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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: The final National Transmission Needs Study finds that interregional transmission will have the highest value between ERCOT and non-ISO regions in the Mountain West and Southwest. | *DOE*

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Your Eyes and Ears on the Organized Electric Markets
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In this week's issue

DOE Signs up as Off-taker for 3 Transmission Projects

Tx Needs Study: US Should Increase Interregional Lines Fivefold by 2035

By K Kaufmann

The U.S. Department of Energy will put $1.3 billion in federal funds into becoming the anchor off-taker for three interstate transmission projects that together will put 3.5 GW of new transmission capacity online, Secretary Jennifer Granholm announced Monday.

Under a program set up by the Infrastructure Investment and Jobs Act (IIJA), the department will start negotiating contracts for up to 50% of the capacity on the lines, with the goal of de-risking and accelerating construction of projects that provide vitally needed new interregional transmission, according to DOE.

Located in the Southwest, Mountain West and New England regions, the projects were selected based on regional needs and priorities detailed in DOE's final *National Transmission Needs Study*, also released on Monday, according to the department.

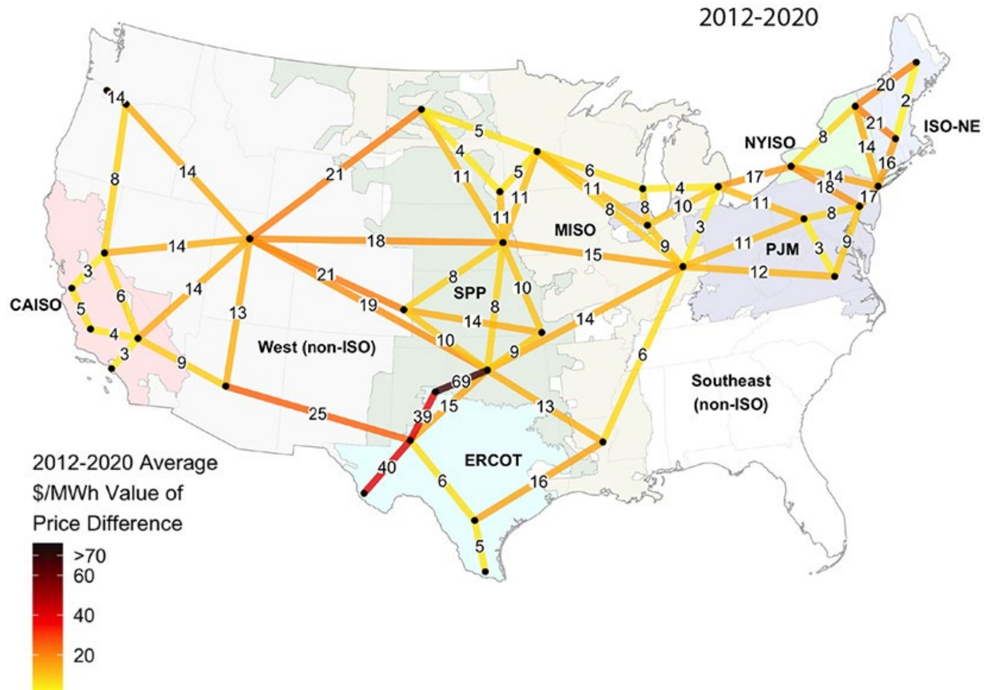
Speaking during an advance press call on Friday, Granholm explained that having DOE as an anchor off-taker — an entity that commits to buying a significant amount of power from a project — will minimize upfront financial risk and give "developers the confidence that they can actually build."

Calling the contracts a "unique and creative solution," Granholm stressed that "these awards are not for construction costs." A developer would not receive any cash until a project is completed and online, and DOE will be able to sell its capacity to other off-takers, ensuring funds are available for contracts or other support for additional projects.

Ideally, the risk to the department will also be minimal. DOE's commitment could draw in other off-takers, so the project is "fully subscribed by other customers before the project is finished and energized," according to a DOE email.

The IIJA provides $2.5 billion for the initiative, officially called the *Transmission Facilitation Program* (TFP), which is being administered by DOE's Grid Deployment Office. The money will be used in a revolving fund that can be awarded to projects via capacity contracts, loans or public-private partnerships.

The program webpage says TFP awards are best suited for projects that are nearly shovel-ready, and that no awards will be made to projects that are already fully subscribed or "have a fully allocated source of revenue."



The final National Transmission Needs Study finds that interregional transmission will have the highest value between ERCOT and non-ISO regions in the Mountain West and Southwest. | *DOE*

A second round of funding, for up to $1 billion, is expected in the first half of 2024, DOE said.

The three projects selected for the first round of TFP funding, all in the form of capacity contracts, are:

- The *Cross-Tie Transmission Line*, a 1,500-MW line running 214 miles between Utah and Nevada. The line will improve grid reliability and resilience, relieve congestion on other lines and allow access to low-cost renewables in the region.
- The *Southline Transmission Project*, a 748-MW line stretching 175 miles between Hidalgo County, N.M., to Pima County, Ariz. This project will support ongoing renewable energy development in southern New Mexico while delivering clean energy to areas in Arizona currently dependent on fossil fuels.
- The *Twin States Clean Energy Link*, a 1,200-MW line connecting New Hampshire and Vermont to clean energy resources in Canada. The bidirectional line will also allow New England to export power to Canada from future offshore wind projects. The 185-mile project includes 75 miles of new underground line and 110 miles of upgraded lines in an existing right of way, according to the *project website*.

The Cross-Tie and Southline projects are expected to break ground in 2025, with the Twin States line to follow in 2026, an administration official said. According to the Transmission Needs Study, all three projects are in regions that will need major amounts of new transmission or interregional transfer capacity by 2030.

In the Mountain West region, the DOE study anticipates a need for nearly 2,300 GW-miles of new transmission as clean energy projects come online, leveraging incentives in the Inflation Reduction Act. The study also predicts 1.5 GW of interregional transmission will be needed in New England.

DOE defines gigawatt-miles as capacity multiplied by distance. The department said the figures in the Needs Study could be met with a mix of projects; for example, the 2,300 GW-miles needed in the Mountain West region could be broken down into nine 200-mile, 500-

FERC/Federal News

kV lines, but other configurations are possible, the department said.

Top Need: Reliability

The Biden administration sees high-voltage transmission as critical to reaching its goal of a decarbonized grid by 2035 and net-zero greenhouse gas emissions economywide by 2050.

Speaking on Friday, National Climate Advisor Ali Zaidi noted the TFP announcement follows other administration initiatives on transmission, such as DOE's recent selection of 58 projects to receive $3.46 billion in IIJA funds for local grid improvements. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

Such federal funding "is doing exactly what it was designed to do," Zaidi said. "It's catalyzing the private sector, industry and labor all to step up at this moment of critical need."

Granholm also hailed the number of jobs the projects could create — 13,500 direct and indirect positions — and the community benefit packages all the projects have negotiated with stakeholders and communities affected by their projects. The Twin States project is providing a community benefits package that includes $60 million to be divided between the nonhost states of Massachusetts, Connecticut, Rhode Island and Maine, according to a DOE fact sheet on the project.

Extreme weather events have also underlined the need for more interregional lines to move power in emergency situations and to allow clean energy produced in remote areas to move to where there is demand for it. The Needs Study calls for the U.S. to double existing regional capacity by 2035 and expand interregional capacity fivefold, according to a DOE press release.

The report's top takeaways, Granholm said, are, "no surprise, that we need to seriously build out transmission in order to improve reliability and resilience, and of course, to lower energy costs and relieve congestion on the grid."

Reliability has remained a key driver for new transmission, growing from 44% of new lines in 2011 to 74% in 2020, according to the report. The most pressing and valuable new lines are needed between Texas and all its surrounding regions, and between the Plains and Mountain West, the report says.

The report anticipates that by 2035, Texas will need a median of 9.8 GW of additional transfer capacity with the Plains region, a whopping 1,201% increase over 2020 levels. Slightly less eye-popping, New England will need to expand its interregional lines with New York about 255%, or 5.2 GW, and the Midwest will need a 156% increase, or about 33.8 GW, of new interregional capacity with the Mid-Atlantic.

Reactions

One of the developers on the Southline project, Michael Skelly, CEO of Grid United, sees the TFP as a kick-starter for interregional transmission growth.

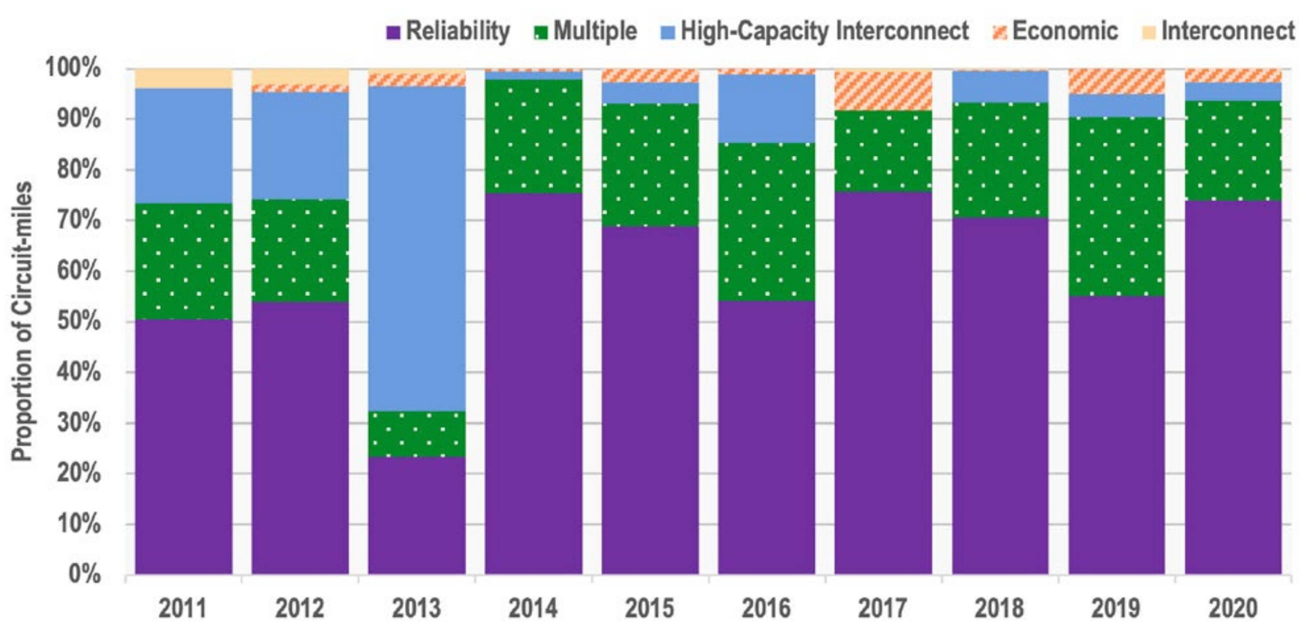
Developers want to sign up off-takers for as much of a line's capacity as possible before putting steel in the ground to minimize their risk, Skelly said in an interview with *RTO Insider*. For Southline, getting the line's 748 MW fully subscribed is "a tall order even in today's markets. So, this lowers the bar. If we get one customer [taking] a few hundred megawatts and we have DOE, off we go," he said.

Echoing DOE, Skelly said having the department on board will draw in other off-takers, so its share of the project's capacity likely will be sold before it goes online. DOE "might actually never put a penny out the door," he said.

