would implement the group's "Step 2" proposal. (See *Pathways Initiative Releases 'Step 2' Proposal for Western 'RO'*.)

Launch Committee member Jim Shetler, general manager of the Balancing Authority of Northern California, recounted a meeting supporters had three months ago with a senior legislative staffer.

"He sat down and he looked across the table and said, 'This is different. You guys are normally in opposition to each other on this issue. You're together, pulling for the same thing.' And I think that's one of the key differences that we look at where we're going," Shetler said.

Why This Matters

To execute their plan to create a new Western 'regional organization, supporters of the Pathways Initiative need California lawmakers to pass a bill relaxing state oversight over CAISO's markets.

From left: Arizona Commissioner Kevin Thompson; Kathleen Staks, Western Freedom; Jim Shetler, BANC. | *© RTO Insider LLC*

Wyoming Commissioner Mary Throne asked Staks and Shetler whether Pathways has any "contingency planning" if the legislature either rejects the bill or "modifies it to such an extent that it doesn't achieve the objectives that you're seeking."

"We can create a new organization today, but for us to be able to get the take advantage of the market constructs that the CAISO currently operates and to use the CAISO markets and keep those going, we have to have this legislation that enables the CAISO to move those services over [to the RO], so it's a critical part of the process," Staks said.

Shetler offered a blunter assessment.

"I won't sugarcoat it: The legislation is absolutely necessary for us to move forward," he said. "We need that in order to make this happen. If it doesn't pass or if legislation is created that makes the proposal non-workable, we will have to regroup."

"I think we're feeling cautiously optimistic about our chances to get this done the way it needs to get done," Staks said.

'Hope and Intent'

Arizona Corporation Commissioner and panel moderator Kevin Thompson asked whether the bill will be a rehash of a previous bill attempting to "regionalize" CAISO or be something different.

Shetler said the bill's language will depend on the content of a final Step 2 proposal, which he said is 99% complete.

"We want to see that final proposal to make sure we understand what the legislation should look like. My anticipation is probably by very early next year, we will have language drafted," he said.

Shetler noted the California Assembly and Senate will begin their next sessions in January, with bills to be submitted in the early part of the year. After reviews by the policy and fiscal committees in the house of origin, the bill would move to floor of that house for a vote, then transferred to the other house for the "same routine."

Shetler said it's the "hope and intent" of Pathways supporters that, by August or September of 2025, they will have a final bill that "can be voted on and that can be signed by the governor."

"My hope and sincere belief is about this time next year, we'll have a piece of legislation that will allow us to move forward," he said. ■

CAISO/West News

BPA Markets+ Support Intact Despite Exec's Resignation, Agency Says

Russ Mantifel's Abrupt Departure Won't Alter Phase 2 Funding Commitment, BPA Tells MPEC

By Robert Mullin

The Bonneville Power Administration's commitment to fund the second phase of SPP's Markets+ won't be swayed by the departure of the executive leading the agency's day-ahead market initiative, a BPA official told members of the Markets+ Participants Executive Committee (MPEC) in an Oct. 22 email obtained by *RTO Insider*.

The executive in question is BPA Director of Market Initiatives Russ Mantifel, who resigned effective Oct. 19, according to agency spokesperson Doug Johnson. Since July 2023, Mantifel has led the BPA's intensive process to explore participation in a Western day-ahead market.

From day one, the effort spurred an increasingly contentious competition for participants between Markets+ and CAISO's Extended Day-Ahead Market (EDAM), in large part because of BPA's outsized importance in the Northwest electricity sector, where it controls more than 70% of the region's transmission system and a massive amount of hydroelectric output.

Case in point: On the same day BPA kicked off its day-ahead markets process, a group of Western utility commissioners issued their letter establishing the West-Wide Governance Pathways Initiative to counter Markets+ by proposing a new organization to provide independent governance for CAISO's EDAM and Western Energy Imbalance Market. (See *Regulators Propose New Independent Western RTO*.)

The competition between the respective camps supporting either market intensified in March when BPA staff released a report recommending that the agency choose Markets+ over EDAM. (See *BPA Staff Recommends Markets+ over EDAM*.)

Former BPA Director of Market Initiatives Russ Mantifel at the agency's July 14, 2023, meeting to kick off its day-ahead market participation process. | © *RTO Insider LLC*

That staff "leaning" was supported by most — but not all — of BPA's customer base of publicly owned utilities and opposed by many environmental groups, Northwest utilities such as Portland General Electric, PacifiCorp and Seattle City Light, and all four Democratic U.S. senators representing Oregon and Washington. (See *'Leaning' Evident in BPA Response to NW Senators*.)

In August, BPA said it would delay making its final decision on a market until May 2025. (See *BPA Postpones Day-ahead Market Decision Until 2025*.)

At the Oct. 22-24 fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB), multiple attendees told *RTO Insider* they were surprised by both the timing and abruptness of Mantifel's departure, in part because the agency is scheduled to hold its next day-ahead participation workshop Nov. 4.

BPA's Johnson said Mantifel's resignation was effective Oct. 19, but the reason was for Mantifel alone — and not BPA — to disclose. Mantifel could not be reached for comment.

Johnson also said BPA is working to put someone in Mantifel's position temporarily in early November and then will begin the process to fill the position long term.

In the meantime, he said, any interested parties should contact BPA's acting Chief Information Officer Nita Zimmerman or Vice President of Power Bulk Marketing Rachel Dibble about market-related issues.

In the email obtained by *RTO Insider*, it was Dibble who told MPEC members that while Mantifel's resignation "does leave a gap in our staffing at BPA, I want to assure you that this does not impact our commitment to Markets+ development. We intend to fund Phase 2 and continue our public process working toward our final decision in May."

BPA's share of funding for that phase is estimated at $25 million, representing a 17.4% share, second only to Powerex's 23.2% share. (See *BPA to Fund Phase 2 of Markets+, Agency Exec Says*.)

The MPEC will meet Nov. 12-13 at the Oregon Convention Center in Portland, near BPA's headquarters. ■

Why This Matters

The resignation of the executive leading BPA's day-ahead market participation is sure to fuel speculation about a change in course around the agency's market choice, which is both key to the viability of SPP's Markets+ and vital to the vision of EDAM supporters who seek a single Western RTO in the future.

CAISO/West News

Arizona G&T Cooperatives Announces Pursuit of EDAM Benefits Study

Study Would Make the Case for Western Area Power Administration to Join CAISO's EDAM

By Ayla Burnett

A group of Southwest electric cooperatives is planning a study that could motivate the Western Area Power Administration's (WAPA) Desert Southwest (DSW) Region to join CAISO's Extended Day-Ahead Market (EDAM).

Arizona G&T Cooperatives (AzGT), a member-owned, nonprofit electric generation and transmission cooperative that accounts for 70% of WAPA's DSW load, is looking for potential benefits if WAPA joined EDAM.

"Today marks an important milestone for the Arizona G&T Cooperatives as we announce our interest in exploring CAISO's EDAM to determine potential benefits for our customers across Arizona," AzGT CEO Patrick Ledger said in a *press release*. "We look forward to continued engagement with CAISO to build on the benefits we have seen through participation in WEIM, and to support WAPA as it explores expanding its participation."

AzGT has not yet decided who will conduct the study.

The announcement follows WAPA's March decision to pull the DSW region out of the second phase of SPP's Markets+ development after determining it would see few benefits from both SPP's and CAISO's day-ahead markets. (See *WAPA DSW Cites Lack of Benefits in Markets + Withdrawal*.)

But WAPA expressed support for AzGT's announcement.

"We applaud this first step by AzGT in considering the benefits of joining CAISO's day-ahead market program," WAPA administrator and CEO Tracey LeBeau said in a separate *press release*. "WAPA remains focused on providing value to our customers, and our leadership and Desert Southwest operations teams support this evaluation of EDAM. As a transmission provider, we know WAPA's transmission system throughout the Southwest and its connectivity across the region will be a crucial factor in determining the value of any day-ahead market construct for our DSW customers."

WAPA DSW has been a member of the Western Energy Imbalance Market since 2023. DSW operates the Western Area Lower Colorado balancing authority in Western Arizona and sells federal hydroelectric power and provides transmission service to nearly 70 cities, electric cooperatives, Native American tribes, government agencies and irrigation districts.

AzGT and more than 20 cooperative members, public power utilities and electrical districts took the first step in the process in September by engaging with CAISO to review the potential benefits of joining EDAM.

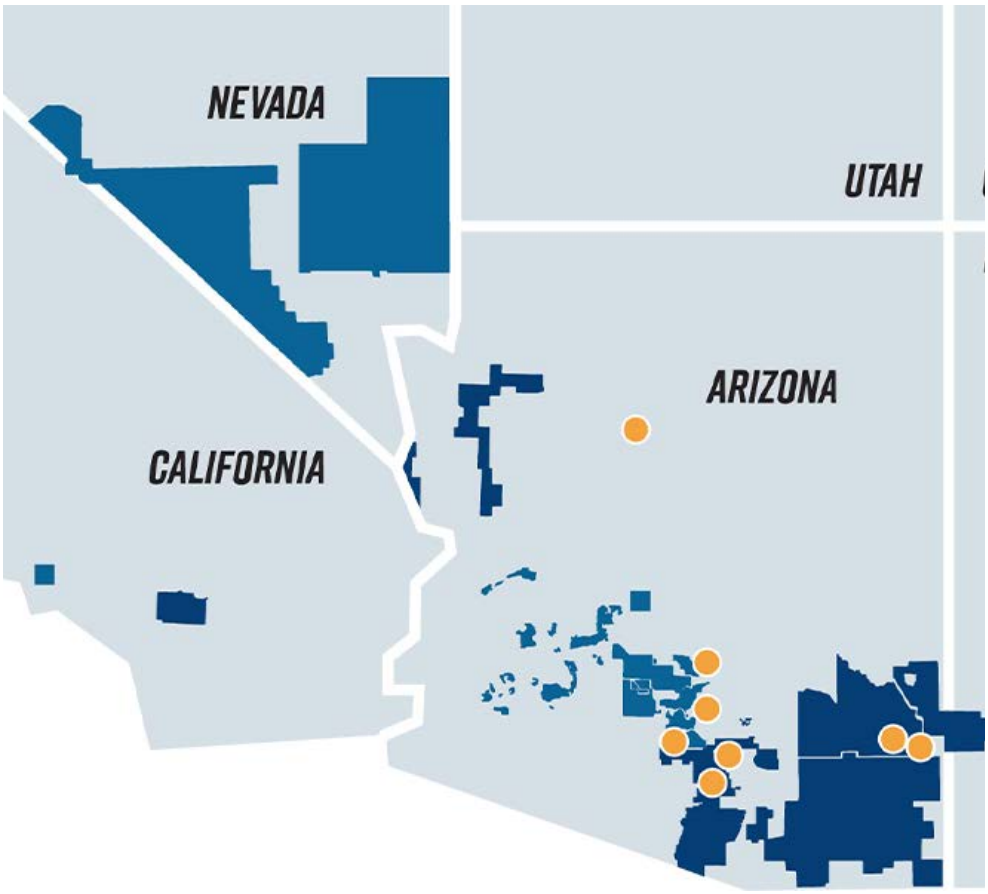
CAISO expressed enthusiasm for the announcement.

"We are honored to provide real-time energy market services for a diverse set of western utility partners, and excited to learn that AzGT intends to explore further benefits from the extended day-ahead market," CAISO CEO Elliot Mainzer said. "WAPA and its customers bring critical resources and connectivity for many in the West, and we look forward to continuing the mutually beneficial partnership."

Other entities engaged in EDAM are PacifiCorp and Portland General Electric, which executed implementation agreements and intend to join in 2026. Several other entities have indicated a leaning toward EDAM, including the Los Angeles Department of Water and Power, the Balancing Area of Northern California, Idaho Power, NV Energy and BHE Montana. ■

Why This Matters

As the competition between CAISO and SPP's day-ahead markets continues to unfold, Arizona G&T Cooperative's pursuit of a study outlining the benefits of CAISO's Extended Day-Ahead Market could be a proxy for motivating the Western Area Power Administration to join EDAM.



Map of Arizona G&T Cooperatives members. | *Arizona G&T*

CAISO/West News

Customer Benefits Must Drive Market Decisions, NM Commissioner Says

Aguilera's Comments Come After Study Shows State Would Gain More from EDAM Than Markets+

By Robert Mullin

SAN DIEGO — Utilities should put customer benefits first when deciding on which Western day-ahead electricity market to join, New Mexico Commissioner Gabriel Aguilera said Oct. 22.

"I think there are also other things that matter — and governance is one of them —but from my perspective, the primary driver is those customer benefits," Aguilera said during a panel discussion at the fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB).

"We owe that to customers," he said.

Speaking with *RTO Insider* after the panel, Aguilera said those benefits should be gauged by improvements to "cost and reliability."

The New Mexico Public Regulation Commission (PRC) member's comments come nearly two months after The Brattle Group released a study showing the state's two major utilities, Public Service Co. of New Mexico (PNM) and El Paso Electric (EPE), would earn greater economic benefits from joining CAISO's Extended Day-Ahead Market (EDAM) than SPP's Markets+ even if neighboring Arizona's three largest utilities — Arizona Public Service, Salt River Project and Tucson Electric — were to join Markets+. (See *Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+*.)

The Brattle study shows, in that scenario, that PNM would reap $20.5 million in projected benefits by participating in EDAM versus $8 million in Markets+, while EPE would earn $19.1 million and $9.1 million, respectively.

New Mexico Commissioner Gabriel Aguilera at the 2024 fall joint CREPC-WIRAB meeting in San Diego. | © *RTO Insider LLC*

Why This Matters

The day-ahead decisions by New Mexico's utilities have become the main object of speculation since NV Energy announced its intent to join CAISO's EDAM in May. It's still unclear how big of a role the state's commission will have in that process.

Aguilera answered in the affirmative when asked whether he thought the Brattle study provided the kind of insight needed to measure customer benefits. He acknowledged again the importance of independent governance for an electricity market, but he also expressed confidence in the ability of the West-Wide Governance Pathways Initiative to bring independent oversight to the EDAM and that an immediate solution to the governance issue shouldn't be necessary for making a market decision.

Aguilera declined to comment on whether the PRC will have final say over the decisions by New Mexico's utilities. He also hesitated to provide a timeline for when the commission would release its "guidance document" regarding market decisions, saying only that he'd completed his contribution to that document.

The PRC's next open meeting is scheduled for Oct. 31. As of Oct. 22, the posted *agenda* for that meeting contained no mention of electricity market issues.

The New Mexico utility decisions became increased objects of speculation in the Western day-ahead market competition after NV Energy in late May announced its intent to join the EDAM, three months after a Brattle study showed the Nevada utility stood to earn more than nine times the benefits in that market compared with Markets+. (See *NV Energy Confirms Intent to Join CAISO's EDAM*.) ■

West news from our other channels

Calif. Revises Clean Truck Rules to Ease Compliance

NetZero Insider

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

CAISO/West News

2 Huge Solar-plus-storage Projects Planned in California

Intersect Power Projects Each Would Provide 1.15 GW of Electricity

By Elaine Goodman

Intersect Power is seeking approval for two 1.15-GW solar-plus-storage projects in California using a streamlined permitting process available through the California Energy Commission.

If built as planned, the projects individually would surpass in size the Edwards & Sanborn solar-plus-storage project that was completed in January in California's Mojave Desert. That project's 875 MW of solar capacity was the most of any facility in the United States, NASA *reported* in January. And its 3,287 MWh of storage made it the largest energy storage facility in the world.

The Perkins Renewable Energy Project, proposed by Intersect Power subsidiary IP Perkins LLC, would be a 1.15 GW solar facility in Imperial County. It also would include up to 1.15 GW of four-hour battery storage, or up to 4,600 MWh of storage.

The Darden Clean Energy Project would consist of a 1.15-GW solar facility and 1.15 GW of four-hour battery storage. Proposed by Intersect subsidiary IP Darden I LLC, the project would be built on about 9,500 acres in Fresno County in the state's Central Valley region.

If completed, the two projects would put a sizable dent in California's battery storage needs — projected to be 52 GW of storage capacity by 2045. The state announced recently it had hit a milestone of 13,391 MW of battery storage. (See *California Hits Milestones for Batteries, DR Grid Support*.)

Streamlined Approval Process

The Perkins and Darden proposals are seeking approval through the California Energy Commission's opt-in certification process — a voluntary process intended to streamline permitting of renewable energy projects.

Why This Matters

If completed, the two projects would put a sizable dent in California's battery storage needs — projected to be 52 GW of storage capacity by 2045.

Under the opt-in process, the CEC becomes the lead agency for permitting and state environmental review. The CEC certificate is in lieu of any permit that normally would be required through the local land-use review process and most state permits.

The CEC has the authority to license thermal power plants of 50 MW or larger. *Assembly Bill 205* of 2022 expanded the agency's authority to include opt-in certification for renewable energy projects such as solar, onshore wind and energy storage systems.

The Perkins project, which will sit partially on federal land, also will receive federal permitting assistance through the FAST-41 program, officials *announced* Oct. 15. FAST-41 is an initiative to streamline permitting through a predictable and transparent process.

Unlocking Renewables

The Darden Renewable Energy Project was discussed Oct. 16 during an environmental scoping meeting hosted by the CEC. An Intersect Power representative said the project would be on retired agricultural land that is "highly disturbed" due to its past use.

And the project has the potential to unlock more solar development in the region. Development there has been slow due to a lack of interconnection opportunities, according to Intersect.

"The Darden project would create a vital new point of interconnection for future renewable energy generators in western Fresno County by building and transferring a new 500-kV switching station to PG&E," the company said in a presentation.

The Perkins project also would create "a vital new point of interconnection for renewable energy" in the Imperial Valley for future projects as well as Perkins, according to the project application.

Although the Darden project previously included an 800-MW green hydrogen facility, that component was removed this month. Removal of the hydrogen facility reduces the project's operational water demand from 1,039 acre-feet per year to 35.

