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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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RTO Insider
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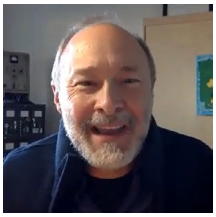
ESSC To-do List: Labor Shortage, Forest Management, Transformers

Ukraine Attacks Underscore Urgency on Speeding Transformer Production

By Rich Heidorn Jr.



Duane Highley, Tri-State Generation and Transmission Association | *U.S. Energy Association*

Solving workforce issues, making transformers easier to replace and improving forest management are among the issues dominating the attention of the Electricity Subsector Coordinating Council, Co-chair Duane Highley said Friday.

The ESSC has been discussing how the industry can deploy federal funding from the Inflation Reduction Act and the Infrastructure Investment and Jobs Act "that would basically triple the rate of expansion of our energy transition," Highley said during a United States Energy Association *virtual press briefing* on transmission.

"The No. 1 factor that's limiting us right now is labor availability. There's just not enough people," said Highley, CEO of Colorado-based Tri-State Generation and Transmission Association. "And so despite the will — we might have all the money in the world — if we don't have the people, we're not going to get it done. And this is a global problem. It's not even just limited to us."

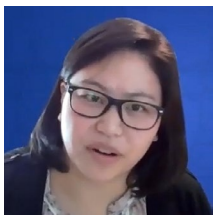
Highley said the ESSC's wildfire working group is completing efforts with the U.S. Forest Service and Bureau of Land Management to create master special-use permits that will simplify the removal of vegetation under transmission lines.

"We've had, in the past, to get separate permits for every single forest district, every single company," he said. "And what we're on the verge of completing now … is a master special-use permit that's going to allow [access] to be negotiated once. And then we can get in and do the work we need to do without so many extra hoops to jump through."

Getting Away from Bespoke Transformers

Highley and Maria Robinson, director of the U.S. Department of Energy's Grid Deployment Office, also spoke of efforts to improve the supply of transformers.

Highley said the ESSC, a public-private partnership formed to improve energy resilience after the Sept. 11, 2001, terrorist attacks, has made major strides. "We're much better today than we were two decades ago," he said. "One of the things we're looking at hard right now is the Defense Production Act capabilities that [the Department of Defense] has been given, and it might allow them to engage in helping make transformer supplies better."



Maria Robinson, DOE Grid Deployment Office | *U.S. Energy Association*

Robinson cited the *Solid State Power Substation Technology Roadmap*, a research and development effort being led by DOE's Office of Electricity to reduce the criticality of substation components.

"One of the biggest issues is that transformers … are made to spec. They're not modular in any way, shape or form," Robinson said. "And there's a lot of investment going into research to allow for more modular parts, recognizing that when you're ordering a very specific design, it could take months or years for that to come in. And from a resilience perspective, we want to make sure that we're able to rebuild more quickly than that."

Ukrainian officials said earlier this month that Russia's strikes on the nation's infrastructure had destroyed *about 30%* of its autotransformers.

Asked what lessons the Russian attacks might hold for U.S. resilience efforts, Highley said: "Defense in depth; redundancy. It's what's always saved us, no matter what happens, whether it's weather, cyberattack or physical kinetic attack."

Florida's Transmission Stands Tall

Also speaking at the briefing was former FERC Commissioner Philip Moeller, now executive vice president of the Edison Electric Institute, who touted the hardening investments made by Florida's utilities before Hurricane Ian in September.

Philip Moeller, Edison Electric Institute | *U.S. Energy Association*

"In the last hurricane, we didn't lose any transmission structures in Florida," Moeller said. "So that tells you that the infrastructure investments — the hardening, the adaptation, the resilience — actually pay dividends."

Moeller cited studies estimating that power outages in Florida can result in economic losses of $1 billion per day.

"So to the extent you can invest to correct those outages, that's a pretty good bargain," he said. "It also points out [the optionality value of] transmission. … As populations change; when congestion occurs; as public policies change; as fuel choices change, transmission is the infrastructure that gives us optionality."

Robinson said DOE has $10.5 billion in funding to improve grid resilience and innovation through matching grants, "specifically looking at some of that hardening work that needs to happen, both at the transmission and distribution levels."

Moeller said additional federal funding also will help expand cybersecurity programs to "more of the smaller energy companies and utilities throughout the country, so that we can have a more comprehensive approach toward the cyber threats that are out there."

More East-west Transmission

Highley and Michael Skelly, founder and CEO of transmission developer *Grid United*, also talked about the need for more interregional transmission to address reliability problems and the solar duck curve.

Michael Skelly, Grid United | *U.S. Energy Association*

"We need a national will to build national transmission east [to] west. So much of what we have now is north to south," Highley said. "The RTOs even tend to be oriented north to south — if you look at CAISO, you look at SPP, if you look at MISO — and that's why we have duck curve problems. … A duck curve exists because the sun sets on a time zone all at once. And if you could move that east and west, you wouldn't have a duck curve at all."

Skelly was asked whether Texas policymakers might consider making ERCOT FERC-jurisdictional by interconnecting with the

FERC/Federal News

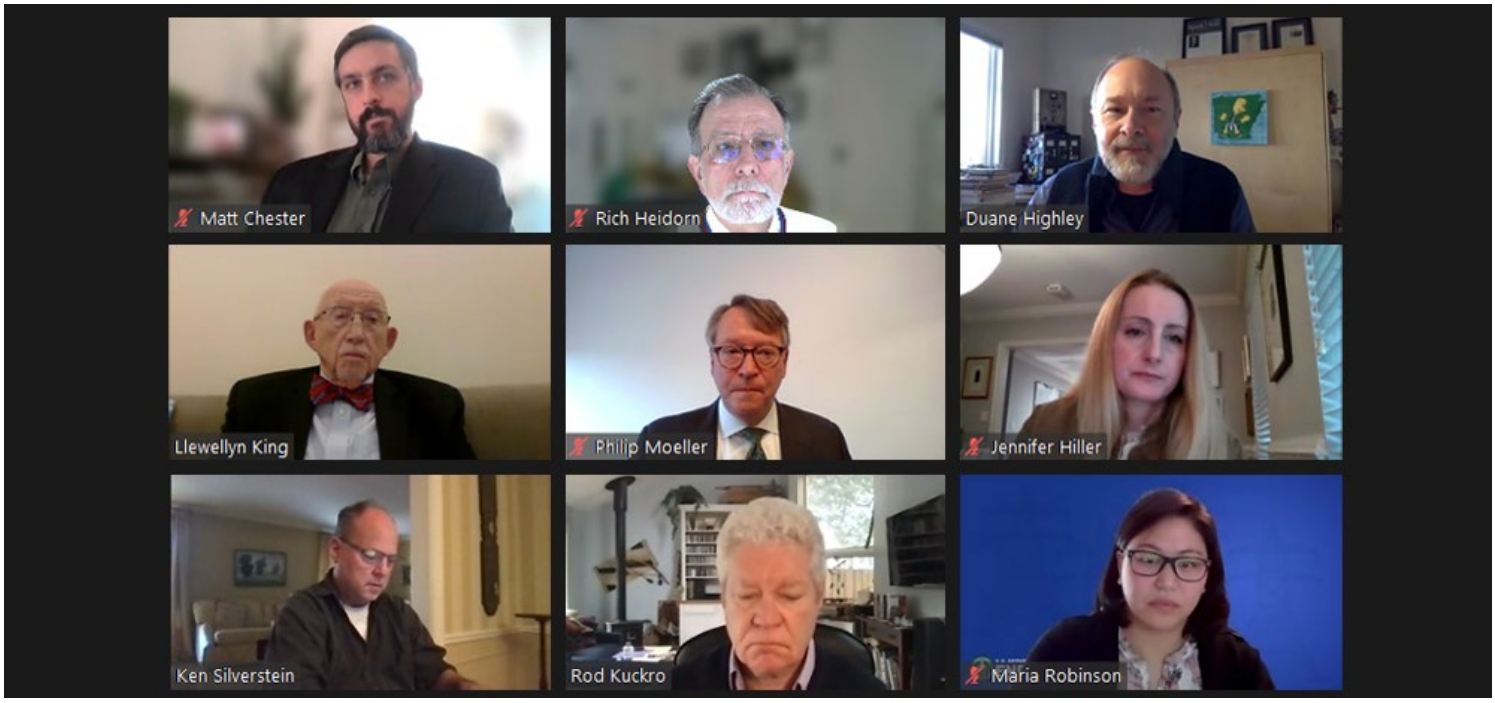
Eastern and/or Western grids in response to the blackouts following the February 2021 winter storm.

"I would say the chances of Texas joining the rest of the country, electrically speaking, are between zero and none," Skelly replied. "But I do think that the prospects for DC connections between ERCOT and elsewhere are fairly good."

ERCOT currently has transfer capacity of only 1,200 MW with "the outside world, as we in Texas, like to call it," Skelly said. His company is proposing a project that would connect West Texas and El Paso. He also mentioned Pattern Energy's *Southern Spirit* project, a 400-mile line between East Texas and Mississippi.

"I think we'll see more projects like that. And they're beneficial, because … ERCOT has tremendous amounts of wind and solar. And these lines would allow ERCOT to share that abundance with the rest of the country, and also provide reliability to ERCOT during stressful grid conditions," Skelly continued.

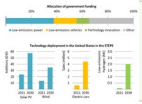
"I know ERCOT has had kind of a rough go in many respects. But one of the reasons that Texas has so much renewable energy — we lead the country in wind; we will soon lead the country in solar — is precisely because of its independence. You have one jurisdiction that can make decisions around grid expansion [with] fairly low barriers to entry. … So I don't think things will change in terms of like FERC jurisdiction, but I do think there's opportunities to connect us through these DC connections, and those will be beneficial all around." ■



Four reporters questioned transmission experts during a U.S. Energy Association virtual press briefing Friday. Top row, left to right: Matt Chester, Energy Central; Rich Heidorn Jr., *RTO Insider*; Duane Highley, Tri-State Generation and Transmission Association; Philip Moeller, Edison Electric Institute; Jennifer Hiller, *The Wall Street Journal*; Second row: Moderator Llewellen King; Ken Silverstein, *Forbes*; freelancer Rod Kuckro; and Maria Robinson, DOE Grid Deployment Office; Michael Skelly, Grid United | *U.S. Energy Association*

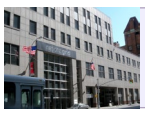
National/Federal news from our other channels

Overheard at RFF Net Zero Economy Summit — NetZero Insider



IEA Solar Will be Top Form of Energy Generation in Next 5 Years — NetZero Insider

NERC Board Approves Cold Weather Standards — ERO Insider



National Grid to Pay $512k for Standards Violations — ERO Insider

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

FERC/Federal News

ClearPath: Nation's Queue Processes Impeding Energy Transition

Nonprofit's Report Recommends Feds Enact Interconnection Improvements

By Amanda Durish Cook

Conservative clean energy nonprofit ClearPath last week joined the chorus sounding the alarm over the nation's congested generator interconnection queues, which it said are undermining carbon-reduction goals.

In a new *report*, "All Queued Up and Nowhere to Go: The Massive Interconnection Challenge Facing Net-Zero Electricity Deployment," the organization released a handful of recommendations for reducing queue delays.

The report concluded that federal agencies should enact policies that include coordinating interconnection and transmission planning processes; allowing expedited treatment for projects proposed in existing rights of way; offering grants and scholarships to electrical engineers who focus on interconnection; and providing technical assistance to those who oversee interconnection processes.

ClearPath analyzed interconnection processes used by transmission providers, utilities and grid operators. It found an average queue wait time of 3.7 years and a "massive backlog, making it incredibly difficult to deploy new generation and storage resources." It said wait times for interconnection between 2000 and 2010 were just 2.1 years in comparison.

"The interconnection queue has become so dysfunctional that some transmission providers are freezing their process to work through the project backlog," Spencer Nelson, ClearPath's managing director for research, said in a press release. "Hundreds of gigawatts of new energy projects — predominantly wind, solar, natural gas, and storage — spend an increasingly long time in the interconnection process. This is now the biggest bottleneck for clean energy development."

FERC NOPR

The nonprofit wasn't keen on FERC's June Notice of Proposed Rulemaking (*RM22-14*) for clearing the queues and giving generators more certainty on upgrade costs, saying the NOPR's proposals are not likely "transformative or flexible enough for the speed and scale of deployment required."(See *RTOs, Utilities Push Back on Interconnection Deadlines, Penalties*.)

It said many transmission providers have already tried FERC's proposed fixes without much improvement, pointing to MISO's multiple filings over the last decade to streamline its queue process.

Turbine assembly at the 288-MW Maverick Energy Center in Oklahoma | *Invenergy*

ClearPath said the commission should embark on a rulemaking to integrate regional and interregional transmission planning with interconnection processes. It also said the U.S. Department of Energy should fund workforce development that specializes in interconnection and update its National Interest Electric Transmission Corridors (NIETCs) to issue more construction permits and provide technical interconnection assistance to states, utilities and RTOs and ISOs.

Finally, ClearPath recommended FERC, DOE and U.S. department of the Interior strengthen their coordination in permitting generation and transmission. It said the agencies should work together to expedite permitting at interconnection points for large, retiring power plants and for rights of way under the U.S. Department of Transportation. It said the agencies should also "proactively pre-site areas on federal land for clean energy and transmission projects along identified NIETCs."

'Unrealistic'

The organization said current net-zero models are "unrealistic" given the current congested queues and warned that the retirement of existing capacity is set to "outpace new additions due to interconnection inefficiencies."

ClearPath said between 2010 and 2016, only 23% of generation projects entering various queues reached commercial operation. It blamed, in part, first-come, first-served study processes that encourage developers to submit more than one interconnection request in the hopes of landing on the cheapest interconnection points. When speculative placeholders withdraw requests, it causes "turmoil," the report said.

The nonprofit cited Princeton University's "*Rapid Energy Policy Evaluation and Analysis Toolkit*," which shows that the U.S. requires 1,101 GW of additional wind and solar generation, 179 GW of natural gas generation with carbon capture technology, and 6 GW of nuclear generation by 2035 to reach net-zero emissions by 2050. Using those figures combined with the national average 23% rate of commercial success, ClearPath said 7,000 GW of capacity would need to enter queues to meet Princeton's 1,300 GW of generation additions.

"Failure to address the current interconnection process at scale will limit the ability to reduce emissions affordably and could hurt grid reliability," Nelson said. "At this point, achieving net-zero emissions in the U.S. by 2050 is impossible without major interconnection improvements."

ClearPath said the U.S. needs record annual capacity additions, not feasible under current processes, to accomplish a net-zero midcentury mark. It said the nation should have somewhere between 74 and 156 GW of capacity additions per year. Though proposed capacity entering queues has recently grown to 500 GW per year, ClearPath said interconnection rates have dwindled. ■

FERC/Federal News

Transmission Conference Focuses on Reliability, Interconnection

By Michael Brooks

WASHINGTON — Transmission stakeholders and federal regulators are concerned about extreme weather and clogged generator interconnection queues, but they're also encouraged by FERC's many proposed rulemakings to tackle those issues.

"We've probably had more headlines this year in MISO related to resource adequacy and the threat of outages than we've had in the last five years combined," Scott Wright, the RTO's executive director of resource adequacy and resource utilization, said at WIRES' annual Fall Conference on Thursday. "The risk profile of the grid is changing significantly."

Variability and uncertainty have always been a part of managing the grid, he said, but both have increased significantly and faster than expected. "So all of our thoughts and plans at MISO had to be reprioritized and changed."

The two are related in a way: States are seeking to interconnect more renewables to address climate change, which is increasing the frequency of extreme weather events.

Eric Vandenberg, FERC | © *RTO Insider LLC*

Eric Vandenberg — recently *appointed* deputy director of FERC's Office of Electric Reliability, after serving as deputy director of the Office of Energy Policy and Innovation (OEPI) — gave a keynote speech focused on the threat of extreme weather. He stood in for Commissioner Willie Phillips, who could not attend because of a death in family, according to WIRES.

Vandenberg noted that several regions have come to the brink of load shedding just this year, including an early cold snap in MISO and an extended heat wave in California. "Looking forward, 'extreme' does not necessarily mean 'rare,'" he warned.

Since the beginning of the year, FERC has issued several Notices of Proposed Rulemakings on transmission, including one on planning processes and cost allocation (RM21-17), and one addressing interconnection queues (RM22-14). Both came as a result of a wide-ranging Advance NOPR issued last year, the results of which the attendees of last year's conference were eagerly anticipating. (See *Transmission Industry Hoping for Landmark Order(s) out of FERC ANOPR*.)

From left: Amanda Conner, AEP; Cynthia Bothwell, DOE; Tristan Kessler, FERC; and Scott Wright, MISO | © *RTO Insider LLC*

But FERC also issued proposed rules that would update NERC reliability standards and direct transmission providers to report on their policies for assessing their vulnerabilities to extreme weather. (See *FERC Approves Extreme Weather Assessment NOPRs*.)

Vandenberg said the NOPRs are designed "to raise that floor" of NERC's standards "for instances of extreme weather" by making utilities address their vulnerabilities.

Meanwhile, "I don't need to harp on the need for reform here with this audience; I think it's pretty obvious to everyone that the interconnection queues are generally pretty backlogged," said Tristan Kessler, an economist in OEPI. He noted the record number of projects submitted to MISO for interconnection just this year. (See *MISO: Record 1,000 Interconnection Requests in 2022*.) "So I'm excited to be at your fall 2032 panel to talk about interconnection issues as well."

Amanda Conner, vice president of FERC and RTO strategy and policy at American Electric Power, asked Wright, Kessler and fellow panelist Cynthia Bothwell, an engineer in the Department of Energy's Wind Energy Technology Office, whether the commission's proposal goes far enough.

FERC's proposed rulemaking on queues would create a first-ready, first-served model for interconnection, which has won wide support. But it would also impose stricter requirements on transmission providers in the form of penalties for failing to meet certain deadlines on completing interconnection studies; RTOs and utilities have not been particularly receptive to these.

Wright said "many things in the NOPR are spot-on," but some "may not help with efficiency or may cause unnecessary work. ... Is FERC going far enough? Well, they certainly proposed things related to very definitive penalties [to which] we would say, 'Don't go farther.'"

Bothwell answered that FERC "is doing a great job of getting that conversation going, but we know that the system is changing, and to get to this big transformation, it's going to happen in steps. And we're going to learn more ... and need additional reforms down the road."

"It's definitely not the end of the process for us," Wright said. "A lot of transmission providers have come to us and proposed other changes ... and I think the commission is generally supportive of that." ■

CAISO/West News

Effective Transmission Planning Requires Western RTO, Panelists Say

ACEG Panel also Discusses Typical Impediments to Regional Projects

By Robert Mullin

Kathleen Staks, chair of the Colorado Electric Transmission Authority (CETA), thinks the creation of an RTO is "imperative" for Western states to develop the transmission network needed to meet their clean energy and electric reliability goals.

Staks, who also serves as deputy director of *Western Freedom*, a self-described "grassroots and grasstops" coalition that is advocating for a Western RTO, also believes it's just a matter of time before one or more organized market takes shape in the region.

Speaking Thursday on a virtual "Transmission Time" panel hosted by Americans for a Clean Energy Grid, Staks noted the "momentum" building in the West from the competing day-ahead markets being prepared by CAISO and SPP.

"I think what you're hearing now, even from the utilities in public forums, is that we are on the path to an RTO — or several RTOs, which is probably the more likely sort of future state — where we have two different operators covering slightly different footprints in the West. But I think there's more of an inevitability in the talking points that you hear at this point in time," she said.

While Staks thinks the proposed day-ahead markets are a "great next step," she said they can't deliver the unified transmission planning and operational benefits of a full RTO.

Staks said legislatures in Colorado and Nevada "lit a fire" in 2021 when they each passed bills requiring their state's utilities to join an RTO by 2030. (See *Polis Signs Bipartisan Bill to Support Interstate Tx* and *Many Next Steps to Follow Passage of Nevada Energy Bill*.)