Stephen Woerner, New England president for National Grid, the lead developer for Twin States, said the TFP announcement "is an important step forward … as we work to make the project a reality for the region. DOE has recognized the significant economic and environmental benefits of this project to New England communities, residents and businesses."

Rob Gramlich, president of Grid Strategies, said TFP "can address the perennial 'chicken and egg' problem with transmission," in which construction may wait upon demand, but demand waits upon construction. Having DOE as an anchor off-taker "promises to work a lot better than the current stalemate," he said in an email to *RTO Insider*.

But Gramlich also feels the program's $2.5 billion pot "only allows [it] to support a very small set of lines. Congress and the administration should prioritize raising that pot in future appropriations." ■



According to the Needs Study, the proportion of overall transmission installed to address system reliability needs has grown from 44% in 2011 to 74% in 2020. | *DOE*

FERC/Federal News

FERC Extends Interconnection Queue Compliance Deadline

Dec. 5 Deadline Moved to April 2024

By Rich Heidorn Jr.

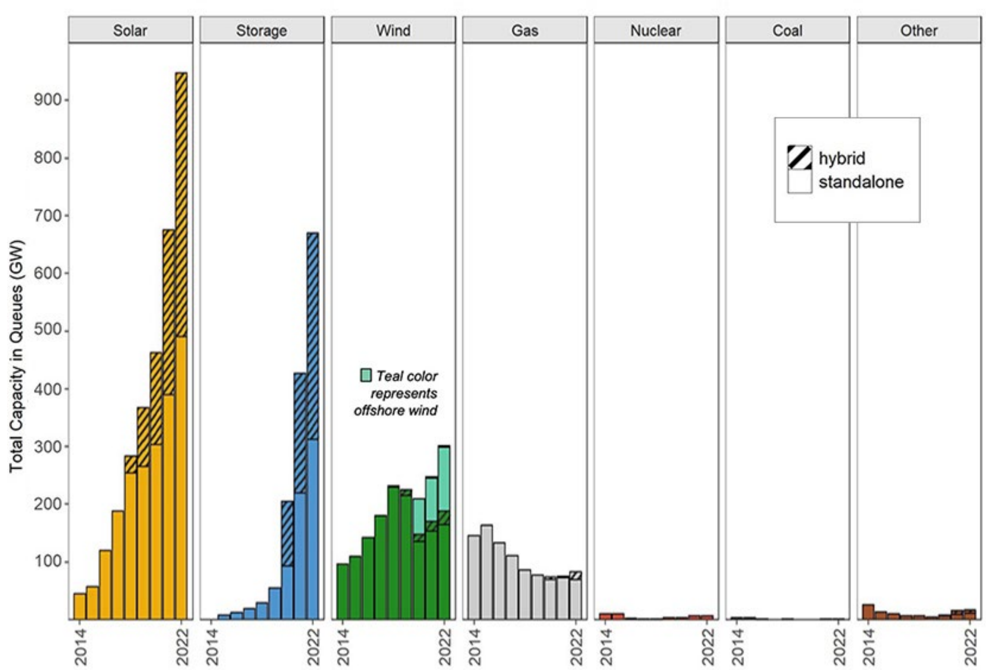
FERC agreed Oct. 25 to extend the compliance deadline for its interconnection queue rulemaking by four months to April 3, 2024, in response to requests from RTOs and utilities (*RM22-14*).

FERC *Order 2023*, issued in July, revised the *pro forma* generator interconnection queue rules to shift from a first-come, first-served serial process to a first-ready, first-served cluster study process, an effort to unclog backlogged queues filled mostly with renewable projects and storage.

The order also increased financial requirements for developers and set penalties for transmission providers that fail to meet deadlines for completing interconnection studies. Interconnection studies also must consider grid-enhancing technologies (GETs). (See *FERC Updates Interconnection Queue Process with Order 2023*.)

American Electric Power, Dominion Energy, PacifiCorp, the Edison Electric Institute and PJM filed requests for rehearing or clarification of the order, which the commission effectively denied when it failed to respond within 30 days.

The same parties, along with MISO and SPP, also asked the commission for additional time to comply, citing the order's complexity and uncertainty over issues raised in the rehearing requests. NYISO also had planned to request a delay. (See *NYISO Plans Early November Filing for Partial Order 2023 Compliance*.)



Capacity in interconnection queues as of the end of 2022. | *Lawrence Berkeley National Laboratory*

The commission responded only to the extension requests, saying it would address the other issues raised on rehearing in a future order.

FERC initially set the compliance date for 90 calendar days after the rule's Sept. 6 publication in the *Federal Register*, or Dec. 5. The new order extends the 90-day clock to 210 days for all transmission providers except for those with wholesale distribution access tariffs, which will have 90 days beginning when their RTO or ISO submits its compliance filing.

The commission said its extension "does not change or modify any other determination or other deadlines established by Order No. 2023, including the deadline for eligibility for interconnection customers to opt to proceed with a transitional serial study (for those interconnection customers tendered a facilities study agreement) or transitional cluster study (for those interconnection customers assigned a queue position) or to withdraw their interconnection requests without penalty (i.e., 30 calendar days after the transmission provider submits its initial compliance filing)." ■

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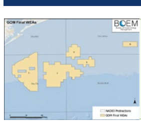

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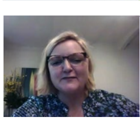

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FERC/Federal News

DOE Releases Draft Interconnection Roadmap Aimed at Fixing Queues

By James Downing

The U.S. Department of Energy on Wednesday released a draft of its "Transmission System Interconnection Roadmap," which offers ways to improve the backlogged process of connecting new generation to the grid.

The draft comes after meetings with more than 2,000 individuals from 350 different organizations, the department said. DOE is hopeful that even more comment on the *draft* so it can come out with a final report, Becca Jones-Albertus, director of the department's Solar Energy Technologies Office, said in an interview Thursday. DOE is working on another report on interconnection issues at the distribution level.

"We're focused at DOE at how we can enable achievement of the president's goal to decarbonize the electric grid by 2035," Jones-Albertus said. "There are a number of big challenges we need to tackle to get there, and interconnection is one of them."

Interconnection queues have about 2,000 GW of wind, solar and batteries in them; if they were all somehow built, it would be nearly enough to reach that decarbonization goal, Jones-Albertus said. Only about 20% or so of projects get built, but the fact that developers sit in them for an average of five years shows they are clogged and need reforms, she said.

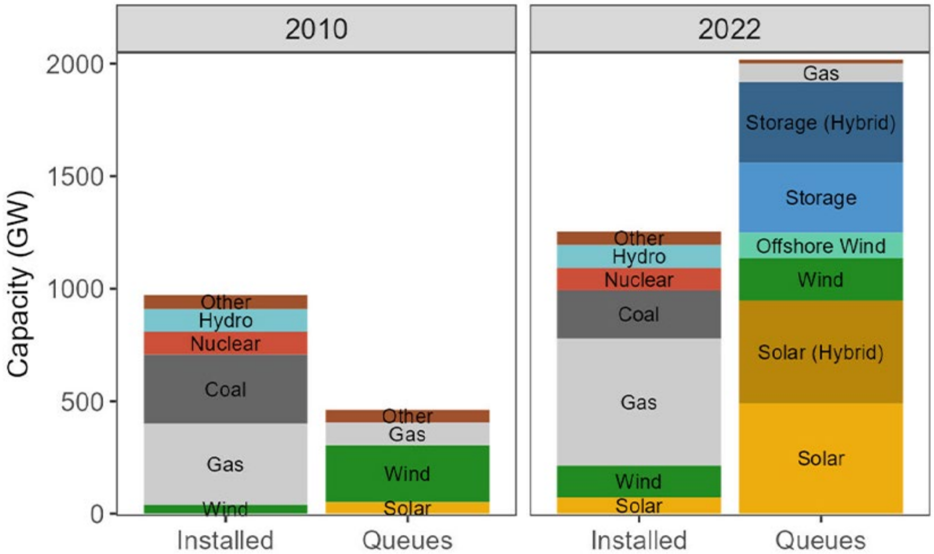
DOE was working on the roadmap at the same time FERC worked on Order 2023, which covers about a quarter of its recommendations, according to the draft. The commission's still-pending Notice of Proposed Rulemaking on transmission planning includes other proposals in the roadmap.

"Though this roadmap contains some solutions that relate to Order 2023, it also introduces additional ideas that support longer-term interconnection process evolution," the draft says. "Such an approach is important not only to facilitate industry-wide discourse that builds upon Order 2023 but also to maintain usefulness for transmission providers that are not FERC jurisdictional."

A major reason queues are so overstuffed is the transition to clean energy, which has led to a spike in requests. The report says that "queue volumes are likely to be large and potentially volatile for the foreseeable future."

When FERC issued Order 2003 20 years ago, it did not contemplate the extent to which resource developers would use interconnection processes to obtain cost and siting information, the report says.

"Because the interconnection process provides accurate, binding information on interconnection costs and operational requirements, resource developers often use the interconnection process to determine ultimate project viability," the report says. "Additionally, due to long queue wait times, resource developers may also submit interconnection requests to maintain a place in line, to be able to turn around projects more rapidly if they can find a buyer."



A chart from the report showing how much the country's interconnection queues have grown in the last 12 years. | *DOE*

Those "speculative projects" have contributed to the larger queues now; some of DOE's recommended improvements are aimed at limiting them going forward.

"We really believe it's possible to get to better processes and doing that by improving the data ... [and] having more information available to developers about where to site projects," Jones-Albertus said.

Order 2023's requirement for transmission planners to offer heat maps should cut back on the use of speculative projects to find cheap spots to plug into the grid, she added. DOE is also focused on bringing new information technology solutions on the queue, upskilling the workforce and tackling the ever-thorny issue of cost allocation.

"By addressing all of these, I believe we can get to much better interconnection processes, where we can get timelines that are down from averages of five years to less than 18 months," Jones-Albertus said. "We can have higher completion rates, lower cost uncertainty and better system reliability."

CAISO and MISO have both proposed strategies that would "ration" interconnection capacity to reduce their queue volumes. CAISO does it by prioritizing interconnection in zones that have available capacity, or resource-rich areas, while MISO would limit interconnection requests to its annual peak demand.

"Administrative rationing may be a short-term strategy for temporarily clearing backlogs, but it would likely be inconsistent with open access and competition policies and may thus be more of a short-term, emergency solution rather than a longer-term one," the report says.

Another reason to speed up the queues is that demand has started to grow for the first time in a decade in many regions. That is expected to increase with electrification efforts, while many traditional generators are retiring.

"Certainly having shorter queue timelines, higher completion rates [and] lower costs will help that additional capacity be built ... in a predictable manner so that grid operators can count on when that generation capacity is going to be there for resource adequacy," Jones-Albertus said. "I think it is a challenge now that it is hard to predict when some of these plants will come online, in part because of the lengthy interconnection process timelines." ■

FERC/Federal News

Report Offers Snapshot of Utilities amid Energy Transition

Itron Finds Wide Understanding of Importance but Varied Levels of Action

By John Cropley

Utilities and their regulators shared their thoughts for a new report on the challenges and opportunities facing the industry as the clean energy transition places a growing reliance on distributed energy resources.

Itron published its *2023 Resourcefulness Insight Report* on Oct. 25. The utility management technology company drew on the input of 250 U.S. utility executives and 10 state-level utility commissioners for the report.