Opt-in Timeline

Under the opt-in certification process, the CEC is required to post a draft environmental impact report within 150 days of the date the application is deemed complete, followed by 60 days for public comment. A final EIR is due within 270 days from the application completion date.

Intersect Power, whose Oberon solar-plus-storage project began operating in Southern California in 2023, has two 1.15-GW solar-plus-storage projects in the state's permitting pipeline. | *Intersect Power*

Other state agencies that retain permitting authority over the project, such as state water boards, must decide on the application by day 360.

The Darden and Perkins projects are two of six proposals under review under the CEC's opt-in certification process.

The other opt-in projects are:

- Compass Energy Storage Project: a 250-MW battery storage system in the city of San Juan Capistrano.
- Fountain Wind Project: up to 48 wind turbines, each with a capacity of up to 7.2 MW, in Shasta County.
- Potentia-Viridi Battery Energy Storage Project: a 400-MW battery storage system in eastern Alameda County providing up to 3,200 MWh of storage.
- Soda Mountain Solar Project: Up to 300 MW of solar and 300 MW of battery storage in San Bernardino County. ■

CAISO/West News

Data Center Load Uncertainty Tied to Broader Economy, Google Rep Says

Large Load Growth Topic of Discussion at Joint CREPC-WIRAB Meeting

By Robert Mullin

SAN DIEGO — The volume of data center load growth in the U.S. will depend on how things play out in the broader economy, a Google representative told a gathering of Western state energy officials Oct. 23.

"You should really think about data center demand as sort of an aggregation of the demand for digital services throughout the economy, and this demand is large and growing," Dylan Sullivan, energy market development strategic negotiator at Google, said during a panel discussion on large loads at the fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) in San Diego.

Sullivan kicked off his comments by asking audience members to raise their hands if they'd worked on a shared document or streamed video in the past week — or checked email within the past 15 minutes.

"That's everybody," he said to laughter. "Well, then you used a data center."

Sullivan ticked off a list of Google's online services, from Maps to YouTube to Gmail. He said Google Cloud provides computing services to hospitals, local governments, schools and "some of America's fastest-growing companies" — including 70% of generative artificial intelligence companies, valued at more than $1 billion.

As a result, Google's global electricity consumption reached 25 TWh in 2023 — "equivalent to a North Dakota-sized state" and more than double its 2019 consumption. But he didn't provide specific figures for Google's demand in the U.S. or the West.

And utility commissioners couldn't pin him down on the company's projections for future growth in data center load.

Washington Commissioner Milt Doumit noted the share of U.S. electricity consumption from all data centers is expected to grow from 4% today to 9% by 2030.

"What is your modeling [showing]? What is growth going to look like beyond 2030, if you can tell us?" Doumit asked Sullivan.

"There's some things that we just don't know the answer to, and I think putting more provisions in place to put more of this forecast uncertainty onto large users is an important way to understand how much we can expect over time, but we don't know the path of [the use of data] visualization and artificial intelligence in our economy," Sullivan said.

From left: Eric Blank, Colorado PUC; Dylan Sullivan, Google; and Antoine Lucas, SPP. | © *RTO Insider LLC*

Sullivan noted that Google has three operating data centers in the West, including in The Dalles, Ore., and Storey County and Henderson, in Nevada, with another under construction in Mesa, Ariz., near Phoenix.

Colorado Public Utility Commission Chair Eric Blank, the panel moderator, asked why companies such as Google are locating data centers in an increasingly heat-stressed area like Arizona, which has seen two straight summers of recording-breaking averages for daytime and overnight temperatures.

Sullivan said the decision largely comes down to the location of its growing segment of cloud-based computing customers.

"Basically, you click the mouse on a laptop, [and] you see the impact of that right on your screen," he said. "If that computer were 200 miles away from you, you would notice the difference and not like it. And cloud customers are the same, so that they have certain requirements for latency [in computing]. They want 'compute' to be close to where they are."

In working with electricity and water utility Salt River Project (SRP) to supply the Mesa data center, Sullivan said Google determined its draw on the local water supply would be unsustainable, so it instead chose to air-cool the facility, which caused "a bit of an energy penalty."

"But we have a mix of resources through SRP that gets us to a very high percentage of renewable energy around the clock now, on a 24/7 basis," he said.

Real or Hype?

A recurring question during the panel and among attendees who spoke with *RTO Insider* at the CREPC-WIRAB meeting was whether the extreme projections for data center load growth are "real" or a speculative overestimate stemming from either hype or the fact that data center companies could be shopping multiple utility service areas for the same proposed facility, causing double-counting across utility load forecasts.

"We don't know how much the demand is real," Sullivan said. He explained that when Google

CAISO/West News

developed its first data center in The Dalles, the company was growing at a time when it was "soaking up" excess energy capacity on the grid, just as overall economic growth in the U.S. was decoupling from its historical connection with parallel increases in electricity use.

"But now, with the onshoring of manufacturing, electrification [and] with data center demand, capacity is now tight, and that creates a problem for the industrial site selectors, where the time it takes to energize a site is lengthening," he said. "And there's uncertainty about the ability to interconnect the site, and that's led to a natural response of people essentially filing multiple requests" for the same data center plan.

"Here's my take on it: The load is real. It's a question of what's the actual volume," said Brian Cole, vice president of resource management at Arizona Public Service (APS). "It's hard to see where there's overlap and where there's not. That makes it difficult."

Cole said APS has created a new data center strategy team to deal with the issue. He said the utility "literally" is having daily conversations with data center companies.

"We're trying to learn from them, trying to understand what they need, trying to work with them, [and] trying to establish what is the best path forward," he said. "Regardless of the path and how we do it, the reality is it's going to require a lot of building, it's going to be a lot of resources, and it's going to be a lot of transmission."

Cole said the utility's goal is to serve all customers while maintaining reliability and avoiding cost-shifts among those customers.

Antoine Lucas, vice president of markets at SPP, said that, since the COVID-19 pandemic, his RTO has fielded 40 GW of customer interconnection requests, with about 15% of those resulting in load interconnection agreements.

"Looking forward, though, we've seen quite a few projections that those numbers will increase," Lucas said, partly driven by new demand, but also because SPP has integrated a large number of renewable resources.

"That has been something that's been attractive to a lot of these entities who are willing to bring data centers or other businesses into the footprint," he said.

Lucas also clarified that he thinks SPP's 15% customer interconnection rate is like the section of prospectus for a mutual fund stating that "historical performance is not indicative of future returns."

"We know there will be an increase, but we know there are also factors that impact it as well — cost being one of those major considerations," he said. "In my opinion, it's not so much whether or not we're going to see an increase, it's just going to be where does it happen?" ■

ERCOT News

Texas Public Utility Commission Briefs

PUC Hears State's First System Resiliency Plan, Filed by Oncor

The Texas Public Utility Commission postponed action on Oncor Electric Delivery's resiliency plan, the first from a state utility under new legislation, during its Oct. 24 open meeting.

Commissioner Jimmy Glotfelty asked for more time before approving, modifying or denying Oncor's three-year *system resiliency plan*. The commissioners — meeting without Lori Cobos, who was excused following a death in her family — agreed to postpone a decision until its Nov. 14 open meeting (*56545*).

"This proceeding is the first of its kind, and I would like to request additional time to consider the plan, the agreed modifications and Oncor's responses to any questions from the commissioners," he said in a pre-meeting *memo*.

Texas *House Bill 2555* directed the state's transmission and distribution utilities to strengthen the resiliency of their systems. Oncor said its resiliency plan is "comprehensive and forward-looking" to proactively withstand, mitigate or quickly recover from the "historical and evolving resiliency events" it expects to affect its system.

An administrative law judge *approved* the Oncor plan in September, finding it in the public interest.

Brian Lloyd, Oncor's vice president of regulatory policy, told the PUC that a "constructive" settlement agreement with commission staff and several other parties gives the utility an opportunity to bring forward some of the plan's spending into this year.

He said the utility mapped its entire distribution system against all extreme weather events since 1998, including extreme heat and cold, major storms and wildfires. Oncor has identified wildfire risk as a major threat to the distribution system; with much of Texas suffering from drought conditions, Lloyd appeared eager to put the plan into effect.

"We have had red flag days on our system this week," he said. "The state is dry. We know that we are ready to go to further address that risk. As soon as you are comfortable with this, do so."

Oncor said it's limiting its recovery of the plan's capital costs to $2.8 billion and an additional $521 million in incremental operations and maintenance expenses for 2024-2028. It will defer $309 million in capital costs and O&M expenses to a fourth system resiliency plan year.

Oncor's Brian Lloyd (center) briefs the PUC on the utility's resiliency plan. | *Admin Monitor*

What's Next

At the Texas Public Utility Commission's next open meeting Nov. 14, it will consider action on:

- Oncor Electric Delivery's resiliency plan.
- CenterPoint Energy's attempt to withdraw a $60 million rate case.

Commission Delays Decision on CenterPoint

The PUC agreed to put off a decision on CenterPoint Energy's attempt to withdraw a $60 million rate case until the commission's next open meeting on Nov. 14 (*56211*).

PUC Chair Thomas Gleeson said he had been ready to reach a decision during the meeting but no longer was prepared to do so. He suggested to his fellow commissioners that they rule on CenterPoint's request no later than the next open meeting.

"I still have some things I need to work through, because I'm still not sure which way to come down on this, honestly," he said. "I think there are really good points on both sides."

CenterPoint said withdrawing the rate case, originally filed in March, and refiling it next year would allow it to use 2024 as the test year. An administrative law judge denied CenterPoint's request to withdraw the rate case in August. The utility then appealed the decision to the PUC.

Gleeson said that during a recent public hearing in Houston, residents expressed a desire for the PUC to evaluate CenterPoint's performance during and after Hurricane Beryl. The Category 1 storm knocked out power to nearly 3 million customers in the Houston area. CenterPoint was castigated for its poor communications during a recovery effort that lasted more than a week. (See *Texas Politicos, Residents Bash CenterPoint*.)

"One way to [evaluate CenterPoint's performance] is to allow them to withdraw this case and then force them to file sometime in 2025 with the 2024 test year, where we could hear evidence about performance during Beryl and

ERCOT News

their infrastructure improvements," he said.

CenterPoint associate general counsel Patrick Peters told the PUC that allowing the utility to withdraw from the rate case would allow it to focus on its work improving resiliency and restoring public trust. He said the utility then would be able to incorporate its learnings from Beryl into a new rate case.

Politicians, including Houston Mayor John Whitmire, and several consumer groups have called for a rate decrease and oppose the withdrawal.

The commission also declined to act on CenterPoint's proposed 138-kV line in a high-growth region north of Houston. The utility said the line is necessary to address the strained existing system, but it has run into opposition from local residents (*55768*).

At the same time, the PUC rejected CenterPoint's settlement with commission staff, the city of Houston and the Gulf Coast Coalition of Cities to adjust the utility's system-average interruption duration index (SAIDI) and system-average interruption frequency index (SAIFI). Gleeson said the utility's continued use of a one-minute threshold for the next seven years is "incongruous" with improved technology that "already addressed the issue" (*55361*).

Processes Set for Permian Projects

The commissioners approved staff's plans to streamline and expedite the selection of transmission companies responsible for building projects in the Permian Basin Reliability Plan (*57152*).

Staff *recommended* a bifurcated contested case system where projects without disputes between transmission service providers (TSPs) and ERCOT over the responsibility for building lines and facilities would be grouped together in one proceeding.

TSPs with disputes will be able to file petitions for authorization to file for permits. Multiple petitions for the same project will be merged into a single contested case proceeding "as soon as practicable." If necessary, the state Office of Administrative Hearings will hold hearings on the dispute.

ERCOT has laid out *suggested principles* it would follow in determining ownership of the plan's projects.

The PUC approved the *plan* in September. It includes 765-kV and 345-kV infrastructure to support the region's current and future power needs and new and upgraded local projects, as well as eight new import paths that will bring more power to the petroleum-rich region. (See *Texas PUC Approves Permian Reliability Plan*.) ■

— Tom Kleckner

National/Federal news from our other channels


DOE Challenge Sends New Cold Climate Heat Pumps to Market — NetZero Insider


GE Vernova Gives Update on Offshore Wind Woes — NetZero Insider


DOE Doubles Down on Advanced Nuclear with HALEU Contracts — NetZero Insider


Weather-security Connections Highlighted at GridSecCon — ERO Insider


GridSecCon Speakers Cite Threats, Opportunities of AI — ERO Insider

Mid-Atlantic news from our other channels


NJ Enacts 200-MW Dual-solar Pilot Program — NetZero Insider


NJ BPU Approves EV Charging Station Rules for MHD Vehicles — NetZero Insider


NJ To Install 167 Heavy Truck Chargers with $250M Federal Grant — NetZero Insider

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

ISO-NE News

ISO-NE Announces Pause of Order 1920 Compliance Discussions

By Jon Lamson

ISO-NE is pausing its discussions with stakeholders on Order 1920 compliance due to uncertainty from outstanding rehearing requests, legal challenges and recent indications of potential updates to the order from FERC commissioners, the RTO told stakeholders at the NEPOOL Transmission Committee on Oct. 24.

The RTO said it has not decided whether to file for an extension of the order's June 2025 compliance deadline, but said it remains "committed to a thoughtful and deliberate stakeholder process."

"This decision was also made in response to significant demand for staff time in the area of system planning, particularly the implementation of the region's new longer-term transmission planning (LTTP) process," said ISO-NE spokesperson Matt Kakley. "Given the uncertainty surrounding Order No. 1920, we believe it is more prudent to have staff focus efforts on the implementation of LTTP while the rehearing and appeals processes play out."

Both Order 1920 and ISO-NE's LTTP, which FERC approved in July, are focused on promoting long-term transmission planning. While Order 1920 requires transmission operators to plan over a 20-year horizon and develop default cost-allocation methods, LTTP gives more deference to the states, allowing them to determine when to pursue a solicitation, which needs they should target and whether to proceed with a project selected by ISO-NE. (See *FERC Approves New Pathway for New England Transmission Projects*.)

The states recently announced their plans to focus the first LTTP solicitation on increasing New England's north-south transmission capacity and unlocking renewables in northern Maine. (See *New England States Seeking Increase of North-South Tx Capacity* and "NESCOE Seeks Feedback on LTTP Solicitation Structure," *ISO-NE Planning Advisory Committee Briefs: Oct. 23, 2024*.)

| © RTO Insider LLC

ISO-NE's pause drew mixed reactions from stakeholders. While some encouraged the RTO to push ahead as much as possible with compliance, others agreed with the need to wait for more certainty on the order.

"This landmark rule requires considerable effort and coordination to comply, but its benefits — including cost savings and increased grid resilience — will outweigh any initial challenges. We strongly urge ISO-NE to follow the lead of other grid regions like PJM, capitalize on the progress already made and comply with Order 1920 to meet clean energy goals and maintain grid reliability," said Claire Lang-Ree of the Natural Resources Defense Council.

Alex Lawton of Advanced Energy United expressed concern that the pause could lead to a compressed stakeholder engagement window but noted an extension would help to ease these concerns. He added that a silver lining to the pause appears to be the ability of the RTO to devote more resources to the LTTP process.

"Deferring compliance allows the ISO to focus exclusively on leveraging LTTP and executing a successful procurement, and also stretches the amount of time it can continue using LTTP unaltered, given the central role states play," Lawton said.

Earlier in October, MISO announced plans to request a yearlong extension of its Order 1920 compliance, saying "much work and assessment is still needed to show compliance." (See *MISO to Request Year Deferral on FERC Order 1920*.)

ISO-NE said it will keep stakeholders updated on its thought processes and will update the public when it plans to resume work on compliance. ■

Why This Matters

While the pause could delay the region's implementation of Order 1920's transmission planning processes, it may allow ISO-NE to focus more resources on transmission solicitations associated with its new longer-term transmission planning framework.

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

NESCOE Seeks Feedback on LTTP Solicitation Structure

The New England States Committee on Electricity (NESCOE) remains "open to various ways to structure the scope" of the first transmission solicitation of the new longer-term transmission planning (LTTP) process, NESCOE's Sheila Keane said Oct. 23.

NESCOE *recently announced* the states' intention to focus the first LTTP solicitation on increasing the region's north-south transmission capacity, with a particular focus on unlocking renewables in northern Maine. (See *New England States Seeking Increase of North-South Tx Capacity*.)

Keane asked for stakeholder feedback on how to structure the solicitation, adding that the states are trying to balance the need for strong minimum requirements for proposals while also leaving enough room for a wide range of potential solutions.

Northern Maine is not currently connected to the ISO-NE grid, but Maine is planning solicitations for renewable generation and associated transmission in this part of the state. (See *Long Road Still Ahead for Aroostook Transmission Project*.)

Phil Bartlett, chairman of the Maine Public Utilities Commission, said the state's request for proposals (RFP) will be "at least somewhat dependent" on the LTTP solicitation.

"As we're thinking about our northern Maine procurement, we are watching this very closely," Bartlett said, adding that he is "hopeful that this process will provide some of those downstream upgrades that increase the likelihood of [a state-selected] project."

However, there remains a long road ahead before any project is selected through the LTTP process. ISO-NE indicated that it expects to issue an RFP around March, followed by an approximately six-month application window and up to a year for ISO-NE to evaluate and develop a cost-benefit analysis for all the proposals.

Keane stressed that there is a lot of work to be done before ISO-NE can issue an RFP and said NESCOE is planning to continue discussions about the RFP with stakeholders at the PAC in the coming months.

Asset Condition Projects and Updates

Dave Burnham of Eversource Energy, representing the six major New England transmission owners (NETOs), provided *an update* on the asset condition project process guide, which the NETOs are developing in response to concerns from the states about a lack of oversight and transparency in the development and selection of projects.

He said the NETOs now require transmission owners to consider a "base alternative" representing the "minimum solution which addresses the identified asset condition problem."

Additional changes to the process guide include standardized grading categories for asset condition evaluations and more transparency into how the decisions are made, Burnham said.