But when panel moderator Kristine Raper, a former Idaho regulator who is now vice president of external affairs at WECC, asked whether other states should follow suit and pass similar laws, Staks demurred, saying additional mandates aren't yet necessary.

"Almost all of the utilities in the West are participating in these day-ahead market developments, and I think there's enough other sort of pressure points — and almost even peer pressure, really — to keep things going," she said.

Fellow panelist Jeremy Turner, director of New Mexico project development at Pattern Energy, said he could see some benefit in states legislating membership in an RTO but thinks a better approach would be for states to direct commissions and utilities to "force the RTO issue a little bit," without specifying exactly how.

"California has done a good job with the Energy Imbalance Market [as] kind of a half-step to a formal RTO, but in order to fully build out the transmission system and align on all the decarbonization goals and meet those, I think it's absolutely going take an RTO in the West," Turner said.

CETA and RETA

That Colorado sees a vital link between a Western RTO and effective regional transmission planning is evidenced by the fact that the 2021 law (SB 72) requiring utilities to join an RTO also established CETA.

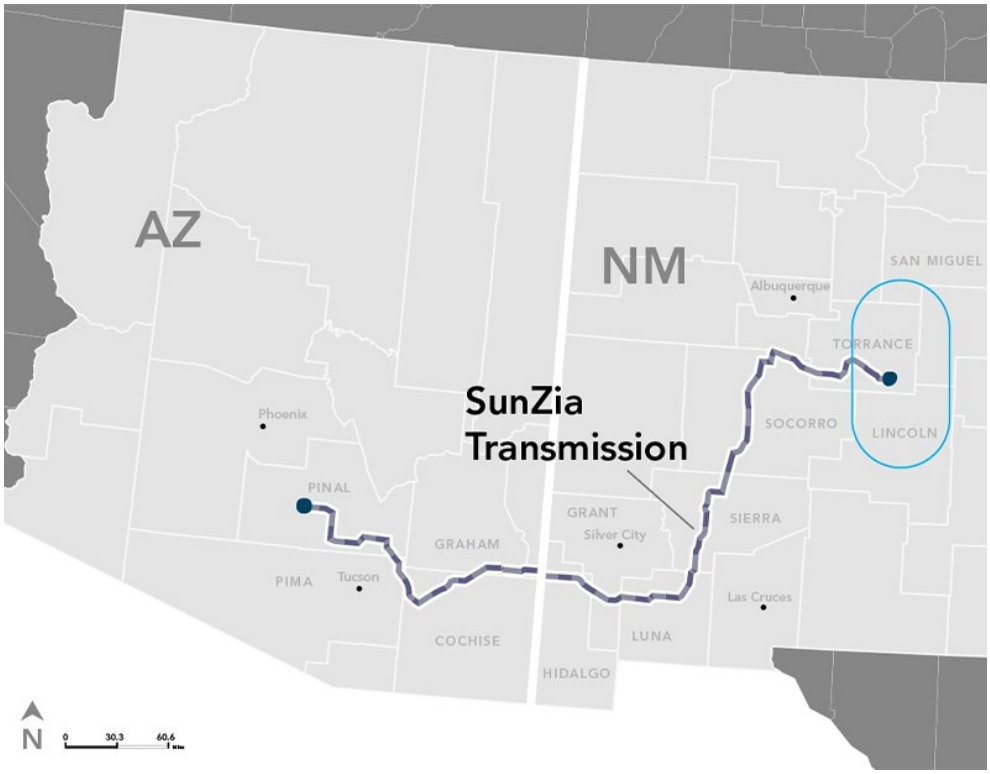
According to the law, CETA is an "independent special purpose authority" that can act as a transmission developer of last resort in areas that the state identifies as needing transmission — particularly those promising for the development of the renewables Colorado needs to meet its clean energy targets. In short, CETA will direct the construction of lines in areas where utilities are declining to build, with an emphasis on interregional projects.

"CETA has eminent domain authority and has the ability to build and own transmission projects," Staks pointed out.

CETA was modeled on New Mexico's Renewable Energy Transmission Authority (RETA), which was established in 2007 "to plan, develop finance and acquire utility-scale, high-voltage transmission lines and energy storage projects," RETA Executive Director Fernando Martinez said during the webinar.

RETA's mission, Martinez explained, is to help New Mexico develop the transmission needed to tap its extensive wind and solar resources, with an eye to serving both in-state needs and exports to neighboring states.

"Our whole [electricity] infrastructure in in New Mexico was set around fossil fuel plants taking the power to population centers, and so our renewable resources were in other parts of the state where very little transmission existed, and we knew that was a landlocked treasure," Martinez said. "And the only way to access that was by building transmission and



New Mexico's RETA is working with Pattern Energy to complete the SunZia transmission project. | *Pattern Energy*

CAISO/West News

energy storage capacity."

Because RETA's jurisdiction ends at the New Mexico state line, the agency relies "almost exclusively" on its transmission development partners to advance lines through other states, Martinez said. He cited the example of Pattern Energy's proposed SunZia project, a 550-mile, 525-kV bidirectional line designed to move wind output from eastern New Mexico to population centers in Arizona.

"So it's really been up to [Pattern] to work with Arizona and get that project going in that state, and we worry about what's going on in New Mexico," he said.

But projects become "a lot more difficult" once they hit the state line, Martinez said.

"The question is, 'Then what?' … And that's one of the primary reasons that we're looking at a regional transmission organization and really promoting that and trying to socialize that idea, because I think that is the most effective way to build an upgraded flexible grid that's geographically diverse, that's meteorologically dissimilar, [and] that has as many interconnections as possible," he said. "And then couple that with building utility-scale long-duration storage. I think that's the only way you're going to get firm capacity."

Building Relationships

Apart from their shared views on interregional planning, the three panelists also agreed that transmission developers face similar on-the-ground hurdles in developing projects in different states across the West.

"I think the biggest challenge here in the West is getting the permission to build the generation; getting the permission to build the transmission and storage projects," Martinez said. "And what I mean by that is there's a lot of laws that must be complied with that a lot of times are run sequentially, rather than concurrently, and so you have a lot of difficulties in the permitting process at the local level, the state level [and] the federal level."

Kathleen Staks, CETA and Western Freedom | *Western Freedom*

Martinez ticked off the various agencies and stakeholders that developers might have to deal with to gain permission for an energy project in New Mexico, including local governments; the state's Public Regulation Commission (for reliability requirements); FERC; the U.S. Bureau of Land Management or Forest Service (for environmental impact statements); tribes; military bases; and private landowners. All told, permitting across various agencies can stretch project timelines to 10 to 20 years, he said, a problem for states attempting to meet climate goals by 2030.

"We need to find a way to streamline that process without cutting any corners whatsoever and — hopefully working with the permitting agencies; we can do that by simply by cutting down sequential permits versus concurrent permitting," Martinez said.

Martinez expressed gratitude for the efforts of the interagency *Federal Permitting Improvement Steering Council*, which has been tasked with speeding up federal infrastructure permitting. Pattern's Turner agreed that the council has been "incredibly helpful" but thinks increased FERC siting authority will be needed to advance transmission projects in the West.

Turner is also encouraged by the creation of state agencies such as RETA and CETA, which have the eminent domain authority that independent developers lack.

But Staks said any transmission authorities set up by Western states must still deal with opposition from landowners and regional stakeholders, she added.

"People don't want transmission lines in their backyards," she said. "They don't want wind projects; they don't want solar projects. They don't want oil and gas pipelines; they don't want anything. They want to be able to sort of maintain their viewshed or their neighborhood or whatever."

She said community involvement and relationship-building around proposed projects will be important tools for CETA.

Turner said Pattern Energy, which has about 750,000 acres of private and state land under lease for wind projects, has found ranchers to be among the strongest supporters of new energy projects.

Fernando Martinez, RETA | *RETA New Mexico*

"Most of the ranchers that we have properties leased [from] are seeing this as a way to supplement their income and actually continue their way of life," he said. "And they're actually the ones that are trying to help advance, in many cases, the transmission development, because they know that is their path forward to continuing that way of life and seeing wind built on their property."

Ordering the List

Raper asked Staks how CETA might approach working with neighboring states that do not share Colorado's political views and climate goals.

Those discussions will come down to appealing to economics of a project, Staks said, imagining such a conversation with a more politically conservative state: "It's your energy resources, Montana. You have the opportunity to sell those to someone else."

Staks said she takes a similar approach when she stumps for a Western RTO.

"When I have conversations with different people about the benefits of an RTO … the list of priorities [and] the list of benefits [are] the same. You're just sort of reordering depending on who you're talking to and where you are," she said. "When you're in Colorado and New Mexico, those climate benefits are going to be really, really important to most of the decision-makers that we're working with. If you're in Idaho and Montana and Wyoming, you're going to prioritize economics and reliability."

"Everybody's going to get those all of those benefits. I think part of it is the order [in which] you're making this list," she said. ■

CAISO/West News

PG&E Faces $255M in New Wildfire Fines, Costs

By Hudson Sangree

Pacific Gas and Electric said Thursday it would incur $100 million in costs from this year's Mosquito Fire, two days after regulators proposed fining the company $155 million for 2020's deadly Zogg Fire.

The potential losses from the Mosquito Fire were reported in PG&E's third-quarter *earnings report* to the U.S. Securities and Exchange Commission and discussed in an earnings call Thursday.

The Mosquito Fire began Sept. 6 in the Sierra Nevada foothills about 50 miles northeast of Sacramento. It burned through nearly 77,000 acres, mainly in the El Dorado and Tahoe national forests, and destroyed 78 structures.

The U.S. Forest Service launched a criminal investigation of PG&E for its role in starting the fire and seized utility equipment near the ignition point, including a PG&E transmission pole. PG&E previously told the California Public Utilities Commission (CPUC) that it had recorded "electrical activity" on the suspect line when the fire started.

PG&E CEO Patti Poppe told analysts that the wildfire costs would be covered by insurance.

"We added the Mosquito Fire to our CPUC reportable ignitions greater than or equal to 100 acres," Poppe said during the earnings call. "Though the investigation is not complete, we can see that the fire started near the base of our 60-kV steel pole … [and] we booked a liability for the Mosquito Fire of $100 million, which is well within our range of insurance."

On Oct. 25, the CPUC *proposed* fining PG&E $155.4 million for the Zogg Fire, which killed four people including a mother and her young daughter who were overtaken by flames while fleeing the blaze.

The fire started Sept. 27, 2020, when a gray pine tree fell onto a PG&E distribution line in rural Shasta County, the California Department of Forestry and Fire Protection found. It burned 56,000 acres and destroyed more than 200 structures.

A contractor working for PG&E had failed to remove the pine tree even though it was leaning dangerously toward the power line and had shallow roots, a federal judge overseeing PG&E's criminal probation said in a February 2021 hearing. The line that the tree struck had remained energized even though PG&E had ordered widespread public safety power shutoffs in the surrounding area because of high winds, the judge learned.

"I think it was reckless, maybe criminally reckless, for PG&E to have left that tree, that gray pine looming," Judge William Alsup said in the hearing. "It was leaning at a 60-degree angle over that line. Gray pines … have a shallow root system. That tree had also been burned earlier. That tree was a clear and present danger to the line, and whoever made the decision to leave that tree up should be looked at very carefully. And PG&E did leave it up."

The CPUC said in its proposed order that the utility had failed "to remove two trees [including the gray pine] previously flagged for removal due to a combination of poor record-keeping, poor communication, and lack of caution. Juxtaposing PG&E's failure to remove the trees with [an arborist's report] — showing that the tree was clearly likely to fall — demonstrates a high degree of culpability in PG&E's conduct."

After the CPUC finalizes its order, PG&E will have 30 days to request a hearing or to agree to pay the penalty and submit a corrective action plan. The plan must show that PG&E has a system in place to keep track of trees slated for removal.

The actions against PG&E for the Zogg and Mosquito fires are the latest in a series of financial penalties, criminal convictions and payments to wildfire victims related to catastrophic fires started by PG&E equipment in the past five years.

The wildfires included the Northern California wine country fires of October 2017; the Camp Fire, which killed at least 84 people and leveled the town of Paradise, in November 2018; the Kincade Fire, which tore through Sonoma County in October 2019; and the nearly 1-million-acre Dixie Fire, the state's second largest wildland blaze, which raged for months in 2021.

The company filed for bankruptcy protection in January 2019 following the Camp Fire and emerged from Chapter 11 proceedings in June 2019, after agreeing to pay a total of $25.5 billion to fire victims, insurance companies and local governments for the wine country fires and the Camp Fire.

PG&E reported third-quarter earnings of $456 million, compared with losses of $1.09 billion in the third quarter of 2021. Its stock closed at $15.60 on Thursday. ■

The Mosquito Fire burned in September in the Tahoe and Eldorado National Forests. | *U.S. Forest Service*

CAISO/West News

PG&E to Offer Nation's First V2G Export Rate

By Hudson Sangree

Pacific Gas and Electric said Wednesday it had received regulatory approval to establish the nation's first vehicle-to-grid export rates for commercial electric vehicles, including incentives for early adopters in the program's first year.

"The V2G export rate promotes EV adoption by providing upfront incentives to help commercial customers offset fleet costs and delivers an innovative solution for these vehicles to export power back to support the grid during peak energy demand periods," the utility said in a news release.

Electric school buses are a main target of the new rate-setting mechanism.

School buses hold larger batteries than standard EVs and can spend peak solar hours parked and plugged into bidirectional chargers. They can discharge energy to the grid when it is needed most, such as the strained conditions that CAISO has encountered on hot summer evenings in the past three years.

"As large vehicles like school buses and commercial fleets continue to electrify, the opportunity grows for these vehicles to serve as crucial, flexible grid resources to support a more reliable, affordable and efficient energy system," PG&E said in the news release. "Greater volumes of these vehicles on the road come at a critical time, as peak energy demand challenges California's grid and novel solutions like V2G emerge."

The rate-setting mechanism was included in an uncontested settlement between PG&E, the CPUC's Public Advocates Office, EV advocacy organization Vehicle Grid Integration Council (VGIC), and charging company Electrify America. The settlement was the subject of a *proposed decision* published Sept. 14 and approved by the CPUC Oct. 20 without discussion.

PG&E first proposed the dynamic, real-time hourly pricing rate structure (RTP rate) for commercial EVs in Oct. 2020.

School buses could export electricity to the grid under the recently approved PG&E V2G rate structure. | *Lion Electric*

"The design of the rate to be used in the export compensation pilot is straightforward," the Sept. 14 proposed decision said. "As with the RTP rate underlying the export compensation rate 'rider,' only the components of the generation rate are affected. The design of the export compensation pilot rate rider would delete the revenue-neutral adder currently applied to the RTP rate but would keep the marginal energy charge and marginal generation capacity cost elements."

PG&E agreed to try to make the export compensation pilot available for enrollment by Oct. 1, 2023. It will operate for three years, unless the CPUC extends it.

The pilot project will include up to $250,000 in incentives for customer enrollment during its first year. Participants will be eligible for incentive payments based on the size of their EV equipment and type of vehicle served, with school buses eligible for an incentive adder.

Equipment of 100 kW or less can receive a base incentive of $1,800 plus a $1,350 school bus adder for a total of $3,150. Equipment greater than 100 kW can get a $3,750 base incentive and a $2,810 adder for a total of $6,560.

PG&E estimates the total ratepayer cost of the export compensation pilot will be between $1.42 million and $1.52 million, the decision said.

"The CPUC's decision is a strong step forward for Californians and in support of the state's grid, implementing the nation's first dynamic export rate for EV charging customers," VGIC Policy Director Ed Burgess said. "As ever-greater numbers of EVs hit the roads, this innovative rate option will allow EV owners to further benefit from their investment in clean transportation." ■

West news from our other channels

EPA Awards US School Districts Nearly $1B for Clean Buses — NetZero Insider

HECO Pilot to Fund EV Chargers at Commercial Buildings — NetZero Insider

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

CAISO/West News

CAISO Approves More Interconnection Enhancements

By Hudson Sangree

CAISO's Board of Governors on Thursday approved the second and more-complex phase of its interconnection enhancements meant to streamline the addition of resources to its grid and shrink its long interconnection queue.

Applications for new interconnections more than tripled to 373 last year as the state aimed to add more renewable and storage resources to meet its 100% clean-energy mandate by 2045 and bolster system reliability.

"The ISO experienced unseen volumes of projects seeking to position themselves to compete in procurement processes," CAISO Vice President of Infrastructure and Operations Planning Neil Millar wrote in a *memo* to the board. "Across the country and in California, stakeholders and regulators have initiated discussions on methods to better accommodate increasing pressure on interconnection processes."

CAISO started meeting with stakeholders last year in a fast-tracked initiative to "improve its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and make process enhancements as resource interconnection needs evolve."

"To date, the ISO has processed nearly 2,000 interconnection study requests, providing interconnection customers with the information needed to make decisions on how to proceed with their projects and to compete for a power purchase agreement with California procurement entities," Millar wrote. "Of that amount, approximately 200 projects [totaling 24 GW] have gone into commercial operation.

"With the significant acceleration in procurement targets, numerous generator retirements, load growth, and state mandates for non-carbon emitting generation, the ISO's processes must continue to evolve," he wrote. "The dramatic increase in competition among suppliers has significantly increased the pressure on the GIDAP."

The initiative's first phase focused on simpler, near-term enhancements that had broad stakeholder support. The CAISO Board of Governors approved that phase in May, and CAISO received FERC approval of the changes in August. (See *FERC OKs CAISO Interconnection Updates*.)

Phase 2 dealt with more complex, long-term enhancements. One involved cost allocation for network upgrades to local systems of less than 200 kV. It would cap costs recoverable from local ratepayers at 15%.

Interconnection requests to CAISO more than tripled last year, mainly from solar and storage. | *Shutterstock*

"There is ongoing concern that the current practice for generator-interconnection-driven local upgrades could unduly impact local ratepayers who solely bear their costs," Millar wrote.

Costs for lower-voltage network upgrades in excess of 15% "will be financed by interconnection customers without cash reimbursement, but with merchant transmission congestion revenue rights if created," the memo said.

Another change established a new network upgrade reimbursement policy when the ISO is an "affected system."

"In the last decade, there have been no instances where a generator's interconnection to a neighboring balancing authority area affected the reliability of the ISO grid such that network upgrades were required," Millar's memo said. "In interconnection terms, the ISO is almost never an "affected system," and has only been asked to perform affected system studies a handful of times. Most of these studies were not performed because the project quickly withdrew.

"However, recently the ISO has received a few notices from neighboring areas that a proposed interconnection potentially may affect the ISO and could warrant ISO study," it said. "Although the probability is very remote that an external interconnection would require network upgrades on the ISO system, Management believes the ISO tariff should have a clear policy on this issue."

The changes still require FERC approval.

Other enhancements do not require tariff changes or board approval, such as making data more easily accessible and publicly available to help developers determine the best locations to connect new resources and to better understand the status of projects in queue. ■

ERCOT News

FERC Corrects Error on ERCOT Probability Assessment

Texas Grid Operator Asked for Revision to Winter Preparedness Report

By Tom Kleckner

FERC has responded to ERCOT's request to correct an "incorrect statement" by making a small modification to its annual *Winter Energy Market and Reliability Assessment*, issued last month.

The commission on Oct. 25 published a revised version of the report, correcting a passage related to ERCOT's probabilistic assessments. Staff corrected the original language by adding "low" before probability and deleting "significant" before risk.

That changed the original sentence from describing ERCOT's 2022-23 winter probabilistic assessment as indicating a "probability of a significant risk of declaring an EEA [energy emergency alert] Level 1" to indicating a "low probability of a risk of declaring an EEA."