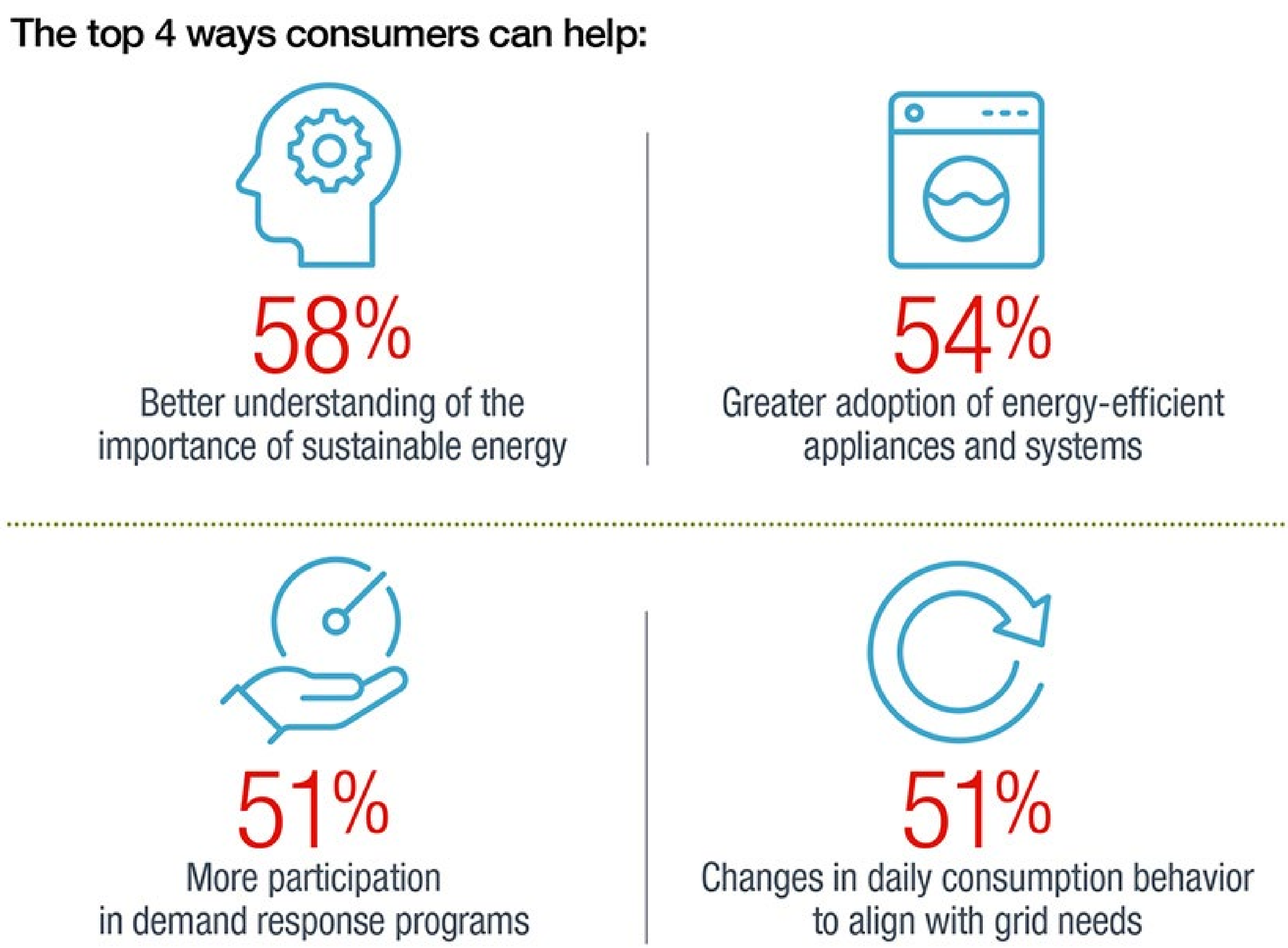
"Powering the Energy Transition: Insights from Utilities and Commissioners on Creating the Future U.S. Grid" reports that 88% of the executives call the transition extremely or very important, and that seven of the commissioners say their state's policies support the transition.

But only 45% of the utilities are actively addressing the transition. Nearly half — 49% — are still in the planning stages, and most of those are only in the early stages. The remaining handful have not yet begun to plan.

Itron CEO Tom Deitrich noted in his introduction the rapidly growing power demand of electric vehicles and electrified buildings and said grid capacity must expand just as dramatically and quickly while providing uninterrupted service from an increasingly intermittent generation portfolio.

"And while many likely see in the energy transition a burdensome challenge," he wrote, "still others see what we see: an opportunity to build a more responsive and intelligent grid that serves communities better and more efficiently than ever before."

The report looks from multiple angles at the



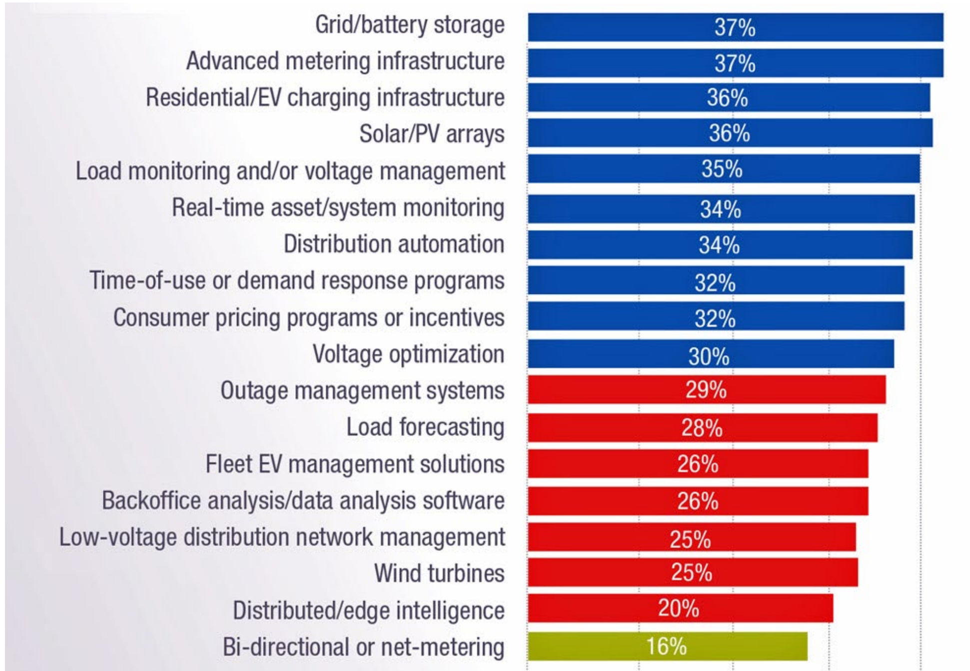
Consumers are a key part of the energy transition, utility executives told Itron for its 2023 resourcefulness report. | *Itron*

FERC/Federal News

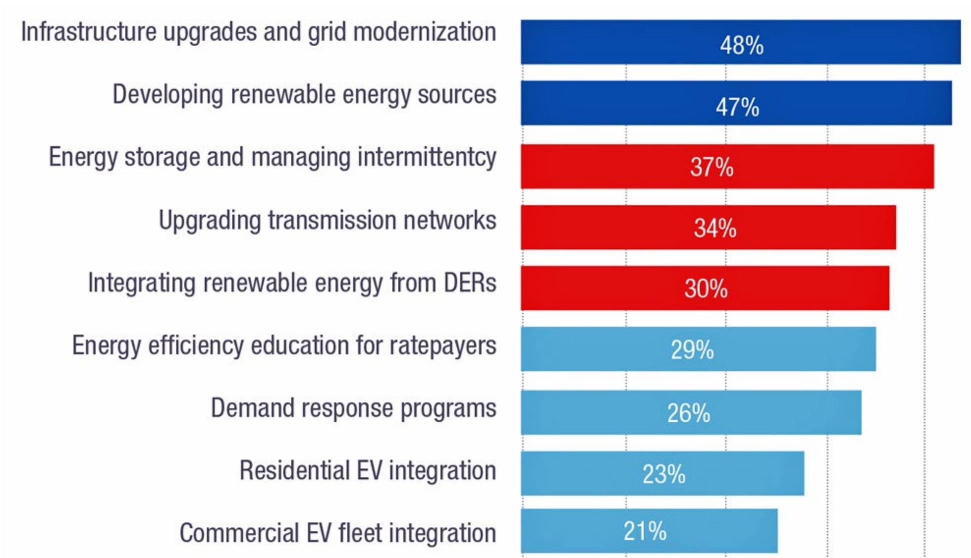
many-dimensional challenge that is utility and grid planning in the 2020s: balancing supply, demand, finances, reliability, regulation, customer expectations and technology limitations to keep the lights on and save the planet in a sustainable and affordable manner.

The report also found that:

- 59% of cooperative-owned utilities rank the transition as extremely important, compared with 34% of those municipal-owned and 33% of investor-owned.
- Utility executives split almost evenly when asked to identify the key driver behind the transition: 37% said public demand, 36% cost savings and 34% environmental concerns.
- 61% of utilities say their state's policies support transition initiatives, and 20% say they hinder progress; policies are rated most supportive in the Midwest (70%) and least in the South (54%).
- Utilities in the West are leading their counterparts elsewhere — 12% say they have fully implemented their transition plans, and 47% are currently doing so. The Northeast is second on both counts.
- 43% of utilities say their customers are a critical part of the solution — driving demand for renewable energy, DERs and energy-efficiency measures — and can significantly impact the success of the transition.
- Top considerations in utilities' decision-making process are reliability (76%), safety (70%) and sustainability; resilience (43%) and equitable access (42%) are at the bottom of the list.
- Technical investments are interwoven and often difficult to pursue individually, but infrastructure upgrades/grid modernization tops the list of priorities at 48%, with developing renewable energy resources close behind at 47%; residential and commercial EV integration lag at 23% and 21%, respectively.
- Utilities reported a tight range of technologies already adopted, including battery storage and advanced metering (37% each); solar arrays and residential EV charging (36% each); and various types of load monitoring or management (32 to 35%). Lagging were distributed/edge intelligence (20%) and bidirectional or net metering (16%).
- Utility priorities for the next five years are load monitoring/voltage management (22%), solar arrays (22%), consumer pricing initiatives (21%), distribution automation (21%) and grid/battery storage (20%); bidirectional or net metering again bring up the rear, at just 6%.



The Itron report finds a wide range of technology being used to varying degrees by U.S. utilities. | *Itron*



Grid modernization is the top priority for U.S. utilities, the Itron report indicates. | *Itron*

All of this, the report concludes, makes the case for utilities drawing up a full to-do list — particularly the 32% of utilities that are only in the early stages of planning. It suggests that utilities take stock of the current state of affairs; lay the foundation for a customized transition; consider how the business will change; present a compelling case for making those changes; and seek out partners with expertise.

"This year's report underscores the pivotal moment we're at in shaping the future of the U.S. grid," Itron Vice President Marina Donovan said in the *official announcement* of the report. "Utilities have a critical role to play in accelerating the energy transition, and stakeholder education is an important part of that effort. By educating consumers, policymakers and regulators about clean energy, conservation and energy management programs, utilities can help overcome these challenges." ■

CAISO/West News

Mixed Views on CAISO Interconnection Process Proposal

Stakeholders Discuss Proposed Scoring Criteria, Consider Interconnection Caps

By Ayla Burnett

CAISO stakeholders have voiced multiple concerns about a straw proposal to revamp the ISO's interconnection process, with some cautioning that the timeline to draw up a final plan is too ambitious given the lack of progress on the effort so far.