Eversource also provided an update on its proposal to rebuild the X-178 transmission line in New Hampshire, which cuts through the White Mountain National Forest. The project has proven to be particularly controversial, receiving pushback from NESCOE and the New Hampshire Office of the Consumer Advocate, and is the *subject of a lawsuit* from two local property owners.

The company previously told the PAC a full rebuild of the line would be the most cost effective way to address degradation on its wood poles, while NESCOE has *expressed concern* that the company has not adequately justified the project, threatening action with FERC. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

The states ultimately have little oversight over asset condition projects – the transmission owners are responsible for assessing the condition of their lines, determining whether upgrades are needed and selecting the most cost-effective solution. The transmission owners' spending on the lines is FERC jurisdictional under the cost-of-service model.

As the costs associated with maintaining the region's aging grid have accelerated in recent years, this process has drawn increased scrutiny into whether the transmission owners are doing enough to minimize the price of these upgrades.

Chris Soderman of Eversource said the cost projection of the full X-178 rebuild has decreased from $384.6 million to $360.6 million since the company presented the project in June "based on bids received."

Soderman stressed that upgrading the line in a more piecemeal fashion would ultimately increase costs for ratepayers, with the estimated price tag ranging from $467 million to $614.1 million.

Kris Pastoriza, a property owner who has sued to stop the project, said Eversource's proposed construction methods and overly impactful and "unethical." Pastoriza argued the photo evidence of the pole degradation provided by the company is unconvincing and called on the company to release its pole inspection reports.

Meanwhile, some stakeholders, including a representative of Wagner Forest Management and Abigail Krich of Boreas Renewables, expressed support for Eversource's proposal to address all the asset condition needs at one time, instead of addressing the needs through multiple project phases that could cause repeated disturbances.

Representatives of the Vermont Electric Power Co. (VELCO) and National Grid also presented asset condition projects to the PAC:

- National Grid is *proposing* to replace all structures, reconductors and install optical ground wire (OPGW) on a line in eastern Massachusetts, with a projected cost of about $74 million.
- The company is also *proposing* to spend about $9 million to refurbish a substation in Worcester, Mass.
- VELCO outlined a *project* to replace 41 structures on a line in northern Vermont, with a total estimated cost of about $6 million.

Boston 2033 Solutions Study

Andrew Kniska updated the PAC on the status of the Boston 2033 Solutions Study, which aims to address issues identified in the Boston 2033 Needs Assessment, published earlier in 2024.

While the needs assessment initially found several time-sensitive overload issues, a combination of modeling error corrections and new asset condition projects have eliminated all peak load time-sensitive needs, Kniska said. ■

— Jon Lamson

In Other Action

- *Asset Condition Projects and Updates*
- *Boston 2033 Solutions Study*

ISO-NE News

ISO-NE Boosts Energy Adequacy Modeling Capabilities

By Jon Lamson

| Shutterstock

ISO-NE is working to add to its probabilistic energy adequacy tool the capability to model preemptive actions to help conserve stored fuel prior to extreme winter weather events, ISO-NE representatives *told the NEPOOL Reliability Committee* (RC) on Oct. 22.

The probabilistic modeling framework, or PEAT, initially was developed in coordination with the Electric Power Research Institute for several long-duration shortfall risk evaluations in 2023. It now is being incorporated into ISO-NE's energy assessments and would be the backbone of the RTO's proposed Regional Energy Shortfall Threshold (REST).

REST is intended to quantify and determine an acceptable level of shortfall risk for the region, and eventually to inform the development of solutions when risks are identified. (See *ISO-NE Details Proposal for Regional Energy Shortfall Threshold* and *NEPOOL Reliability/Transmission Committee Briefs: Aug. 13-14, 2024*.)

ISO-NE plans to run REST analyses seasonally to evaluate near-term shortfall risks and over longer periods to better understand risk trends in the region.

The PEAT modeling is being improved to account for both preventive and corrective *capacity deficiency actions*, said Mike Knowland of ISO-NE. While the PEAT modeling already includes corrective actions, modeling preventive actions is a new addition.

"Incorporating both preventive and corrective actions directly into PEAT allows for a robust quantitative estimate of the impacts of these actions on shortfall amounts," Knowland said, adding that the modeling will be able to isolate the effect of preemptive actions.

The preemptive modeling is intended to help the RTO optimally dispatch resources prior to and during extended periods of resource adequacy risk, which ISO-NE expects to increase as intermittent renewables proliferate.

Jinye Zhao of ISO-NE said the RTO also "has significantly enhanced PEAT to incorporate a multiday rolling-horizon economic dispatch for the 21-day energy assessment," which looks out three days in advance on a rolling basis to optimize the dispatch of stored fuel resources.

"Based on system conditions and fuel availability in the future days, the model can decide the appropriate time to trigger preventive actions and allocate the appropriate amount as needed to alleviate an anticipated energy shortfall," Zhao said.

In the new process, ISO-NE first will conduct its 21-day energy assessment using only modeling of corrective shortfall actions. Following the identification of an energy shortfall, the RTO will run the assessment again and include modeling of both preventive and corrective actions.

Net import relief and net conservation relief, which will be incorporated in both the preemptive and corrective PEAT modeling, each will be "modeled as a block of up to 500 MW," Zhao said.

For the REST project, the modeling improvements could enable "a multimetric criteria which may include an additional metric that captures the duration of energy shortfall," the RTO told stakeholders.

ISO-NE is scheduled to present its initial proposal on the REST at the RC in November. It has emphasized the need for stakeholder input on the level of acceptable shortfall risk for the region.

Determining an acceptable risk threshold will require more than just modeling expertise — it will pose political questions about how much the states are willing to pay for reliability insurance on the grid, and it could have a significant impact on regional programs supporting stored-fuel or dispatchable resources.

"Following establishment of the REST, a subsequent effort will evaluate if adherence to the REST requires development of specific regional solutions," Knowland noted.

ISO-NE's inventoried energy program (IEP), which compensates generators for keeping stored fuel on site during the winter, is set to expire after this winter. While the IEP was intended as a short-term solution, the RTO has not committed to either ending or continuing the program.

Presenting the results of the RTO's Economic Planning for the Clean Energy Transition *report* at the Planning Advisory Committee meeting in August, Patrick Boughan of ISO-NE emphasized that new market enhancements may be needed in the long-term to support dispatchable resources as renewables proliferate. (See *ISO-NE: New Mechanisms May be Needed to Ensure Future Grid Reliability*.) ■

Why This Matters

Improved energy adequacy modeling tools could help ISO-NE better prepare for and manage extended extreme winter weather events.

ISO-NE News

Mass. Clean Energy Permitting, Gas Reform Bill Back on Track

By Jon Lamson

After negotiations extending well past the end of the formal legislative session, Massachusetts lawmakers are nearing passage of a wide-ranging climate and energy bill including provisions to expedite clean energy siting and permitting, reform gas utility regulation and authorize the procurement of 5,000 MW of energy storage resources.

The *139-page bill*, dubbed "An act promoting a clean energy grid, advancing equity and protecting ratepayers," passed in the Senate on Oct. 24. The bill now sits in the House, where Republicans have stalled its passage by calling for a roll-call vote. Gov. Maura Healey (D) has indicated her support for the bill.

The major focus of the legislative session — and one of the key components of the resulting bill — has been the overhaul of the state's energy permitting and siting processes.

The bill would consolidate state and local permitting for renewable energy projects and grid infrastructure into a single review process and would cap the review timeline at 15 months for large projects and 12 months for smaller projects.

The permitting reforms "are taking a process that has gone seven to 10 years and bringing it down to 12 to 15 months," said Rep. Jeff Roy (D), the lead House negotiator on the bill.

Long permitting and siting timelines have slowed the development of clean energy in the state, and reforming the process has been a key priority for a broad coalition of interests.

Following the publication of recommendations from the Massachusetts Commission on Energy Infrastructure Siting and Permitting, top legislators and Healey's administration reached a general agreement on the permitting language, which was included in separate bills passed in the Senate in late June and House in mid-July. (See *Mass. Commission Issues Recs on Energy Project Siting, Permitting*.)

In the updated process, the state's Energy Facilities Siting Board (EFSB) would coordinate and issue consolidated permits for all large projects, which would encompass all required state and local permits. For smaller projects not in the EFSB's jurisdiction, the bill would allow developers to challenge the denial of a local permit to the EFSB, which could overrule the local decision. (See *Mass. Legislature Faces Looming Deadline to Pass Permitting Reform*.)

Dan Dolan, president of the New England Power Generators Association, expressed strong support for the bill's siting and permitting provisions.

"I appreciate that siting remains the centerpiece of this legislation," Dolan said. "It is a testament to the commitment from the governor to get this done that the legislature is taking extraordinary procedural steps to bring this over the finish line."

While the permitting and siting agreement largely was in place in time for the end of formal session on July 31, the Senate and the House could not overcome their differences on several key issues prior to the deadline. (See *Mass. Lawmakers Fail to Pass Permitting, Gas Utility Reform*.)

The Massachusetts State House in Boston | *Shutterstock*

Why This Matters

The bill, which appears likely to pass, could provide a significant boost to the development of clean energy generation in Massachusetts, along with the grid solutions needed to connect this generation to the grid.

However, lawmakers continued to work behind the scenes to reach a compromise throughout the summer and into the fall and now say they are happy with the bill that has emerged.

The Senate reconvened a formal session to pass the bill 38-2 on Oct. 24. While the House leadership has attempted to pass the bill via informal session, House Republicans have *stalled its passage* by challenging the presence of a quorum. Despite the short-term challenges, House leaders have expressed optimism they eventually will send the bill to Healey.

Gas Utility Reform

One of the key disagreements that held up the bill in July centered around how aggressively the state should move away from natural gas.

"We had some differences in opinion as to what should happen with the decommissioning of the gas system," Roy told *RTO Insider*. "We thought that the Senate was moving too quickly to decommission gas, so we had differences there that we eventually ironed out. Once we ironed out those differences, it made it easier to come together on everything else."

Throughout the negotiations, Sen. Mike Barrett (D), the lead Senate negotiator on the bill, emphasized that the permitting and siting reforms could lead to an expensive expansion of the electrical system and therefore must be coupled with efforts to rein in costs from the gas system.

Ultimately, the Senate and House agreed to add language amending the definition of a gas distribution company, explicitly authorizing gas utilities to "make, sell or distribute utility-scale non-emitting thermal energy, including

ISO-NE News

networked geothermal and deep geothermal energy."

The bill also would update the state's gas system enhancement program (GSEP), which is intended to reduce leaks from the gas system. GSEP costs have increased in recent years — with an expected total price tag of about $34 billion *according to one consultant* — spurring concerns from climate and consumer advocates that the new pipes installed under the program will become stranded assets.

While the existing GSEP statute centers around pipe replacement, the bill would authorize pipe retirement as part of the program.

Barrett added that the legislation would amend the "right to gas" in *state law*, which allows customers to petition for gas service.

This right "was the primary tool used to keep gas infrastructure in place, even as people have started to migrate to cleaner alternatives like heat pumps," Barrett said, noting that right could enable a single customer to hold up the retirement of an entire segment of the gas distribution system.

"We've changed that," Barrett told *RTO Insider*. "You can no longer be the hold-out on your block — if you do hold out, you could keep the entire block's worth of natural gas infrastructure in place at great expense to ratepayers, even if everyone else has migrated to something better."

The statutory changes were developed in coordination with the Massachusetts Department of Public Utilities (DPU), which ruled in 2023 that the decarbonization of the state's gas network should center around electrification. (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

Under the new rules, the DPU would be able to consider the public interest, "including the public interest in reducing greenhouse gas emissions," when evaluating petitions for gas service.

Cumulative Impact Analysis

The bill would require project developers to submit a cumulative impact analysis, which would consider "any existing environmental burden and public health consequences impacting a specific geographical area in which a facility, large clean energy infrastructure facility or small clean energy infrastructure facility is proposed."

This requirement was a key priority of environmental justice advocates in the state, who said it is a necessary safeguard to ensure the new permitting and siting process does not exacerbate existing energy infrastructure burdens on vulnerable communities in the state.

While advocates previously expressed concern that the cumulative impact analysis definition included in a prior iteration of the bill fell short, the new bill features "a robust definition of a cumulative impact analysis," said Claire Karl Müller, coordinator of the Mass Power Forward *coalition*.

"We got to a good definition through really persistent, thoughtful advocacy," Müller said. "We're excited about the bill — it has some really good pieces."

Clean Energy Procurement

The legislation would authorize a massive procurement of energy storage resources — it directs the state's electric utilities to contract for 5,000 MW of storage by mid-2030, including 750 MW of 10- to 24-hour storage and 750 MW of storage with a duration greater than 24 hours. The minimum storage duration for the procurement would be set at four hours.

For offshore wind, the legislation would increase the potential length of long-duration contracts, allowing contracts from 15-30 years. Offshore wind contracts currently are capped at 20 years in the state.

It also would enable the state to coordinate with other New England States "to consider competitive solicitations for long-term clean energy generation," including generation from the region's two existing nuclear plants.

This provision comes during ongoing discussions about Massachusetts buying power from the Millstone Nuclear Power Plant, which is propped up by Connecticut, in exchange for the state buying power associated with the recent multistate offshore wind solicitation. (See *Multistate Offshore Wind Solicitation Lands 2,878 MW for Mass., RI*.)

This language also would enable the state to contract for onshore renewable energy in northern Maine. Government officials in Maine are preparing to issue procurements for renewable generation and associated transmission in the northern part of the state. Massachusetts previously committed to buying power from an onshore wind solicitation which later was terminated by Maine. (See *Long Road Still Ahead for Aroostook Transmission Project*)

While the Senate advocated for a more expansive procurement proposal to give the Department of Energy Resources significant latitude to procure clean energy as needed, these changes ultimately were left out of the compromise bill.

"That's a compromise in which the House won some important concessions," Barrett said.

Electric Vehicles

Regarding electric vehicles, the bill directs state agencies to conduct a 10-year forecast of EV demand, enabling the evaluation of sites for charging hubs. After the assessments are complete, the electric utilities would be required to submit infrastructure plans to meet demand.

The legislation would authorize municipalities to buy chargers and electric vehicles, including electric school buses.

It also would direct the state Division of Standards, which regulates gas stations, to develop regulations for electric vehicle chargers "to make sure these charging stations are delivering what they say," Roy said.

Odds and Ends

The wide-ranging bill includes several other notable provisions, including:

- Requiring electric utilities to consider advanced transmission technologies (ATTs) and other non-wires alternatives when planning new infrastructure and directing the DPU to investigate the use of ATTs.
- Adding fusion energy to the state's definition of clean energy.
- Creating a commission to study how the clean energy transition is impacting the fossil fuel workforce.
- Authorizing regulators to update appliance standards "to facilitate the deployment of flexible demand technologies.

There are several key proposals not included in the bill, including regulations targeting predatory competitive electricity supply companies, updates to the state bottle bill and a requirement for commuter rail electrification.

While the Senate and the state Attorney General's Office have pushed for a full ban on retail third-party electricity suppliers, the House has argued for a more scaled-back reform package.

Larry Chretien, executive director of the Green Energy Consumers Alliance, expressed disappointment about the lack of action regarding competitive retail suppliers, and said reform will be a key priority for the next session.

"Every day that goes by there are more people that are going to be overcharged," Chretien said. ■

MISO News

OMS, OPSI Pen 2nd Letter to MISO and PJM to Compel Meaningful Interregional Planning

By Amanda Durish Cook

The Organization of MISO States and Organization of PJM States Inc. have dropped a second letter at MISO and PJM's doorsteps to emphasize the need for vigorous interregional transmission planning.

This time, the regulators asked in an Oct. 24 *letter* that MISO and PJM's interregional transfer capability study include more steps to ensure MISO and PJM conduct wide-ranging and transparent planning.

State regulators requested MISO and PJM as soon as possible compile a list of projects under consideration, their estimated costs and benefits and details as to why the projects are set to either advance or be abandoned.

OMS and OPSI said benefits "could include energy savings, reduced line losses, etc., as long as the benefits calculated lead to real, not hypothetical or theoretical, savings."

The two organizations stressed that MISO and PJM should perform stakeholder outreach, firm up study deadlines, provide regular progress updates and communicate preliminary findings with stakeholders as soon as practical.

Most OMS members voted in favor of the letter at their Oct. 24 annual meeting; regulators from MISO South abstained from the vote. OMS President and Iowa Utilities Board Member Joshua Byrnes and OPSI President and D.C. Public Service Commissioner Emile Thompson signed the letter. They addressed it to MISO and PJM heads of planning Aubrey Johnson and Paul McGlynn, respectively.

The second letter arrives after some OMS members panned MISO and PJM's original aim to study only smaller projects as too shallow to fit the constructive planning the regulators asked for. OMS and OPSI wrote their first joint letter in February to inspire MISO and PJM to do more interregional planning. (See *Some MISO Regulators Signal Early Discontent with New MISO-PJM Interregional Study* and *Smaller Projects Expected from Maiden MISO-PJM Joint Tx Study*.)

Regulators and the grid operators since have met repeatedly in private to discuss the goals of the study; MISO and PJM have pledged the study will be a multi-act affair, with the first likely producing smaller upgrades and later iterations tackling longer-term needs. The RTOs have said they likely will settle on a first round of small project contenders early next year.

OMS and OPSI's second letter also recommended the RTOs conduct at least the second segment of the study in accordance with FERC Order 1920, which dictates that solutions be tested against 20-year planning scenarios.

"We understand that a 2032 planning horizon is likely appropriate to identify the near-term upgrades for phase one of this study. However, given that FERC Order 1920 imposes a 20-year planning horizon, a 20-year planning horizon would likewise be more appropriate for future studies beyond phase one," regulators wrote.

OMS and OPSI added that a follow-up to the first study should take "a more expansive look at interregional planning, including more ambitious studies and process reforms."

The regulators said they would welcome MISO and PJM working from a joint model and the two adding more interfaces between their systems.