The original assessment apparently drew the attention of the Texas Public Utility Commission, which has regulatory oversight over ERCOT. A PUC spokesman *said the report contained "inaccuracies"* and that ERCOT had called on FERC to correct the record.

"ERCOT's assessment reflected a 'low' probability of energy emergency events occurring during the expected daily peak load hour. We have asked FERC to correct this error, which they have done," spokesperson Trudi Webster said in an email to *RTO Insider*.

The Texas grid operator plans to release its final winter assessment later this month.

In its assessment, FERC said that with above-average temperatures expected across most of the continental U.S., the country's electric reliability appears well positioned for this winter. However, the commission singled out ERCOT, ISO-NE and MISO as being in danger of "especially tight" capacity during extreme weather conditions. (See "ERCOT, MISO Vulnerable to Winter Weather," *FERC: Natural Gas Prices to Rise During Mild Winter*.)

FERC Chair Richard Glick speaks before SPP's board and stakeholders. | *SPP*

During a press conference following FERC's monthly open meeting Oct. 20, Chairman Richard Glick was asked whether the commission is confident ERCOT has addressed the issues from the February 2021 winter storm.

FERC headquarters | *© RTO Insider LLC*

"Things have been moving in the right direction, but I think it would be premature and probably an overestimate to say everything is hunky-dory," he said. "There are concerns going into this winter. The assessment … does discuss that ERCOT is one of the areas of concern."

ERCOT has added winterization requirements for its members' generating units after legislation and PUC rules passed in the wake of the winter storm. Staff dedicated to winterization now inspect generators to ensure compliance, and the PUC can also assess financial penalties on those that fall short of the requirements. Other generators have added firm fuel supply service to strengthen their availability.

The grid operator has also brought more generation online sooner and purchased additional reserve power, especially when the weather forecast is uncertain, as part of its conservative operations posture.

"The reliability of the Texas electric grid is our No. 1 priority," Webster said.

PUC Chair Peter Lake and Gov. Greg Abbott, who appointed Lake to his post after the winter storm claimed the careers of his three predecessors, have both frequently said the Texas grid is more reliable than it has ever been.

"Things are improving, but there's still a lot of work to be done in terms of winterizing plants," Glick said.

Glick recommended twice last month that ERCOT interconnect with its neighbors to be able to share power during emergencies. He noted that SPP and MISO did not suffer the same problems as ERCOT because they were able to import power.

"Texas, quite frankly, they're a little bit stubborn because they don't want to be subject to FERC regulation, and I understand that part," he said during last month's press conference. "But do you really want to cut your constituents off from power because you don't want to be subject to FERC regulation and then have people die? That's just not the right way to do it."

On Oct. 25, Glick made his first visit to SPP's headquarters in Little Rock, Ark. His comments before the RTO's Board and Directors and Members Committee were starker.

"We get pushback from Texas in particular saying, 'Well, we don't want to be subjected to FERC regulation,'" he said. "Well, I understand that's an important issue. But are you willing to actually have hundreds of people die? Are you willing to have massive blackouts, four- or five-day blackouts, because you don't have power from elsewhere?" ■

ISO-NE News

Eversource Calls on Feds to Prepare Emergency Actions for New England

By Sam Mintz

New England's largest utility is piling on to calls for winter help from the federal government.

In a *letter* to President Biden last week, Eversource Energy CEO Joseph Nolan asked the administration to start preparing for possible emergency action as New England stares down what could be a dicey winter for the region's electric grid.

"As both an energy company CEO and a lifelong New Englander, I am deeply concerned about the potentially severe impact a winter energy shortfall would have on the people and businesses of this region," Nolan wrote.

He laid out a problem that has become familiar to energy policymakers in the Northeast: pipeline constraints, a lack of fuel storage capability and a volatile LNG market, which together could mean rolling blackouts if the region sees a period of extreme, extended cold.

Nolan pointed to four possible emergency actions that the federal government could take:

- a waiver of the Jones Act to make it easier for imported LNG to get to terminals in New England;
- an emergency order under Federal Power Act Section 202c, which allows the secretary of energy to order "temporary connections of facilities and such generation, delivery, interchange or transmission of electric energy";
- an emergency order under the Natural Gas Policy Act, which addresses a "severe natural gas shortage"; and
- using the Defense Production Act to prioritize domestic energy supplies.

Waiting until an emergency arrives would be too late, Nolan wrote, asking the federal government to start making a plan with the region.

"The need for action now is compelling. Many of the solutions require advance planning because they may require actions by regulators, finding new resources, chartering vessels, arranging for additional fuel deliveries and other yet-to-be-identified extraordinary actions," he said.

Eversource's request for help follows others in the region, including New England's governors, who wrote to the Biden administration in August asking for consideration of a Jones Act waiver and work on a new Northeast energy reserve. (See *New England Governors Ask Feds for Help with Winter Reliability*.) ■

| *Shutterstock*

ISO-NE News

Can New England Conserve Like California?

By Sam Mintz

New England state and grid officials are refining their plans to use conservation pleas in the case of an energy emergency, buoyed by the success of California's call to action during this summer's heat wave.

ISO-NE hasn't had to employ a conservation request since 2013, when a July heatwave led it to *ask energy consumers* to raise their AC temperatures, turn off lights and appliances, and defer chores like laundry.

But increasing worries about winter resource adequacy in the case of extended cold weather has ISO-NE thinking about the next time it might have to ask New Englanders to voluntarily cut back, and what might be different this time.

At a *regional tabletop exercise* that the grid operator organized last month, communication with the public about its ability to help was a central topic, said Matt Kakley, spokesperson for ISO-NE.

"A lot of what we talked about in the tabletop and in our standard emergency planning and discussions is how do we coordinate those messages? How do we make sure that everyone from the ISO to the utilities to the government folks is in the loop on things and understand what's going on and what the ask is?" Kakley said.

ISO-NE would be the entity that would make the decision to call for energy conservation, based on its near- and medium-term forecasts.

But with its limited reach, the grid operator would rely on help from state governments and utilities (which already have customers' email addresses and phone numbers) to get the message out.

"Close coordination with stakeholders such as our regional grid operator, emergency management officials and our fellow utilities among others is fundamental to any emergency response, and participation in regional trainings and exercises helps us to be ready in the event ISO-NE must take emergency action," said William Hinkle, an Eversource spokesperson.

Learning from California's Success?

Policymakers in New England see California's recent experience as a strong example of the power of conservation.

The state's urgent text to residents shortly before a period of impending record electricity demand, coordinated by the Governor's Office of Emergency Services, was widely hailed as a successful, if drastic, step to stave off potential rolling blackouts. (See *California Runs on Fumes but Avoids Blackouts*.)

CAISO saw demand drop by 2,000 MW just 20 to 30 minutes after the text went out.

To ISO-NE, it was "comforting," said Kakley.

"They were able to keep demand under the level they were able to serve, and not have to resort to the extreme measure of controlled power outages," he said. "What that really drove home, what we've always known, but seeing it in a real-world example, was that if you ask the public to do something, and you're clear in what you're asking to do, they will respond."

New England state officials have called for the region to employ that sort of call to action if needed.

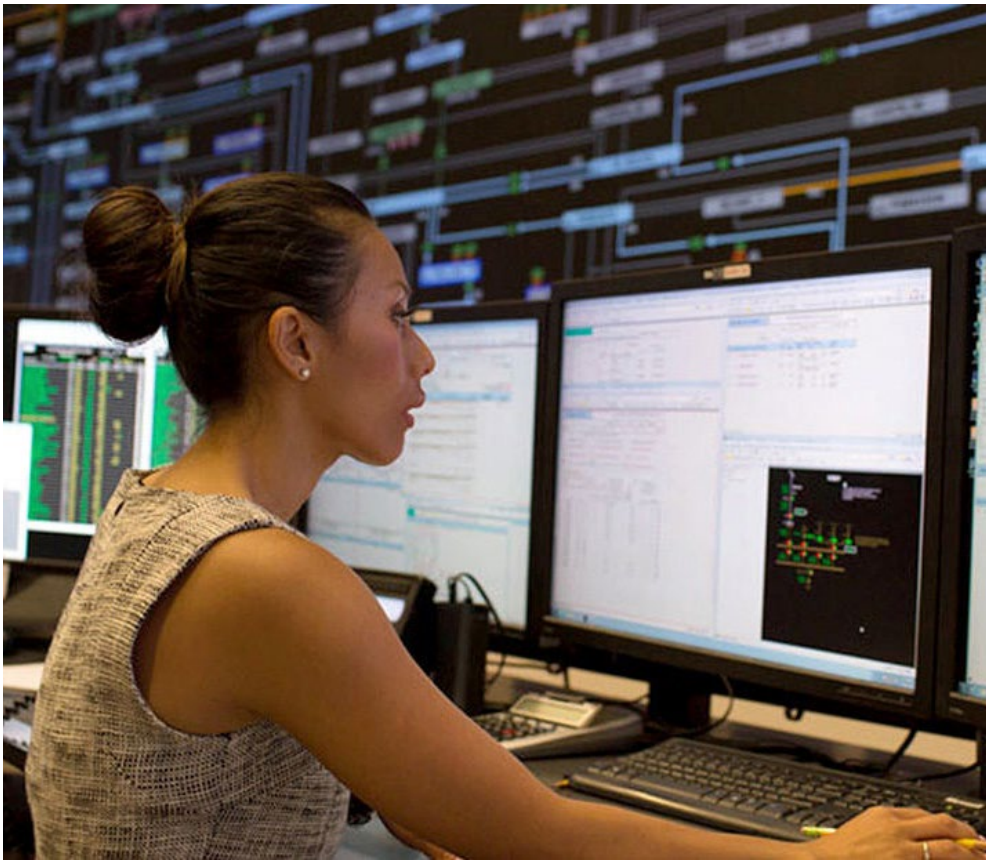
June Tierney, commissioner of the Vermont Department of Public Service, made that point at the FERC forum in Burlington, Vt., in September.

"Let's not underestimate the people of the United States," she said. "Let's not underestimate the people of New England. If they're called upon, as millions of Californians were on their cell phones, to reduce demand immediately, they will respond."

But ISO-NE has also acknowledged that the scenario presented in an energy emergency in the New England winter takes on a different shape: Rather than a capacity crisis lasting just a couple hours, it could be a fuel shortage that lasts as long as multiple days.

It's a nightmare possibility that the region has been wrestling with for years, with increasing anxiety each winter, as the region continues to rely on volatile LNG markets.

"We spent a lot of time talking about how that call for conservation would be different," Kakley said. "It's a different kind of request and one that people haven't spent a lot of time thinking about. We're realizing that our messaging needs to be very clear." ■



Operator inside the ISO-NE control room | *ISO-NE*

ISO-NE News

NEPOOL to Consider Raising ISO-NE Board Age Limit

By Sam Mintz

NEPOOL stakeholders will consider whether to increase the age limit for members of ISO-NE's Board of Directors this week, as the grid operator looks to expand the pool of candidates for the job.

The proposal, put forward by NextEra Energy's Michelle Gardner, will get a vote at the Participants Committee this week.

A provision of the current ISO-NE and NEPOOL rules, in place since the Participants Agreement was adopted in 2004, prohibits anyone over the age of 70 from being elected or re-elected to the board.

Gardner plans to argue that best practices have changed since 2004, according to her *presentation*. Her proposal would raise the age limit to 75.

Two other RTOs have age limits of 75, and the rest have no limits at all, she says.

"In recent years, the age limit has contributed to difficulty in finding high-quality director candidates to serve on the ISO board," according to Gardner's presentation. It's "challenging for actively employed executives to serve" on the board because of the time commitment it requires. And as many executives are now working full-time jobs into their 60s, "the present age limit shortens their service window."

ISO-NE's Code of Conduct also limits the ability of stakeholders to consider candidates who have been recently affiliated with market participants or are invested in companies that interact with ISO-NE. FERC's interlock rule also comes into play.

ISO-NE Board Chair Cheryl LaFleur | © *RTO Insider LLC*

ISO-NE spokesperson Matt Kakley said the grid operator supports the change.

"Making this change would bring ISO New England in line with our ISO and RTO peers and corporate best practices," Kakley wrote in an email to *RTO Insider*. "Increasing the age limit will allow for a broader pool of candidates while maintaining existing parameters laid out in our Code of Conduct and FERC's interlock rules."

The board will meet today, the day before the Participants Committee, for its first public meeting as part of a commitment by ISO-NE to the New England states to be more accessible and transparent. ■

ISO-NE News

Maine Voters to Decide on Upending Utility Landscape in 2023

By Sam Mintz

Maine voters may have the chance to upend the state's utility landscape and send its two biggest players packing in November 2023.

Our Power Maine, a coalition pushing for a referendum to replace Central Maine Power and Versant Power with a nonprofit, consumer-owned alternative, announced on Monday that it has acquired the signatures necessary to get it on the ballot next year.

The initiative calls for creating a new utility called Pine Tree Power, which it says would be privately operated and controlled by a mostly elected board.

"The company's purposes are to provide for its customer-owners in this state reliable, affordable electric transmission and distribution services and to help the state meet its climate, energy and connectivity goals in the most rapid and affordable manner possible," the ballot question would state, if it's approved by Maine's secretary of state.

What's not stated outright in the referendum question, but is a driving force behind the campaign, is that the utilities it aims to push out are some of the most unpopular in the country. In their respective categories in the *J.D. Power 2021 Electric Utility Residential Customer Satisfaction Study*, CMP and Versant are dead last. Their customers also pay rates that are among the highest in the country.

"It's this strange inequity where we get what is clearly the worst and least popular service in the nation and pay kind of a lot comparatively for that," Andrew Blunt, executive director of Our Power Maine, said in a recent interview.

A group of three Maine economists wrote in an *op-ed last year* that the refinancing and replacement of CMP and Versant would save residents money right away.

Opponents say the initiative would be a costly one for the state.

Versant and CMP have fiercely opposed the initiative; Our Power says the utilities have spent $6 million fighting it. Other business interests in Maine are opposed too.

Maine State House | *Shutterstock*

"This risky $13.5 billion proposal to take over our electric grid will create a tremendously volatile business environment in Maine for years to come," Dana Connors, president of the Maine State Chamber of Commerce, said in a statement. "Companies will be forced to think twice about investing in our state, and what do customers get in return? Higher rates, a debt three times the annual state budget, unaccountable politicians controlling the state's critical infrastructure, and no guarantee of better service. Maine businesses depend on safe, reliable, affordable electricity, and we can't afford to gamble that all away on this proposal."

CMP parent company Avangrid has also funded an opposing campaign called No Blank Checks, which also collected signatures in an effort to force a statewide vote on any new government debt over $1 billion, which would apply to the utility buyout, although the exact cost to the state is under debate.

The consumer-owned utility proposal made it through Maine's legislature in 2021, only for it to be vetoed by Gov. Janet Mills, who claims that her opposition was more about process and specifics of the legislation (which also would have put the question to voters) rather than the underlying idea of replacing the state's incumbent utilities. (See *Mills Tells Maine Legislature to Slow Down on Plan to Replace IOUs*.)

"L.D. 1708, hastily drafted and hastily amended in recent weeks without robust public participation, is a patchwork of political promises rather than a methodical reformation of Maine's complicated electrical transmission and distribution system," Mills *said* at the time. ■

MISO News

FERC: Rush Island Plant's Extension Essential to MISO Reliability

Commission Grants SSR Agreement, Questions Ameren's Requested Payments

By Amanda Durish Cook

FERC on Oct. 24 approved an agreement that will keep an Ameren Missouri coal plant online beyond its planned retirement date to maintain MISO grid reliability (*ER22-2691*).

In a separate order, the commission also said that Ameren might be overcharging customers to keep the plant operating and set the matter to hearing (*ER22-2721*).

MISO in August filed a 12-month system support resource (SSR) designation for the 1.2-GW Rush Island plant's two units. The grid operator said that its analysis found "no alternative available at this time to avoid the need" for an SSR agreement and said that without the agreement, it could face severe voltage stability issues that might set off cascading outages.

MISO uses SSR agreements as a last-resort measure to sustain system reliability. It said it explored generation additions, dispatch changes, system reconfiguration, operation-guideline changes, amplifying demand response or load reductions, and adding new transmission projects, all to no avail.

The Illinois Municipal Electric Agency and the Wabash Valley Power Association lodged protests at the commission, alleging that MISO's consideration of alternatives to the agreement was unsatisfactory. The commission said the grid operator properly arrived at a "determination that no feasible alternative exists at this time that could be implemented to allow suspension of the Rush Island Units by the requested September 1, 2022, suspension date."

Coal coming off a stacker at Ameren Missouri's Rush Island plant in 2018 | *Power Techniques Inc.*

FERC found that both Rush Island units are necessary despite the stakeholders' claims that one unit will suffice. The commission said MISO's retirement study showed transient voltage recovery issues that would violate both NERC standards and Ameren's local planning criteria and "pose a risk to the St. Louis metro area and Peoria, Ill." It concluded the RTO presented "sufficient support" for the SSR agreement through next summer.

However, FERC agreed with Wabash Valley and Illinois Municipal that Ameren's proposed $9.3 million monthly SSR payment could be too steep and ordered a hearing with possible refunds. The commission also rejected Ameren's inclusion of a 50-basis point return-on-equity adder in the monthly payment calculation, saying the ROE adder for RTO membership is reserved for transmission owners, not generation facilities.

In the interim, MISO will assign proposed SSR costs associated with the Rush Island units to load-serving entities that require their continued operation.

Ameren last year fast-tracked the plant's closure rather than install a court-ordered wet flue gas desulfurization system by March 31, 2024, to correct Clean Air Act violations. The utility originally intended to operate Rush Island until 2039, but the 2019 ruling from the U.S. District Court for the Eastern District of Missouri cut its plans short (19-3220).

Rush Island's units date back to 1976 and 1977. Together, they currently emit approximately 18,000 tons of sulfur dioxide annually.

MISO recommended in this year's transmission planning cycle $120 million of new static synchronous compensators to reinforce the system with Rush Island's retirement. Those transmission solutions aren't expected to be in-service until mid-2025, making it likely that the grid operator will renew the SSR, which it can do on an annual basis. However, the RTO has committed to a yearly re-examination of alternatives to the SSR. (See *MISO's 2022 Tx Planning Cycle Exceeds $4B*.) ■

MISO News

DTE Energy Pledges Fast-tracked Energy Transition

Utility Addresses Reliability Audit by Michigan PSC

By Amanda Durish Cook

DTE Energy executives promised a more aggressive clean energy transition during their third-quarter earnings call Thursday.

Pointing to the Inflation Reduction Act, the utility's leadership told financial analysts to expect a speedier resource changeover when it files a new integrated resource plan with the Michigan Public Service Commission in early November. CEO Jerry Norcia said the plan will detail how DTE plans to accelerate its decarbonization efforts.

DTE earned $311 million ($1.60/share) for the quarter, $21 million higher in a year-over-year comparison because of deferred tax amortization and lower operations and maintenance expenses.

Norcia said "climate change remains our generation's defining public policy issue." He said the utility is committed to investing in clean energy and grid modernization to ensure reliability against extreme weather and to accommodate new load from electric vehicles.

"We are focusing on updating and improving our aging infrastructure for this additional demand while continuing to provide safe, reliable and affordable energy," Norcia said. "Two important factors affecting our grid are climate change and emerging electrification technologies. We need to build the grid of the future to ensure we can continue to provide clean, safe, reliable and affordable energy."

Norcia promised a "shift towards renewables and natural gas and away from coal generation."

CFO Dave Ruud said the IRA will help accelerate DTE's clean energy transition and keep customer costs in check. Norcia said the legislation's passage will have "a very positive impact" on the company's IRP, lower the cost of renewable investments and improve the affordability of carbon-capture and storage technologies.

"We have now the opportunity to invest greater amounts in our renewables build-out, so very positive impact overall," Norcia said.

He also said DTE's voluntary renewables program, MIGreenPower, continues to show "substantial growth" with a new 400-MW customer joining this week, bringing the program's subscription to 2.1 GW.