Stakeholders shared their views at an Oct. 24 meeting of CAISO's Interconnection Process Enhancements Working Group. Top among their concerns: the ISO's plan to introduce scoring criteria designed to rank requests to join the grid based on project readiness, as well as a proposed interconnection cap to limit any one developer's ability to dominate the queue.

Stakeholders expressed frustration over a lack of information on how to implement the scorecard, including uncertainty about in which transmission zones projects would be developed, how open access and equal competition would be upheld and fears that the initiative's timeline was rushed.

CAISO's *2022-2023 Transmission Plan*, developed in coordination with the California Public Utilities Commission and the California Energy Commission, outlined action items that could help transform the process of connecting new resources to the grid.

Key among the items, also discussed in the ISO's Interconnection Process Enhancements *straw proposal*, was the introduction of designated geographic zones that should be prioritized for resource development. The approach would prioritize projects in areas where there are planned capacity additions approved in CAISO's transmission planning process.

According to the plan, the CPUC would direct load-serving entities (LSEs) to focus energy procurement in those zones, and the ISO proposal will use the scoring criteria to select projects once the resources in a transmission zone reach 150% of the available or planned capacity in that zone. But some stakeholders contend that the straw proposal contains insufficient information regarding the location and details of the zones.

"If we're going to move forward with this scoring criteria, it needs to be absolutely clear to both the CAISO and developers what locations are in and out of a zone," Bridget Sparks, interconnection policy manager at AES Clean Energy, said. "If you're asking developers to invest millions of dollars in land and other development activities, there shouldn't be any uncertainty on whether or not a certain point on a transmission line is in or out of a zone."

Cathleen Colbert, director of CAISO market policy at Vistra Corp., echoed that concern, saying that CAISO hadn't provided enough data transparency on zone locations. She asked the ISO to use the heat maps requested in FERC Order 2023 (*RM22-14-000*) to provide more clarity, and that they be available in time to inform the next opening of an interconnection cluster window. Sparks also suggested CAISO provide line diagrams to identify zones.

Anish Nand of the Northern California Power Agency asked that CAISO provide line diagrams before the release of the draft final proposal, but Danielle Mills, the ISO's principal of infrastructure policy development, said the grid operator could not commit given the strict timeline.

Approval, Pushback on Scoring Criteria

In a presentation at the meeting, Southern California Edison pushed back on a few key aspects of the scoring criteria, including the proposal to include demonstrated interest from off-takers as part of the scorecard. Because letters of interest from off-takers are non-binding, SCE proposed instead to include a bonus point system in which LSEs are given a certain number of points based on their load share. This modified process, according to the utility, would allow LSEs to better identify projects that serve their mandated needs, increase the scrutiny of projects and, in turn, decongest the queue.

The utility also proposed adding the procurement of long-lead equipment that could indicate commercial readiness as one of the scoring criteria.

"I think something like the bonus points concept is appropriate," said Lauren Carr, senior market policy analyst at CalCCA. "It would be a good way to get some more granularity around LSE interest, where there can be a range of points assigned based on how interested an LSE is on a particular project."

Some independent power producers (IPPs) expressed support for the proposal, but others, such as Terra-Gen LLC, were concerned that the addition of an LSE bonus points system could hinder open access and equal competition.

"We also believe that doing a load-ratio type share would unfairly favor larger LSEs," said Terra-Gen Director of Energy Market Policy Chris Devon. "This addition of another bonus point criteria for LSE interest would further give more negotiating power to the LSEs and reduce competition."

Interconnection Caps

Another key element in the straw proposal was the introduction of an interconnection cap. CAISO proposed that each developer be limited to only submitting projects that would take up 25% of available transmission across the footprint to address market power and domination of the queue by a small group of developers.

However, in a presentation to the working group, AES highlighted that the ISO provided no evidence or data to prove that market power is a current issue.

AES also raised concern over an interconnection cap leading to discriminatory treatment between IPPs and utilities, since non-CPUC jurisdictional utilities are automatically accepted into the queue without capping and included in the studied 150% of available transmission. On the flip side, IPPs would be subject to both the developer cap and the scoring criteria within the studied 150% of available transmission.

Strict Timeline

The draft final proposal is set for Nov. 15, leaving some stakeholders frustrated by the lack of solid progress with the initiative despite the strict timeline in which to move forward.

"It seems like CAISO isn't really giving enough time for the stakeholder process to work and [is] so wedded to a specific end timeline, and you're considering such a radical change in the way that the interconnection process is done," Sparks said. "We would rather get this right the first time than to rush through a process that has a lot of unintended consequences or hasn't been thoroughly thought through."

CAISO acknowledged the frustration.

"I know the pace is exhausting," Mills said. "We're just really trying to push it as fast as we can for you, not because we don't care what you think." ■

CAISO/West News

Study Shows Uneven Benefits for Calif., Rest of West in Single Market

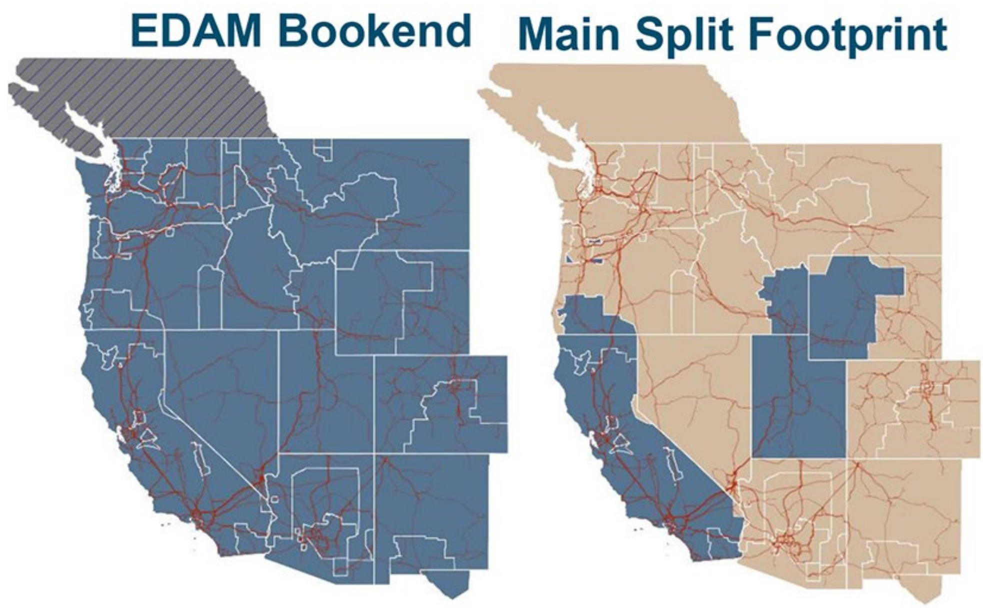
BPA Gives Western Stakeholders Glimpse into WMEG Day-ahead Study Findings

By Robert Mullin

The long-awaited results from a key study on the financial impact of an organized day-ahead electricity market in the West indicate that many entities outside California would see more benefits from a two-market outcome while the Golden State has the most to lose from such a split.

And while some industry stakeholders in the Northwest had speculated that the *Bonneville Power Administration* would be among the losers in a single-market solution, the findings — adjusted by BPA itself — paint a more complicated picture in which the federal agency could be either winner or loser in either scenario.

BPA discussed the findings during an Oct. 23 workshop, one of a series of stakeholder meetings related to its decision whether to join a day-ahead market.



The Western Markets Exploratory Group study compared results between two market scenarios. In the 'EDAM Bookend' scenario, the entire U.S. portion of the Western Interconnection joins CAISO's EDAM, while the 'Main Split Footprint' scenario assumes EDAM membership for only PacifiCorp, LADWP, BANC, Turlock Irrigation District and Imperial Irrigation District, with the rest of the West joining SPP's Markets+.

The study was conducted by Energy+Environmental Economics (E3) on behalf of the *Western Markets Exploratory Group* (WMEG), a loose coalition of 26 transmission-owning entities covering most the Western Interconnection. The WMEG was established in 2021 to evaluate the region's electricity market options, and its membership quickly expanded alongside broader discussions about the issue.

The WMEG asked E3 to limit the scope of the study's cost-benefit analysis to variable production costs and energy market prices, while not considering potential investment savings that could be realized from lower capacity needs due to resource and load diversity, the ability to procure resources over a wider geographic area and coordinated regional transmission planning.

"Other market studies have shown those other benefit categories can create 2-10x the impact of production cost savings alone," E3 noted in a presentation at the workshop.

"We think of our results as being quite conservative and intentionally so," E3 senior partner Arne Olson said.

The study was structured to show a comprehensive picture of potential benefits for the West as a whole, while also breaking down results for individual utilities. While results were provided to WMEG study participants early this summer, they were not released publicly due to concerns about confidential information related to individual utilities. The BPA workshop offered a wider set of stakeholders and the public their first look into the analysis.

The study's results are important because they likely will influence the choices of Western utilities weighing whether to join *CAISO's Extended Day-Ahead Market* (EDAM) or *SPP's Markets+*, decisions that likely will set the course for whether the West ends up with a single RTO in the future or two — or more — organized markets divided by seams.

"Today's conversations represent just one element of the business case that Bonneville will use in helping arrive at a leaning [toward a market] in 2024," Andy Meyers, BPA public utility specialist, said during the workshop. "And just to reemphasize something that we've shared before but want to make clear: We have not made any proposals about a leaning for 2024 at this point."

EDAM Bookend vs. Main Split Footprint

In presenting the findings, E3 noted that the study was designed to provide WMEG members with "credible information" about the benefits of joining either EDAM or Markets+.

The results focused on three core scenarios for 2026:

- A business-as-usual (BAU) case assuming continuation of the West's current bilateral market for day-ahead energy combined with the existing footprint of CAISO's Western Energy Imbalance Market (WEIM) for real-time trading. The BAU assumes no entities join either day-ahead market, E3's Jack Moore said during the workshop.
- An "EDAM Bookend" case that assumes a single combined day-ahead and real-time market that covers the entire Western Interconnection, excluding the Canadian provinces of British Columbia and Alberta. This scenario assumed no charges for wheeling power within the system, Moore said.
- A "Main Split Footprint" that assumes participation in the EDAM by CAISO, PacifiCorp, Los Angeles Department of Water and Power, Balancing Authority of Northern California, Turlock Irrigation District and Imperial Irrigation District, while the rest of the West (excluding Alberta) participates in Markets+. This scenario assumed charges at the seams between the two markets, Moore said, noting that it was difficult to know what would be required to coordinate between the two, given that they wouldn't be full RTOs.

CAISO/West News

Compared with the BAU case, the study found, the EDAM Bookend scenario results in $60 million in annual savings for the West as whole. But in breaking the results down by balancing authority area, the study indicates that California entities would realize $80 million in savings in that scenario, while WMEG members outside California would see a $20 million loss compared with the status quo. And results even vary among those WMEG members, Moore noted, with some realizing net benefits while others suffer losses at varying levels. Exact results for individual utilities must remain confidential, he added.