Finally, OMS and OPSI advised MISO and PJM to determine their current interregional transfer capability to use it as a baseline in the study.

"This will help identify current system limitations, the extent transfer capacity is underutilized today and will inform future needs as the bulk electric system continues to evolve," the regulators said.

In a statement to *RTO Insider*, PJM said it appreciated "the constructive tone of the correspondence" from OMS and OPSI.

"PJM will review the requests made and will plan to communicate our thoughts to both organizations in the near future," spokesperson Dan Lockwood said.

MISO likewise said it appreciated the "ongoing collaboration from OMS and OPSI" on interregional studies and promised to share preliminary results of the first interregional transfer capability study at the Nov. 22 *teleconference* of MISO and PJM's Interregional Planning Stakeholder Advisory Committee.

MISO spokesperson Mike Deising pointed to MISO's work on its near-final, second long-range transmission plan (LRTP) as evidence that the RTO is prepared to advance infrastructure for reliability. At $21.8 billion, Deising said the second LRTP is the largest transmission expansion portfolio in the nation and will establish a 765-kV backbone in the footprint that will "facilitate power transfers from the eastern edge of our footprint to the Dakotas." (See *MISO Affirms Commitment to $21.8B Long-range Tx Plan in Final Workshops*.) ■

Why This Matters

After hearing that MISO and PJM's first interregional transfer capability study would yield only small transmission projects, the regulatory agencies of the two RTOs have issued a second call for meaningful seams planning.

| © RTO Insider LLC

MISO News

RA Fear and Load Growth at OMS Annual Meeting

By Amanda Durish Cook

MADISON, Wis. — State regulators, MISO and members remain anxious over the fragile state of resource adequacy, how much load growth to expect and what a potential new resource adequacy standard might look like.

Regulators and stakeholders descended on Madison, Wis., to talk about the issues at the Organization of MISO States' annual meeting Oct. 23-24.

OMS annual meeting Oct. 24 in Madison, Wis. | © RTO Insider LLC

Load Growth: Swift! Shocking! Legitimate?

Electric Power Research Institute's David Larson said data center growth mapping efforts quickly become outdated as requests for interconnection routinely exceed expectations in number and size.

He said the "AI race has now become a powering-AI race."

"There is a question of: 'How much of this is real?'" Larson said. He said utilities sometimes treat requests as not definite until construction begins, while some assume only a percentage is likely.

Mike Benn, with data center developer STACK, said "availability and certainty of power" is top of mind for companies that require newly built data centers. He said that though load growth numbers are big and real, some speculators are calling utilities to inquire about available capacity or those in a race to try to hoard capacity.

Benn said it's important that data centers be part of the solution in securing energy.

"It might be very cathartic to call up the utility and yell, 'You promised you had this capacity to serve us, now you don't!' That helps no one," Benn said.

"Has anybody checked their email by phone or computer? If so, you've used a data center," Google's Tyler Huebner asked.

Huebner said individual companies for the most part have abandoned their backroom servers and have migrated services to data centers. The eradication of the small server rooms to large data centers is more efficient and ultimately saves more water and power, he said.

Huebner said Google strives to forge partnerships with utilities and companies to become a market force for sustainable energy, backing geothermal projects, storage and small nuclear reactors, sometimes above market prices.

"We're willing to bring financial commitments and collateral to the table," he said.

However, Huebner said while Google doesn't want to raise customer prices, it also doesn't want to entirely fund projects it no longer has use for, especially when those projects' output gets claimed by other industries.

Huebner said it used to be a matter of securing real estate and then figuring out the rest to site a data center.

"Now it's power and nothing else," he said.

NextEra Energy's Erin Murphy said NextEra is approaching MISO, looking for ways to link proposed generation resources and their designated loads in MISO's generation interconnection study process to meet the needs of industrial customers.

Murphy said with the MISO queue's current five-year wait times, a MISO fast-track for resources with contractual agreements to serve load would be helpful.

Larson said some hyperscale loads might be flexible but that EPRI encounters challenges getting data centers to publicly share demand response capabilities for analysis.

"Data access is a huge bottleneck for us. We'll have folks that say, 'Trust us, it's a flat load,'" he said.

Huebner said Google is working with peers on demand response and said the company does have a "vested interest" in MISO's recent proposal to reduce capacity credits for its load-modifying resources. (See *MISO Tries to Win over Stakeholders on New LMR Capacity Accreditation*.)

'Angsty' Times

Ryan Long, Xcel Energy president of Minnesota and the Dakotas, said much of the "angst" associated with the energy transition today boils down to the industry "living between" major eras.

"We're in the seam between power-sector decarbonization and economy-wide decarbonization. … We're trying to find our way through the energy transition and bring along other industries," he told attendees.

Long said when Xcel Energy's Northern States Power retires its Allen S. King and Sherco coal plants by 2030, it will lose 3 GW of its 9 GW portfolio.

MISO News

"That means we're going to lose a third of generating on our system. And we have a whole lot of work to do and construction to do," he said.

Long said Xcel doesn't assume it will rely on the MISO market to serve load in future-looking analyses. He said the move is somewhat controversial, but he believes load-serving entities should build generation to meet their native loads and use the market only to optimize financial outcomes and earn economic hedging.

Long said the rise of data center load can be considered the "first ship in the port," with manufacturing and transportation growth to follow as the energy industry further decarbonizes and adds firm resources.

Long said ratepayers can benefit if utilities carefully structure agreements with large customers. He said large customers can help steer a swifter transition, and he predicted hyperscale customers will drive the advancement of small modular reactors.

"We're running out of nuclear plants that are sitting around that could be brought back online," he joked, and later said: "There is a real need to think about how we can all move faster."

That's led Xcel to turn to an iron-air, "rusting and unrusting" battery facility in Becker, Minn., through a partnership with Form Energy; a solar farm at the Sherco site; and extending

Ryan Long, Xcel Energy | © RTO Insider LLC

the lives of its two nuclear plants beyond 2050, Long said. He added that Xcel is betting on battery storage by planning to build an additional 600 MW in addition to the iron-air battery facility.

He also said Xcel proposes to add anywhere from 400 MW to 1 GW of distributed resources at strategic locations.

"At the distribution level, you can add resources fairly quickly, and it feels like the moment certainly calls for an all options on the table strategy," Long said.

Mark Tiemeier of Midwest Reliability Organization (left) and DL Oates of MISO | © RTO Insider LLC

RA Targets on the Move

MISO Executive Director of Markets and Grid Research DL Oates said given the zeitgeist, MISO's role in providing supply and demand outlooks becomes more critical. He pointed to MISO and OMS's annual resource adequacy survey and its regional resource assessment as increasingly important reference points for construction plans.

Oates said because the environment is so uncertain, publishing a range of possible outcomes from scenario-based modeling is appropriate. He said he realizes utilities are building long-lived assets, and a planned facility sometimes can be found to help under several possibilities.

Oates also said because risks are growing more complex, MISO needs a more complex reflection of resource adequacy, expressed partly through its new capacity accreditation method, which FERC happened to approve the next day (*ER24-1638*). (See related story, *FERC Approves New MISO Probabilistic Capacity Accreditation*.) Oates said MISO understands it needs to conduct analyses to predict how its proposed resource accreditations for resource classes are likely to change over time based on how much they can help.

Midwest Reliability Organization's Mark Tiemeier said across NERC, EPRI and ESIG, there's consensus that the one-day-in-10-years loss-of-load standard is passé when used alone.

"To me, it's a very binary answer," he said, though he added that he didn't think grid operators would scrap it entirely.

Tiemeier said with the past no longer an indicator of what's to come with reliability, grid operators need to turn more toward a least-regrets standard that combines multiple elements.

He also said MRO has asked for more consistency across the data regions to provide NERC for its reliability assessments. He said more data consistency would lead to more accurate comparisons between regions.

Oates agreed MISO likely needs multiple metrics beyond its one-day-in-10-years standard to measure adequacy. (See *MISO Dips Toes into Potential New Resource Adequacy Standard; States Demand Key Role*.) MISO has said it might consider a combination of conditional value at risk, loss-of-load hours and expected unserved energy in addition to the one-day-in-10-years criterion.

Oates said while multiple grid operators

MISO News

explore adopting new modes of resource adequacy measurements, they're not all examining the same methods, creating the possibility that RA standards will become even less homogenous.

"When you look at where to move to, there's a lot of heterogeneity there. And I think that's a hallmark of living in a time of change," he said.

"I think if there's anything that be taken from this, it's complicated," joked Wisconsin Commissioner Marcus Hawkins.

Signifying how often RA issues have come to the fore, OMS members passed a motion to create a resource adequacy committee.

From left: Kent Chandler of R Street, OMS Executive Director Tricia DeBleeckere and Minnesota Public Utilities Commissioner Joe Sullivan | © *RTO Insider LLC*

Former State Regulator Says Commissions Need More Hands, Data Analysis, Openness

Known for his frankness, Kent Chandler, former Kentucky Public Service Commissioner and a new addition to center-right think tank R Street, was invited to speak on how commissions should equip themselves as resource adequacy concerns and load growth take firmer hold in the footprint.

Chandler encouraged commission staff to "shoot for the stars" with their budget asks and correct understaffing now. He advised commissioners to double the level of resources they think they can operate with.

Chandler said commissions suffer from getting "asymmetrical" data from utilities. He said at the Kentucky commission, just one staff member usually would review data submittals from utilities for completeness.

Chandler also said commissions are privy to substantially more information from vertically integrated utilities in RTOs versus vertically integrated utilities that aren't in RTOs.

"I couldn't tell you where any congestion is on the [Louisville Gas & Electric and Kentucky Utilities] system," he said as an example.

Chandler told commissioners and staff to "hold your utilities to account" based on the data they can retrieve. He told them to ask utilities what they're doing about resource planning, why they're making certain offers in the wholesale market, or why they're not addressing congestion "that shows up five days a week."

Commissions also are "woefully" short on distribution system expertise, Chandler said.

"Very few people who I've ever interacted with know how the distribution system works," he said.

Chandler said it's important to recruit people with distribution system knowledge as distributed resources — demand response, batteries, generation — will play a more integral role in resource adequacy, like it or not.

Chandler also said while he wouldn't say MISO has it right on resource accreditation, it's moving in the right direction by measuring capacity contributions when resource adequacy is the frailest.

"I think it gives owners an incentive to make sure their generation is best in class," he said, adding that MISO could add a layer to its accreditation where it shows locally what type of generation would be most helpful.

"This is my Festivus. It's my airing of the grievances. It's professional; it's not personal," he joked.

Finally, Chandler said it might be worthwhile for OMS to set up private meetings between its board and the MISO Board of Directors to discuss major initiatives to be filed at FERC. He said the MISO board should want to know how its regulators fall on MISO's proposals.

In closing, Chandler told regulators to be willing to admit when their processes aren't working and work to improve them. He also told regulators to not be afraid to hear opposition, and said he never understood denying interventions in dockets. Chandler said though he's not a "Kumbaya-type of person," there's value in interacting with people who disagree with you.

"Everybody thinks their baby is the cutest. It's almost never true. There can only be one cutest baby. There's always a way to do things better. ... You can make your baby cuter," Chandler said. ■

The OMS annual meeting was held at the Best Western Premier Park Hotel steps from the Wisconsin Capitol in Madison. | © *RTO Insider LLC*

MISO News

Exploring Alternatives to Hyperscale at USEA Energy Tech Forum

Companies Tap Stranded, Underused Projects to Power Smaller Bitcoin, AI Facilities

By K Kaufmann

WASHINGTON — Not every data center has to be hyperscale, according to Andrew Webber, founder and CEO of Digital Power Optimization.

Finding the sites and hundreds of megawatts of power these massive facilities need is "rather limited," Webber told the audience at the U.S. Energy Association's Energy Tech Connect Forum on Oct. 24. Rather, DPO looks to co-locate its data centers with smaller stranded or underused power projects.

"That's kind of the point of our business," he said. "We can flow like water in the cracks and around the energy sector and make use of assets that are otherwise undervalued. … Our view is size isn't the only deciding factor, and in fact, the most efficient developments, the lowest-cost power may be in smaller sizes. It's more distributed in smaller footprints all over the country … using existing infrastructure."

DPO started out in 2022, powering cryptocurrency mining facilities from a 6-MW hydropower facility in Wisconsin. This year, it entered into a *partnership* with Schneider Electric to develop modular artificial intelligence data centers that will draw on up to 100 MW of power from existing wind energy installations in Texas.

Webber was one of three speakers on a panel looking at companies that have developed different, profitable models for meeting the challenges of powering the digital economy. Much of the dialogue in the power and tech industries has revolved around the tech giants — Microsoft, Google and Amazon — developing hyperscale facilities, said Tom Mapes, president of the nonprofit Digital Energy Council, who moderated the session.

Exact estimates from different industry analysts vary, but the general consensus is that energy demand from U.S. data centers will grow two- to threefold by 2030, accounting for anywhere from 7.5% to 9% of total electricity consumption. (See *EPRI: Clean Energy, Efficiency Can Meet AI, Data Center Power Demand*.)

"We're using this kind of broad language to try to hit this generation demand issue, and it's more nuanced than that," Mapes said. "There are more pieces to this puzzle than just data centers, AI."

Exploring alternatives to hyperscale at the USEA Energy Tech Connect Forum were (from left) Tom Mapes, Digital Energy Council; Andrew Webber, Digital Power Optimization; Sean Farrell, TeraWulf, and Scott Garrison, CleanSpark. | *© RTO Insider LLC*

Why This Matters

As the electric power industry obsesses over how to meet the growing power demand from data centers, some developers are finding new and innovative answers in unlikely places — like former coal plants, underused substations and towns off the beaten path in rural Georgia.

TeraWulf, which develops both bitcoin and AI data centers, looks for "dirty sites" to clean up, said Sean Farrell, the company's senior vice president of operations. "We're heavily looking at coal plants, pulp and paper, and steel plants across the U.S. and outside the U.S. A lot of those were built 30 to 40 years ago."

Located on the New York shore of Lake Ontario, TeraWulf's Lake Mariner data center campus is built on the site of a former coal plant but is powered primarily with hydropower and nuclear. This month, the company *announced* a new long-term lease for the site that will allow it to expand its facilities from 500 MW to 750 MW.

CleanSpark brings bitcoin mining facilities to small towns, where it can have major positive impacts on local economies, said Chief Operating Officer Scott Garrison. The company has 26 sites in Georgia, totaling around 700 MW, which can serve as grid assets for municipal utilities or electric cooperatives.

CleanSpark owns all the servers in its facilities, so for "many of our utilities, I can shut the power off and give it back at any time," Garrison said. "We're building infrastructure for small, rural towns."

Keeping its facilities small also gives the company flexibility to take power off local electric systems for shorter periods of time, he said. For example, a utility might build a substation for a new data center, which will not be at full capacity for several years. "I can sit there for

Continued on page 30

MISO News

FERC Approves New MISO Probabilistic Capacity Accreditation

By Amanda Durish Cook

| EDP Renewables

FERC on Oct. 25 authorized MISO's move to a capacity accreditation method that blends probabilistic availability with historical unit performance beginning with the 2028/29 planning year (*ER24-1638*).

The commission said that MISO had shown its new method "captures a range of risks in the planning and operations horizons, aligns operational needs with non-discriminatory market and planning requirements, and will result in transparent market prices that reflect marginal contributions to reliability during highest-risk hours."

The new method stands to shrink most resources' accredited capacity. MISO will use a two-step process that marries historical performance of individual generators with a probabilistic performance during simulated loss-of-load events. (See *MISO: New Capacity Accreditation Filing Imminent*.)

First, the RTO will calculate a probabilistic, resource-class average accreditation using its loss-of-load modeling. Then, it will tailor resource class-level accreditations to individual generators based on their availability during normal operating conditions and at high-risk hours, which includes hours containing low margins or hours with an emergency event in place. MISO plans to give a greater, 80% weight to hours that contain emergency or near-emergency conditions in the ensuing method.

The RTO said it targeted both a prospective and retrospective approach to accreditation.

FERC rejected stakeholders' arguments that MISO's methodology differs from NYISO's and PJM's effective load-carrying capability method, noting that it has the authority to accept a range of designs. It called the RTO's design a "reasonable balance of a range of complex tradeoffs that are inherent to any capacity accreditation methodology that includes probabilistic and deterministic elements."

The commission said it found no evidence that the new method will introduce too much volatility in capacity values year over year, as the Arkansas and Mississippi public service commissions alleged. It countered that MISO is moderating volatility by using 30 years of weather data over its multiple simulations and including ordinary and low-margin operating hours in addition to loss-of-load hours to inform its accreditation.

FERC said MISO's method recognizes "the diminishing marginal returns of surplus resources as the resource mix changes over time, which should send accurate price signals that will prevent oversaturation of one resource type, as well as encourage investment in diverse resource types."

The commission also dismissed the Organization of MISO States' argument that the RTO did not demonstrate how its weighting of emergency, near-emergency and ordinary hours is an improvement over strictly using loss-of-load hours. FERC said MISO is responsible only for proving its method is reasonable, not that it's superior to alternatives.

FERC also said it wasn't concerned with MISO using its loss-of-load expectation modeling as a centerpiece of the accreditation. While some stakeholders criticized MISO's LOLE modeling as not sophisticated enough, the commission agreed with MISO that it has been a ballast of the RTO's resource adequacy requirements for more than 15 years.

The commission likewise found nothing unfair in MISO's LOLE modeling of storage, which assumes storage is deployed only after thermal and renewable resources can't cover needs. MISO's modeling "reasonably captures the value and limitations of storage resources," it said.

MISO has told stakeholders it will focus on improving its LOLE modeling in a separate effort.

The commission overruled clean energy groups' arguments that the new method would undervalue contributions from wind and solar resources. FERC said the design uniformly assigns capacity values among resources "based

Why This Matters

FERC's approval of MISO's new, marginal capacity accreditation means that generation owners generally will have less capacity value in their resources at the start of the 2028 planning year. Solar in particular is expected to take a big hit.