Public tour of a DTE solar park in August | *DTE Energy*

DTE Energy has a goal to achieve net-zero carbon emissions by 2050.

Last month, the Ann Arbor City Council voted 10-1 to fund a $500,000 feasibility study on breaking away from DTE Energy. City officials have said their existing clean energy plans are an obstacle to meeting the city's goal to achieve carbon-neutrality by 2030.

Activist group Ann Arbor for Public Power said DTE "fails to provide reliable electricity, charges residents more than the national average and gets more than 50% of its power from coal."

The earnings call came as DTE and Consumers Energy *face an audit* from the Michigan PSC over compliance with outage and safety regulations. Last summer, storms left Michigan ratepayers on extended outages, leading to inquiries from state regulators. (See *Mich. PSC Issues Emergency Order Following Devastating Storms*.)

Norcia said he thinks the audit will ultimately strengthen DTE's relationship with the commission and better align their views on the utility's investments. He said current discussions with PSC staff are "really collaborative."

Norcia said DTE's grid averages 99.9% availability and its best-in-class utility performance is about 99.97%. He said all of DTE's capital investment plans are "pointed at how do we get to that 99.97% availability for our grid."

"So, I feel that this process with the Commission will create stronger alignment," Norcia said, adding that DTE has systems that must be "replaced, modernized and automated." ■

MISO News

MISO Members Revisit Possibility of Resilience Obligations

MISO members have reopened the suggestion that the grid operator enact resilience criteria within its footprint, saying it has a role to play in preparing to withstand and recover from high-impact, low-probability events that wreak havoc on the system.

During an Advisory Committee teleconference Wednesday, several members said MISO could address resilience through projects that harden and build redundancy into the system, resource diversity and operational protocols. They said the RTO's long-range transmission planning will reinforce the system, but it could do more in bolstering interregional links, which have proven invaluable during extreme weather events.

ITC Holding's Brian Drumm said staff could establish minimum intraregional and interregional transfer levels.

"How do we know we're resilient now if we don't have metrics?" the Lignite Energy Council's Jonathan Fortner asked, advocating for defined measures of adequate transmission capability and available generation.

The Union of Concerned Scientists' Sam Gomberg said MISO "should be on the forefront" of partnering with national laboratories and agencies to understand evolving risks of climate change. He said the grid operator's "blind spot" is that it doesn't proactively analyze and plan for future risks "that the science is telling us are going to become numerous."

Gomberg said MISO might define when heat waves and winter storms cross an "extreme" threshold. He said "smart, low-cost solutions or behaviors" could lower risks and that MISO, states and load-serving entities have a "huge opportunity" to save lives and lessen disruptive events' economic devastation.

WEC Energy Group's Chris Plante said the conversation was reminiscent of one the Advisory Committee held four years ago. He said continued attention on the topic without sets of criteria means that it is difficult to pin down resilience objectives. ■

— Amanda Durish Cook

MISO Carmel, Ind., headquarters | © *RTO Insider LLC*

MISO News

Search for Small SPP-MISO Interregional Projects May be Fruitless

By Amanda Durish Cook

| © RTO Insider LLC

MISO and SPP prepared stakeholders last week for the possibility they may come up empty-handed in their joint hunt for interregional transmission upgrades.

SPP's Neil Robertson said that the grid operators are still "hopeful" they can identify at least one beneficial targeted market efficiency project (TMEP) in their study. But he also said there's a "strong possibility" that they won't find any recommended upgrades.

"I think the likely outcome is we're not going to have any … candidates come out of this first study, but I don't want to close the door on this just yet," Robertson told stakeholders Friday during a MISO-SPP Interregional Planning Stakeholder Advisory Committee (IPSAC).

"The cost of the solutions may far exceed the budget," Robertson said, adding, "We're still refining the congestion dollar values."

MISO and SPP have said they would screen for possible TMEPs when a market-to-market flowgate has amassed $1 million or more in congestion costs over a two-year period. The RTOs *catalogued* seven permanent flowgates that have racked up between $10 and $43 million worth of congestion. (See *MISO, SPP Identify Hotspots for Smaller Interregional Tx Projects*; *MISO, SPP Hunt for Small Interregional Tx Projects*.)

They have proposed that TMEPs cost $20 million or less, must not be greenfield projects, be in service by the third summer peak from their approval, and completely cover their installed capital cost within four years of service through avoided congestion.

The grid operators borrowed many of their standards from MISO's and PJM's TMEP criteria.

Stakeholders remained adamant that the grid operators are using a cost cap that's too restrictive to result in any valuable projects.

American Clean Power Association's Daniel Hall asked whether the absence of qualifying TMEP projects means that the RTOs might consider "tweaking" the criteria to increase the cost threshold or payback period.

Robertson said staffs plan to hold lessons-learned discussions following the study's conclusion but probably wouldn't change criteria "purely in the interest of getting Project A or Project B across the finish line."

"There is merit in shifting [these] criteria or [those] criteria, but we have to balance all of the considerations," he said. Staffs are looking for upgrade candidates that "truly give us the return on investment we're looking for" and are not entertaining a change to the $20 million cost cap at this time, Robertson said.

Several stakeholders said inflation has dated the proposed TMEP cost threshold.

Clean Grid Alliance's Natalie McIntire argued that "the value of dollars changing" means that the cost maximum is "ripe for reconsideration."

"You should consider keeping up with inflation," she told the RTOs' planners.

American Electric Power's Brian Johnson agreed and said MISO should "right-size the figure to match market conditions." He said with the current criteria, a TMEP would have to be "almost across the street" for MISO and SPP to recommend it.

The grid operators said they will announce any project candidates during a Dec. 12 IPSAC meeting.

Robertson also said the RTOs are working out a way for one RTO's transmission owners to fund an upgrade on the other RTO's system when it stands to benefit them. Robertson said situations where a TO will overwhelmingly benefit from a project on the other side of the seams are becoming increasingly commonplace.

He said the grid operators could "pass the funding across the fence" should there be cross-border construction under MISO and SPP's interregional planning process. ■

NYISO News

NYISO Monitor: Freezing Weather Could Threaten Eastern NY Reliability

By John Norris

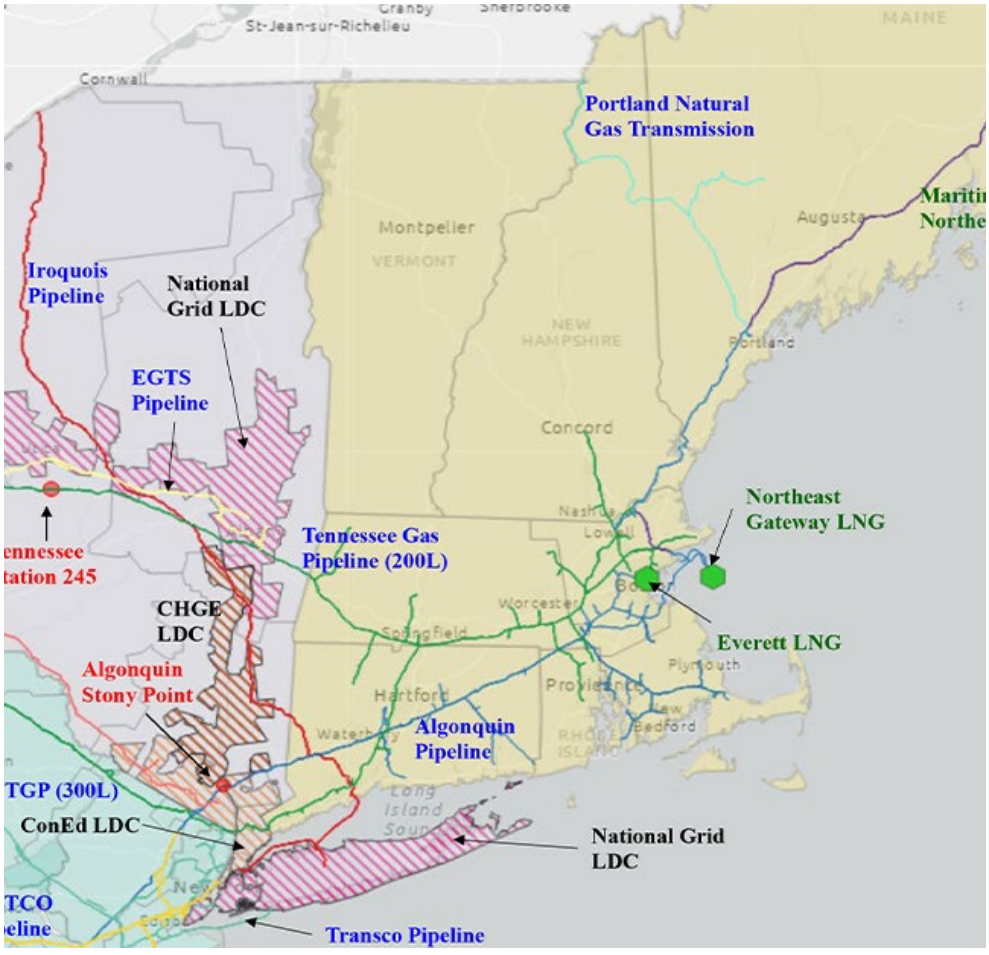
RENSSELAER, N.Y. — Gas supplies to Eastern New York (ENY) could be limited during freezing weather in winter because of demand exceeding interstate pipeline capacity, resulting in a reliance on imported LNG from New England, NYISO's Market Monitoring Unit *told* stakeholders last month.

Speaking to the Installed Capacity/Market Issues Working Group on Oct. 20, Potomac Economics' Joseph Coscia said the findings suggest NYISO should adjust its resource adequacy models and capacity accreditations to reflect the gas limitations likely to occur in winter. Such constraints would force the ISO to rely on imported LNG from New England, he said, a region that itself relies on imported LNG during winter for reliability.

Coscia also said the ISO should discount emergency assistance from non-firm gas from out-of-state generators during the winter and consider the availability of oil-fired units with limited capacity to ensure grid reliability in the case of very cold days when heat demand peaks.

The analysis focused on the availability of gas to the greater region of ENY and New England because it is served by eight critical interstate pipelines, such as the Iroquois, Algonquin and TETCO pipelines; has greater constraints limiting total flows than the rest of New York; and local distribution companies have systems in the area that serve many of the consumers in the entire state.

LDCs secure supply to meet their "design days": the estimated maximum retail gas demand based on the historically lowest temperatures. Peak winter demand for design days hovers above 10 million dekatherms/day. Potomac found that the estimated total import capability of the interstate pipelines, excluding LNG, was roughly 8 million dekatherms/day, which is both "far below the total design day demand of the local gas utilities" and "is even below the estimated peak demand of the coldest winter seen in the past five years."



Interstate pipelines serving Eastern New York (2022) | *S&P Global*

LNG and compressed natural gas is available, but these should be thought of as limited fuels because they are restricted to "either cargoes contracted in advance" or serve as "limited storage" for short periods of time.

The analysis found that "an increasing sense of tightness of the gas system in the region" had meant that LDCs in ENY have held "large amounts of firm pipeline capacity" and are increasingly "relying on holding rights to the firm transport capability in order to satisfy design day requirements."

ENY and New England are heavily reliant on LNG storage and imports to meet peak regional supply demands. Potomac emphasized that LNG importers generally do not "provide speculative supply or short-notice cargoes to the region," threatening ENY's reliability during extreme winter storms.

Potomac recommended that the NYISO resource adequacy model "discount external assistance from New England" to avoid "counting on imports from a region affected by the same set of gas constraints affecting winter reliability."

Mark Younger, president of Hudson Energy Economics, asked Coscia if Potomac had seen "other areas of New York indicating significant concern" around gas supplies.

Coscia replied that gas bottlenecks are "primarily at the borders of the ENY and NE region." Though it is possible that "pockets of specific generators elsewhere in the state have difficulty accessing gas," they are "less acute outside of the ENY region."

One stakeholder questioned the relevance of the analysis, noting that "New York has a state policy pushing for the elimination of every molecule of gas" and that this problem might "vanish" as the state "continues to electrify the heating, building and generation sectors."

Coscia responded that "even with aggressive implementation" of state climate or energy policies, downstate New York utilities are anticipating "core gas demands to grow" over the next couple of years, so even if residential heating demands decline quicker than expected, the MMU is "focusing on the system as it is today." ■

NYISO News

NYISO RNA Raises Concerns over Timing of Peaker Unit Retirements

By John Norris

NYISO's *draft* 2022 Reliability Needs Assessment (RNA) found no reliability issues until 2032 but did identify tightening transmission security and resource adequacy margins across New York, staff told the Management Committee on Wednesday.

Those margins mean generators affected by the state's so-called "peaker rule" may need to remain operational until either the Champlain Hudson Power Express (CHPE) transmission project or other resources are completed.

The rule imposed strict nitrogen oxide emission requirements on state power plants, which will force many old gas-fired plants to deactivate. It goes into effect May 1, 2023; plants must comply with it by that date or be shut down.

Several members of the committee, which voted to recommend the draft RNA for approval by the ISO's Board of Directors, expressed concern that certain utilities' transmission projects will not be completed by the deadline.

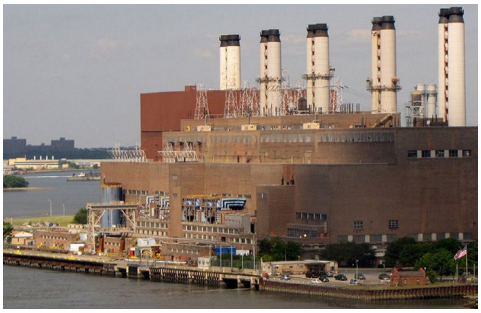
"It's Oct. 26. There are growing concerns about what's going to happen May 1," said attorney Doreen Saia, of Greenberg Traurig. Saia was particularly concerned about a Consolidated Edison project being built to account for the retirement of the Astoria plant in Queens. "It is critical for the NYISO to — in writing, in a presentation — to confirm that you have been advised that the project is on schedule and will be completed by the May 1, 2023, date. It is not good for the market to have the kind of uncertainty that is sitting out there."

She said that more transparency around the status of Con Ed's local transmission plans would alleviate many of the concerns and suggested that the ISO conduct a peaker assessment to help stakeholders better forecast resource planning.

Liam Baker, vice president at Eastern Generation, concurred with Saia, saying that as "the largest owner of assets impacted by the peaker rule," it is "very hard to make plans" without knowing what the future holds.

Zach Smith, NYISO vice president of system and resource planning, responded that the ISO's short-term assessment of reliability (STAR) reports have included such assessments since the peaker rule compliance plans were filed in 2020, and that the ISO will continue to get the information across to stakeholders as "transparently as possible."

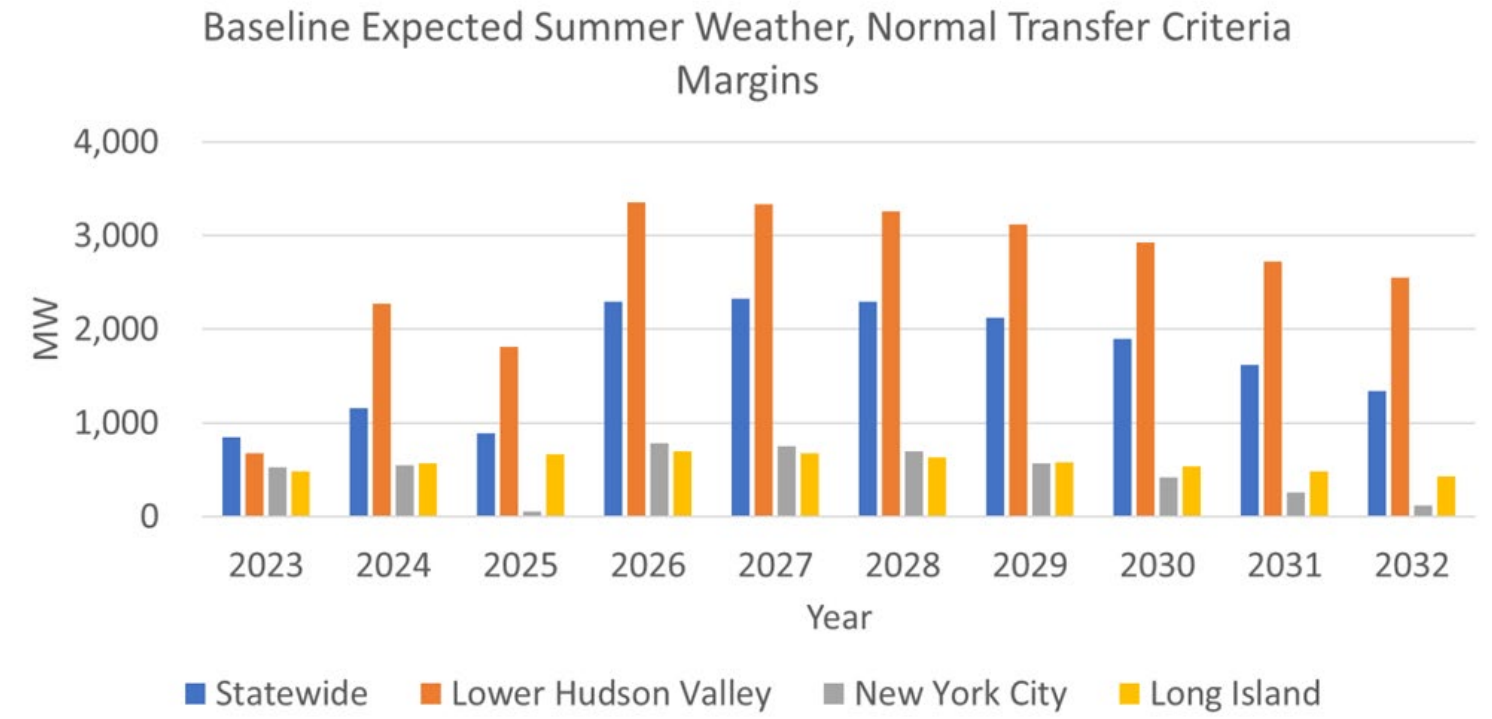
Kevin Lang, partner at Couch White, asked when NYISO would "notify developers that they need to stay on" so that they have "enough time to take whatever measures" necessary to remain active and avoid any "gap periods."



Astoria Generating Station in Queens | *Ben Schumin, CC BY-SA-2.0, via Wikimedia*

Smith responded that the ISO needs to "continue monitoring this on a quarterly basis" and that these decisions would likely be reported in any future STAR reports.

The ISO also emphasized that the CHPE project is important to the state's future reliability and that if it is delayed, New York City could see its transmission security margins become deficient by 2028. (See "ISO: Champlain Hudson Critical to NY Reliability in Future," *NYISO Operating Committee Briefs: Oct. 13, 2022*.) ■



New York summer security margins (2023-2032) | *NYISO*

NYISO News

NYISO OC Approves CY21 Cost Allocations

By John Norris

The NYISO Operating Committee last week approved the class year 2021 (CY21) study report, triggering the 30-day period for generation developers to decide whether to accept or reject their cost allocations for needed transmission upgrades.

Stakeholders expressed some concern over the ISO's anticipated CY21 schedule, specifically as it relates to whether the additional system deliverability upgrade (SDU) studies for projects will be complete by the 2023 class year's (CY23) upcoming annual transmission baseline assessment (ATBA) lockdown.

The ATBA is the pre-existing baseline system, which is used to evaluate the addition of the CY projects and identify whether system upgrade facilities (SUFs) are necessary.

Certain stakeholders expressed that they were "unclear" about whether CY21 projects undergoing an additional SDU study would be included in subsequent class years or had "lost their opportunity to participate" in the next class year.

Mark Reeder, representing the Alliance for Clean Energy New York, gave a theoretical timeline of events, attempting to demonstrate how NYISO could not "know what your ATBA base case is if you lock it down" before all the additional SDU study projects in CY21 have accepted or rejected their cost allocations.