The cost-benefit outcomes get flipped in the Main Split Footprint case. In the scenario with two markets, West-wide costs increase by $221 million compared with BAU, with California entities taking a $247 million hit. Most of those increased costs stem from California's need to fire up relatively expensive internal natural-gas-fired generation to substitute for cheaper imports, Moore said.

However, the Main Split market scenario showed $26 million in savings for WMEG members in general, although some members would face losses compared with the BAU case.

"The trade-off has different effects for different entities," Moore said.

E3 said the results indicate the importance of "critical" transmission lines between the Northwest and Southwest in the Main Split case, where transactions would depend heavily on paths in Idaho, Nevada and Montana to avoid wheeling through the EDAM.

"Northwest to Southwest becomes a pretty significant pinch point" in the Split scenario, Moore said. Olson added that the transmission constraints in that scenario also could depress energy prices in the Northwest and reduce the value of the region's flexible resources.

BPA Findings

Presenters at the workshop saved the most anticipated findings — BPA's results — for last.

The study's initial findings showed BPA seeing financial losses relative to BAU in both the EDAM Bookend and Main Split scenarios, largely because of a sharp decline in transmission wheeling charge revenues within its territory under either market. E3 assumed that a more robust market would undercut the need for customers to secure wheeling contracts from BPA, reducing those revenues from $251 million in the 2026 BAU case to $5.5 million in EDAM and $31.8 million in Main Split.

But BPA Director of Market Initiatives Russ Mantifel said the agency drew a different conclusion about the impact of day-ahead market participation on those charges. Most wheeling revenues are derived from long-term contracts, the agency found, and counterparties are likely to maintain those agreements for the foreseeable future.

By restoring wheeling revenues to expected 2026 levels, BPA and E3 estimated the agency's annual net benefits would rise to $134.7 million in the EDAM Bookend scenario and $28.8 million in the Main Split scenario.

"I think the wheeling revenue numbers in the study do a good job of articulating something that we as a region and that Bonneville has intuitively known, which is, for Bonneville, there's probably some amount of transmission that for us, is probably long-term, firm point-to-point transmission that's purchased and rolled over and over and over again," Mantifel said.

But it was clear the recalibrated study results showing how BPA could benefit from both day-ahead market scenarios were not a clincher for either market.

"There's no study that tells you exactly what you're supposed to do," Mantifel said. "These are big decisions with a lot of different complicated factors, and so Bonneville is going to try to utilize all this information, but we're going to be based in the sort of decision framework" the agency has previously laid out for choosing which market to join. ■

CAISO/West News

AES Fined $6M for CAISO Resource Adequacy Violations

By Ayla Burnett

FERC on Oct. 24 fined independent power producer AES $6 million for failing to fulfill resource adequacy obligations related to eight of the company's 12 generating units operating in Southern California (*IN23-15*).

At issue in the order was the performance capability of eight AES units at the Alamitos and Redondo Beach power plants, which were contracted through CAISO resource adequacy purchase agreements from June 2018 to May 2020. All 12 of AES's units received payments for providing capacity to the ISO's market during that time frame.

CAISO had contracted with the resources to bid energy into the ISO market and deliver their maximum output — or Pmax — should it become necessary during Southern California's hot summer months. Before entering the contract, AES was required to submit a master file containing the operating and technical characteristics of each unit, including their Pmax ratings. ISO guidelines stipulate that a Pmax value be based on the highest MW output a unit can sustain over a 30-minute interval.

However, in August 2019 CAISO's Department of Market Monitoring (DMM) notified FERC's Office of Enforcement (OE) that AES had submitted inaccurate master file parameters to the ISO that overstated some of the resources' Pmax values before entering the contract.

DMM reported to OE that summer readiness tests CAISO performed in spring 2019 and exceptional dispatches occurring in July 2019 showed that AES's Alamitos units 3, 4, 5 and 6 and Redondo Unit 7 were unable to meet the Pmax values submitted to the ISO in the original master file, resulting in a total deficiency of 91.80 MW.

AES's Alamitos Energy Center in Long Beach, Calif. | *The Greater Southwestern Exploration Companya*

According to the DMM's referral, the eight AES units were either unable to reach or maintain full capacity for a 30-minute interval after they were dispatched by CAISO. Regardless, AES had sold and, in some cases, financially benefited from RA contracts stating that their resources were operating at full capacity, FERC said.

As a result, OE found AES to be in violation of multiple sections of the CAISO tariff. The company did not admit or deny the violations but agreed to pay $2.97 million in disgorgement to CAISO and $3.03 million in civil penalties to the U.S. Treasury.

AES owns and operates a portfolio of generation of approximately 32,300 MW of energy worldwide. As of 2022, AES was one of the largest independent producers in California, with a capacity of 3,799 MW in the state. ■

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ERCOT News

ERCOT Board, IMM Debate Ancillary Service Costs

By Tom Kleckner

Carrie Bivens explains the IMM's ancillary services report. | *ERCOT*

Speaking before the ERCOT Board of Directors on Oct. 17, the grid operator's Independent Market Monitor, Potomac Economics' Carrie Bivens, defended her organization's recent report that the grid operator's newest ancillary service "likely" raised the real-time market's energy value by at least $8 billion.

Several directors latched on to the $8 billion figure during their meeting before Bivens stood at the podium, saying the figure was "erroneously reported" and "a billion-dollar headline that was inaccurate."

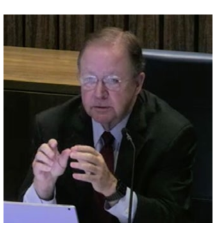
In the report, the IMM said *ERCOT*'s recent implementation of ERCOT contingency reserve service (ECRS), its first ancillary service in 20 years, has nearly doubled the amount of required online reserves and resulted in "enormous" increases in market costs and shortage pricing when the market is long.

Procuring and deploying the service has reduced supply and liquidity in the day-ahead market, "significantly" raised demand for ancillary products and resulted in inefficient day-ahead ancillary service (AS) price spikes, Bivens said during a September working group presentation. (See *ERCOT IMM Raises Concerns over Newest Ancillary Service*.)

"We know that this service has not increased efficiency because of the analysis that we perform," Bivens said, noting the ECRS business case focused on improving market efficiency. She said the report's purpose was to show an "order of magnitude" so the board could understand the costs involved.

Bivens said the IMM intends to provide comments to staff's annual AS methodology report to "tweak" how ECRS and non-spinning reserve is purchased "to bring that into alignment with what we think are more reasonable reliability goals."

"I hope that we can engage you guys in December to talk more about the ancillary services methodology," she said.


Board Vice Chair Bill Flores | *ERCOT*

Former Rep. Bill Flores (R), the board's vice chair and a proponent of dispatchable thermal generation, debated Bivens over AS products and their value in avoiding load shed, saying their additional costs are worth the alternative.

"When you look at the cost of ancillary services that's paid for to try to encourage reliability to try to create a reliable grid, the offset to that is that there was a cost of avoided load shed. What is the value of that?" he asked. "Basically, ancillary services are paying for the avoidance of load shed. I think you'd bet that reliability is important and that ought to be the goal of any grid operator."

"Of course, absolutely," Bivens responded. She said ancillary services are "very specific capacity products," not general capacity products to meet a reliability standard.

"They're very specific to follow the load and to ensure that the frequency is followed or, if a unit trips, to be able to replace those megawatts, but you still have reliability," she said. "What I'm trying to point out is that they have very specific uses and, as specific uses, can be studied and analyzed to determine how many do you need to meet them."

"The cost they're offsetting is avoided load shed," Flores said. "We need to look at the value of that. Somewhere, that's got to be baked into this analysis ... because load shed has a cost to consumers, the economy, to people, to physical health and so forth."

"We should absolutely procure enough to have a reliable grid," Bivens said. "We should have the right services to meet the specific attributes that the grid needs. But we should not buy more than that. More megawatts is just more cost. It's not actually buying you any additional reliability. I think we would have been just as reliable this summer without these excess ECRS megawatts."

The Public Utility Commission has a request for proposals out for the next four-year contract for a market monitor. Responses were due Oct. 30, with the new contract beginning Jan. 1. (See *ERCOT Monitor's Name Change Raises Legislative Concerns*.)

1-Hour SOC for ESRs

The board approved a nodal protocol revision request (*NPRR1186*) that sets the minimum state of charge (SOC) for energy storage resources participating in two of ERCOT's ancillary services (ECRS and non-spinning reserve), a move one energy storage developer said will have a "chilling effect" on attracting longer-duration batteries.

As modified by ERCOT and endorsed by the Technical Advisory Committee last month, the protocol change will reduce the requirement for storage resources to maintain a two-hour SOC down to one hour. The NPRR was remanded back to TAC by the board during its August meeting for further discussion and to address a "stranded energy" issue during

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scarcity conditions. (See *ERCOT Technical Advisory Committee Briefs: Sept. 26, 2023*.)

Storage developer Eolian, speaking for its segment, has opposed the measure throughout the stakeholder process. It says ESRs' fast-ramping capability can be crucial during scarcity events and give other resources additional time to come online.

Ironically, ESRs produced a record 2.17 GW on Sept. 6, when ERCOT, faced with constrained renewable energy in South Texas, declared a Level 2 energy emergency alert after voltage dropped. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

ERCOT began the summer with more than 3 GW of energy storage and expects that total to hit 9.5 GW next year.

During a discussion before the board's Reliability and Markets (R&M) Committee on Oct. 16, the ISO said it needs to know that a resource with an ancillary service obligation is available during the times it has bid into being available. The R&M unanimously approved NPRR1186.

"We came up with a better product," committee chair Bob Flexon told the board. "We really did air it all out yesterday. I feel that all parties had ample time to express their thoughts and considerations."

The board will direct staff to file priority NPRRs to handle compliance issues and financial penalties for nonperformance. The changes may be sent directly to TAC.

The board also approved two other revision changes:

- *NPRR1184*, which clarifies ERCOT's management of the interest it receives and is owed to counterparties for posted cash collateral and requires staff to credit counterparty collateral accounts for interest every month. The NPRR also requires ERCOT to report the interest calculation.
- A system change request (*SCR824*) that increases the attachment file size and quantities allowed within the resource integration and ongoing operations system.

F&A Proposes Revised Budget

Flores, who chairs the board's Finance and Audit Committee, said a review of ERCOT's financial performance indicates the organization's improved financials need to be considered when the PUC takes up the grid operator's 2024-25 budget next month.

ERCOT has proposed a budget, approved by the board in June, that increases its system administration fee 27.9%, from $0.555/MWh to $0.710/MWh. The budget drew several questions from the PUC during an Oct. 13 public hearing. The commission will take up the budget a final time during its Nov. 2 open meeting. (See *ERCOT Defends Admin Fee Increase Before PUC*.)

Flores said interest income is expected to be about $27 million higher than initial forecasts and that this summer's administration fee revenues were up about $6 million because of the additional load. Expenses that are down $4 million have given ERCOT about $36 million more available for 2025 than originally projected, he said.

"Those additional resources should be made available to reduce the impact of the cost of the system admin fee on the consumers of the state," Flores said. "If you were to prepare the budget today and present that to the PUC, you could possibly come up with a system admin fee somewhere less than the 71 cents that we originally proposed."

The F&A Committee, following Flores' lead, has asked ERCOT staff to submit a revised rate calculation to the commission.