MISO News

on their expected ability to meet the system's resource adequacy needs" while accounting for "the differing performance of all resources within a resource class using the same metric."

FERC said that if, for example, a high penetration of solar resources pushes risky hours later into the evening, it's appropriate for their accreditation to reflect their declining marginal value.

The commission said there seemed to be sufficient data transparency worked into MISO's resource class aggregation calculations. It said the RTO's proposed use of aggregated, masked and class average data is consistent with how it handles generators' data in other applications.

"We note that MISO has committed to working with stakeholders to further address data transparency issues to find a mutually acceptable process that maintains confidentiality while providing stakeholders with the information they need to replicate accreditation values," FERC added.

FERC also accepted MISO's proposal to include its 11 current resource classes in its tariff: gas and oil, combined cycle, coal, hydropower, nuclear, pumped storage, storage, solar, wind, run-of-river and biomass. It rejected arguments that the categories were too vague and said MISO grouped resources fittingly based on fuel type and similar operating characteristics. FERC also waved away arguments that the RTO should create resource classes for hybrid and co-located resources, ruling that tailoring classes to numerous combinations would result in too many that contain too few resources to return stable accreditation figures.

MISO has said it will create a process under its Business Practices Manuals to indicate when it and stakeholders should consider adding resource classes or adjusting them.

FERC refused to grant stakeholders' requests to delay the method taking effect until 2030 at the earliest. The commission said a three-year transition period should give generation owners enough time to prepare while respecting MISO's need to "act in a timely manner to address changes in its generation fleet that are impacting reliability."

Finally, FERC addressed the Mississippi Public Service Commission's concerns that MISO's stakeholder process leading up to the proposal had become "form over function" and a "check-the-box exercise, where MISO makes a presentation and requests feedback; stakeholders provide feedback; MISO responds to the feedback it chooses with generalized summaries; but MISO ultimately files whatever it wants because stakeholder opinions are advisory only."

The commission noted that MISO began working with stakeholders on the new method in early 2022. It said MISO appears willing to take under advisement ways it could further improve its probabilistic modeling and said staff appear ready to help generation owners understand how the change in methodology will affect their capacity values. ■

Exploring Alternatives to Hyperscale at USEA Energy Tech Forum

Companies Tap Stranded, Underused Projects to Power Smaller Bitcoin, AI Facilities

Continued from page 28

two to three years, create revenue for your town and your state, and then we can move on to other places," he said. "There are plenty of areas that have stranded power."

Webber agreed, arguing that bitcoin mining should be viewed "as energy management infrastructure. … From the standpoint of the ability to turn it on and off, the ability to ramp it up and ramp it back down, it's the perfect tool for energy companies to use for their own purposes and their own benefit, if only they understood it a little better.

"There's a way to make energy companies more profitable by deploying these [facilities] in a more thoughtful way."

Massive Capacity Waste

Farrell pointed to another benefit of TeraWulf's model of putting data centers on the site of former coal plants with existing interconnection infrastructure: shorter times in interconnection queues.

For a project in MISO's service territory, TeraWulf has applied for MISO's Net Zero Interconnection Service, which allows a generation project to use excess interconnection service at a point of interconnection, he said.

But Farrell also cautioned that different kinds of data centers — for bitcoin mining, high performance computing and AI — have different power backup and interconnection needs. Grid modeling will have to incorporate different options for "how we can optimize those assets at those locations, because definitely one size does not fit all," he said.

High-performance computing, or HPC, differs from AI in that it uses clusters of computers to process large amounts of data at super high speeds, as opposed to the sophisticated algorithms that AI uses for higher computing functions, like data analysis.

Webber said the way forward for data centers is "to try to find a pathway … without needing to change regulations or without needing to modify someone's opinions or approvals or the regulatory overlay, because again, it's [more] time."

Data centers' search for clean, dispatchable power — like advanced nuclear — could drive major changes, but no easy answers in the electric power industry, he said. Regulators and other decisions makers need to familiarize themselves with the different generation technologies, different types of data centers and potential impacts of both on the grid.

One example, Webber said, is that hyperscale data centers can be highly inefficient because although they run 24/7, they may not always use their full computing capacity 24/7.

"That is just an absolutely massive amount of capacity waste, infrastructure waste [and] capital waste," he said. "If you've got the connection and you've got the power availability, make sure you're actually using it, and that will help prevent the need to build quite so much," he said.

The challenges surrounding data centers and their power demand power — and their possible solutions — are not likely to be affected by the coming election, Mapes said. "No matter who wins in a couple weeks, this conversation is only going to grow," he said, and it needs to move out of what he sees as separate tech and energy industry silos.

As data center efficiency improves, Mapes envisions "different data centers for different opportunities and regions."

"What we're trying to do is … get some of these conversations up to the forefront, start talking about these now on the front end as opposed to trying to fly the plane and build it at the same time," he said. ■

MISO News

Outgoing MISO President Moeller Puts out Call for More Humanity in Industry

By Amanda Durish Cook

MADISON, Wis. — As he prepares to exit MISO, President and longtime employee Clair Moeller delivered parting advice, telling industry players to remember the human aspect in energy.

Moeller is set to retire from MISO at the end of 2024; the Organization of MISO States invited him for a final address at its annual meeting Oct. 24. (See *Longtime MISO President and COO Moeller to Retire*.)

Moeller said a spirit of collaboration will be crucial. He said MISO's first, $10 billion long-range transmission plan (LRTP) approved in 2022 encapsulated that cooperation.

"Nobody tried to stop it from happening. And that was magic," Moeller said. "Our society has really learned how to keep stuff from happening."

Moeller said even when members' goals don't run parallel, they can intersect.

"That intersection of interest can get the ball moving forward. We don't all have to agree. We don't all have to have the same carbon goals," he said.

Moeller said the entire industry can use some grace and basic decency as it navigates a bumpy transition.

"We're working hard on this resource adequacy stuff. It's wrong. But it's less wrong than it used to be. And it'll be less wrong in the future," he said.

Moeller said MISO, for instance, was too slow to adopt a marginal capacity credit for solar resources based on their contributions. He said if MISO had gotten its vision for solar capacity accreditation in front of stakeholders sooner, the region might boast three times the amount of solar.

Moeller said he was visiting San Antonio in early 2021 when Winter Storm Uri walloped Texas and devastated ERCOT's grid. He said he was struck when he drove into a Walmart supercenter to find only a bag of Bugles left in the food section.

"We're three days from chaos. So, this resource adequacy thing is very important," he said.

Moeller urged the MISO community to have the "grace and openness" to accept feedback and be realistic about the risks that MISO, utilities and states are trying to plan against. He said he often asks staff at MISO which mistake they want to make.

"Because you will be wrong: Which way do you want to be wrong? Do you want to be wrong because you built the thing two years too soon or because you built the thing five years too late?" he asked rhetorically.

Moeller said what he likes about the past five years of brutal winter events is that "everyone has had a turn in the barrel" and has been saved by more far-reaching transmission and a neighbor's willingness to help.

"Everyone has bailed each other out," he said approvingly.

Moeller said the LRTP's goal of pushing energy east will help MISO be of service more often while being able to leverage PJM's supply.

But he warned that transmission alone won't keep MISO adequate as the industry moves through the energy transition in an era of growing load.

"The problem that is upon us, we don't understand mathematically or personally, the risk that we're taking as we shift the fleet," Moeller said. He said the industry never has traded old technology for new technology without leaving a significant subset of the old online.

Moeller said in the past, operators needed only to worry about "load forecast and what machines were going to break." Now, he noted that MISO relies on several probabilistic forecasts to get through an operating day and can find itself calling on operating reserves for a sudden drop in wind output.

He said MISO cannot navigate the energy transition by disregarding load growth, or by ignoring environmental goals and building fossil plants to meet it.

"The risk of not making the transition is not acceptable, either," he said. "We have a lot of policy goals, and it's important to have deadlines, but pay attention. Don't try to reach them regardless of the outcome."

Moeller invoked the blackout of 2003 as the catalyst for knocking on MISO's door for a job after spending 25 years at Xcel Energy. He said he was betting at the time the RTO would become ground zero for the "fun work" of working through the aftermath to a more reliable system.

He said his trajectory to MISO was a far cry from his father's career as a lineman in Iowa. Moeller said his father in 1951 was hand-digging holes for poles that would bring electricity to farming communities for the first time.

"I spent most of my career worrying about reliability and not reliability. People bet their lives and their livelihoods on us getting this right," Moeller said.

Moeller received a standing ovation from OMS members, regulatory staff and stakeholders attending the meeting. ■

Indiana Utility Regulatory Commissioner Sarah Freeman (left) listens to MISO President and COO Clair Moeller at the Oct. 24 OMS annual meeting. | © *RTO Insider LLC*

NYISO News

Transmission Security Floor Discussion Causes Consternation at NYISO

And Other Highlights from the Oct. 22 ICAP WG

By Vincent Gabrielle

Long-simmering frustration came to the surface during NYISO's Installed Capacity Working Group discussion of the *transmission security floor Oct. 22* as stakeholders raised questions about NYISO's plan to update its methodology for the 2025-2026 capability year.

"We proposed the following enhancements to account for the coincident peak load, and an update to the five-year derating factor for intermittent resources," said Keegan Guinn of NYISO ICAP Market Operations.

He began outlining the updates to the floor calculations, including using the ICAP Manual Attachment N methodology for intermittent derating factor calculation and continuing to use the average 5-year EFORd (a measure of historical performance) minus outages caused by transmission issues (termed 9300 events).

Stakeholders began questioning the process before Guinn could finish his first slide. Stakeholders have *been* raising concerns about how NYISO values transmission security and what they see as a disconnect between how different NYISO departments handle transmission security. Many stakeholders seemed to want this fixed by next summer.

"Given that the ISO has acknowledged that the current planning framework that includes the 9300 events is improper, and is searching for how to come up with a better approach that excludes that data, why are we still struggling to adhere to something that the ISO itself concedes is not the right approach?" asked Howard Fromer, director of regulatory affairs for Bayonne Energy Center.

Fromer said he didn't think NYISO was going to update its process to exclude the transmission-related outage data from how generator reliability was assessed in time for the upcoming capability year.

"We are going to be left with the same problem we've had for the prior couple of years, where you're going to set a requirement here for the capacity market that is going to be an inflated reliability need that the ISO is going out and solving through out-of-market actions" Fromer said.

| © RTO Insider LLC

At this point, Yvonne Huang, NYISO's senior manager of installed capacity market operations stepped in, saying NYISO was still working on a solution. The problem, Huang said, was that planning assumptions use the NERC class average reliability data, which includes the 9300 events.

"9300 events should not be a part of the framework, and how do we back that out from the NERC class average," Huang said. "That action item is still ongoing at this point. I don't think there's any conclusion at this point."

After some back-and-forth, Doreen Saia of Greenberg Traurig suggested that NYISO could come up with two sets of numbers for the TSL floor. One calculation could use the current methodology. The other could remove the 9300 events data under the assumption that the planning department could devise an alternative source of reliability data for generators.

"I hear you that it makes it more complicated, but there's nothing that prevents you from doing both tracks," Saia said. "While it is more difficult and time consuming, we are where we are. It is absolutely the case that this issue has been raised for some time now and has yet to be resolved. "

Mark Younger, of Hudson Energy Economics proposed that NYISO use local data on the impact of 9300 outages on New York generators.

"I encourage the ISO to be back next week with a plan to get it resolved in, I don't know, six weeks? Four weeks?" said Younger, addressing the data substitution plan. "We shouldn't be retaining capacity that's not necessary because of an inflated number and then turning around to have market results that are consistent with us not having any reliability need at all."

Later in the discussion, Younger said some of the contributors to NERC class average data came from areas that weren't good proxies for New York because they didn't have a capacity market and might also feature market and environmental elements that were not representative of local conditions.

Operating Reserves Performance Penalty

As the grid becomes more reliant on intermittent resources, NYISO and various stakeholders have become concerned that the market is not designed to compensate generators for their actual performance in response to

NYISO News

NYISO dispatch.

Under current market rules, when a generator's day-ahead operating reserve schedule is converted to real-time energy, the generator must buy out its day-ahead reserve schedule. If it does not perform, it also buys out the energy not provided. But there is no defined operating reserve penalty for failure to perform, i.e. actually deliver promised energy.

NYISO presented its proposed penalty mechanism for generators that don't perform during "reserve pickups." It would apply a monetary penalty to generators or other resources that fail to perform. The intent is to recover costs to consumers for operating reserves that were paid for but not provided, while incentivizing reserve generators to perform as promised and scheduled.

"This project will seek to assess methods for evaluating the performance of an operating reserve provider and also develop a proposal for improving the market rules, creating financial consequences for resources that misstate their operating reserves capability and or perform poorly when called upon to convert operating reserves to energy," said Katherine Zoellmer, market design specialist for NYISO.

Zoellmer said NYISO intends to finish this market design and the associated tariff updates and votes this year.

"The penalty proposal will apply in two different scenarios," Zoellmer said. The first instance, she explained, is if the resource is "out-of-merit" for failing to follow basepoints from dispatch. The penalty can also be triggered if three conditions are met: The resource is operating below what they were committed to day-ahead, the resource's day ahead reserve schedule is greater than zero and the resource is undergenerating relative to the real-time energy schedule by at least 3% for 15 minutes.

"Effectively, we're capping the penalty at that day-ahead reserve schedule," Zoellmer said. "A resource would not be penalized more than the day-ahead reserve schedule."

Some stakeholders were skeptical of the penalty and said it didn't take into account real-time schedules, meaning that if the real-time a resource was dispatched down, they could be penalized.

"It's not the generator's fault that, going into the real-time reserve pickup, they were scheduled by the ISO for the energy to be 10 [MW] or 20 MW below what they had offered to sell on the day ahead and been scheduled for on the day ahead," Younger said. "It just doesn't work."

NYISO responded that it heard the concern and would welcome proposals to hone the penalty equation.

Kevin Lang, a lawyer at Couch White LLP representing large energy consumers, asked whether the penalty project was going to still include a procedure for removing resources that consistently fail to perform. Zoellmer replied that that was still a part of the project and that details would be forthcoming.

Multiple stakeholders brought up that the penalty structure might miss poor performers that were infrequently called on due to their high prices.

"It's always going to be a less expensive source that would be asked to convert to energy sooner," Fromer said. "We don't want to disincentivize the less expensive unit, for them to say, 'Hey this is crazy, I'm the only one getting whacked here.'" ■

NYISO News

Attentive Withdraws NY Offshore Wind Proposals

Elsewhere, Maine Loses Bid for OSW Port Grant, Leading Light Agrees to Buy OSW Cables

By John Cropley

Barely three months after it was launched, New York's fifth offshore wind solicitation has its first casualty: Attentive Energy has withdrawn the 1,275-MW proposal it submitted this summer.

Attentive said it remained committed to offshore wind and to helping the region meet the environmental and economic goals that offshore wind is expected to benefit.

New York's fifth solicitation (NY5) has turned into a near-repeat of NY3. (See *NY OSW: If at First You Don't Succeed, Try, Try Again*.)

Attentive, Community Offshore Wind and Vineyard Offshore's Excelsior Wind were awarded contingent contracts in NY3, but NY3 was canceled in April when GE Vernova halted development of the turbine that was key to those contracts. (See *NY Offshore Wind Plans Implode Again*.)

NY5 opened in July. The same three developers submitted proposals again, along with a new entrant: Ørsted's *Long Island Wind*.

Their deadline to submit offer pricing for the combined 25 proposals was Oct. 18. On that date, Attentive withdrew its four proposals.

The New York State Energy Research and Development Authority expects to notify the three remaining bidders of contingent awards by Nov. 8 but will not disclose details publicly until the contracts are finalized, likely in the first quarter of 2025.

Attentive is a joint venture of TotalEnergies, Rise Light & Power and Corio Generation.

U.S. Energy Secretary Jennifer Granholm, center, speaks in April 2023 at a fossil-fired New York City power plant that would be converted to a landing site for offshore wind export cables as part of the Attentive Energy One proposal. | *U.S. Energy Secretary Jennifer Granholm*

In a prepared statement Oct. 21, it said: "Attentive Energy commends the state's steadfast support of offshore wind and will continue to evaluate market conditions and future opportunities as they arise."

Attentive's lease area is closer to New Jersey than to New York. It won a contract in NJ3 and has submitted a bid in NJ4. (See *NJ Awards Contracts for 3.7 GW of OSW Projects* and *3 OSW Proposals Submitted to NJ*.)

In other offshore wind news along the East Coast:

No Federal Grant for Maine Port

The state of Maine did not get the $456 million U.S. Department of Transportation grant it sought to help build a port to support the floating offshore wind industry.

The state hopes to grow into a leader in floating wind, which relies on still-expensive and immature technology, but which is poised for growth, as most offshore areas are too deep for fixed-bottom turbines.

The first-ever Gulf of Maine wind lease auction is *scheduled Oct. 29*.

DOT on Oct. 21 *announced 44 grants* totaling more than $4.2 billion through the Bipartisan Infrastructure law. Among them were 18 large port projects, but Maine's was not among them.

In a prepared statement, MaineDOT Commissioner Bruce Van Note responded:

"We knew the grant program would be extremely competitive and that our application was ambitious. We believe the result is a reflection of the fiercely competitive nature of this program and that it does not reflect, or undermine, the widely recognized need for this port, the strong merit of Maine's plan, or the vast economic and environmental benefits associated with port development."

Van Note added that the state still is awaiting word on another, smaller grant that would help cover the cost of designing and permitting the port.

The port has other hurdles to clear: The state's preferred site is an island that is a nature preserve. (See *Maine Chooses Nature Preserve for Floating Wind Port*.)

Preservationists have vowed to fight the plan, and they have a long track record of successfully beating back other development proposals.

Why This Matters

Offshore wind is expected to play a critical role in decarbonization, and a key component is the infrastructure that would connect it to the grid. But projects in the Northeast have been plagued with economic uncertainty.