Thinh Nguyen, senior manager of interconnection projects, said that "if for some reason the additional SDU studies are not complete in time to join the subsequent class year," then those projects will need to "preemptively request the ISO to join the subsequent class year." The ISO will not automatically put CY21 projects undergoing an additional SDU study into CY23, and that "projects that don't request" to be included in CY23 will see their additional SDU study "terminated" when the "subsequent ATBA is locked down."

Developers who reject their project cost allocation will trigger additional decision rounds in which NYISO will issue a revised study within 14 calendar days that no longer includes those projects. Remaining developers will have an additional seven days to provide the ISO with notice of their election for the revised cost allocations.

This iterative process will continue until all remaining CY21 members accept or reject their cost allocations. Assuming it goes only one decision round, the ISO estimates CY21 ending on Dec. 2 and CY23 beginning on Jan. 3, 2023. ■

PJM News

NJBPU OKs $1.07B OSW Transmission Expansion

JCP&L, Shell/EDF Projects Selected

By Rich Heidorn Jr.

The New Jersey Board of Public Utilities voted unanimously Wednesday to spend $1.07 billion on transmission upgrades to deliver 6,400 MW of offshore wind generation to the PJM grid, saying the projects would minimize costs, environmental impacts and permitting risks (Docket No. QO20100630).

The BPU made its selection from among 80 proposals submitted by 13 developers in response to a solicitation issued by PJM at the BPU's request under FERC Order 1000's State Agreement Approach.

The solicitation asked for four categories of transmission upgrade proposals, including Option 2 for new offshore transmission connection facilities — extending the PJM grid into the ocean — and Option 3 for new offshore transmission network facilities. (See *PJM Sees Wide Range of Costs in NJ OSW Tx Proposals*.)

But Andrea Hart, BPU's senior program manager for offshore wind, said BPU staff and consultants Brattle Group rejected those options as too costly, narrowing its selection to Option 1b proposals for new onshore transmission connection facilities and Option 1a proposals for upgrades to resolve reliability criteria violations resulting from the generation injections.

Andrea Hart, N.J. Board of Public Utilities | *NJ BPU*

Hart said most of the Option 2 proposals connected only a single project to each offshore substation, resulting in no reduction in the number of export cables compared with a baseline scenario without coordinated procurement. In addition, transmission-only projects would not qualify for the 30% federal investment tax credit available to generation projects, foregoing as much as $2.2 billion in subsidies. The Option 3 proposals, which were contingent on Option 2, were also rejected. "Staff remains optimistic that the costs of a coordinated transmission will continue to decrease, which could open the door for procurement of option two facilities through a future SAA solicitation," she said.

In addition to $575 million in necessary Option 1a upgrades, staff selected what it called the Larrabee Tri-Collector Solution, which includes parts of FirstEnergy's Jersey Central Power and Light's 1b proposal and pieces of *Mid-Atlantic Offshore Development*'s Option 2 proposal.

The centerpiece of the $504 million project will be a new substation adjacent to JCP&L's existing Larrabee substation. Mid-Atlantic Offshore Development, a joint venture of Shell New Energies US and EDF Renewables North America, will build the AC portion of the new Larrabee Collector Station to accommodate three future HVDC circuits. The project will include sufficient land for the installation of up to four DC converter stations. "This will ensure robust competition is maintained — upholding open-access transmission principles — throughout future OSW solicitations," the board said.

The collector station will use existing JCP&L rights of way to distribute up to 4,890 MW to three points of interconnection (POI): the Smithburg 500-kV, the Larrabee 230-kV substation and the Atlantic 230-kV.

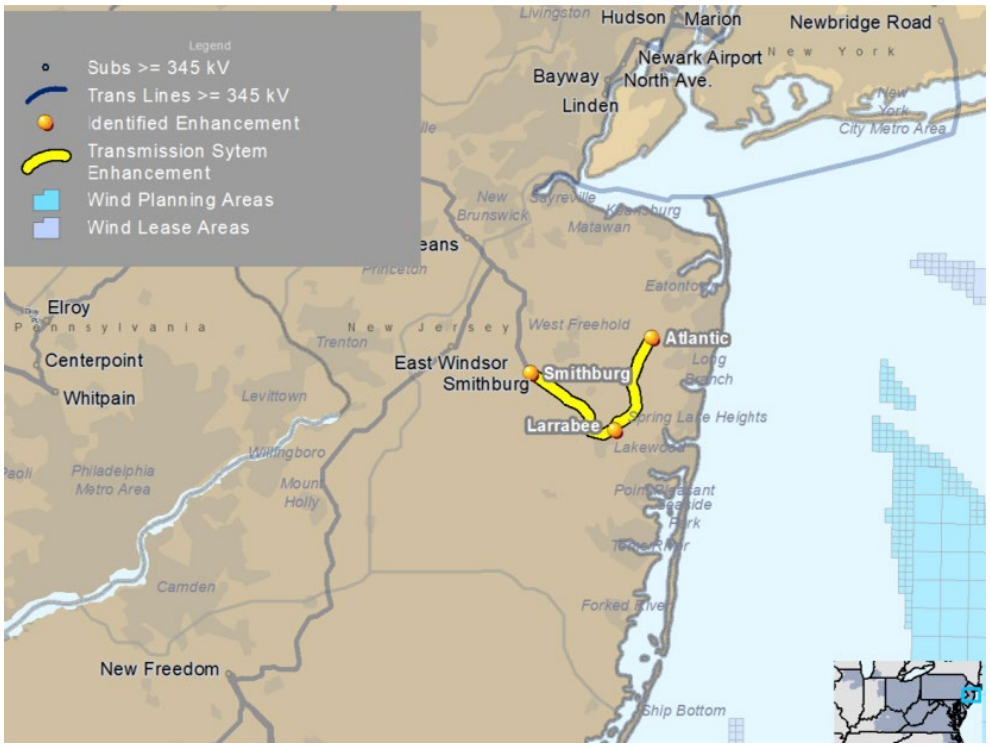
Although the BPU's order does not provide a shore crossing solution under the SAA, its order noted that the MAOD proposal identified the National Guard Training Center at Sea Girt as the preferred crossing point.

The board said the Larrabee collector is "an innovative transmission solution, creating a single onshore POI while leveraging existing rights of ways, an outcome that would not have been possible without coordinated planning and a competitive solicitation."

"The awarded projects also position the state to seek direct federal funding for future expansions of the OSW transmission grid, including the potential to award a full OSW backbone in connection with the board's future OSW solicitations, and preserves preferable interconnection locations and transmission corridors for future use," the board said.

Although the MAOD-JCP&L Option 1b solution was intended to connect three 1,200-MW HVDC systems, PJM said the equipment in the AC substation can handle up to 4,530 MW of future injections from DC converter stations.

"PJM's analysis suggests that this provides an excellent platform for accessing additional headroom on the PJM system with modest ad-



The BPU selected Jersey Central Power and Light's proposal to expand its existing stations to enable offshore wind injections of 2,490 MW at Smithburg, 1,200 MW at Larrabee, and 1,200 MW at Atlantic. | *PJM*

PJM News

ditional upgrades in the future," the BPU said.

The Missing Link

The SAA solicitation was intended to provide sufficient transmission to provide 6,400 MW of OSW capacity, helping the state meet its original goal of 7,500 MW of OSW by 2035. Ocean Wind I, which was awarded offshore wind renewable energy certificates for 1,100 MW in the state's first OSW solicitation, is not eligible to use the capacity resulting from the SAA.

The BPU acknowledged that the transmission projects it selected under the SAA would not prevent future OSW generators from proposing different landing points or different routes from their landing points to the Larrabee collector.

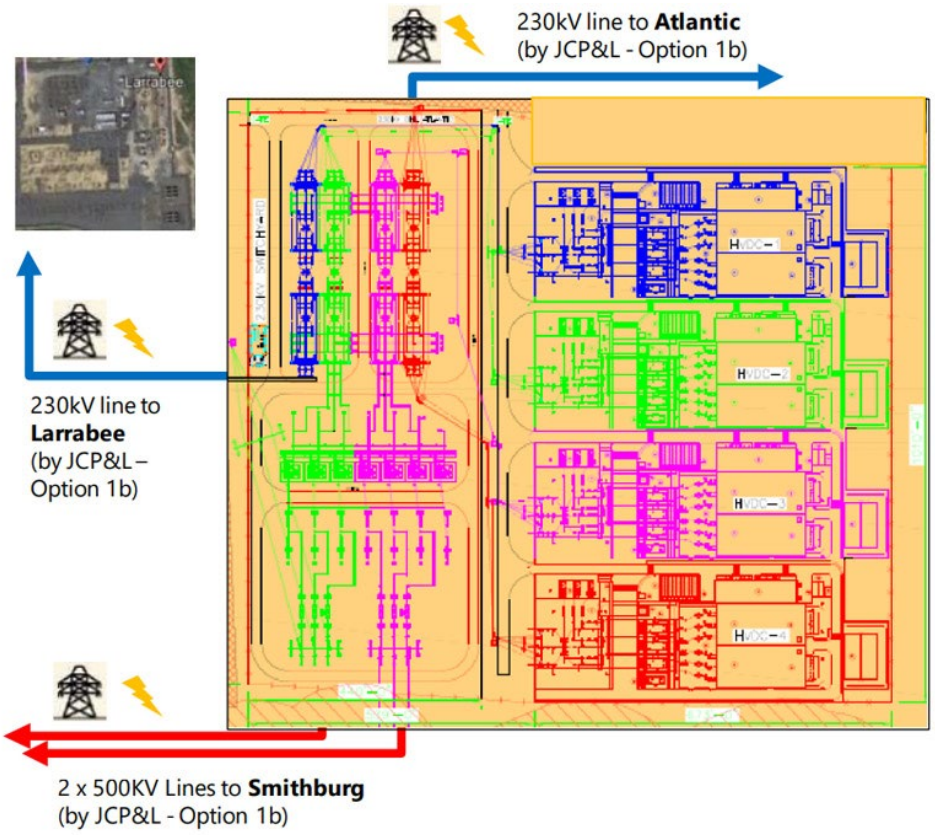
As a result, the board said it will require a successful bidder in its third OSW solicitation, scheduled for the first quarter of 2023, to "prebuild" a single corridor from the shore crossing to the Larrabee collector, ensuring a single onshore transmission corridor.

In September, Gov. Phil Murphy increased the state's OSW goal to 11,000 MW by 2040. The board's order directs staff to begin a second round of coordinated transmission planning to meet the increased goal, potentially including a new SAA solicitation.

Pending approval of the PJM board, the RTO will include the projects selected by the BPU in its Regional Transmission Expansion Plan as baseline public policy projects.

In addition to the Larrabee collector, the BPU approved $575 million in upgrades to existing onshore transmission identified by PJM as necessary to support the OSW injections, including:

- PSE&G's proposed Brunswick to Deans and Deans subprojects and Windsor to Clarksville subproject: $40.3 million;
- LS Power's additional Hope Creek-Silver Run 230-kV submarine cable plus upgrade: $61.2 million;
- Atlantic City Electric's proposal to reconductor the Richmond-Waneeta 230-kV line: $16.9 million;
- Transource's North Delta A proposal: $109.68 million;
- PPL to reconductor the Gilbert-Springfield 230-kV: $380,000;
- PECO to replace four Peach Bottom 500-kV breakers: $5.6 million; and
- BGE to upgrade one Conastone 230-kV breaker: $1.3 million.



The Mid-Atlantic Offshore Development proposal will provide routes to three points of interconnection on Jersey Central Power and Light's transmission system: the 230-kV Larrabee substation, two 500-kV transmission lines to the Smithburg substation, and one 230-kV line to the Atlantic substation. | *Mid-Atlantic Offshore Development*

Because the State Agreement Approach requires New Jersey to assume 100% of the costs of the $1.07 billion in spending, the bills of average residential customers will increase by $1.03/month, the BPU said.

The BPU said its selections would save $900 million over the baseline scenario, evidence of the board's "prudent and careful" approach, BPU Chair Joseph Fiordaliso said.

BPU Chair Joseph Fiordaliso | *NJ BPU*

But Commissioner Dianne Solomon said she was concerned about the costs of this and future transmission expansions. "I'm sure my fellow commissioners agree we must work with others in our region to oversee and share the costs of the build out of offshore wind," she said.

The BPU's order said "it may be beneficial, prior to initiation of the second SAA, to review with other states, both inside and outside the PJM region, the potential for jointly undertaking an offshore wind planning process and incorporating those larger needs into this future SAA. While such a multi state process may present additional complexities, it is also likely to reduce costs to ratepayers by identifying even more robust regional solutions by considering a wider range of public policy needs, and by enabling the sharing of costs with other states who participate in the SAA process."

Comments

MAOD did not respond to a request for comment. FirstEnergy spokesperson Chris Hoenig called the award "a landmark development opportunity in new, regulated transmission assets."

PJM CEO Manu Asthana called the BPU's action "an important milestone in the development of offshore wind in the U.S."

"We see the State Agreement Approach as a model for how states can leverage PJM's processes to advance their policy goals," he added. ■

PJM News

Utilities Oppose NJ BPU Plan Limiting EDC Storage Ownership

By Hugh R. Morley

Public Service Enterprise Group and three trade groups told the New Jersey Board of Public Utilities (BPU) on Oct. 21 that utilities should play a greater role in owning and operating storage facilities than the one allowed under a proposal by the agency.

During an over three-hour hearing into the storage plan that attracted 300 participants, PSEG pushed back on the BPU's plans to limit utility participation in order to encourage private investment and ownership of the new facilities that the state hopes to develop as part of its plan to have 2,000 MW of storage in place by 2030.

The BPU's *proposed* Storage Incentive Program (SIP), released on Sept. 29, would go to privately owned and operated storage, consistent with New Jersey's "restructured competitive market structure." But "there will also need to be a robust effort by EDCs [electric distribution companies] to ensure that the grid is capable of connecting storage devices at the distribution and transmission levels," the proposal says.

"Thus, while the New Jersey SIP does not propose to allow for utility ownership or operation of devices, EDCs will play a key role in building the grid infrastructure necessary to enable the effective dispatch of energy storage devices," it says.

"So it wouldn't be just 'OK, the utilities can just install and ratebase'" the development of new storage, explained Paul Heitmann, a BPU staffer who presented the proposal at the hearing.

But a PSEG representative argued that given the "urgency" of reaching the state's goal, utilities should be able to do more under the plan.

"We believe that the board needs to use every available resource to meet this challenge," said Kate Smith, managing counsel for PSEG's state regulatory group. "And we respectfully suggest that the these goals may not be feasible without more participation from the EDCs and that the EDC should be a resource that should be more a part of this New Jersey SIP solution now."

Smith said the utility believes "that we need to be more of a part of these solutions from a utility deployment standpoint." She noted that PSEG in 2018 filed a proposal for the utility to develop 35 MW of storage. That plan, in which *PSEG proposed to spend $180 million*, is still pending, and the utility has agreed to put it on hold while the BPU develops its policy.

"We don't believe that the goals expressed here, and the plan that's put forth here, are mutually exclusive to utility investment," Smith said. "We think that the EDCs can support and complement private investment."

Storage is 'Critical'

The hearing, the first of three to be held on the SIP, is part of the BPU's effort to jumpstart the development of a storage sector after several years of inactivity. The next meetings are scheduled for this Friday and Nov. 14.

The state Energy Master Plan in 2019 said the state would need 9 GW of storage capacity to manage its clean energy goals, and the state Clean Energy Act, enacted in 2018, said that the BPU should create a process for putting 600 MW of storage in place by 2021 and 2,000 MW in place by 2030. Yet the state today has only about 500 MW in place, much of which is decades old. (See *NJ Lagging in Energy Storage Progress*.)

The SIP sets a target of building 1,000 MW of four-hour-plus storage by 2030 and is part of a

AES Lawai solar and storage project | *National Renewable Energy Laboratory*

PJM News

two-pronged approach to reaching the 2,000-MW goal. The remaining 1,000 MW would come from the Competitive Solar Incentive (CSI) program, which is designed to provide incentives for grid-scale solar projects, along with co-located storage. Final rules for the CSI program are expected to be released this year.

Storage is widely seen as a paramount element needed to manage electricity supply without relying on fossil fuel as intermittent renewables increasingly dominate the resource mix.

"Whether it's the board's energy [plan], or New Jersey's Energy Master Plan, or any number of other pathways to 100% clean energy, energy storage is really a critical element in keeping the grid balanced and making sure that we can do the clean energy transition on time and on budget," Abe Silverman, executive policy counsel for the BPU, told the hearing.

The BPU's plan would provide incentives for both utility-scale and distributed projects. About 30% of the incentives would be paid to storage projects as fixed annual incentives, with a set value per kilowatt-hour of capacity. The remainder of the incentives would be paid through a "pay for performance" mechanism and tied to the environmental benefits.

Speaking at the hearing, Sarah Steindel of the New Jersey Division of Rate Counsel said the BPU needs to closely monitor the cost of the plan and look beyond ratepayers for funding, such as federal infrastructure money and private research funding.

"We need a plan for how much we're going to spend on this, including the costs of utility infrastructure, and how much measurable non-speculative benefits we're going to get from this," she said. "The board's well aware that many ratepayers are already stressed. They're already paying for solar, offshore wind, nuclear subsidies" and electric vehicles. "And we need to think carefully about the money we're spending and how we're spending it."

Seeking an Additional Utility Role

Other speakers also said they were not convinced that allowing solely private investment in storage would enable the state to reach its storage targets, and they advocated for utilities to be able to participate more.

"Given the magnitude of the state's storage goals — in addition to efforts for electric vehicles, energy efficiency, peak demand reduction, renewable targets, and the need to ensure reliability and resiliency — EDC ownership should remain a viable option because of the expertise and knowledge the EDCs have about their unique systems," said Christopher Wehr, staff analyst for FirstEnergy, parent of Jersey Central Power & Light. "And they're kind of best suited to identify the areas where these strategic investments will provide the benefits to customers."

That view was echoed by trade groups including the New Jersey Utilities Association, the New Jersey Alliance for Action and New Jersey Energy Coalition. Allison McLeod, public policy director for the New Jersey League of Conservation Voters, encouraged the BPU to look for an additional role for the utilities, saying that "their participation could be a valuable resource to the board and to the overall efforts to electrify."

Too Little Support Early on

Other speakers focused on the allocation of incentives in the proposal.

Scott Elias, director of Mid-Atlantic state affairs for the Solar Energy Industries Association (SEIA), questioned the impact of what the SIP proposal describes as a "declining block structure" for allocating incentives. The program would set capacity blocks at a certain incentive, and once the BPU has allocated a block of incentives to storage projects, a new block would open at a lower incentive rate. BPU officials say the system would enable the agency to assess the demand for incentive's to build storage capacity at certain rates and adjust it if there are too few applications at particular levels.

Elias said that SEIA is concerned at the "size and cadence of the capacity blocks."

"Backloading most of the capacity to later years and later blocks means that a single grid supply project, for instance, could eat up the entire capacity" for a year, he said.

Lyle Rawlings, president of the Mid-Atlantic Solar and Storage Industries Association, said he also believes that there needs to be more incentives in the first two years of the program. In addition, his organization is concerned by the SIP's plan to allocate incentives to develop three times as much storage from grid projects as from distributed energy projects. Given that the BPU plans to secure half of its storage development from solar-tied storage in the CSI program, which would also come from grid-scale projects, the state is giving too little focus on the distributed energy sector, Rawling said.

"There should be a much greater emphasis on distributed" energy storage, he said. With "distributed generation, there's a lot of pent-up demand ready to go. So this can quickly be deployed to meet the goals." ■

PJM News

FirstEnergy Q3 Adjusted Earnings at Top of Guidance

By John Funk

FirstEnergy on Wednesday reported third-quarter earnings of $334 million (58 cents/share) on revenues of $3.5 billion, down from $463 million (85 cents/share) on revenue of $3.1 billion a year earlier.