PUC Holds Weatherization Workshop

ERCOT staff and stakeholders updated the PUC on Friday during a public hearing reviewing winter weather preparedness, grid reliability and resiliency, and industry compliance with weatherization standards ahead of the 2023-24 winter season.

The grid operator said weatherization inspections are ahead of schedule in meeting PUC rules. Power plants are required to winterize their equipment against extreme cold and identify critical components susceptible to cold weather.

ERCOT also briefed the commission on its new *firm fuel supply service*, which ensures generators have backup fuel available on site, and demand response programs in the ERCOT region.

"Today's work session was a great opportunity for us and the public to review the many steps Texas has taken to prepare for extreme cold weather," Commissioner Will McAdams said.

The grid operator does not expect emergency conditions this winter but has issued an RFP for 3 GW of additional capacity to increase its operating reserves. Resources have until Nov. 6 to respond to the RFP; awards for three-month contracts (December-February) will be announced Nov. 23. (See *ERCOT Searching for 3 GW of Winter Capacity*.) ■

ERCOT News

Solicitor General: SCOTUS Should Reject Texas ROFR Appeal

Prelogar Says Appeals Court Order was 'Correct'

By Tom Kleckner

The U.S. solicitor general has urged the Supreme Court not to review an appeals court decision on Texas' right-of-first-refusal law. | *Shutterstock*

Solicitor General Elizabeth Prelogar has urged the Supreme Court to dismiss a petition to review a 2022 appeals court ruling that found Texas' right-of-first-refusal law violates the Constitution's dormant Commerce Clause.

Prelogar filed a brief with the high court Oct. 23 asking it to deny Texas' request for a writ of certiorari, a formal request to review a lower court's judgment against the petitioning party (*No. 22-601*).

At issue is the 5th Circuit Court of Appeals' ruling last year that the Texas law (*Senate Bill 1938*) giving incumbent transmission companies the right of first refusal (ROFR) to build new power lines within the state is unconstitutional. Texas, with former Public Utility Commission Chair Peter Lake as the lead petitioner, requested the review in December. (See *Texas Petitions SCOTUS to Review ROFR Ruling*.)

"The court of appeals correctly determined that SB 1938 discriminates against interstate commerce by prohibiting any company without an existing in-state presence from competing in the market for the construction and operation of electric transmission facilities that would be part of the interstate transmission grid," Prelogar said in her filing.

She said the Texas law "discriminates on its face against interstate commerce" and that the state's "contrary arguments lack merit." Prelogar also noted that FERC *Order 2023*, which would overhaul transmission planning, would render moot a review of the 5th Circuit decision.

"If FERC were to adopt the proposed rule (or some alternative) while this case was pending before the court, that development might require supplemental briefing or otherwise complicate this court's consideration," she wrote.

Consumer advocacy group Electricity Transmission Competition Coalition welcomed the solicitor general's filing.

"ROFR laws are not just unaffordable, they are unconstitutional," the organization's chair, Paul Cicio, said in an emailed statement. "Texas' ROFR law was unconstitutional from the outset, and this was affirmed by the [appeals court]. Electricity transmission competition benefits consumers in the form of lower electricity prices; the filing of the United States is a welcome addition to the cause of lower electricity prices."

Chris Reeder, a partner with Husch Blackwell in Austin, told *RTO Insider* that the Supreme Court's request for the solicitor general to provide its opinion "indicates the court views the legal issues as having significant constitutional implications on which the government should weigh in."

The opinion also means briefing on Texas' request has been completed, he said. The justices will vote on whether to grant review and, if they do, the case will be set for argument and additional briefing requested.

"If it declines review, then the Supreme Court proceeding is over as a practical matter," Reeder said. "The 5th Circuit's ruling would become the 'law of the case.'"

Texas could seek a rehearing of the denial, but those rehearing requests are almost never granted, Reeder said.

The appeals court's order remands the proceeding back to the district court. (See *5th Circuit Finds in Favor of NextEra's ROFR Appeal*.)

NextEra Energy brought an appeal to the 5th Circuit after the U.S. District Court for Western Texas rejected the utility's challenge of SB 1938. The district court ruled the legislation didn't discriminate against interstate commerce because it "regulates only the construction and operation of transmission lines and facilities within Texas."

At the time, NextEra had been awarded a pair of competitive projects by MISO and SPP in Texas' non-ERCOT regions. Both projects have since been cancelled, but NextEra has said it intends to pursue other projects in Texas. ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

TAC Tables DRRS Revision, to Discuss Options with PUC

ERCOT stakeholders last week agreed with the staff's decision to table a protocol revision request implementing a new ancillary service that faces a tight statutory timeline.

Kenan Ögelman, ERCOT's vice president of commercial operations, told the Technical Advisory Committee Oct. 24 that tabling the protocol change would give the Public Utility Commission time to "digest" a recent filing by state lawmakers pushing back against the grid operator.

State Sen. Charles Schwertner (R) and state Reps. Justin Holland (R) and Todd Hunter (R) sent a *letter* to ERCOT and the PUC objecting to an ERCOT nodal protocol revision request (*NPRR1203*) that would create the new service, dispatchable reliability reserve service (DRRS), as a subset of non-spinning reserve service. The legislation (*House Bill 1500*) they helped push through earlier this year mandates DRRS be implemented as a standalone service by Dec. 1, 2024.

"We studied every way we could think of a standalone DRRS delivered by Dec. 1, 2024, and none of those were feasible," Ögelman told TAC. "I could try to reprioritize as much as I wanted, and there's just not enough time."

He said creating DRRS as a standalone service would require market testing "that adds time to the option."

The lawmakers differed and urged the commission to direct ERCOT to revise NPRR1203 and to establish DRRS as a standalone ancillary service, "even if doing so will cause a delay."

Combining DRRS into non-spin will create a single clearing price that could have a negative impact on consumer costs and diminish "market incentives to invest in the specific type of dispatchable resources needed to improve reliability," the lawmakers said.

"The purpose of this provision was to create a targeted ancillary service product that could leverage flexible, dispatchable generation resources to more efficiently manage operational uncertainty within the ERCOT market," they wrote. "We are concerned the current proposal does not meet the legislature's goal of creating an ancillary service product designed to meet actual system needs in a targeted, transparent manner and could have a negative impact on consumer costs."

ERCOT filed a *response* with the PUC, requesting guidance from the PUC on whether to proceed with implementing DRRS as a non-spin subtype to meet the deadline or to begin developing a standalone product. It said work already has begun on the former option and that "any pause in this work would introduce risk of missing the delivery deadline" (*55156*).

ERCOT's Kenan Ögelman explains the need to table NPRR1203. | *ERCOT*

The grid operator said TAC and its board will need to vote on NPRR1203 and two related binding document revisions (*OBDRR049* and *OBDRR050*), also tabled, during their December meetings to stay on schedule.

The PUC plans to take up the matter during its open meeting Nov. 2.

To be eligible for DRRS, resources must be dispatchable, be off-line and able to come online within two hours and capable of operating at their high sustained limit for at least four hours. NPRR1203 would establish a maximum amount of non-spin that can be provided by DRRS as a sub-type of non-spin. HB1500 also requires reliability unit commitment activity be reduced by the amount of DRRS procured.

Non-spin reserves in ERCOT also are off-line capacity that can start up and provide power, usually within 10 minutes.

Representing Reliant Energy Retail Services, Bill Barnes said stakeholders are concerned DRRS delays could push back real-time co-optimization (RTC), a market mechanism that clears energy and ancillary services every five minutes in the real-time market and is scheduled to come online in 2026.

"As stakeholders, when we compare the two, I think we see much more value in RTC in terms of impact to consumers," he said. "I think we would have concerns if that [DRRS] change in direction would change the implementation and push that back significantly."

ERCOT's Independent Market Monitor prefers a standalone product that it says would better address reliability needs and have more accurate pricing.

ERCOT to Propose Price Correction

ERCOT staff told TAC they were investigating a potential price correction after an Oct. 22 problem with the security constrained economic dispatch (SCED) system. Following the meeting, ERCOT made it official by issuing a *market notice* that said the pricing issue met the grid operator's initial criteria for the Board of Directors to review the real-time prices before

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they become final.

Staff will take the price correction to the board's Reliability and Markets Committee Dec. 18 and then the directors Dec. 19 for their approval. They also will present the potential price correction to TAC during its Dec. 4 meeting.

According to the market notice, SCED was unable to consume specific three-part supply offers (energy offer curves) and real-time energy bids for several resources after an issue with the market management system (MMS). That resulted in SCED failing to produce valid prices for its intervals between 12:15 p.m. and 12:54 p.m. Another related issue caused SCED to fail to run from 12:56 p.m. to 1:09 p.m.

Staff ran into another error trying to process the price correction data and were unable to post the corrected prices before they became final.

Ögelman said an integer field that tracks submissions, each with a unique identifier through the ISO's systems, exceeded a limit of more than 2 billion submissions. At that point, additional submissions were rejected. That led to price spikes before noon and a little after 1 p.m.

Staff addressed the issue by freeing up some of the numbers and letting market participants resubmit. They then were able to clear the day-ahead market, Ögelman said.

"It is a parameter that dates back to nodal go-live," he said. "It was not envisioned that we would exceed that number, but clearly, we did. I do think that ultimately, we would need to change that cap."

Sreenivas Badri, director of grid and market solutions, told members it would take "probably five, six years" before the issue would happen again. In the meantime, he said, staff is working with a vendor to make application changes and implementing a revision that would significantly reduce the growth of unique identifiers.

TAC Endorses RUC Change

TAC approved a revision request (*NPRR1172*) brought forward by consumer groups that removes the mitigated offer cap multipliers and creates a 100% clawback for RUCs. The revision's intention is to encourage generation resources to self-commit.

"It makes sure that the generator that's committed by ERCOT through RUC, which would have no downside risk because its costs are guaranteed, can't make money from the RUC," Eric Goff, who represents residential consumers, said. "It encourages self-commitment because in today's environment, a generator that is marginal could trade some of their profits in exchange for a guarantee that they won't lose any money."

Not surprisingly, the generator segment opposed the measure, casting three of five dissenting votes. The cooperative segment accounted for the other two opposing votes when the NPRR passed, 23-5 with 2 abstentions.

"This is bad policy. I fundamentally disagree with Eric's assertion that there is no downside risk because costs are guaranteed," Luminant Generation's Ned Bonskowski said. "I encourage anyone that is sympathetic to resources having [been] effectively co-opted by many times a load forecast that is in excess of what the market believes and incurring costs ... ideally they should have full recovery, but our experience has been that is not always the case."

The consent agenda, passed unanimously, included two NPRRs and changes to the nodal operating guide (NOGRR) and planning guide (PGRR) that, if approved by the board and the PUC, would:

- *NPRR1192*: Incorporate the other binding document "Requirements for Aggregate Load Resource Participation in the ERCOT Markets" into the protocols.
- *NPRR1196:* Correct and update equations used to determine ancillary service (AS) failed quantity calculations for load resources other than controllable load resources (NCLRs) developed under *NPRR1149*. Changes would include: calculation updates to account for AS allowances and restrictions that NCLRs can and cannot carry simultaneously with ERCOT contingency reserve service's (ECRS) implementation; specifying the snapshot components to be used for the "telemetered AS for the NCLRs as calculated" variable; and adding a non-zero check for the "telemetered ECRS responsibility for the resource as calculated" variable.
- *NOGRR257*: Resolve a conflict in emergency response service event-reporting timelines between the operating guide and protocols by striking the guide's 90-day event-reporting requirement.
- *PGRR110:* Remove a paragraph from the guide to accommodate the release of steady-state planning models in node-breaker format pursuant to a *system change request*. ■

ISO-NE News

Form Energy Wants to Bring Long-duration Storage to New England

By Jon Lamson

When FERC convened the New England Winter Gas-Electric Forum in Portland, Maine, in June of this year, the commissioners grilled ISO-NE executives, government officials and company representatives about how they will meet the impending electricity demand from electrification. (See *NE Stakeholders Debate Future of Everett at FERC Winter Gas-Elec Forum*.)