Cables for Leading Light

Hellenic Cables announced it has reached an agreement to supply 132-kV inter-array cables for the Leading Light Wind proposal off the New Jersey coast.

The Garden State chose the Leading Light plan for a contract in January as part of NJ3.

At 2,400 MW, it is one of the largest wind farm plans yet announced off the U.S. coast, but developers have run into a problem they must solve before they can put Hellenic's 65 kilometers of submarine cable to use: They need wind turbine generators with a combination of output and cost that will render the project economically viable.

The New Jersey Board of Public Utilities in September granted the developer more time to shop for turbines, lest the project become financially untenable under terms negotiated with the state — the same fate that doomed many of the now-canceled contracts along the Northeast coast. (See *New Jersey BPU Approves Invenergy Offshore Wind Delay*.)

Leading Light Wind is a rarity in the still-young U.S. offshore wind industry — it is led by two American companies, Invenergy and energyRE.

A commercial and industrial ecosystem to support offshore wind energy development is growing in the United States, but the sector still has a heavy European component at this stage.

To wit: Fulgor will manufacture the cables in Corinth, Greece. Fulgor is a subsidiary of Hellenic Cables, headquartered in Athens. Hellenic is a subsidiary of Cenergy Holdings, based in Brussels. Cenergy is a subsidiary of Viohalco, originally of Greece but now of Brussels. ■

NYISO News

NY Project Alleviates Transmission Chokepoint

Replacement of Old Lines Brings Wind Downstate

By Vincent Gabrielle

A major transmission project completed *last year* is already alleviating *congestion* on a historic chokepoint between upstate and downstate New York. On its blog, NYISO claims these upgrades, particularly to the Central East Interconnection, have paid dividends, reducing wind energy curtailments along the transmission corridor.

NYISO claims these are the most significant upgrades in 30 years, boosting the transfer capability by about 1,000 MW.

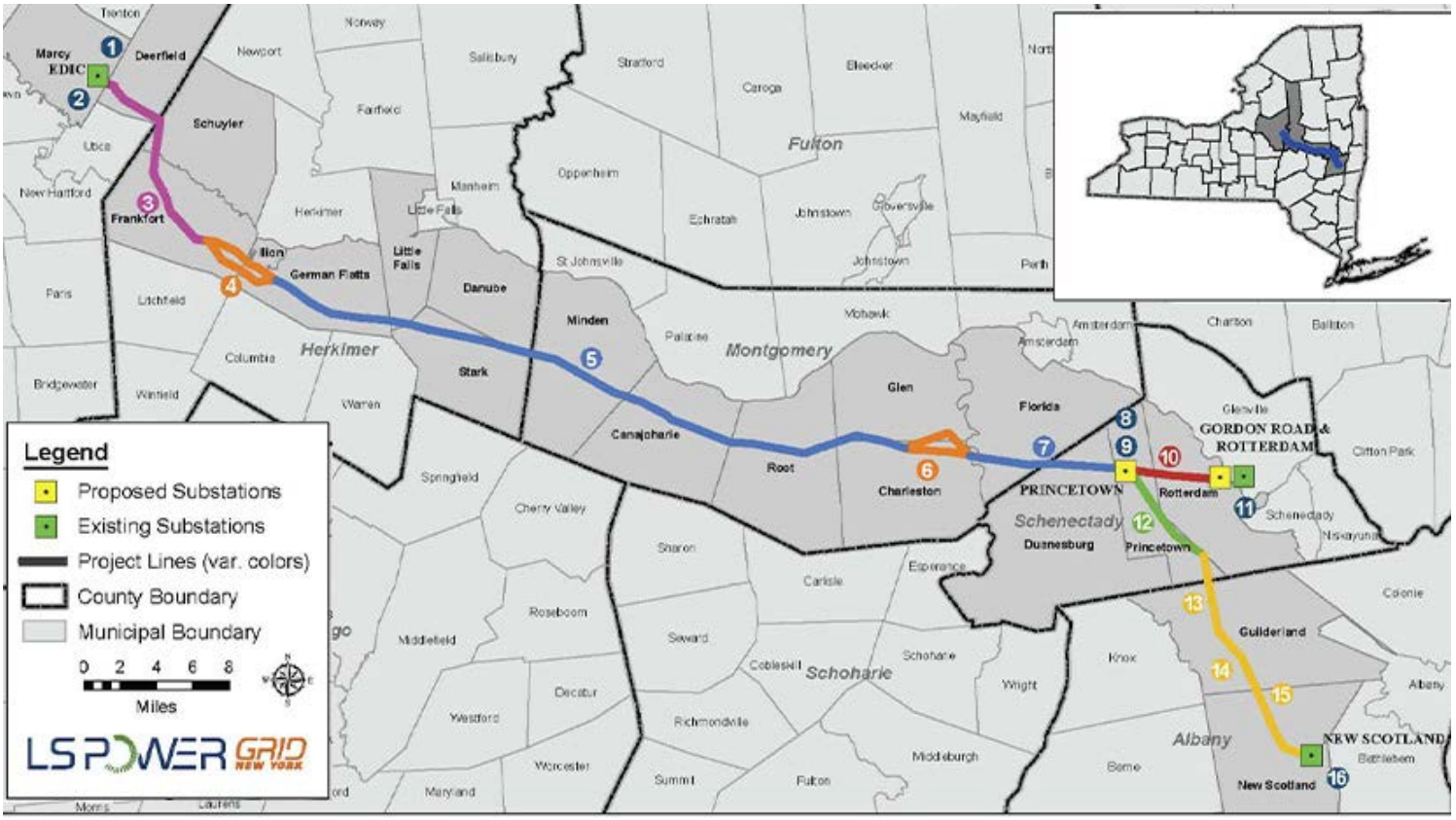
The Central East Interconnection slides through the hills of upstate New York along the relative smoothness of the Mohawk River. It forks, hooking into the rest of the grid at Schenectady and southward out of the river valley into New Scotland, a distant suburb of Albany.

"Albany was functionally downstate," said Marguerite Wells, executive director of the Alliance for Clean Energy New York (ACE NY). "Even though nobody in Albany thinks they live downstate and nobody in New York City thinks that Albany is anything other than upstate."

The bottleneck grew out of multiple historical trends, including the industrial development along the Mohawk River and the piecemeal creation of the power grid. The last time the corridor was updated was during the 1960s.

"The issue was that this whole corridor … they had old, existing 230-kV transmission lines as well as some old 345-kV lines," said Girish Behal, vice president of projects and business development for the New York Power Authority. "These were old existing transmission lines in old existing corridors that over a period of time got utilized to a point where you couldn't put more energy on it."

Behal likened the upgrade to transforming a state road to an interstate highway, using the same right of way but upgrading the engineering specifications to allow more capacity.



1. Marcy substation upgrades (by NYPA)
2. Edic substation upgrades (by others)
3. 345kV reconductoring on existing structures (12 miles)
4. Two new single circuit 345kV monopoles. Remove two 230kV H-frames (5 miles)
5. New double circuit 345kV monopoles. Remove two 230kV H-frames (37 miles)
6. Two new single circuit 345kV monopoles. Remove two 230kV H-frames (4 miles)
7. New double circuit 345kV monopoles. Remove two 230kV H-frames (9 miles)
8. Existing 345kV Edic-New Scotland line to connect outside Princetown to one of the new 345kV lines to Gordon Road
9. New Princetown 345kV switchyard 6 position breaker and a half GIS
10. Two new single circuit 345kV monopoles. Remove two 230kV H-frames (5 miles)
11. New Gordon Road (fomerly Rotterdam 345kV) GIS 5 position breaker and a half substation, two 345/230kV and two 345/115kV transformers. Retire existing Rotterdam 230kV
12. New double circuit 345kV monopoles. Rebuild existing 345kV circuit on monopoles (6 miles)
13. New double circuit 345kV monopoles (4 miles)
14. New double circuit 345kV monopoles. Remove single circuit 115kV (2 miles)
15. New double circuit 345kV monopoles (6 miles)
16. New Scotland substation upgrades (by others)

Central-East Energy connection map | *LS Power Grid New York*

NYISO News

A collage of images from the New York Power Authority showing initial construction of the Central East Interconnection transmission upgrades. | *NYPA*

"It increased the Central East interface thermal transfer limit by 350 MW and the voltage transfer limit by 875 MW — a significant amount of capacity on those transmission lines to move those electrons around," he said.

About 93 miles of new lines were from new steel monopoles from Albany County to Oneida County, effectively quadrupling the power through the corridor.

Curbing Wind Curtailment

NYISO says the upgrades mean this choke-point on the grid has opened. Wind curtailments, once a norm, have plummeted. In December 2023 in the early evening, the interface flow for Central East *surpassed* 3,000 MW for the first time since 2005.

Before the upgrade, the Capitol District was powered mostly by gas turbine plants. Much of the new power comes from renewable sources. According to NYISO, about *30*% of the state's installed wind capacity is in the Mohawk Valley.

In 2023, NYISO *asked* wind generators to turn off to the tune of 162 GWh because the grid could not handle the energy. Roughly 80% of those requests came in the first four months of 2023, before the upgrades to Central East were completed.

"It's not incorrect for ... NYISO to say that the Central East Interface improvement unbottles wind because it unbottles the whole state," Wells said.

Wells explained that this particular upgrade helps the entire state move power more effectively. Because upstate has more renewable energy than downstate, this effectively unbottled wind without touching the transmission infrastructure that hooks directly to wind generation.

She said the next phase of upgrades to transmission would directly improve the lines that attach to wind generation, reducing curtailment even further.

A Big Step in a Massive Process

This is far from the only upgrade that's necessary for New York's energy transition. At the ACE NY fall conference, Bart Franey, a vice president at National Grid, said some of the circuits in need of upgrades are over 100 years old.

"They were designed to basically import 100 MW. Now they're being asked to export 1,000," Franey said in a panel on transmission infrastructure. "What we've come up with, supported by the state, is what we call the Upstate Upgrade. That's 1,000 miles of rebuilding and modernizing upstate New York transmission."

Schuyler Matteson, the clean energy planning lead for the New York Department of Public Service, echoed these comments.

"We live in a state that has some of the oldest electrical infrastructure in the world — not just the region, but in the world," Matteson said. He ran through the preliminary results of the Coordinated Grid Planning Process, saying that to meet the state's generation needs, the number of interconnections would have to triple. "Then we need to find ways to get those electrons to customers."

Later in the panel discussion, Franey and Matteson made it clear the 1,000 miles of new upgrades were just the beginning and not all of that would involve new transmission lines. They mentioned dynamic voltage support, grid-enhancing technologies and other avenues to make the best use of existing infrastructure and rights of ways.

In an interview with *RTO Insider*, Behal also emphasized the Central East Interconnection upgrade was far from the last upgrade needed. New York, as the birthplace of the electrical grid, has many sections in need of refurbishment.

"We have some transmission lines in upstate New York that were built in the 1940s," Behal said. "It's an antiquated system that now, with renewable generation coming in and trying to connect there's a very significant need to upgrade those to a higher voltage or higher conductor size." ■

What's Next

The next phase of upgrades to transmission would directly improve the lines that attach to wind generation, reducing curtailment even further. But this is far from the only upgrade necessary for New York's energy transition; some of the circuits in need of upgrades are more than 100 years old.

Northeast news from our other channels

NY Receives Largest OSW Proposal Yet

NetZero Insider

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

NYISO News

NYISO Monitor Highlights Gap Between Planning, Market Requirements

By Vincent Gabrielle

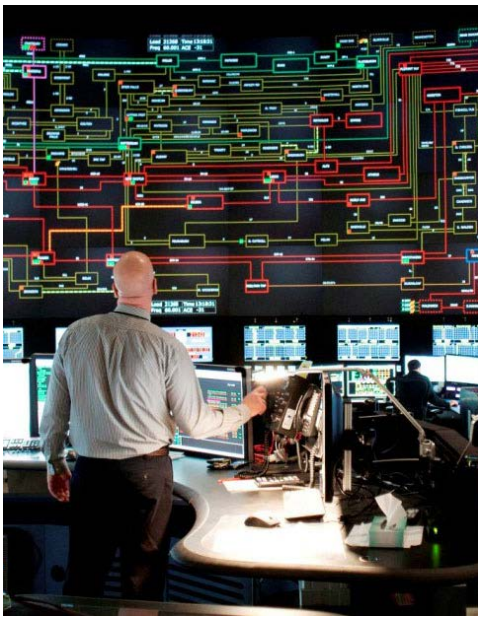
NYISO's transmission planning requirements result in a need for more capacity than is required in the ISO's market rules, according to Potomac Economics, the Market Monitoring Unit.

Potomac highlighted the gap between what it calls the "effective planning requirement" for transmission security and capacity market requirements in a *presentation* before the NYISO Operating Committee on Oct. 24.

"The reliability planning process effectively requires more capacity to meet transmission security needs than is represented in the capacity market requirements that are ostensibly based on transmission security," according to a *memo* Potomac sent to the ISO. For the 2025/26 capability year, Potomac said the effective requirement for New York City is 743 MW higher than its locational capacity requirement.

NYISO this month found a potential reliability need by 2033 for New York City, which would trigger a process in which the ISO solicits solutions from utilities and stakeholders, including non-market interventions. (See *NYISO Draft RNA Finds Reliability Need for New York City*.)

"Within the next five years, the base case assumptions become much more important when reliability needs appear," Pallas LeeVanSchaick, vice president at Potomac, told the committee. "If there are not forthcoming market-based solutions, then there's the potential to identify a need that requires an out-of-market investment to resolve it. That



NYISO control room in Rensselaer, N.Y. | *NYISO*

raises concerns."

The MMU noted the 565 MW of peaking units retained in Brooklyn to address a reliability need identified in a Short-Term Assessment of Reliability in 2023. Despite that, the city is expected to have an over 800-MW surplus in summer 2025.

"Out-of-market actions to satisfy the planning requirements increase risk to investors by depressing capacity prices below anticipated levels," it said.

LeeVanSchaick said that special-case resources — a type of demand response for large loads — were not being counted in transmission security analyses because they are only called upon in emergency conditions. Surplus capacity, he said, was being overcompensated in part because it was being set by the inflated transmission security floors.

"When SCR program resources also participate in peak shaving programs, the resulting load reductions are not counted towards satisfying the reliability need even though they occur during normal operations," the MMU said. "This treatment significantly increased capacity shortfalls in the transmission security analysis of the RNA and inflates the transmission security limit for New York City by a comparable amount."

The MMU recommended including loads participating in peak shaving and emergency DR programs in transmission security analyses and compensating capacity suppliers based on the requirements they contribute to meeting. It also repeated a previous recommendation that NYISO implement more granular capacity zones, particularly in places like New York City, and update them dynamically.

The OC voted to send the draft RNA to the Management Committee, though it changed the motion from an approval of the draft itself to an approval of its findings.

NYISO also presented the results of the *2024-2025 Winter Assessment*, finding that the ISO expects sufficient winter capacity assuming that all firm fuel generation is available under both normal and extreme weather conditions. The ISO cautioned that disruptions in fuel supplies could create problems for the grid given the reliance on firm fuel generation during extreme cold weather. ■

PJM News

PJM, Monitor Seek Contract Resolution by End of Nov.

By Devin Leith-Yessian

COLUMBUS, Ohio — The PJM Board of Managers and Monitoring Analytics are seeking a resolution by the end of next month to negotiations on the company's contract to serve as Independent Market Monitor after more than a year.

Speaking during the Organization of PJM States Inc. (OPSI) Annual Meeting on Oct. 22, PJM Manager David Mills said the contract review was initiated as a "corporate hygiene" effort to review longstanding agreements. The two parties have been meeting weekly with a mediator appointed through the FERC dispute resolution process — the sticking points of which Mills said are confidential. (See *PJM Stakeholders Discuss Monitor Contract Review*.)

"There is no one in the room that wants this resolved more than I do," Mills said. "It's been a challenge; it's a lot of work; but I want to go down why we started on this path: ... [The board] has a series of fiduciary responsibilities. One of them is the duty of care, and so when this board took a look at all the existing contracts that the organization has in place, we had an eye to those that had not been reviewed and renegotiated."

Monitor Joe Bowring said the board did not have a proper succession plan in place to share information between outgoing and incoming members. While he expressed disappointment in the board's review thus far, he said he is cautiously optimistic regarding [the] prospect of the mediation concluding in the coming weeks, stating that the efficacy of the process will be clear by late November. If common ground has not been found by that time, he said the Monitor will "move to whatever the next steps are."

"We're disappointed in the board's failure to engage in what we regard as productive and timely discussions at this point, but we've been trying to talk to the board about this for two or three years, and as the cliché goes, 'actions speak louder than words,'" Bowring said. "So we don't think the board fully understands or appreciates the role of a truly Independent Market Monitor."

Bowring said the continued negotiations and uncertainty around their outcome are impinging on the firm's ability to fulfill its monitoring role, with staff wondering if their jobs are secure and considering taking positions elsewhere.

"We're already at the point where this is impinging on our planning; we're already at the point where it's affecting how we enter into contracts for hardware and software," Bowring said. "So it's already having a significant effect on the morale of my folks. ... We're not willing to let it go past the end of November without taking some additional action," though he is "not sure what that would be."

"This is the longest it's ever taken," Bowring continued. "It's never gone this late into the process before, so we're in uncharted waters. But it creates very significant uncertainty for us and makes our ongoing functioning more difficult; we've lost some people as a result of this; I suspect some people are starting to look around as it becomes more public what's going on."

North Carolina Utilities Commission Senior Attorney Jennifer Harrod said the Monitor operates on a defined-term contract that is regularly reviewed by PJM and state commission staff. She said the ongoing negotiations have no clear benefit to consumers and create a distraction affecting the Monitor's work.

"Independence of the Market Monitor is paramount," she said. "We can't have an RTO without that independent market monitor, and I speak not out of any loyalty to Dr. Bowring in particular or Monitoring Analytics. ... The functioning of the market requires that independence, and we are definitely extremely concerned that independence is under attack. And it's not necessarily as a result of the intent of PJM or the PJM board ... but at least to a certain extent, it's the perception that that independence is under attack."