Excluding special charges or credits, the company's operating earnings were 79 cents/share, at the top of analysts' guidance range. That compares to operating earnings 82 cents/share a year ago.

"Our continued solid results, together with the ongoing efforts to strengthen our culture, accelerate improvement in our balance sheet and achieve operational excellence, are creating positive momentum at FirstEnergy and positioning us to capitalize on significant opportunities for growth through long-term, customer-focused investments," John W. Somerhalder II, board chair and interim CEO, said in a statement accompanying the results. "I'm confident our leadership team and committed employees will continue to drive these strategies to transform the company into a best-in-class utility."

The company updated its full-year forecast for adjusted earnings to a range of $1.145 billion to $1.26 billion ($2.01 to $2.21/share) based on 571 million shares outstanding.

The company reported that power deliveries for the third quarter were flat, with a 2% uptick in industrial demand offsetting a decline in residential and commercial demand.

The company's regulated transmission business showed improved results, primarily from the company's ongoing capital investment program, which yields guaranteed income.

In its quarterly report filed with the U.S. Securities and Exchange Commission, the company said it had recalculated transmission and distribution expenses as demanded by a FERC audit issued earlier this year.

"FirstEnergy completed an analysis during the third quarter of 2022 of these costs and how it impacted certain FERC-jurisdictional wholesale transmission customer rates for the audit period of 2015 through 2021," the company said.

"As a result of this analysis, FirstEnergy recorded in the third quarter of 2022 approximately $45 million ($34 million after-tax) in expected customer refunds, plus interest, due to its wholesale transmission customers, and reclassified approximately $195 million of certain transmission capital assets to operating expenses for the audit period, of which $90 million ($67 million after-tax) are not expected to be recoverable and impacted FirstEnergy's earnings since they relate to costs capitalized during stated transmission rate time periods. …

"These reclassifications also resulted in a reduction to the Regulated Transmission segment's rate base by approximately $160 million, which is not expected to materially impact FirstEnergy or the segment's future earnings." ■

| FirstEnergy

PJM News

PJM Stakeholders Reject Clean Energy Requirement for Board

By Devin Leith-Yessian

CAMBRIDGE, Md. — PJM's Members Committee on Wednesday rejected a proposal from the Illinois Citizens Utility Board to require that at least one member of the Board of Managers have clean energy qualifications.

The *proposal* would have amended PJM's Operating Agreement to add a qualification that one board member "shall have expertise and experience in the development, integration, operation or management of clean energy resources." The amendment failed with 32% support, well short of the two-thirds margin required in the sector weighted vote.

Albert Pollard of CUB told the committee in September that PJM's board needs expertise in carbon-free generation as the grid transitions away from fossil fuels.

"This is not a proposal to have a clean energy advocate on the board, and I would oppose such a thing," Pollard said. "This is clean energy expertise. This is someone who, through their leadership, can work with the other experts on the board to call balls and strikes," he said.

Paul Sotkiewicz of E-Cubed Policy Associates said the focus should be on promoting reliability rather than having expertise in any one form of generation, which he said would introduce potential bias and undermine the board's independence.

"This would lead to some advocates on the board because let's face it, everyone comes with some bias," he said.

Pollard said the amendment would not change the composition of the board as there are currently sitting members who already meet the qualifications the CUB was seeking to add. During the MC's first read of the proposal on Sept. 21, PJM CEO Manu Asthana and General Counsel Chris O'Hara clarified that the measure would not be adding a dedicated seat, but rather a qualification. (See "Board Member with Clean Energy Expertise," *PJM MRC/MC Briefs: Sept. 21, 2022*.)

Albert Pollard, Illinois Citizens Utility Board | © *RTO Insider LLC*

Adrien Ford of Old Dominion Electric Cooperative said that based on her experience on the nominating committee she believes the existing process is sufficient for determining the experience that would create the strongest board composition. Additional requirements would limit the committee's flexibility, she said.

"The nominating committee really works to make sure we have the core expertise needed on the board [and] has the flexibility … to fill in what additional experience is needed on the board," she said.

Jason Barker of Constellation Energy said the amendment would reflect the discussions at PJM's Annual Meeting regarding the challenges posed by the clean energy transition. Ensuring that the board has expertise in the types of resources that will increasingly dominate the grid will be critical to managing reliability, he said. ■

PJM News

PSEG Faces Final Decision on NJ Ørsted Project

Utility Considers Options on Ocean Wind Project

By Hugh R. Morley

Public Service Enterprise Group is mulling whether to remain a 25% partner with Ørsted in the Danish developer's Ocean Wind 1 project in New Jersey, CEO Ralph LaRossa said Monday as he laid out the company's future clean energy plans in its third-quarter earnings call.

The company acquired the share shortly after the New Jersey Board of Public Utilities (BPU) in 2019 picked Ørsted's 1,100-MW project to be the state's first offshore wind project. LaRossa spoke in his first earnings call since he took over from his predecessor, Ralph Izzo, on Sept. 1.

"We are approaching a final investment decision [FID] on Ocean Wind 1 in New Jersey to determine if we will proceed to the construction phase," LaRossa said. "We are reviewing our options related to our 25% equity investment as well as our option to purchase" 50% of Ørsted's Skipjack Wind 2 project in Maryland, he added.

On Ocean Wind, "one of the things we're looking at there is where the costs come in, and what that project looks like from an investment standpoint," he said. Also part of the consideration are changes in revenue and expenses, he said. Under questioning from investment analysts, CFO Dan Cregg said there is no date stipulated in the contract for the decision.

An "FID moves you to the construction phase of the project, and so it's when things are ready to move to that phase," he said. Company officials gave no indication as to whether they would withdraw from the joint venture or remain as a partner.

Offshore Transmission Opportunity

LaRossa said that despite the fact that the BPU last week awarded PSEG only a small part of the work to upgrade the state's transmission system in preparation to handle energy from the offshore wind projects, the utility believes that it could still get a substantial share of future work.

The BPU on Wednesday voted unanimously to spend $1.07 billion on transmission upgrades to deliver 6,400 MW of offshore wind generation to the PJM grid, saying the projects would minimize costs, environmental impacts and permitting risks (QO20100630). The BPU made its selection from among 80 proposals submitted by 13 developers in response to a solicitation issued by PJM at the BPU's request under FERC Order 1000's State Agreement Approach. (See related story, *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

At PSEG's third quarter earnings call, new CEO Ralph LaRossa said the company has yet to fully commit to its 25% partnership in the Ocean Wind 1 offshore wind project. | *Shutterstock*

Among the submissions for the solicitation were proposals by PSEG individually and the *Coastal Wind Link*, submitted with Ørsted, which would use an offshore mesh system to transmit electricity onshore. Rizzo in May said PSEG could potentially secure projects costing $3 billion under the solicitation, although he also acknowledged the company may also get nothing. (See *PSEG Sees Potential $3B OSW Transmission Spending*.) LaRossa said that based on the contracts awarded last week, the offshore work potentially available to the PSEG-Ørsted partnership could be between $2 billion and $7 billion.

"We remain optimistic that our emphasis on reliability and resiliency will keep it as a strong contender for any future offshore transmission solicitations to bring regional offshore wind projects onshore," he said. If the company did pull out of the Ocean Wind 1 project, it potentially could invest more in transmission systems linking the offshore projects, he said, noting that the BPU solicitation sought transmission proposals only for the state's goal (at the time) of 7.5 GW of offshore wind power by 2035. New Jersey Gov. Phil Murphy on Sept. 21 announced that he had increased the state's offshore wind target to 11 GW by 2040.

"We're still hopeful on that offshore transmission and a full mesh network," LaRossa said. "We think our mesh network is absolutely the most resilient and most robust."

Nuclear Tax Credits

LaRossa said that the company also expects to benefit from the Inflation Reduction Act, which he said would have "important revenue visibility and price-stabilizing benefits" for the utility's 3,770-MW nuclear fleet. The *act*, which was signed by President Biden on Aug. 16, provides production tax credits of up to $15/MWh for certain nuclear plants, from 2024 through 2032.

The credits will "will extend the visibility and stability of cash flows into the next decade," LaRossa said *in an earnings release*. "These incentives will lower customer costs over time and support the continued operation of existing nuclear plants — which are New Jersey's largest carbon-free base load energy resource."

PSEG reported net income of $114 million ($0.22/share) in the third quarter, compared to a net loss of $1.564 billion ($3.10/share) a year earlier. The 2021 loss was from an impairment charge from the sale of the utility's fossil assets.

Non-GAAP operating earnings for the third quarter of 2022 were $429 million ($0.86/share) compared to non-GAAP operating earnings of $495 million ($0.98/share) in the third quarter of 2021. ■

PJM News

PJM MRC Briefs

PJM CEO Manu Asthana Warns of Potential Generation Shortfalls

CAMBRIDGE, Md. — PJM CEO Manu Asthana said 40 GW in planned retirements and lagging construction of new generation is raising questions about the long-term reliability of the grid.

"We cannot take the reliability that we enjoy in our region for granted through this energy transition; we have to take concrete steps to ensure that it will continue," Asthana said during his keynote address for the 2022 Annual Meeting of Members prior to the convening of the Markets and Reliability Committee Oct. 24.

He said about 40 GW of generation is expected to retire by 2030, mostly due to policy decisions rather than economics, leaving PJM without a way to incentivize the units to remain online. On top of that, data centers are expected to add 10 to 15 GW of load, with an unknown amount of growth from electrification.

Approximately 30 GW worth of new interconnection service agreements have been signed this year and there's an additional 250 GW in the interconnection queue. However, the new generation is lagging the pace of installation that has been anticipated, Asthana said. Of the 30 GW of ISAs signed this year, only 1.5 GW has been built so far.

If the pace of constructing new generation doesn't ramp up, he said it could lead to more reliance on demand response — with curtailments becoming more commonplace than many DR participants signed up for.

"We have time, but we don't have time to waste," he said. "We need to take action to ensure we retain an adequate supply of dispatchable generation through the transition."

The stakeholder process has proven itself through the challenges of the past several years, Asthana said, and will be essential to navigating the clean energy transition as well.

"I still firmly believe that the way to solve the really complex problems of the energy transition is together as a stakeholder body. Not because it's the quickest way to get there … but because it's the best way to get to a resilient, durable and lasting set of solutions."

PJM CEO Manu Asthana | © *RTO Insider LLC*

Black Start Fuel Requirements Advance to Members Committee

PJM stakeholders endorsed a slate of revisions to the tariff and several manuals to reduce the risk of black start generators being offline due to fuel unavailability. The joint PJM, Brookfield Renewable and D.C. Office of the People's Counsel package received 94% support in the sector-weighted vote.

The *proposal*, which is set to go before the Members Committee next month, creates a new category of "fuel assured" generators and requires at least one such unit in each transmission zone. The criteria to qualify as a fuel assured unit vary based on the resource type, including connections to multiple interstate gas pipelines, on-site fuel storage and dual-fuel capability.

PJM Senior Engineer Dan Bennett said the effort will create a methodological approach to looking at black start reliability. "We want to make sure this service is compensated fairly and recognized for what it brings to the grid," Bennett said.

Black start resources whose unavailability during a blackout would cause the projected zonal restoration times to increase by 10 hours or more were identified as "high impact" sites with possible mitigation strategies laid out. The proposal calls for $28,175,000 in additional black start annual revenue for mitigation of the high-impact sites.

Calpine's David "Scarp" Scarpignato said the requirement of one fuel-assured BSR per transmission zone may be insufficient, raising the possibility of a generator being offline or damaged during a blackout. He also noted that having penalties for fuel assured resources which fail to meet the requirements, but none for non-assured generators could discourage participation in the higher tier.

Joe Bowring, president of Independent Market Monitor Monitoring Analytics, said the proposal could result in overpayments as some BSRs which would qualify as fuel assured elect not to seek that designation, forcing PJM to enroll an additional fuel assured generator. He has also questioned the value of having non-assured resources such as intermittent generators providing black start.

Monitoring Analytics' own package, which would have prohibited intermittent resources other than run-of-river hydro from enrolling as BSRs, did not receive the support of the Operating Committee and Market Implementation Committee. Bowring did, however, thank PJM for incorporating some of his suggestions into the joint package and said that overall it's a proposal that provides a needed solution.

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Stakeholders Narrowly Reject Demand Response Problem Statement and Issue Charge

The MRC narrowly rejected an initiative to consider the use of statistical sampling for interval-metered residential customer participation as demand response in wholesale markets. The *problem statement* received 48% sector-weighted support, just shy of the 50% required. (See "Stakeholders Endorse Prohibiting Gas Infrastructure Participation in DR," *PJM Market Implementation Committee Briefs: Oct. 6*.)

CPower's Ken Schisler said the requirement that curtailment service providers use customer meter data for measurement and verification is "an unreasonable barrier for residential metering." Obtaining access to the data from electric distribution companies remains a challenge and once that data is received, Schisler said CSPs must manage hundreds of thousands of data points when calculating winter peak load.

He also raised the possibility of security issues related to holding large volumes of residential electric usage data, saying that privacy concerns could be greater for personal versus industrial data.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said the proposal offered an opportunity to receive information about barriers to the usage of smart meter data and noted that the adoption of a problem statement would not necessitate the adoption of any solutions examined.

The electric distributor sector had the strongest opposition to the proposal, joined by transmission and generator owners. End use customers unanimously supported the proposal and other suppliers had mixed support.

Adrien Ford, ODEC | © *RTO Insider LLC*

Alex Stern of Public Service Electric and Gas told *RTO Insider* he believes the MRC was right to oppose PJM becoming involved in residential demand response, which he believes should be addressed by state legislators and regulators before the RTO examines its own rules.

"We really need to respect the states and consider the policy issues, including but not limited to privacy — respecting the privacy of customers, as well as the … rights and responsibilities of states versus PJM," he said.

Bowring also told the MRC that he believes access to meter data is a state policy issue and said he worries that PJM allowing statistical sampling as a workaround to issues in obtaining that data would create a disincentive for states and CSPs to find a more direct solution.

Paul Sotkiewicz of E-Cubed Policy Associates said the usage of statistical sampling could introduce inaccuracies in the markets and questioned why metering for demand response should be treated any differently from the requirements that generators are held to. "It opens up a can of worms we shouldn't even be talking about."

Support for Circuit Breaker Remains Mixed

Stakeholders remained divided on *several proposals* to impose a circuit breaker to limit the price and duration of high energy prices. None of the seven packages produced by the Energy Price Formation Senior Task Force received 50% support over the status quo in two task force polls, with a proposal from Calpine receiving the highest at 34%.

Presenting the *joint stakeholder package*, which received 14% support in the polls, Adrien Ford of Old Dominion Electric Cooperative said price spikes can be helpful to encourage generators to respond to issues the grid is facing. However, sustained high prices can result in load paying for tens of millions in higher rates every day that prices remain elevated and a risk of cascading market defaults.

Under the joint package, the circuit breaker would be triggered if the average LMP was above $1,000 for a rolling 24-hour period or above $850 for a rolling 168-hour interval. PJM would also be permitted to trigger a circuit breaker response but could not block one under the proposal.

The circuit breaker would remain in effect until the price cap had not been reached for five consecutive business days.

Alex Stern, PSE&G | © *RTO Insider LLC*

The proposal would also include administrative adders to provide cost recovery if the cost to generate power exceeds the circuit breaker price cap. Ford said the current rules require generators to go before FERC to seek cost recovery; the joint stakeholder language would shift the decision to PJM instead.

Bowring said that a circuit breaker should not suppress the market price below fundamentals like the cost of gas. Nor should it artificially increase prices by including any administrative adders, like Operating Reserve Demand Curve penalties or transmission constraint penalty factors, he said.

The Calpine proposal would cap the energy component of the LMP at $2,000 when the circuit breaker is triggered; generators would be paid uplift if the LMP is too low to cover their costs. The trigger would be 90 hours of non-consecutive shortage events since June 1, followed by any subsequent event during that delivery year lasting three or more hours. The circuit breaker would continue until the shortage event has ended.

Scarpignato said the $850 price cap under the joint stakeholder proposal would likely be below the cost of gas during many emergencies, while Ford said allowing prices to go as high as the $5,700 per MWh — which is the highest they can go under cost-based offers, reserve shortages and a $2,000/MWh transmission constraint penalty factor — would result in $61 billion in energy costs for a typical winter load or nearly $40 billion without the TCPF.

Jason Barker of Constellation and Sotkiewicz both said they could not support any of the current proposals and urged further discussion to find a compromise package. The MRC is scheduled to consider endorsing a package at its next meeting.

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MRC Discusses Transmission Constraint Penalty Factor Revisions

The MRC reviewed a proposal to provide PJM with added flexibility to modify the transmission constraint penalty factor when transmission upgrades are already underway. The *PJM proposal* aims to provide a solution to an issue identified in 2020, after one of just three transmission lines into Virginia's Northern Neck peninsula was put on outage for a planned upgrade.

The outage caused price fluctuations that pushed the TCPF to its default of $2,000/MWh in the real-time energy market. Since the completion of the upgrades would resolve the issue and it wouldn't be possible for new generation to be added prior to the work being finished, PJM successfully argued to FERC that the design of the penalty factor created "unjust and unreasonable energy market rates" for consumers. (See *FERC Approves Pause of PJM Tx Constraint Penalty Factor in Va.*)

Bowring argued that while PJM's filing proposal addressed a real issue, its proposal would allow the RTO to subjectively determine penalty factors and does not address why penalty factors are triggered so often. Bowring said the penalty factors increased average PJM prices 11.2% in the first half of 2021 and 6.1% in the first half of 2022. Bowring stated that PJM reduces transmission line ratings by 5% and triggers these transmission constraint penalty factors unnecessarily.

A second IMM proposal failed to garner significant support over the PJM package and the status quo in an EPFSTF poll. The IMM's alternative would broaden the trigger criteria and use a different methodology for the circuit breaker.

The PJM proposal is scheduled to be considered for endorsement by the MRC at its next meeting.

Two Proposals Remain on Variable Operations and Maintenance Costs

The MRC continued discussion of two competing packages to streamline the accounting of variable operations and maintenance costs.

The *PJM proposal* would create default adders for minor maintenance and operating costs as an alternative to generators submitting unit-specific information and would provide definitions of major maintenance and minor maintenance for more clarity on which costs fall into each.

The *Constellation package* mirrors the PJM language with the exception of removing the refueling and associated maintenance from variable costs, with Barker saying those expenses should be considered part of the unit's capacity offer, rather than its cost-based energy offer. He said such operations are "fixed" costs that don't vary with run time.

"Defining planned outage costs as a component of VOM will require a significant annual VOM accounting for all nuclear units; akin to developing an ACR for each unit each year," Constellation's presentation said.

The Market Implementation Committee endorsed the PJM package with 70% support at its Sept. 7 meeting, with Constellation's advancing as an alternative with 54% support. (See "Two Alternatives on VOM Advance to MRC," *PJM Market Implementation Committee Briefs: Sept. 7, 2022*.)

Stern said PSEG supports Constellation's language because it aligns with efforts to preserve nuclear power as a zero emission resource.

Bowring and Sotkiewicz, however, said the package would create a special carveout for one type of generation, with the latter asking if Barker would support an amendment to include time-based operations from other resource types. Barker said such a change would be too major for him to accept as a friendly amendment and would require additional stakeholder input.

Reworked Language on Critical Gas Infrastructure Participation in Demand Response Presented

PJM gave an *overview* of changes made to the language of a slate of Operating Agreement, Reliability Assurance Agreement and manual revisions to prohibit critical gas infrastructure from participating in demand response programs. Following MIC feedback that the definition of the infrastructure to be affected could be vague, staff removed the word "significantly" from the phrase "which if curtailed, will significantly impact the delivery of natural gas to bulk-power system natural gas-fired generation. (See "Stakeholders Endorse Prohibiting Gas Infrastructure Participation in DR," *PJM Market Implementation Committee Briefs: Oct. 6*.)