As weather-dependent renewables replace legacy fossil fuel units, how will the region ensure it has enough power during extended winter periods when the wind dies down and there is little sunlight to draw upon?

While others highlighted the uncertainty associated with predicting the future resource mix past 2030, Richard Paglia of the gas pipeline company Enbridge was quick to point to a simple solution: more natural gas.

"To me, the glue that holds all of this together [is] the gas plants that are highly dispatchable and can solve that problem," Paglia *said*. "But we don't have the supply to allow those plants to run when needed."

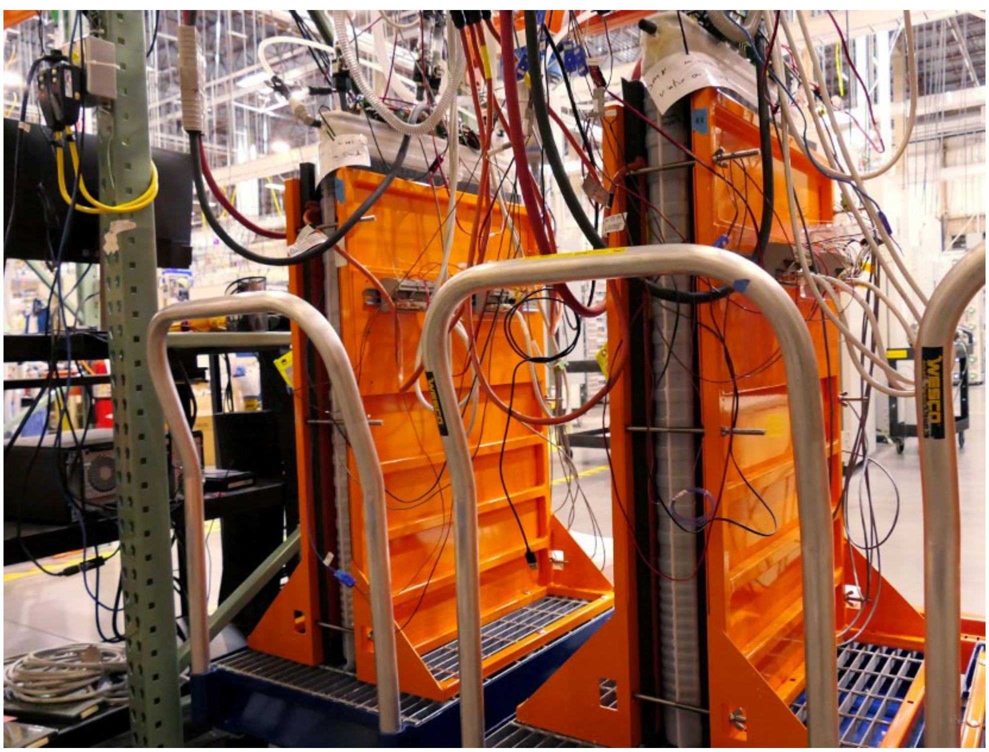
In September, Enbridge followed up on its prescribed solution and announced a project to significantly expand the capacity of the Algonquin gas pipeline into New England, which the company hopes to complete by the end of 2029. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

But this solution would not come without major tradeoffs: Five of the six New England states have set strong decarbonization goals, and natural gas is one of the major sources of carbon emissions and air pollution in the region. Meanwhile, climate and environmental justice groups have vowed to fight the expansion and hold climate-focused politicians to their rhetoric.

At the same time, early-stage clean energy companies are scrambling to address this energy reliability gap, hoping to fill the firm generation role that has historically been dominated by fossil fuel resources.

Form Energy, a company started in 2017 and headquartered in the city of Somerville, Mass., is developing long-duration iron-air batteries that it hopes to pair with renewable energy to firm up that generation across extended stretches.

Form's batteries are built to provide 100 hours of energy and charge by converting rust to iron, a process that is reversed when discharging to produce electricity.



Test battery cells | © *RTO Insider LLC*

"The technology is quite ready," Marco Ferrara, Form's co-founder and senior vice president of analytics and software, told *RTO Insider*. While the company has made significant scientific advances in getting high capacity out of the batteries, "the technology is inherently simple."

Most current grid-scale batteries have comparatively short durations, sitting in the two- to four-hour range. The U.S. Department of Energy defines inter-day long-duration energy storage (LDES) as the ability to shift power 10 to 36 hours, and multiday LDES as shifting power for a period greater than 36 hours.

According to a DOE *report* on LDES released in March, the U.S. could need between 225 and 460 GW of LDES capacity to reach net-zero by 2050, which would require about $330 billion in capital investment.

The report found that LDES could replace the need for over 200 GW of new natural gas capacity by 2050, and that LDES reduced the need for natural gas in all modeled scenarios.

"Analysis shows that by 2050, net-zero pathways that deploy LDES result in $10 billion to $20 billion in annualized savings in operating costs and avoided capital expenditures compared to pathways that do not," the DOE report concluded. To achieve this, LDES deployment capacity must reach 10 to 15 GW per year by 2030 and 30 GW per year by 2040, the report found.

Form does not have any utility-scale batteries in operation but has several pilot and demonstration projects in the pipeline. The company is currently developing a 1.5-MW pilot project with Great River in Minnesota, two 10-MW projects with Xcel Energy in Minnesota and Colorado, a 5-MW project with Dominion Energy in Virginia, a 10-MW project with the New York State Energy Research and Development Authority and a 15-MW project with Georgia Power. The expected in-service dates range from 2024 to 2026.

The two projects with Xcel will be located at the sites of two retiring coal plants, chosen in part because of the ability to charge the project with nearby renewable power, existing water-supply infrastructure and the ability to upgrade grid interconnection infrastructure.

The company performs most of its research and development in its Somerville lab, where engineers test all sorts of variables in thousands of battery cells lined up in long rows, separated by grocery store-style aisles.

ISO-NE News

While the company does not have any projects in development for New England, it sees great potential for the technology in the region. A white paper published by the company in late September found that by adding 23 GW of multiday storage capacity by 2050, the New England grid would see a 33% reduction in the cost of eliminating fossil fuel generation and reduce clean energy curtailment by 83% compared to a scenario with no multiday storage.

"Pairing sufficient multiday storage with offshore wind can create a firm zero-carbon energy resource that would support grid reliability during all times of the year for a cost that is 80% less than with short-duration storage," the report found.

The study modeled the grid during all days of the year under different weather scenarios. Ferrara emphasized that modeling weather and load across all hours of the year, instead of short representative stretches, is essential to understanding the true reliability attributes of a resource.

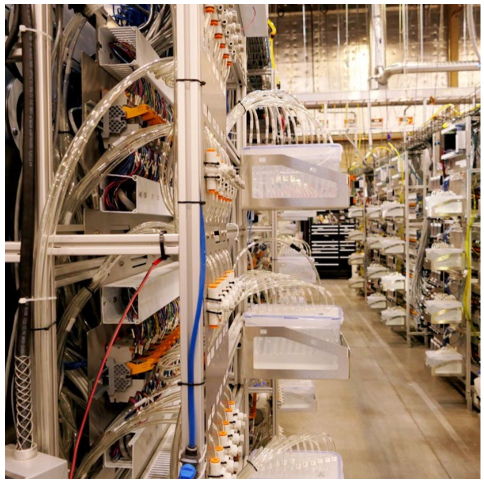
"Methodology matters," Ferrara said. "If you solve a capacity expansion problem with that richness of information, you come up with a portfolio that is truly robust across weather years."

Along with portfolio planning methodologies, Ferrara highlighted several key challenges to scaling up Form's technology. He said the company's ability to rapidly increase manufacturing would likely be the limiting factor as it works to meet growing demand.

"We don't see any particular blockers on the supply side; we see a lot of opportunity on the demand side for our technology; and we're there in the middle," Ferrara said, noting the relative availability of the battery's key components: iron, water and air. The company is fast-tracking construction on a large manufacturing facility in Weirton, W.Va., and is hoping to begin operations at some point in 2024.

Ferrara also pointed to the need for appropriate compensation mechanisms to account for the grid benefits that long-duration storage could provide. At a meeting of ISO-NE's Consumer Liaison Group in June, a Form representative said the company is interested in bringing projects to the region but is limited by the RTO's current market structure. (See *Activists Want ISO-NE to Push for Renewables*.)

Currently, ISO-NE does not differentiate between short-term and long-term battery storage systems in its capacity accreditation system, although the RTO is working to change this dynamic in its ongoing Resource Capacity Accreditation (RCA) project.



Form Energy's Somerville lab | © *RTO Insider LLC*

"Determining how to account for the reliability attributes of storage systems, which have different sizes, durations, etc., is a major component of the RCA project," an ISO-NE spokesperson told *RTO Insider* in a statement. They added that while the region currently relies on stored fuels like oil and LNG when other resources are not available, "in light of the ongoing clean energy transition, it is clear that the region will need to explore alternative resources to provide these essential services."

ISO-NE's 21-day energy simulator — used to study future resource adequacy — only models two-hour batteries and pumped hydro. The RTO denied stakeholder requests earlier this year to look at long-duration storage in its Operational Impacts of Extreme Weather study, saying that developing a tool to model this could not be completed to fit the timeline of the study.

The inability to study a wider range of storage durations "is problematic for system modeling and transmission planning, where energy storage can act as a transmission-enhancing technology, as well as for the [alternative resource] sector's larger goals of seeing energy storage markets advance in ISO-NE," said Alex Lawton of Advanced Energy United, a clean energy association whose membership includes Form Energy and other storage types.

In future analyses, ISO-NE said it plans to continue improving its modeling capabilities, including adding the ability to model long-duration and multiday storage.

FERC recently approved an ISO-NE proposal to allow energy storage to serve as transmission-only assets to solve transmission issues. These new rules will allow batteries to function as transmission assets for the first time, but they impose strict limits on their use, including largely prohibiting them from participating in the RTO's markets and limiting their total capacity on the grid to 300 MW. (See *FERC Accepts ISO-NE Filing to Allow Storage as a Tx-Only Asset*.)

In a filing prior to the commission's ruling, United called the changes a "first step" while recommending that the RTO develop guardrails to allow transmission-only storage assets to participate in ISO-NE markets and consider lifting the capacity limits as it gains operational experience with them.

As the region sits on the precipice of major new investments in fossil fuel generation and infrastructure, Ferrara said he hopes ISO-NE considers investing in and incentivizing zero-emission reliability solutions like long-duration and multiday storage. He advocated for reforming the capacity markets to account for differences in storage durations, as well as the establishment of a "zero-carbon capacity product."

In January, Massachusetts released a proposal for a forward clean energy market (FCEM), which included a "clean capacity certificate" product aimed at incentivizing non-emitting capacity resources. However, this proposal has failed to gain traction with the other New England states.