Mills responded that there is no endgame to replace the Monitor or impugn the independence of the role. The focus is on reviewing an agreement that has seen little change since it was implemented, he said. (See *PJM, IMM Extend Contract Through 2025*.)

"The contract is more than 20 years old. Yes, you're correct the current version of the contract was inked, I believe, in 2018, but the contract and the service level agreements and rate schedules attached to it have lived on nearly virtually unchanged since they were conceived," Mills said.

Maryland Public Service Commissioner Michael T. Richard said his colleagues, as well as the Maryland Office of People's Counsel, rely on the Monitor to understand the complexities of PJM's markets.

"Talking to commissioners in my state and some of our People's Counsel and others, they all just emphasize how much we depend on the Market Monitor to have confidence in PJM," Richard said. "And at this point with the complicated issues before us and the turmoil that is all around us in the PJM footprint, this is something that's very distracting. We need to have a Market Monitor that can fully focus on these important issues. ... I want you to be able to do your job with whatever this hygiene is you're talking about, but again what's really important is we get on with making sure we have a fully functioning Independent Market Monitor right now." ■

Independent Market Monitor Joe Bowring (center) speaks at the Organization of PJM States Inc. Annual Meeting on Oct. 22, as Indiana URC Commissioner David Veleta (left) and PJM Manager David Mills listen. | *© RTO Insider LLC*

PJM News

AEP Ohio Proposes Revised Data Center Tariff

PUCO Staff, Consumer Advocate Back Plan to Lock in Revenue from Large New Facilities

By John Cropley

AEP Ohio has *submitted a settlement agreement* that would provide a buffer on the cost risks of building infrastructure to serve future data centers that may not use as much electricity as they initially propose.

The move is a potential resolution of AEP Ohio's May 13 filing with the Public Utilities Commission of Ohio (*24-0508-EL-ATA*). It requested a groundbreaking tariff that would require developers to pay for 90 to 95% of the projected energy demand of their proposed data center or crypto currency mine in its first decade of operation — even if they use less. (See *AEP Ohio Asks PUCO for Data Center-specific Tariffs*.)

Other stipulations were included to further insulate the utility and its ratepayers from the potential costs of building infrastructure for demand that did not materialize.

Amazon, Google and other tech firms criticized this proposal, and on Oct. 10, they *submitted a joint recommendation* of their own to PUCO.

That counterproposal would have dropped the minimum payment to a range of 75 to 85%.

AEP Ohio said the offer contained problematic details and omitted important consumer protections.

On Oct. 23, AEP Ohio submitted the settlement agreement, in which it was joined by PUCO staff, the Ohio Consumers' Counsel, the Ohio Energy Group, Ohio Partners for Affordable Energy and Walmart.

The agreement contains some compromises from the original request, including a decrease of the minimum payment to 85% of the anticipated demand.

It would require PUCO approval.

In a prepared statement, AEP Ohio President Marc Reitter said, "The agreement insulates our other customers — including residents, small businesses, manufacturers and other industries — from the impact of the necessary infrastructure improvements. Our goal throughout this process has been to provide customers with protections while keeping Ohio an attractive place to run and grow a business. This proposal provides that balance and was developed with PUCO staff and consumer advocates."

AEP Ohio is facing the same squeeze many in the industry face with the simultaneous rise of energy-intense data facilities, attempts to revitalize American manufacturing and the drive to electrify swaths of the economy: Building generation, transmission and distribution to accommodate all these demands will be an expensive and time-consuming process.

AEP's headquarters in Columbus, Ohio | *Shutterstock*

Why This Matters

Because of the simultaneous rise of energy-intense data facilities, attempts to revitalize American manufacturing and the drive to electrify swaths of the economy, it will be an expensive and time-consuming process to build generation, transmission and distribution to accommodate all these demands.

AEP Ohio in its *initial request May 13* said its peak demand in Central Ohio is about 4 GW, and before instituting a data center moratorium, it had signed binding service agreements for 5 GW of new data center load to come online by 2030. Meanwhile, more than 50 customers have submitted requests to reserve more than 30 GW of new or increased load at about 90 sites, it said.

AEP Ohio wants to cut the risk of building infrastructure to serve this demand with a requirement that those proposing the demand help pay for the infrastructure.

The settlement agreement submitted Oct. 23 also requires data centers to prove they are financially viable and able to meet these requirements, and to pay an exit fee if they cancel their project or are unable to meet the obligations of their contracts.

It creates a sliding scale to allow small- to midsized facilities greater flexibility. Contracts would run for eight years, plus a ramp-up period of up to four years.

Reitter said, "We welcome the incredible investment large data centers are making in Ohio. Our agreement strikes a balance between the costly investments required for high-powered cloud and AI needs and protections for AEP Ohio's other customers." ■

PJM News

Panels Debate PJM Capacity Market Design at OPSI Annual Meeting

By Devin Leith-Yessian

COLUMBUS, Ohio — Uncertainty was the throughline across several panels on the state of PJM's markets during the Organization of PJM States Inc. (OPSI) Annual Meeting, as state regulators, market participants and RTO officials discussed a possible delay in the 2026/27 Base Residual Auction (BRA) and debated the eightfold price spike in the prior auction.

PJM CEO Manu Asthana said that any time a change to auction rules or timelines is made, regardless of the merits, investor and consumer confidence in the outcomes can be damaged. Without certainty about price signals, he said the financing necessary to bring new resources to the markets can also be impacted at a time when PJM is projecting resource adequacy shortfalls in the latter years of the decade. Balancing the need to deliver prices reasonable to consumers while sending price signals to invest could mean making hard decisions about what priorities the U.S. has in designing the future of the electric sector.

"I have a fear that without more explicitly choosing whether we're going to actually relax some of our environmental goals; or if we're going to relax our desire to win the AI race; or we're going to be willing to pay higher prices; or we're going to put all of our chips in to invent a new technology that comes up with this green and cheap power; that we will not actually have any of these things. We will not have a reliable grid; we will not have an affordable grid; and we may not be able to serve all of the data centers," Asthana said.

Contrasting the state of the grid with when he spoke at the 2022 OPSI meeting about burgeoning concerns about resource adequacy, Asthana said he is more worried today because of the confluence of permitting and supply chain challenges, accelerating load growth and increasing public policy pressure on generators. Developers considering building new gas-fired capacity in PJM have to weigh EPA regulations that require carbon capture and sequestration against the revenues that can be received through PJM's markets.

"You're seeing that in investment: If you look at what is coming through our queue, the picture is pretty dramatic. You saw gas plants, gas plants, gas plants; this year, almost no gas," he said. "I'm not saying we only need gas; we need everything."

PJM CEO Manu Asthana speaks at the OPSI Annual Meeting on Oct. 21. | © *RTO Insider LLC*

To address those resource adequacy concerns, Asthana said PJM is seeking to make three key changes to how resources can come onto the grid: the process for transferring capacity interconnection rights (CIRs) from a deactivating generator to a new resource; surplus interconnection service (SIS) to allow new resources to be co-located at underused interconnections; and a reliability resource initiative (RRI) to create a one-time expedited application window for high capacity factor resources to be studied in Transitional Cycle 2.

The RRI concept has been met with criticism from many stakeholders who argue that it would amount to preferential treatment for some resource classes at the expense of renewables that have been waiting years for interconnection studies to be completed. PJM has responded that new resources with a high reliability contribution are needed to ward off a potential capacity shortfall in the 2029/30 delivery year. (See *Stakeholders Divided on PJM Proposal to Expedite High-capacity Generation*.)

The Planning Committee endorsed a proposal from a coalition of stakeholders to create an expedited study process for resources receiving CIRs from deactivating generators during its Oct. 8 meeting. (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

Elevate Renewables, the original sponsor of that package, told *RTO Insider* that it is encouraged by PJM's supportive statements during the OPSI meeting and the recognition that a process is needed to allow the efficient development of new resources in the place of retiring units.

"The replacement of existing resource should not be relegated to the back of a backlogged, multiyear-long interconnection queue process," Elevate said in an email. "Instead, there are efficiencies gained by aligning the timing of the de-energizing of the deactivating resource with the energizing of the new replacement resource. However, the current state of the PJM queue creates a timing mismatch, which, as we've seen, has resulted in mass closures of generating facilities, affecting more than just reliability but employee and communities."

Elevate said SIS presents PJM with an opportunity to optimize the capacity contribution of resources that are not fully utilizing their maximum facility output. The RTO's current

PJM News

rules prohibit any projects that would increase line flow or short circuit current from using the SIS process to fast-track their interconnection.

"However, as currently deployed, the PJM [SIS] process creates significant roadblocks for battery storage and many other newer technologies and fuel types to utilize the process FERC directed all RTOs to adopt in Order 845," Elevate said. "We are hopeful that as PJM makes statements that they plan to make tweaks to the surplus interconnection service process, that those tweaks would include changing the triggering criteria for project failure in the SIS process to be actual reliability criteria violations, e.g., line overload or breaker over duty as failing criteria."

OPSI Speakers Discuss Future Auction Design

Speaking on a panel focused on the future of the capacity market, Executive Vice President of Market Services and Strategy Stu Bresler said PJM is working toward a Federal Power Act Section 205 filing in December to make several changes to the design of the BRA.

While the 2026/27 auction is currently scheduled to be conducted in December, PJM has asked FERC to delay its opening by six months (*ER25-118*).

The filing could include changes to how PJM models the output of generators operating on a reliability-must-run (RMR) contract, the topic of a complaint filed in September by the Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and the Union of Concerned Scientists that argues that the expected output of RMR units should be included in the capacity market supply stack (*EL24-148*).

Bresler said PJM is also looking at changing the reference resource for the 2026/27 auction, which would be the first to use a combined cycle rather than combustion turbine as the model unit on which several parameters are based. Because of the higher energy and ancillary service revenues for combined cycle generators, the net cost of new entry (CONE) value fell to $0, bringing the Capacity Performance (CP) penalty rate for units that fail to deliver during emergency conditions to zero as well.

The disparity between the net and gross CONE also resulted in a significantly sharper variable resource requirement (VRR) curve capped at $696/MW-day should 145,774 MW or less clear the auction, falling to $0 at 149,455 MW.

"I think the reason why we went to [the Reliability Pricing Model] and the sloped demand curve in the first place is because we thought that the sort of boom-bust cycle associated with a more vertical demand curve was not the best answer for long-term lowest reasonable cost to the customer," Bresler said. "And so getting back to a VRR curve and a slope of a VRR curve that results in a more stable pricing outcome given the supply and demand conditions I think is important."

Vitol's Jason Barker said a vertical demand curve with a narrow band of prices can create whiplash that undermines the auction's value as a data point for investors evaluating PJM's markets.

American Municipal Power Vice President of Transmission and Regulatory Affairs Steve Lieberman noted that the Members Committee had endorsed an AMP-sponsored proposal to redefine the penalty rate to be based on the BRA clearing price, a change that was rejected by the PJM Board of Managers. Complaints were subsequently brought by the Independent Market Monitor and East Kentucky Power Cooperative, both of which were rejected by the commission in August. (See *PJM Board Rejects Lowering Capacity Performance Penalties*.)

Because the bonus payments for overperforming during a performance assessment interval (PAI) are paid out of the pool of penalties collected under the CP construct, Lieberman said the status quo net CONE would eliminate the incentive to perform during an emergency.

Monitor Joe Bowring said RMR units are being retained to provide reliability services and thus should be included in the capacity market supply stack, which is one component of a package of changes to PJM's generation deactivation rules proposed by the Monitor at the Deactivation Enhancements Senior Task Force. The results of an online vote on four proposals before the task force are set to be presented during its Nov. 14 meeting. (See *PJM Stakeholders Delay Vote on Generator Deactivation Rules*.)

The need to enter into RMR agreements constitutes a deeper market failure, Bowring said, driven by market rules that do not recognize the full reliability contribution of generators.

PJM has defended not including RMR units in the supply stack by arguing that those resources have a stated desire to leave the market, so a price signal is needed to incentivize development to replace them. It has also pointed to differing obligations for capacity resources, which are held to CP rules that penalize underperformance, and RMR agreements that limit when units can be deployed. Going beyond counting them in the supply stack to require that RMR units offer into the capacity market would also subject those units to PAI penalty risks, creating a disincentive for voluntarily entering into an RMR agreement.

Bresler noted that in some cases RMR agreements only allowed PJM to dispatch those units to resolve specific transmission security needs, which is something that PJM may be rethinking. He cautioned that a one-size-fits-all approach likely does not make sense for a construct created to address specific transmission needs.

"No. 1, when it comes to RMR resources, I don't think we want to include them or treat them or model them as supply in the auctions unless the service they're providing is comparable to that of a capacity resource," Bresler said. "Otherwise they're not interchangeable, so you wouldn't want to change the supply-and-demand balance on the basis of that assumption unless that's the comparable service that they are providing."

Barker expressed a similar outlook, stating that RMR units have different performance obligations from capacity resources and including the former in the supply stack could be unduly discriminatory if they are treated comparably to capacity without being held to CP standards.

Susan Bruce, representing the PJM Industrial Customer Coalition, said the compressed auction schedule has left little time for developers to respond to the high price signals prompted by a generator leaving the capacity market to operate on an RMR contract. At the same time that consumers are paying higher capacity prices, they are also paying for transmission upgrades necessary to resolve the violations necessitating the RMR agreement, she said.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said the repeated auction delays have led to risk being shifted to consumers, pointing to a "miscalculation" in the reliability requirement for the DPL South zone in the 2024/25 auction that cost consumers about $100 million in higher capacity costs with no corresponding reliability benefit.

It also left little time for market participants to respond to changes in the guidelines for energy efficiency resources offering into the following auction, which caused a marked drop in supply, Poulos said. A PJM filing at FERC would eliminate the resource class outright from the capacity market. (See *PJM Asks FERC to Eliminate Energy Efficiency from Capacity Market*.)

PJM News

Given the little direct insight consumer advocates have on market decisions, they are often reliant on PJM estimates of the potential impacts market changes could have on prices, Poulos said. He urged PJM to use the information at its disposal to do more proactive modeling and analysis, which he said would improve consumer confidence in future auction outcomes.

Additional analysis and modeling of potential market changes could give stakeholders more certainty on proposals they are asked to vote on and increase certainty in future auction outcomes, he said.

Maryland Public Service Commissioner Michael T. Richard, moderator of the panel, said high prices can disrupt the economies and lives of ratepayers in PJM states.

"Markets are created for the customer. The concern I think some of us have is that after we see a sudden 800% jump in the market, we just have to ask, is this really a stable and predictable environment for customers, for state economies?" Richard said. "This essential service needs to be available to everybody and needs to be something that's affordable."

Panelists Discuss Price Surge in 2025/26 Auction

Speaking on a panel focused on the results of the 2025/26 BRA, Bresler defended the eightfold increase in prices, stating that the increase properly reflected tightening supply and demand. He said the capacity market has seen years of low prices owing to a surplus of generation in the market, leading to deactivations that are now putting pressure on supply.

LS Power Senior Vice President of Wholesale Market Policy Marji Philips commented that the original concept of the capacity market was for prices to increase when demand is tight and fall when it is low, averaging out to net CONE over the lifespan of the reference resource. While regular market interventions have been creating price volatility and uncertainty, she said the return of prices to net CONE levels signals that investments in new generation are needed.

Bowring disagreed that the auction had accurately reflected supply and demand, stating that administrative changes to the definition of capacity, namely the use of marginal effective load-carrying capability for resource accreditation, actually inflated prices. He also argued that supply is being suppressed by PJM's categorical exemption of intermittent and storage resources from the requirement that all resources holding CIRs offer into the BRA. Both points were raised in the first two sections of the Monitor's report on the 2025/26 auction. (See *PJM Market Monitor Releases Second Section of 2025/26 Capacity Auction Report*.)

"The design of the market did not reveal what the actual supply and demand was," he said.

Clara Summers, campaign manager of the Consumers for a Better Grid project at the Illinois Citizens Utility Board, said there were changes in supply and demand, but they were not significant enough to account for the scale of the price jump seen in the July auction. Moreover, she argued that the capacity market is incapable of sending price signals to build because of the backlogged interconnection queue, an issue she said is also present when considering if high capacity prices can incentivize replacement resources while transmission upgrades are built. ■

PJM News

PJM MRC/MC Preview

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

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance drafted through the document's periodic review. The changes include clarifications to the transmission facility ratings process, grammatical corrections and removing the legacy NERC Functional Model.

C. Endorse proposed *revisions* to Manual 14F: Competitive Planning Process proposed as part of the manual's periodic review. The revisions would make formatting and grammatical corrections, remove out-of-date references, update instructions for uploading files to PJM and reorganize some sections.

D. Endorse proposed *revisions* to Manual 21B: PJM Rules and Procedures for Determination of Generating Capability to update the definition of dual fuel gas generators to align with tariff language approved in *ER24-1988*. (See "Stakeholders Endorse Dual Fuel Manual Definitions," *PJM PC/TEAC Briefs: Oct. 8, 2024* .)

E. Endorse proposed *revisions* to the tariff and Operating Agreement (OA) to eliminate the High/Low and Marginal Cost Proxy approaches to interface pricing. (See "PJM Proposes Elimination of Two Interface Pricing Models," *PJM MRC Briefs: Sept. 25, 2024*.)

Issue Tracking: *Interface Pricing for Non-market Entities*

Endorsements (9:10-10:30)

Credit Risk Arising from Bilateral Capacity Transactions (9:10-9:30)

PJM's Gwen Kelly will review a *proposal* to increase its review of the creditworthiness of parties to a bilateral capacity transaction. (See "First Read on Increased Review of Credit Risk for Bilateral Capacity Transactions," *PJM MRC Briefs: Sept. 25, 2024*.)

The committee will be asked to endorse the proposed solution and corresponding tariff *revisions*.