The timeline for scheduling of future votes on the package has also been changed, with a vote at the Members Committee moved to December to avoid having the MRC and MC voting on the measure on the same day. ■

SPP News

SPP Board Bypasses Stakeholders on PRM Obligation Exemptions

Directors OK State Regulators' Version of Tariff Change

By Tom Kleckner

SPP's Board of Directors has given its state regulators the go-ahead to file a proposed tariff change that would allow load-responsible entities (LREs) to qualify for and receive exemptions from deficiency payments for not meeting their planning reserve margin (PRM) requirements.

Under the RTO's tariff, the Regional State Committee has the authority to direct staff to file changes with FERC without the board's approval. SPP's directors yielded to the RSC on Oct. 25 by authorizing the filing after the committee's earlier approval of the revision requests (*RR 515*).

In doing so, the board disappointed stakeholders who had approved a slightly different version of RR515 brought forward by the Supply Adequacy Working Group (SAWG) two weeks earlier. (See "Members Address Resource Adequacy," *SPP Markets and Operations Policy Committee Briefs: Oct. 10-11, 2022*.)

Denise Buffington, Evergy | © *RTO Insider LLC*

Speaking for the stakeholders she represents as the Markets and Operations Policy Committee's chair, Evergy's Denise Buffington said she expects the waiver process to fail at FERC.

"Not because of the substance of the process, but because it is likely to be protested by SPP stakeholders," she told the board last week. "This gives FERC an easy path to deny something that is hard. I believe they'll do that because, first of all, they don't like granting waivers. So, if we are not in lockstep about what the waiver looks like and the criteria and all … the easy thing for FERC to do is to say, 'There is no waiver.' So essentially, the results of the decision that was made yesterday means that more responsible entities are likely not to have an option of a waiver."

Several members suggested SPP's stakeholders should ensure that important issues are vetted appropriately. Board Chair Larry Altenbaumer agreed, saying, "This is a tough issue because it tends to be a bifurcated issue.

"There are certain responsibilities that are vested with the RSC. This is one of them. And I think the RSC has the full authority to determine how they want to reach their decisions," Altenbaumer said. "Where I sit as a board member, I think we all strive and desire and try to help facilitate reaching consensus and alignment among our stakeholders. My view is that what we are attempting to do here is to try to reengage the stakeholder process to see if we can now come up with something that might be a balanced outcome.

"I think in the final analysis, the board has to act independently," he added.

The RSC approved a version proposed by its Cost Allocation Working Group and tweaked by the Market Monitoring Unit. It calls for up to a two-year exemption from deficiency payments, whereas the MOPC version allows a three-year exemption. The CAWG proposal also requires LREs to meet two tests to claim the waiver, while MOPC's only required complying with one of the two.

LREs would qualify for the waiver in both versions by demonstrating they have enough capacity to meet forecasted load for the upcoming season and the prior effective PRM. Under the CAWG version, they must also prove by a certain date each year that sufficient capacity for purchase has not been identified on a virtual bulletin board; they have a contracted obligation to purchase capacity; and they have a pending request for enough interim, surplus or replacement generator interconnection service to provide planning reserves to SPP.

During a closed-door education session for the RSC on Oct. 24 before its regular meeting, the MMU presented its revisions to the CAWG proposal that included extending the deadline for waiver exemptions from March 10 to May 1 and allowing LREs to cure at least a portion of their deficiency, thus reducing the penalty. The RSC accepted both suggestions.

Buffington protested the lack of stakeholder input into the MMU's recommendations. RSC President Randy Christmann, a member of North Dakota's Public Service Commission, countered by telling the board that the assertion that the MMU's changes were never brought to MOPC "almost makes it sound like it was some surprise thing that was brought on the membership yesterday."

"Well, the fact of the matter is I studied it up in North Dakota and learned about it, and multiple other states did as well, and I'm confident that companies are aware of those postings," Christmann said.

The board in July approved an increase to the RTO's planning reserve margin from 12% to 15%, effective next year. MOPC had recommended a "stair-step" increase by adding a percentage point to the PRM over three successive years. (See *SPP Board, Regulators Side with Staff over Reserve Margin*.)

Stakeholders have said they support an adequate PRM, but that the sudden 25% increase has left them with just a few months to acquire significant enough capacity to meet contractual obligations. Some also complained that not enough excess capacity is available for purchase.

"People have been ghosted. … They've been offered capacity, but then it's pulled back," Golden Spread Electric Cooperative's Natasha Henderson, the SAWG's chair, told the RSC. "It's pulled back because of the uncertainty that we're dealing with [over] what's the right policy."

Several state regulators expressed concern that the stakeholder process had not reached full consensus. However, they approved the modified CAWG version by a 9-3 margin. Kansas' Andrew French, Oklahoma's Dana Murphy and Texas' Will McAdams all voted against the measure.

"Everything I've heard this week is that we have more time to explore this. We've had these issues in the past where people want to continue debating … I don't feel like we're right there yet," French said. "My biggest concern is, have we really run this down to the best solution it can be? This will be in the tariff. … It's going to be the process moving forward."

Evergy, Golden Spread, Liberty Utilities, Oklahoma Municipal Power Authority, Public Service Company of Oklahoma and Southwestern Public Service were the only representatives of the 22-person Members Committee to vote against authorizing RR515's filing.

A virtual bulletin board for informational purposes only will be developed so LREs and generation owners can view and post requests to buy or offers to sell power. All information on the board will be confidential, with only the MMU able to review the data.

SPP bases its reserve margin requirement on a probabilistic loss-of-load expectation study during summer months that is performed every two years to determine the capacity needed to meet the reliability target of a one-day outage every 10 years (0.1 days/year). ■

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SPP Board/Members Committee Briefs

FERC's Glick Shares Thoughts on Grid Reliability, RTO Markets

FERC Chair Richard Glick made his first in-person visit to SPP's Arkansas headquarters last week, joining the grid operator's stakeholders for their regular quarterly governance meeting.

The trip wasn't Glick's first to Arkansas. He served as former U.S. Sen. Dale Bumpers' (D-Arkansas) legislative director and chief counsel for seven years, which brought him to The Natural State several times.

"The first question I would always get was, 'You're not from here, are you?'" Glick, a son of the North, said during the meeting.

He watched from the sidelines as the Board of Directors and the Regional State Committee, comprised of SPP's state regulators, conducted their business in meetings that were closed to non-rostered members. Glick came away impressed with the RSC's deliberations on resource adequacy.

"It was a real education because there's a lot of other regions that have different approaches to state input and state stakeholder processes, and this is definitely unique," he said. Nodding to SPP's expanding Western market services, Glick added, "I can see why that's attractive to others … especially in the West."

Glick said SPP's approach to state regulatory input will play a role as the RTO competes with CAISO to offer market services in the Western Interconnection.

"I'm pretty sure everyone would probably agree that eventually, there's going to be at least one if not more than one RTO developed in the West. It's certainly moving in that direction, and you all are playing a significant role," he told stakeholders. "I think just providing an alternative to the California ISO, a structure which is obviously hobbled by the way that the ISO deals with independence or doesn't have independence in terms of [its] board relationship. I think … the Regional State Committee approach is something that's very attractive to a lot of the state regulators."

Glick stressed the importance of accrediting generating resources' capacity — and not just that of intermittent resources — to maintain grid reliability. He noted that in recent years "more traditional generating plants" have shut down when they should have been available, mostly because of extreme weather.

"It's something that everyone needs to think about and be much more precise in how we define and accredit capacity," he said.

Glick said FERC has devoted two years of technical conferences and internal discussions about the best way to structure markets going forward, given the challenges of ensuring reliability and the transition to clean energy.

"One of the questions is [whether] the markets are currently operating in a way that really achieves or maximizes the benefits associated with the transition," he said. "We've had discussions about capacity markets, about ancillary services, about energy markets and other market reforms as well, and the one recurring theme that comes up in all of them is flexibility, the need for more flexibility as we go forward. It can be flexible natural gas; it can be storage; it could be other technologies as well.

"When I first came to FERC … at the beginning of the Trump administration, there was a lot of discussion about, 'We need more baseload generation, we need to subsidize baseload generation," Glick said. "To me, that's the debate that's kind of not really relevant for today. Today, the relevance to me is how do we incentivize flexibility? I don't anticipate the commission coming up with anything in the near future on that issue, but it's something I think we still think about and wanted to move on at some point in the future."

$245M Operating Budget Approved

The board approved SPP's 2023 operating budget, net revenue requirement and capital budget following unanimous endorsement by the Members Committee.

The $245.6 million budget is a 6.2% increase over the current year — about two-thirds less than last year's 17.7% — with salaries and benefits representing the largest share of growth. SPP instituted a one-time, across-the-board raise for staff this year to compensate for inflation.

American Electric Power's Richard Ross raised concerns that SPP is "too ambitious with our activities that are not a part of our core functions." Ross often refers to those functions as the grid operator's "food and shelter" responsibility.

"I'm concerned that we are too ambitious with our activities that are not part of our core functions, in particular, the Western expansion," he said, citing "recent studies" that indicate the current footprint will see "minimal" benefits from the effort. "I think we need to strongly evaluate whether or not we need to continue the major push that we're under and whether or not that is truly in the best interest of the core functions of SPP in the long-term."

SPP CEO Barbara Sugg | © *RTO Insider LLC*

"It's definitely a known item, and there is focus on how that is going to get addressed, because resourcing is critical," CEO Barbara Sugg responded.

She said SPP has onboarded 81 new staffers this year, but that the turnover rate remains high. She said leadership is taking steps to recruit the "best and the brightest, but also to increase retention."

The net revenue requirement (NRR) will rise 4.7%, from $176.3 million to $184, Finance Committee Chair Susan Certoma said. SPP's tariff limits the NRR to a ratio of estimated annual transmission usage, capped at $0.465/MWh. That rate has been set at $0.448/MWh for 2023 but is projected to peak at $0.494/MWh in 2025 before decreasing.

CFO Dunn Retires

Directors and members honored SPP CFO Tom Dunn, who is retiring after 21 years on Dec. 2.

"So, there's still plenty of time to harass him," Sugg said.

She said SPP's headcount increased by 500 employees and its operating budget by $175 million under Dunn's leadership, and he secured more than $400 million in financing to fund the RTO's growth while maintaining the lowest cost of service by any system operator.

"Tom has been an invaluable resource to me as well as to all of SPP. I'm thrilled that Tom hung in there with me as the new CEO," Sugg said. "He has taught me so much about his area of responsibility, but he's also such an asset to the executive team … who can present different alternatives and suggestions and just kind of help us think out of the box a little bit, which I think is a tremendous asset for all of our executives."

At first reluctant to speak after the board's

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resolution, Dunn recalled one of his first staff meetings. Former CEO Nick Brown asked him to explain finance to the employees. Dunn complied.

"I spent 30 minutes, and [Brown] never invited me to do it again," he said. "I enjoyed my time at SPP. It's the best career move I've ever made."

Membership Elects 2 New Directors

The RTO's membership elected two new directors and one incumbent to the board during SPP's Annual Meeting of Members.

Joining the board are former ISO-NE general counsel Ray Hepper and Steve Wright, a former Bonneville Power Administration CEO and general manager of Washington's Chelan County Public Utility District. Bronwen Bastone was elected to a second three-year term.

Wright's term is effective immediately, as he replaces long-time director Julian Brix, who recently retired from the board. He gives SPP a second director with experience in the Western Interconnection in addition to John Cupparo, which could come in handy as the RTO expands its Western services.

Wright said in a *press release* that he hopes to "strengthen the bridge" to SPP's potential Western members. "SPP is at the center of our nation's ambitious efforts to attain a reliable, affordable and clean electric power system," he said.

Hepper's term will begin Jan. 1. He was elected to ERCOT's board in 2020 but only served a few weeks before the 2021 winter storm came within minutes of collapsing the Texas grid. After several days of outages, Texans directed their ire at the ISO's out-of-state independent directors, who also resigned.

The SPP board will undergo several other changes next year. Current chair Larry Altenbaumer, who has been on the board since 2005 and has one year left on his term, will step aside in favor of Certoma. Elizabeth Moore will replace Certoma as vice chair.

Mark Crisson is also retiring after six years on the board. The board and members honored Crisson with a standing ovation and a resolution recognizing his service.

"I told Mark it's been an honor for me to serve with someone like him. … He is perhaps one of the most quietly effective individuals you will encounter," Altenbaumer said. "He is a very straightforward individual, and if he disagrees with you, he will very constructively let you know that he disagrees with you. I really value that in terms of his role as a board member and the guidance that he sometimes shared with me, even when it wasn't guidance."

The membership also elected six new members and six incumbents to the 22-person Members Committee.

Joining the committee for the first time are EDP Renewables' David Mindham (Independent Power Producer/Marketer segment); Tri-State Generation and Transmission Association's Mary Ann Zehr (Cooperative); Arkansas Electric Cooperative Corporation's Buddy Hasten (Cooperative); Google Energy's Will Conkling (Large Retail); American Clean Power Association's Daniel Hall (Alternative Power/Public Interest); and Southwestern Public Service/Xcel Energy's Adrian Rodriguez (Investor-owned Utility).

Re-elected to the committee are American Electric Power's Peggy Simmons (Investor-owned Utility); Northwestern Energy's Bleau LaFave (Investor-owned Utility); City Utilities of Springfield's (Mo.) Chris Jones (Municipal); Dogwood Energy's Rob Janssen (IPP/Marketer); ITC Great Plains' Brett Leopold (Independent Transmission Company); and Basin Electric Power Cooperative's Tom Christensen (Cooperative).

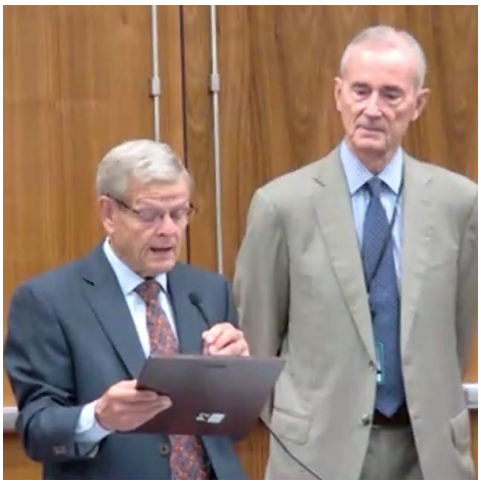
Board Approves 2022 ITP, Consent Agenda

The board approved staff's 2022 Integrated Transmission Plan, a reliability-only portfolio. The 17-project, $35.4 million plan solves 25 system needs in rebuilding 11 miles of transmission but will not result in any new transmission.

Its unanimously approved consent agenda included chairs for the following stakeholder groups: Credit Practices Working Group, Caleb Head (Northeast Texas Electric Cooperative); System Protection & Control Advisory Group, Chris Angland (Omaha Public Power District); Project Cost Working Group, Brian Johnson (AEP); and Market Working Group, Richard Ross (AEP).

The agenda included the Corporate Governance Committee's nominations for several committee assignments: Golden Spread Electric Cooperative's Mike Wise to the Finance Committee; GridLiance High Plains' Noman Williams to the Human Resources Committee; and AEP's Ross, Basin Electric's Christensen, NextEra Energy Resources' Matt Pawlowski, and Golden Spread's Natasha Henderson to the Strategic Planning Committee.

It also included several modified and withdrawn notifications to construct, an amended and restated Western Joint Dispatch Agreement to facilitate three Black Hills Corp. subsidiaries' 2023 membership into the Western Energy Imbalance Service market, and six revision requests previously endorsed by MOPC:



Board chair Larry Altenbaumer reads a resolution honoring six-year director Mark Crisson (right). | *SPP*

- *RR499:* Adds new language to the planning criteria concerning terminology and their definitions, new capability and new operational testing requirements, out-of-season capability testing, capability and operational testing for new or upgraded units, and accreditation for thermal and hydro units.
- RR508: Allows LREs to use deliverable capacity to meet their winter season obligation.
- RR512: Requires LREs to submit used and unused capacity on behind-the-meter resources that have qualified as accredited capacity that can be used to respond to emergency conditions.
- RR514: Updates the operating constraint and spin violation relaxation limits by increasing the values of all operating reserve constraints not subject to market-to-market coordination to $1,500
- *RR516:* Codifies the increase of the planning reserve margin from 12% to 15%.
- *RR520:* Gives the balancing authority greater ability to forecast and measure non-registered, available demand response by analyzing data submitted daily from affected LREs. ■

— Tom Kleckner

SPP News

SPP Congestion-hedging Recommendations Gain Traction

RTO Says Two-part Proposal Will Increase Opportunities for Hedges

By Tom Kleckner

SPP's effort to improve its congestion-hedging processes appears to be gaining traction with its stakeholders, thanks to a recommended hybrid approach that first focuses on equitably allocating congestion rights instruments and then increases the pool of awards available.

Staff presented its proposal to SPP's Markets and Operations Policy Committee Oct. 11 and then again last week during the RTO's quarterly joint stakeholder briefing, which stretched over two days. They were expected to bring a final recommendation to the board but asked that a vote be delayed until the directors meet again in January. (See *SPP Markets and Operations Policy Committee Briefs: Oct. 10-11, 2022*.)

In setting the stage for Day 2 of the discussion, COO Lanny Nickell used a mixed metaphor to explain staff's two-part proposal to improve congestion hedges.

Nickell said that aligning the models will require five or six different changes on the process' market-design side and then modifying transmission planning.

"I see those two things working together as one; we're trying to create better balance, more equity on the market side and then increasing the amount of congestion hedges that might be available," he said.

"Think about this as being a big pizza pie. Today, on the market side, you get one bite at the apple. We take the whole pie, we throw it out, the ravenous wolves all come charging in and they'd get as much as they can get, but there's always somebody left hungry," he said.

"Instead of throwing out the whole pie and letting the hungriest and the biggest do whatever they can to get as much as they can, let's split that up into five different pieces. Let's throw out a piece at a time. Everybody comes in and gets what they can, and you throw out the next piece, the theory being that by splitting things up into multiple pieces and giving people multiple chances, you're more likely to have nobody left hungry. What we're trying to do on the transmission side is increasing the size of the pie so that the pieces you throw out are even bigger than what they were before."

"I understand this better. It's not perfect, but I don't know anyone that gets everything they want out of the [current] process," Nebraska Public Power District CEO Tom Kent said.

SPP's Lanny Nickell explains staff's congestion-hedging recommendations. | *SPP*

"I think the staff has come up with a pretty unique and creative solution to the problem," American Electric Power's Richard Ross said. As chair of the Market Working Group, Ross has overseen several years of stakeholder efforts to address the situation.

"I think AEP is probably going to be close to neutral as an overall portfolio," he said, "but the important thing is this aligns the congestion instrument with the congestion cost so that folks can see things and secure things directly rather than having to rely on the slush bucket at the end to hope they get fulfilled. This is doing something different … and it's a pretty creative idea."

If handled properly, Ross said, the improved process will help wind-rich utilities export their excess power out of the region, a recurring topic over the past few years.

EDP Renewables' David Mindham said his company has struggled to gain auction revenue rights. He said congestion costs of $70/MWh have hampered wind developers' ability to send power eastward to other regions.

"To put [it] in perspective, the cost of exporting that energy is two to three times the levelized cost of actually selling that generation to an entity outside of SPP," Mindham said. "There's no hedge for us. I think I can speak for the [wind energy] industry when I say none of us are even considering another export deal until this is fixed. It's just it's way too expensive."

"What [staff] has advanced is a fairly comprehensive and solid concept in terms of moving forward," Board of Directors Chair Larry Altenbaumer said. "We still need to work through the stakeholder process. This is not a final product here. There's work to be done, but I do believe from my standpoint that it is responsive to the path forward that I was looking for anyway."

JTIQ Studies to Replace AFS Studies?

Antoine Lucas, SPP's vice president of engineering, said staff's work with MISO to unclog interconnection queues and facilitate transmission along the RTOs' seam could replace SPP's affected system study (AFS) process.

The studies are conducted to determine whether generators seeking to interconnect in one RTO require transmission upgrades on the other side of the seam.

Lucas said the joint targeted interconnection queue study benefits will improve cost certainty for the RTOs' generator interconnection requests, provide interconnection customers with AFS costs before cluster studies, and eliminate unknown AFS network upgrades and AFS study costs.

"We're looking to use this process as a springboard into replacing the affected system studies. This aligns with where the industry is heading and also optimizes upgrades along

SPP News

the seam," he said. "Rather than a [generator interconnection] customer identifying the interconnection and then upgrades made from bottom up, we would step back and look at an optimal set of projects."

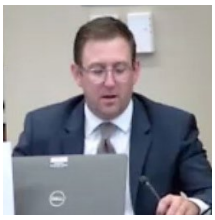
RSC Membership Turnover

The Regional State Committee honored several departing members during its Oct. 24 business meeting, including its longest-serving state regulator, Oklahoma Corporation Commission Chair Dana Murphy. A former RSC president, Murphy has been on the committee since 2011.

"Eleven years of time — you just blink your eyes and then it's gone," Murphy said. She will be replaced by the OCC's Todd Hiett.

Jefferson Byrd, who is running for land commissioner in New Mexico, is also stepping down. Ted Thomas previously stepped away after resigning from the Arkansas commission. (See *Arkansas PSC's Thomas Makes Way for His Successor*.)

The RSC also approved its Nomination Committee's choices for next year's officers. Kansas' Andrew French will succeed Randel Christmann as president, with Iowa's Geri Huser serving as vice president and Texas' Will McAdams as secretary and treasurer.



Incoming RSC president Andrew French, KCC | *SPP*

In other actions, the committee approved:

- *RR497*, which installs as a business practice the Project Cost Working Group's oversight for applicable transmission projects that are funded through direct assignment of cost;
- *RR499*, which adds new language to the planning criteria concerning terminology and their definitions, new capability and new operational testing requirements, out-of-season capability testing, capability and operational testing for new or upgraded units, and accreditation for thermal and hydro units;
- *RR508*, which allows load-responsible entities to use deliverable capacity in meeting their winter season obligation;
- *RR516*, which codifies the increase in SPP's planning reserve margin from 12% to 15%.

The RSC also approved a clean audit of its 2021 financial statements.

SLC Pancaking Strawman Still in Flux

Murphy, who leads the RSC's representation on the Seams Liaison Committee, a joint group with the Organization of MISO States to develop coordinated seams policies, reviewed with the committee an SLC working group's proposed strawman for rate pancaking.

The Rate Pancaking Working Group in August listed several recommendations for treatment of unreserved use charges and emergency ties on the RTOs' seams, improving the ability to obtain congestion hedges for procuring firm transmission, eliminating or reducing rate pancaking for long-term contracts, and eliminating interregional projects could cause unintended rate pancaking issues from interregional projects. (See *MISO, SPP Regulators Finish Pancaking Strawman*.)

Murphy said her SLC co-chair, Missouri's Ryan Silvey, updated the OMS in September and requested feedback from the commissioners. She said he had not received that input when she last talked with him in October.

The SLC meets again on Nov. 21. ■

Company News

Suitors Line up for AEP's Unregulated Renewable Assets

NextEra, Xcel Report Mixed Earnings Results

By Tom Kleckner

American Electric Power executives said Thursday that "the usual suspects" are interested in the company's unregulated renewable energy assets as the company seeks to become a "pure play" regulated utility.

AEP launched the two-step sale process for the 1.37-GW portfolio in August and has accepted bids for the first phase of the auction process. The company announced the sale in February. (See *AEP to Sell Unregulated Renewables Portfolio*.)

"Selling the portfolio will allow AEP to shift focus and rotate capital towards regulated businesses as we continue to transform our generation fleet and enhance transmission infrastructure," CEO Nick Akins told financial analysts during a Thursday conference call. He said a sale agreement is on pace to be signed during the second quarter next year and to close by midyear.

The Columbus, Ohio-based company *reported* earnings of $684 million ($1.33/share), as compared with earnings of $796 million ($1.59/share) for the same quarter a year ago. The results exceeded analysts' expectations of $1.56/share.

Transmission will be key to AEP's earnings growth plan. The company plans nearly $26 billion in wires investment opportunities over the next five years as it focuses on "improving the reliability and resiliency of the grid and integrating new resources to support the clean energy economy," CFO Julie Sloat said.

AEP said it is *responding to a second subpoena* from the U.S. Securities and Exchange Commission related to a corruption probe into the passage of an Ohio nuclear and coal subsidy bill.

"We view it as a continuing part of the process. … We said we would be transparent, and we have been transparent, and we'll continue to work in a positive fashion with the SEC," Akins said. "They just need more information, and we're going to supply it. We'll continue to work with them to get this thing resolved."

The first subpoena asked for documents related to the bill's passage and AEP policies, financial processes and controls. Akins said the company has recognized it needed to make changes in a nonprofit's governance, "and we made those changes."

AEP's share price finished the week at $89.40, up $1.96 after its pre-earnings close.

The analyst call marked Akins' last after 11 years as AEP's CEO. He will be replaced by Sloat, who takes over on Jan. 1. (See *Akins Steps down as AEP President; Sloat to Become CEO*.)

"I'm confident in [Sloat's] deep knowledge of AEP, as well as the emphasis she places on consistency, quality of earnings and dividends and shareholder and customer value creation that will be instrumental to AEP's continued success," Akins said, marking the occasion with his trademark references to rock music.

Quoting Rush's "*Closer to the Heart*" and Led Zeppelin's "*Thank You*," the rock musicophile said, respectively, "And the men and women who hold high places must be the ones who start to mold a new reality closer to the heart. … And so today, my world, it smiles."

NextEra Again Exceeds Expectations

NextEra Energy said that a 13% increase during the third quarter in adjusted earnings year-over-year, reflecting continued strong performance by its utility and clean-energy subsidiaries, has the company well positioned to achieve its overall objectives for the year.

The Juno Beach, Fla.-based company *delivered* quarterly earnings of $1.69 billion ($0.86/share), compared to $447 million ($0.23/share) for the same period a year ago. Wall Street had expected earnings of 80 cents/share; NextEra has exceeded expectations for the past two years.

The Inflation Reduction Act's passage "provides a tremendous opportunity set for us across the board," CEO John Ketchum told analysts during a conference call Friday. "It creates a lot of immediate money opportunities for us going forward on wind, solar and on battery storage."

NextEra Energy Resources, the company's wholesale supplier subsidiary, added 2.3 GW of new renewable resources and storage projects during the quarter.

NextEra said Hurricane Ian's landfall in September knocked out service to more than 2.1 million Florida Power & Light customers, but that a restoration workforce of about 20,000 workers and FPL's grid-hardening and smart-grid investments restored service to about two-thirds of those affected customers after the first full day. It was the fastest restoration rate after a major hurricane, officials said.

AEP's corporate headquarters in Columbus, Ohio | *Electric cat, CC BY-SA 3.0, via Wikimedia Commons*

The company's share price closed Friday at $79.03, a gain of $3.56 (4.7%) on the day.

Xcel: IRA Will Lower Renewable Costs

Xcel Energy on Thursday *reported* third-quarter earnings of $649 million ($1.18/share), up from last year's third quarter net total of $609 million ($1.13/share). The company cited capital investment recovery and other regulatory outcomes for the improvement.

CEO Bob Frenzel said the IRA's passage will reduce the cost of the Minneapolis-based company's clean energy transition and improve liquidity through tax credit transferability, besides providing "significant" customer benefits. He said the legislation will lower the cost of the recently approved 460-MW Sherco Solar project by more than 30% and also reduce the expense of the 10 GW of approved renewable resources in its Minnesota and Colorado resource plans.

"It shows the tremendous customer benefits of being an early leader in the clean energy transition," Frenzel told analysts during Thursday's call.

The quarter's performance was short of analysts' expectations of $1.22/share. However, Xcel's share price closed the week at $65.37, up $2.80 (4.5%) from its pre-earnings close. ■

Company Briefs

ERCOT Names Robert Black VP of Public Affairs

Pablo Vegas, ERCOT president and CEO, last week announced Robert Black as the organization's new vice president of public affairs, effective Nov. 7.

Black joins ERCOT from AEP Texas, where he served as vice president of external affairs.

More: *ERCOT*

Southern Co. Trims Vogtle Costs, Sees Earnings Jump in Q3

Southern Company last week reduced the cost estimate for Georgia Power's share of two nuclear reactors under construction at the Vogtle plant from $10.453 billion to $10.383 billion.

The Vogtle reactors, which are billions of dollars over budget and years behind schedule, are the only nuclear units under

construction in the U.S. The company did stick to its projected 2023 in-service dates of the first quarter for Unit 3 and the fourth quarter for Unit 4.

With the announcement, Southern also reported third quarter profits of $1.5 billion — up $400 million from the same period last year. Through the end of September, the company's earnings are also up by nearly $1 billion compared to the first nine months of 2021. Company revenues also climbed to $8.4 billion in the third quarter, compared to $6.2 billion in the third quarter of 2021, an increase of more than 34%.

More: *Reuters*, *The Atlanta-Journal Constitution*

Enphase to Manufacture Solar Inverters in US

California-based Enphase last week announced it will launch its first U.S.-based clean energy hardware manufacturing thanks to tax credits included in the Inflation Reduction Act.

Enphase said it plans to launch U.S. manufacturing with one new partner and two partners it already works with elsewhere in the world. By the second half of 2023, they will collectively open four to six factory lines that should produce between 3 million and 4.5 million microinverters per quarter. Factory locations have not been announced.

Enphase is a leading supplier of inverters for residential and small commercial solar. Inverters convert solar panels' direct current output into alternating current for use in the home or for exporting to the grid.

More: *Canary Media*

Federal Briefs

Biden to Travel to Egypt for COP27 Climate Conference

President Joe Biden will attend the U.N. COP27 climate conference in Egypt on Nov. 11, White House spokesperson Karine Jean-Pierre confirmed last week.

After the climate conference, Biden will travel to Phnom Penh, Cambodia, to participate in the annual U.S.-ASEAN Summit and the East Asia Summit on Nov. 12-13. He will then attend the G20 summit in Bali, Indonesia, from Nov. 13-16, according to the White House.

More: *POLITICO*

Biden Signs Climate Treaty Aimed at Limiting GHG in Refrigeration

President Biden last week signed a treaty, known as the Kigali Amendment to the Montreal Protocol, which aims to phase down the use of hydrofluorocarbons (HFCs). Under the treaty, parties are forbidden from trading HFCs with countries that are not included in the agreement.

The U.S. was already on its way to limiting HFCs when in 2020 Congress passed and then-President Donald Trump signed a bipartisan energy bill that required the phase down of HFCs by 85% over a 15-year period. It's a law that the EPA has already taken steps to implement.

HFCs are frequently used in appliances such as air conditioners and refrigerators.

More: *The Hill*

Court of Appeals Rejects Red States' Attempt to Block Climate Cost

The 8th Circuit Court of Appeals last week rejected an attempt by red states to block the Biden administration's use of an assessment of how much climate change costs society.

The three-judge panel wrote that the states lack standing because they can't pinpoint a specific way in which the administration's climate cost estimates have harmed them.

Republican-led states have challenged the administration's use of certain uniform values across agencies to estimate the cost of climate damage. These social costs are used during the process of agency consideration and justification of policies.

More: *The Hill*

Mid-Atlantic news from our other channels

NJ BPU Approves $16M for 1st MHD EV Charger Program

NetZero Insider

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

State Briefs

FLORIDA

FPL Seeks $1.1B from Customers to Cover Hurricane Ian Costs

Florida Power & Light last week said it will seek approval to recoup about $1.1 billion from customers to cover costs associated with Hurricane Ian.

About $220 million of the $1.1 billion would be used to replenish a storm reserve. FPL and other utilities brought in workers from other states to help restore power and rebuild damaged infrastructure. FPL said it assembled about 20,000 workers.

It is not immediately clear when FPL will file a proposal at the Public Service Commission.

More: *WLRN*

GEORGIA

Georgia Power Proposes Rooftop Solar Interconnection Fee

Georgia Power last week proposed a $200 interconnection fee for rooftop solar customers that will raise average bills by about $16 a month.

However, joint testimony and analysis by the Solar Energy Industries Association shows that Georgia Power has drastically overcharged its customers for the last 11 years with over-collection charges peaking in 2020 and 2021 with nearly $500 million in additional revenue.

The testimony urges the Public Service Commission to reject the proposed interconnection fee and asks the PSC to strengthen its oversight of utilities to prevent over-collection.

More: *Solar Power World*

ILLINOIS

Chenoa Approves Solar Farm

The Chenoa City Council last week approved a solar farm on city property.

Solar developer Cenergy recently announced plans for the project on 18 acres. No exact construction timetable was given.

More: *Pontiac Daily Leader*

Commerce Commission Approves ComEd Rate Increase

The Commerce Commission last week unanimously approved a $50 million rate increase for ComEd.

The increase is the first and smallest of two requests that the ICC is expected to approve this year. In total, the two increases are expected to add an additional 25 cents to the average residential monthly bill.

More: *WTVO*

LOUISIANA

Air Products Blue Energy Sues Parish over Carbon Capture Project

Air Products Blue Energy, the world's leading hydrogen supplier, last week sued Livingston Parish over attempts to block the company from storing carbon from its proposed $4.5 billion plant beneath Lake Maurepas.

Air Products Blue Energy argued that state and federal law preempts the parish council's recently passed moratorium on the drilling of wells needed to test the area's ability to store carbon long-term. Those laws render the local moratorium "invalid and unenforceable," according to the lawsuit. The company also argued that if the local ordinance took effect, it would "directly contravene" the authority of several state and federal agencies.

The moratorium aims to halt the construction for Class V injection wells for one year within Livingston Parish and its waterways.

More: *WRKF*

MASSACHUSETTS

Commonwealth Wind Project No Longer Viable

Commonwealth Wind last week filed a motion with the Department of Public Utilities claiming its 1,200-MW offshore wind project "is no longer viable and would not be able to move forward" under the terms of contracts filed in May.

Commonwealth filed for a one-month delay in DPU's review, telling the state its project can no longer move forward as planned. The developer said a one-month freeze "would give the parties an opportunity to evaluate the current situation facing the project and potentially agree upon changes to the PPAs, along with other measures, that could allow the project to return to viability."

Mayflower Wind, the other developer tapped last year to construct a 400-MW offshore wind farm, told the DPU it supports the request from Commonwealth Wind but did not specifically say that its project is at risk.

More: *The New Bedford Light*

NEW MEXICO

Environmental Board Approves New Carbon Dioxide Rule

The Environmental Improvement Board last week approved a new carbon dioxide emission rule for coal-fired power plants that will go into effect Jan. 1.

The carbon dioxide rulemaking is a result of the Energy Transition Act, which limits carbon dioxide emissions to 1,100 pounds per MWh after Jan. 1, 2023. This limit will be calculated on a 365-day rolling average.

More: *NM Political Report*

NORTH CAROLINA

Gov. Cooper Calls for Faster Shift to Electric Trucks, Buses

Gov. **Roy Cooper** last week issued a climate-related executive order to increase the sales of electric trucks and buses.

Cooper's Executive Order 271 directs environmental regulators to develop Advanced Clean Trucks regulations by May 15, 2023. The ACT rules program would require truck and bus makers to increase sales of EVs in the coming decades. If adopted, North Carolina would be the seventh state in the nation and first in the Southeast with such rules.

Cooper signed a multi state agreement in 2020 that calls for electric trucks and buses to reach 30% of vehicle sales by 2030 and 100% by 2050.

More: *WUNC*

OHIO

Solar Project Killed by Local Government Opposition

In an opinion and order issued last week, the Power Siting Board denied an application from Birch Solar seeking to construct a 300-MW solar farm in Allen and Auglaize counties.

The board's order acknowledged "numerous public benefits" from solar projects but said all four government entities with physical contact to the project acted to oppose certification of it. That includes the Allen County commissioners, the Auglaize County commissioners, Shawnee Township in Allen County, and Logan Township in Auglaize County. The board also noted public comments were 80% opposed to the project.

In October 2021, a new state law gave local governments veto power over renewable energy generation sites. The board said this case was not impacted by the law, which only applies to projects filed after Oct. 11, 2021. Birch Solar began the process for filing for approval in October 2020.

More: *Ohio Capital Journal*

OREGON

Portland General Electric Buys into Montana Wind Farm

Portland General Electric last week announced it is buying a share of Montana's Clearwater Wind Farm in a deal that will keep the utility generating electricity in Montana beyond the closure of Colstrip Power Plant.

PGE will pay $415 million to acquire a 208-MW share of the 750-MW wind farm and expects to begin drawing power from it by the end of 2023.

More: *Billings Gazette*

TEXAS

Brownsville Votes to Halt Power Disconnections

The Brownsville City Commission last week unanimously approved the first vote to freeze any electric disconnections, late fees or penalties from the Brownsville Public Utility Board.

To take effect, the first vote requires a second vote. If passed, the freeze would take immediate effect and bar BPUB from cutting power to homes through Feb. 28, 2023. The ordinance also prevents BPUB from charging late fees or charges for delinquent payments during the freeze. BPUB officials were already operating as if the disconnection freeze was in effect, the commission was told.

More: *KVEO*

VIRGINIA

Dominion, AG Reach Agreement in OSW Case

Dominion Energy last week announced it had agreed to implement several consumer protections in connection with its massive offshore wind project under an agreement with the Office of the Attorney General.

Attorney General Jason Miyares said the agreement would provide "first-of-its-kind" protections for ratepayers while ensuring the 176-turbine project moves forward in a fiscally responsible way. It calls for a cost-sharing arrangement for any overruns beyond the estimated $9.8 billion price tag. The company would also cover 50% of construction costs between the range of $10.3-$11.3 billion and 100% of costs between $11.3-$13.7 billion. If construction costs exceed $13.7 billion, the issue would go back to the State Corporation Commission.

The agreement, which includes performance reporting requirements and provisions laying out a degree of construction cost sharing, is subject to final approval by the SCC.

More: *The Associated Press*

Supreme Court Upholds Dominion Carbon Market Charge Decision

The Supreme Court of Virginia last week ruled that the State Corporation Commission met legal requirements when it approved a charge added to Dominion Energy bills to pay for participation in the Regional Greenhouse Gas Initiative.

A 2020 law authorizing Virginia's participation in RGGI allowed Dominion to recover from ratepayers the "necessary" costs of buying allowances at auction. In November 2020, shortly before power producers joined their first auction, Dominion asked the SCC to approve plans to recover roughly $168 million to buy allowances through July 31, 2022. The utility had calculated this amount would cover the allowances necessary to comply with RGGI as well as backup allowances to provide flexibility if auction prices became volatile. Regulators approved the request the following year. Environmental nonprofit Appalachian Voices appealed the decision, arguing that regulators hadn't properly vetted Dominion's proposal because their review hadn't shown all the costs were necessary.

The charge, which equaled $2.39 extra on the average monthly bill, stopped being added in July 2022. Dominion had asked the commission in May to suspend the charge in anticipation of Gov. Glenn Youngkin's plans to withdraw the state from RGGI. The commission approved the proposal in June.

More: *Virginia Mercury*

WEST VIRGINIA

DEP Suspends Lexington Coal Mine Permit

The Department of Environmental Protection last week suspended a mine permit for the Lexington Coal Company because of environmental violations.

The DEP cited 10 violation notices issued to Lexington since November 2021 in its suspension order, which requires the company to stop all mining operations immediately. It also orders the company to submit a plan that will correct the unabated violations within 10 days.

More: *Charleston Gazette-Mail*