Issue Tracking: *Credit Risk Arising from Bilateral Capacity Transactions*

Capacity Market Enhancements — Data Transparency (9:30-9:50)

LS Power's Tom Hoatson will review a *problem statement* and *issue charge* asking stakeholders to consider expanding the transparency of PJM's effective load carrying capability (ELCC) approach to accreditation. (See "LS Power Issue Charges on Accreditation Transparency, Unit-specific Performance," *PJM MRC Briefs: Sept. 25, 2024*.)

The committee will be asked to endorse the proposed issue charge.

ELCC Capacity Accreditation Methodology (9:50-10:10)

Hoatson will review a second *problem statement* and *issue charge* pair addressing the marginal ELCC design and how it is used to determine resource accreditation.

The committee will be asked to endorse the proposed issue charge.

Storage Integration (Phase II): Transmission Asset Utilization in Operations (10:10-10:30)

PJM's Dave Anders will review a *problem statement* and *issue charge* exploring the implementation of storage as a transmission asset (SATA). During the Sept. 25 first read, Anders said discussion on SATA had been tabled by stakeholders four years ago. But PJM believes the subject should be reopened, as storage is increasingly viewed as a solution to costly reliability must-run agreements with deactivating resources. (See "PJM Proposes Reopening Discussion of Storage as a Transmission Asset," *PJM MRC Briefs: Sept. 25, 2024*.)

The committee will be asked to approve the issue charge.

Members Committee

Consent Agenda (1:35-1:40)

B. Endorse proposed *revisions* to Manual 15: Cost Development Guidelines prepared through the document's periodic review. The changes include correcting several formulas throughout the manual and removing the variable operations and maintenance (VOM) default values table to point instead to annually updated values on the PJM website. (See "Other Committee Activities," *PJM MIC Briefs: Sept. 11, 2024*.) ■

— Devin Leith-Yessian

SPP News

SPP, MISO Await FERC's Approval of JTIQ Project

By Tom Kleckner

LITTLE ROCK, Ark. — SPP and MISO are coordinating responses to the August FERC filings to facilitate their Joint Transmission Interconnection Queue (JTIQ) process and cost-allocation methodology.

Clint Savoy, SPP's manager of interregional strategy and engagement, told the RTO's stakeholders Oct. 16 that the comment period for the filings closed Sept. 19. The RTOs have asked for an order by Nov. 14.

"There were some comments in support, some protests, some limited protests," he said. "We're looking to file those responses as soon as possible so that we give FERC enough time to issue a ruling in the time that we requested."

SPP filed tariff revisions related to the JTIQ on Aug. 21 (*ER24-2825*) and MISO did the same Aug. 26 (*ER24-2871*). SPP and MISO also submitted matching modifications to the commission for their joint operating agreement (ER24-2798 and ER24-2797, respectively).

The tariff revisions have drawn nearly 50 intervenors in each docket. Six regulatory bodies have intervened, primarily over cost allocation.

The RTOs expect a grant of up to $464.5 million in matching federal funds under the U.S. Department of Energy's Grid Resilience and Innovation Partnerships program to offset about 25% of the $1.7 billion portfolio's capital costs that would have been charged to interconnection customers. (See *MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant*.)

The grid operators told FERC that JTIQ transmission owners will be "fully compensated" for capital costs associated with their respective upgrades through the portfolio subscription methodology. The costs will be covered through a combination of GRIP funding, charges to interconnection customers benefiting from the portfolio and, if necessary, temporary or permanent backstop funding from load.

JTIQ Portfolio	Location by RTO
Bison – Hankinson – Big Stone South 345 kV	MISO
Lyons Co - Lakefield 345 kV	MISO
Raun – S3452 345 kV	MISO - SPP
Auburn – Hoyt 345 kV	SPP
Sibley 345 Bus Reconfiguration	SPP

The five projects in the $1.7 billion MISO-SPP Joint Transmission Interconnection Queue portfolio | *SPP*

The Arkansas Public Service Commission filed *clarifying comments* in MISO's docket, saying it opposes the JTIQ backstop proposal. Saying it was concerned that the backstop "fails to allocate costs commensurate with the benefits received," the APSC asked the RTO to either make the interconnection customers pay the backstop funding or allocate the costs to the subregion where the projects will be built.

The JTIQ portfolio, centered on the RTOs' northern seam, is expected to enable 28 GW in generation additions through its backbone net. The backbone of network upgrades consists of five projects, cut down from the original seven identified by SPP and MISO:

- Bison-Hankinson-Big Stone South, 147 miles of new 345-kV lines in the Dakotas (MISO).
- Lyons Co.-Lakefield Junction, 80 miles of new 345-kV lines in South Dakota and Minnesota (MISO).
- Raun 345/161-kV project, new 345/161-kV double circuit, and rebuilt 161-kV lines near Omaha, Neb. (MISO, SPP).
- Auburn-Hoyt, new 345-kV lines in Nebraska (SPP).
- Expanding and rebuilding a 345-kV substation in Sibley, Iowa (SPP).

The DOE reached a cooperative agreement with Minnesota's Department of Commerce in September. The department is responsible for administering the federal money, which will be awarded to the RTOs, TOs and other parties involved should they meet their objectives.

"That sets us up to begin establishing the processes that we need to be able to take advantage of this program," Savoy said.

Responding to an SPP member's question during the Oct. 16 meeting as to whether Minnesota would be able to influence the disbursement of funds, a spokesperson for the commerce department said the state won't be "putting its thumb on the scales."

"That would not be appropriate with federal funds," the department's Jessica Burdette said. "That's not a thing people need to worry about."

The RTOs said in their FERC filings that board approval is a "major decision point" in whether the GRIP funds can be disbursed and is based on whether the commission approves their tariff revisions and JOA updates.

Assuming FERC approval, the grid operators' staff members plan to take the JTIQ portfolio to their respective boards' upcoming meetings for their approval. SPP's board meets in December and February and MISO's in December and March. ■

Why This Matters

Now that SPP and MISO have filed their Joint Transmission Interconnection Queue portfolio and process at FERC, all they need is commission approval — followed by that of their respective boards — before federal construction funds can be distributed.

Company News

NextEra Adds Renewables, Eyes Nuclear Restart

Company's Q3 Earnings Jump as Emissions-free Portfolio Grows

By John Cropley

NextEra Energy reported deals for 3 GW of new renewables with its third-quarter financials and said it has reached a framework agreement totaling 10.5 GW with two major corporations.

CEO John Ketchum also indicated the company is interested in recommissioning an Iowa nuclear reactor shut down after storm damage in 2020. Customers, particularly data centers, are showing keen interest in the emissions-free power it would supply, he said.

The third-quarter report issued Oct. 23 was another strong and confident assessment from one of the nation's leading renewables developers and utility operators.

It was the second quarter in a row that NextEra Energy added 3 GW of new renewables and storage to its backlog. Ketchum said if NextEra achieves only midpoint expectations, it will more than double its renewable generation portfolio from 38 GW today to 81 GW by the end of 2027.

Data centers' massive power needs are well known, Ketchum said, but the demand growth spreads far beyond them.

The two Fortune 50 firms that struck the 10.5 GW framework agreements with NextEra are not data center operators and are not even part of the technology sector. NextEra will not identify them at this stage but said they are building facilities that will need power, and they would prefer to meet those needs with low-carbon resources.

"Cost, capacity and speed are the three big issues that need to be addressed in meeting power demand, and as we have demonstrated in Florida, a mix of new renewables, storage and gas generation is the solution," Ketchum said.

He added: "When it comes to economics, renewables and storage are the lowest-cost generation and capacity resource for customers in many parts of the U.S. We believe new wind is up to 60% cheaper and new solar up to 40% cheaper than new gas-powered generation, and that's on a nearly firm basis when paired with a four-hour battery."

Ketchum's remarks on NextEra's Duane Arnold nuclear plant in Iowa had a different tone than those just three months earlier. During the second-quarter earnings conference call in July, he said the company would consider a restart only under the right circumstances. (See *NextEra Reports Continued Growth in Renewables*.)

Now the company is "very interested."

The problem with nuclear is that it essentially is a future-tense solution, Ketchum said. New technology will not come online at scale for at least a decade, he predicted, and existing technology is famously slow and expensive to build. So nuclear is not a short-term solution — unless one is referring to Duane Arnold and just a few other idled plants that could be brought back online. (Work is underway to recommission two others in Michigan and Pennsylvania.)

Duane Arnold is a half-century old, but it is a simpler boiling water design and can be refurbished in less time and at lower cost, Ketchum said.

Unlike other nuclear proponents, NextEra is not jumping on the bandwagon for small modular reactors (SMRs) just yet, and probably will not any time soon.

"We have been following SMRs for a very long time," Ketchum said. "We actually advise a couple of Fortune 100 companies on SMRs today."

NextEra's assessment: Only a few of the nearly one dozen manufacturers trying to bring SMRs to market have the capitalization to make it happen in the next several years; each design will be an unproven first-of-a-kind technology that carries "a ton of risk"; they initially will be too expensive to compete with a mix of renewables, storage and gas; and an entire supply chain must be built to fuel them.

"That's why we're just not bullish on SMRs,"

Why This Matters

The company's results are based mainly on the performance of its subsidiaries Florida Power and Light, the nation's largest utility by customer count, and NextEra Energy Resources, the world's largest generator of wind and solar power.

The East-West Tie is shown under construction in Ontario. NextEra Energy Transmission Canada is a partner. | *NextEra Energy*

Company News

Ketchum told an analyst during the Oct. 23 conference call. "We think it's kind of an end-of-the-next-decade alternative."

NextEra Energy's third quarter net income per share was up 50% on a GAAP basis from the same period in 2023 and up 9.6% on an adjusted basis. The company projects continued annual growth in earnings per share through 2027 and expects to increase its dividend by about 10% per year at least through 2026.

NextEra Energy's third quarter results are based mainly on the performance of its subsidiaries Florida Power and Light, the nation's largest utility by customer count, and NextEra Energy Resources, the world's largest generator of wind and solar power.

NextEra Energy Partners, a separate business that shares corporate leadership with NextEra Energy, posted a net loss of $40 million for the third quarter of 2024, which compares with a net income of $53 million in the same quarter of 2023.

Chief Financial Officer Brian Bolster said NextEra Energy Partners will complete a review over the next three months but added that it has many potential avenues of growth, given the demand for electricity.

NextEra Energy's stock closed 1.5% higher on a day of widespread losses across the major U.S. markets, while NextEra Energy Partners' stock was down 16.3%. ■

The Duane Arnold Energy Center in Iowa is shown prior to shutdown in 2020. NextEra Energy is "very interested" in recommissioning the nuclear reactor. | *NextEra Energy*

Company Briefs

Dominion Completes Sale of CVOW Stake, Acquisition of Kitty Hawk

Dominion Energy last week announced it has completed its $2.6 billion sale of a 50% noncontrolling stake in its Coastal Virginia Offshore Wind (CVOW) project to investor Stonepeak.

Dominion will retain full operational control of construction and operations of the $9.8 billion project. As of August, the 50th monopile foundation of CVOW's 174 turbines was installed and the project is expected to be completed in 2026.

Dominion also announced the completion of its purchase of the Kitty Hawk North offshore wind lease area from Avangrid for $160 million. Avangrid will retain ownership and associated rights to the Kitty Hawk South lease and will continue the development of the area.

More: *Virginia Business*, *offshoreWIND.biz*

Tesla Reports Q3 Profit Increase

Tesla last week said its profits for the third quarter increased 17%.

The company said it earned $2.2 billion from July through September, compared with $1.9 billion in the same period last year. Sales were $25.2 billion, compared with $23.4 billion a year earlier.

Sales of storage batteries jumped 52% in the quarter, while revenue from services like charging climbed 29%.

More: *The New York Times*

Google Signs PPA for 350-MW Texas Solar Project

Google last week announced it has agreed to a deal with Engie North America to offtake 350 MW from the company's Chillingham solar project in Texas.

The solar farm is being installed north of Austin. Google will use the procured electricity to meet the demand of its state operations.

More: *Renewables Now*

Federal Briefs

DOI Approves Nevada Lithium Mine

The Department of the Interior last week approved a permit for a new lithium-boron mine in Nevada.

The Rhyolite Ridge mine will help expedite production of lithium, which is a key component in EV batteries.

Construction of the mine should begin next year.

More: *The Associated Press*

FAA Issues Final Rule on Air Taxis

The Federal Aviation Administration last week issued the final rule for air taxis and other electric-powered aircraft, calling the regulations the "final piece in the puzzle" to introducing the aircrafts.

The final regulation lays out the qualifications and training required for instructors and pilots to fly aircraft in the "powered lift" category, along with the operational requirements for the electric-powered aircraft, the FAA said.

FAA Administrator Mike Whitaker noted the powered lift category is the first new aircraft category in nearly 80 years.

More: *The Hill*

US Installs 5 GW of Storage So Far in 2024

The U.S. has installed 5 GW of battery storage nationally through July, according to the EIA.

As of July, more than 20.7 GW of battery storage capacity was available in the country.

The EIA predicts the capacity could double again to 40 GW by 2025 if further planned expansions occur.

More: *The Guardian*

State Briefs

CALIFORNIA

Kern County Approves Carbon Capture, Storage Project

The Kern County Board of Supervisors unanimously approved the Carbon Terra Vault project that will capture carbon dioxide and inject it into the ground.

The project by California Resources, the state's largest producer of oil and gas, will capture and inject carbon dioxide into the ground at an oil and gas field in the San Joaquin Valley. The EPA would have to sign off on the project as well.

Construction would take about two years for the carbon capture plants and a year for the pipelines.

More: *CalMatters*

FLORIDA

FPL Hurricane Costs to Top $1B

Florida Power & Light expects to seek approval to collect about $1.2 billion from customers in 2025 to cover costs of restoring power after hurricanes Debby, Helene and Milton and to replenish a storm reserve fund.

FPL will seek to recover about $800 million stemming from Hurricane Milton. FPL also had an estimated $300 million in costs from Debby and Helene.

The Public Service Commission must sign off on the plan.

More: *WFOR*

IOWA

Clinton Expands Wind Turbine Moratorium

The Clinton County Board of Supervisors last week placed a moratorium on applications for MET towers, sodar equipment and any other equipment related to the development of utility-scale wind turbine developments, effective until Dec. 31.

There is currently a moratorium on applications in the county for utility-scale wind turbine developments, also effective until Dec. 31.

Discussions on revisions to the county's ordinances are set to resume Oct. 30.

More: *Clinton Herald*

KANSAS

Evergy Plans to Build Two New Natural Gas Plants by 2030

Evergy CEO David Campbell last week said it plans to build two 705-MW combined-cycle natural gas plants in Sumner and Reno counties in 2029 and 2030, respectively.

In its long-range plan filed in 2022, Evergy planned to exclusively add wind and solar facilities over the coming decade. A year later, it scaled back the planned renewable energy facilities, forecasted plans to add natural gas plants, and delayed the retirement of the Lawrence coal plant. Evergy's latest update, filed earlier this year, almost doubles the amount of natural gas generation it will add between now and the early 2030s.

More: *Kansas Reflector*

KENTUCKY

LG&E and KU: Less Power from Coal, More from Natural Gas

In its integrated resource plan filed before the Public Service Commission, Louisville Gas and Electric and Kentucky Utilities outlined the steps to meet demand by replacing coal-fired power with natural gas.

The plan anticipates adding no new coal-fired generation while building as many as four natural gas-fired plants plus battery storage systems for solar energy — in addition to a natural gas plant already slated for construction.

The PSC will consider the plan over the coming months.

More: *Kentucky Lantern*

LOUISIANA

Solar Farm Unveiled in Franklinton

D.E. Shaw Renewable Investments unveiled its 50-MW solar facility on about 447 acres of private farmland near Franklinton.

The Sunlight Road Solar facility boasts new technology in the form of all-terrain, sun-tracking sensors.

The farm will sell electricity to Entergy Louisiana.

More: *Louisiana Illuminator*

MASSACHUSETTS

Vineyard Wind to Resume Pile Driving for Turbine Foundations

Even as it prepares to take down additional defective blades, repair others and retrieve the remaining debris from the July 13 blade failure, Vineyard Wind will forge ahead with the construction of its 62-turbine wind farm this week.

The company announced the crane vessel Orion would return to the area to conduct pile driving and installation of the remaining monopile foundations within the lease area.

While Vineyard Wind remains under a suspension order from the Bureau of Safety and Environmental Enforcement stemming from the blade failure in July, the agency subsequently modified the order to allow Vineyard Wind to resume installing towers and nacelles.

More: *Nantucket Current*

MINNESOTA

PUC Approves Minnesota Power Rate Increase

The Public Utilities Commission last week unanimously approved a 4.9% rate increase for residential customers of Minnesota Power.

The company initially asked for a 12% rate increase, worth $89.1 million, but will have to accept an increase that will raise residential customers' bills about $5 a month. It will also raise rates by 4.4% for industrial and large commercial customers.

Minnesota Power said the rate increase would help it recruit and retain its workforce during the transition from fossil fuels, spend money on infrastructure, and address inflation and supply chain issues.

More: *The Minnesota Star Tribune*

NORTH CAROLINA

Duke University Becomes Carbon Neutral

Duke University announced it has fulfilled its pledge to become carbon neutral by 2024. It is one of only 14 U.S. colleges and universities to reach the milestone.

The achievement was made possible by reductions in energy use and investment in renewable sources, as well as the purchase of $4 million worth of "high-quality" carbon offsets. Duke originally made the commitment in 2007 when then-President Richard Brodhead signed the American College and University Presidents' Climate Commitment.

More: *Duke Chronicle*

OHIO

Madison County to Appeal Solar Project Construction

Madison County commissioners said they will appeal the approval of a solar project to the state Supreme Court.

The Power Siting Board voted 7-2 to approve the Oak Run solar project in March. Earlier this month, county commissioners voted 2-1 to pursue legal counsel to appeal the project. This project, once constructed, would be the largest agrivoltaic project in the U.S.

More: *WYSO*