ISO-NE has indicated that it is up to the states whether to pursue an FCEM, telling *RTO Insider* that "the New England states have communicated that they are not interested in pursuing this market design at this time. As a result, we have not conducted further analysis."

A spokesperson for Massachusetts' Executive Agency of Energy and Environmental Affairs told *RTO Insider* that the state is "committed to exploring new long-durational energy storage technologies that not only could reduce our dependence on the grid and our carbon footprint, but also offer savings for residents and businesses."

With the dual challenge of impending state decarbonization targets and electricity demand increases, Ferrara said it is important to start developing projects in the region as soon as possible. He noted that the company's white paper found that the least-cost 2030 storage portfolio to prevent outages would include about 3 GW of multiday storage.

"If we're really serious about goals in 2040 and 2050, and we're building assets that last 20 years, we need to build them now," Ferrara said. ■

MISO News

OMS Leaders Reminisce on 20 Years at Annual Meeting

Officials Past and Present Discuss Rethinking RA, Obstacles to Transmission

By Amanda Durish Cook

GULFPORT, Miss. — The Organization of MISO States took time to celebrate its 20-year anniversary at its annual meeting while exploring familiar themes of restructuring resource adequacy and barriers to large transmission buildout.

OMS was incorporated in mid-2003, two years before MISO's energy markets went live. Former OMS board members and chairs reminisced about the past two decades of the organization during the Oct. 26 meeting.

Bill Smith, OMS' original executive director, said he hatched a nascent idea for the organization by scrawling notes on a "too early" flight. He said OMS was formed before cellphones and even conference calls.

"We were working in a different kind of technology," Smith said.

Founding OMS board member Steve Gaw said state commissions at the time were looking for a way to bridge state matters with RTO and federal matters.

Gaw said commissioners were motivated to form OMS based in part on a worry that if they didn't do it, someone else might. He said initially, founding members didn't know how they would conduct meetings and get funding, or whether MISO would object to the organization's creation and how much information the RTO would share with it.

"I didn't know if this was going to be a long-lived thing, or if someone would challenge it or in two to three years, [or] it would go away," Gaw said. "The reason it's still here is because it's valuable."

Gaw said several commissioners involved in OMS still share a spirit of working together and moving past differences.

David Boyd, former OMS board member and Minnesota commissioner, said the Minnesota Public Utility Commission didn't create staff positions dedicated to RTO matters until funds were freed up with the Emergency Economic Stabilization Act of 2008 (the so-called Wall Street bailout). He said OMS is key to state collaboration and understanding MISO initiatives.

"You felt like you had colleagues all across the country," former OMS President and Michigan Public Service Commission Chair Sally Talberg said.

The OMS annual meeting underway with the RA panel | © *RTO Insider LLC*

Outgoing OMS President and current Michigan PSC Chair Dan Scripps said organization leadership this year focused on making it more unified. He said it was a strategic choice to have OMS' 20th annual meeting in a MISO South state.

"There are regional differences; there are state differences; but they make us stronger," Scripps said.

The OMS Board of Directors unanimously elected Wisconsin's Tyler Huebner to serve as the 2024 president.

Also at the meeting, members created the David Carr Award for Outstanding Staff Contributions, an annual award for regulatory staffers and named for Mississippi Public Service Commission counsel *David Carr*, who died in late December. Carr's father, Mississippi PSC Commissioner Wayne Carr, received a standing ovation upon the award's unveiling.

Werner Roth, an economist at the Public Utility Commission of Texas who helps chair multiple MISO stakeholder committees, is the award's first recipient.

Reconsidering Resource Adequacy

Sixteen years after OMS helped shape MISO's first comprehensive resource adequacy plan, regulatory staffs are again rethinking the RTO's RA construct and invited experts to speak at the meeting on what they would prescribe.

National Association of Regulatory Utility Commissioners staffer Elliott Nethercutt said with 72% of the nation's dispatchable, on-demand generation expected to retire by 2040, the entire industry must reconsider RA. He predicted state regulatory organizations like OMS are going to become even more critical as states test approaches to decarbonization.

Kelli Joseph, of the University of Pennsylvania's Kleinman Center for Energy Policy, called for "coordinated, reliability-informed" RA and operating reliability planning in which states and RTOs alike have a role. RTOs should assess states' resource plans collectively and advise on red flags, she said. That way, states could understand the effect of their resource planning decisions on other states.

"The lack of this type of planning is a reliability risk," Joseph said.

MISO News

In addition to operating reserves, Joseph said grid operators need resources that meet public policy goals alongside "balancing resources," or quick-start, fast-ramping resources in the form of either gas or batteries.

Joseph said scarcity pricing "has never been a sufficient investment signal to meet reliability targets"; that's becoming especially apparent in the resource transition. She said LMP is helpful only to encourage short-term dispatches, and "using a price alone" to incent the entry of certain types of resources is flawed.

"I think we're at the point where we need to have conversations about what we're doing: … what is the public good, and what are we doing to manage this public good of a reliable electric system?" she said. "It's too essential to get this wrong."

"It's hard to have long-term market signals," agreed former Arkansas Public Service Commission Chair and Energize Strategies founder Ted Thomas. The system needs a "sharing of responsibility and sharing of costs" when it comes to operations reliability.

"Who wants to be the regulator to put in a gas plant with carbon capture with a per-unit cost of a gazillion? Who here wants to do that?" he asked rhetorically.

Joseph said RTOs could help states determine if they want to divvy the costs of building critical but seldom-used resources.

Thomas said MISO's filing at FERC for a sloped demand curve in its capacity market exemplifies the consequences of states' inaction. From 2015 onward, states protested MISO's suggestion to use a sloped demand curve in the auction, insisting it would impede states' authority on resource planning — that is, Thomas said, until the 2022/23 Planning Resource Auction cleared Midwestern zones at a $240/MW-day cost of new entry. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.) He said after that, states asked MISO, "'What are you going to do about this?'" resulting in the sloped curve's rebirth.

"We have to get in front of this if we want jurisdiction. Because we have a problem, and if we don't get ahead of it, we're going to get the sledgehammer and, with it, a chunk of our jurisdiction [taken away]," Thomas said.

North Dakota Public Service Commissioner Julie Fedorchak said that while she isn't worried about RA in the long run, she is worried about the next five years "because everyone is really eager to get going on these goals" and shift the resource mix without enough attention on how demand will be met at all times.

The OMS annual meeting took place at the Courtyard Gulfport Beachfront, steps from the ocean. | *© RTO Insider LLC*

"This is not a place for experimentation. This is the foundation of our society, and we have to get it right," Fedorchak said.

Thomas also said he wished EPA would reread MISO's comments raising the alarm on the agency's new proposed emissions standards for power plants. The RTO said the proposal would supercharge retirements so they outstrip the commercialization of new technologies like green hydrogen and carbon capture. (See *EPA Power Plant Proposal Gets Mixed Reception in Comments*.)

He also said there is currently a lack of balance in political power over energy decisions, as the left has taken the lead over decisions on the energy transformation.

"The right has no credibility because they're on a hangover from climate denial. They have no credibility right now to say the science might be exaggerated," Thomas said.

Overcoming Transmission Planning Challenges

Regulators also touched on the venerable subject of stumbling blocks to transmission planning while the federal government pushes for a sturdier system.

Grid United CEO Michael Skelly said he views new transmission lines as essential to maintaining RA while dealing with load growth, two topics on his mind lately.

Panelists agreed that long-distance buildouts are useful to dodge blackouts during extreme events.

"Look at [Winter Storm] Uri: We're paying no matter what we do. I don't know about the rest of the world, but in Texas, we're paying $9/month for pretty much ever," Skelly said.

MISO long-term planning studies and revived federal studies like the *National Transmission Planning Study* to pinpoint beneficial line routes embody the Hippocratic Oath of "first, do no harm," Skelly said. "I think if you look at all these studies and squint, it'll point the way."

"Projects are not shockingly hard to come up with. We've seen the same lines come up time and time again," MISO Senior Vice President of Planning and Operations Jennifer Curran said of interregional transmission needs under MISO's Joint Targeted Interconnection Queue (JTIQ) portfolio of 345-kV lines. The $2 billion portfolio has received $464 million from DOE under the Infrastructure Investment and Jobs Act. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

Curran said that while line needs are relatively easy to deduce, how to share the costs of those lines is a major sticking point that slows the transmission planning process. MISO is trying to reproduce a JTIQ-style study for its seam with PJM, but Curran expressed reservations over the differences between the RTOs' planning styles.

"SPP and MISO think about transmission planning very similarly. PJM and MISO do not. We're going to try, but I have my optimism a little tempered," she said.

Serving as moderator, OMS President Scripps joked that sometimes when he looks at the overlays of prescribed transmission line opportunities and thinks of all the permitting and cost allocation obstacles that can topple them, he is sometimes "bullish" on a future with high distributed energy resources instead.

"This is a very exciting time to be doing this," Skelly countered. "This must have been how it felt to develop infrastructure in the '60s. Because people want so much of it."

But Skelly said too much is heaped on the transmission siting process, including environmental concerns, land acquisition, some cost allocation details and landowner concerns.

"We really burden the siting process with a lot of stuff," he said. "That's a lot to put into one process."

Skelly said Grid United is trying to "de-pancake" siting by isolating risks to development and handling land acquisition of routes first before moving onto other steps of the process. ■

MISO News

Midwestern States Become More Open to Small Modular Reactors in 2023

By Amanda Durish Cook

Several Midwestern states on opposite ends of the political spectrum have taken steps this year signaling receptiveness to small modular reactor (SMR) development while a factory in Ohio has begun producing uranium tailored to the smaller plants.

Most recently, Maryland-based Centrus Energy opened a uranium enrichment plant this month in Piketon, Ohio, to produce high-assay, low-enriched uranium (HALEU).

The Department of Energy awarded Centrus a competitive, cost-shared contract in 2022. The company was required to begin production of HALEU by the end of 2023 under the agreement. HALEU is tailored for types of SMRs and contains between 5% and 20% fissile uranium, while large nuclear reactors use fuel with up to 5% fissile uranium.

"We hope that this demonstration cascade will soon be joined by thousands of additional centrifuges right here in Piketon to produce the HALEU needed to fuel the next generation of advanced reactors, low-enriched uranium to sustain the existing fleet of reactors and the enriched uranium needed to sustain our nuclear deterrent for generations to come. This is how the United States can recover its lost nuclear independence," Centrus CEO Daniel Poneman said in a press release.

Deputy Secretary of Energy David Turk said that for the first time ever, "an American company is producing HALEU on American soil."

The 16-centrifuge cascade produces only about 900 kilograms of HALEU per year, but Centrus said it could expand the Ohio operation to 120 centrifuge machines if it secures enough offtake commitments and funding.

Centrus has TerraPower and Oklo Inc. lined up to execute fuel supply contracts; both are trying to get their own SMR designs certified with the Nuclear Regulatory Commission (NRC). Oklo plans to build two of its liquid metal-cooled, metal-fueled fast reactors in Piketon to supply energy for Centrus and the surrounding area. The plants will be situated on land owned by the Southern Ohio Diversification Initiative, a community reuse organization. The plans are part of the Department of Energy's push to re-industrialize the area around the Portsmouth Gaseous Diffusion Plant.

Elsewhere in Midwestern states, utilities were in the early stages of development while bills meant to assist SMR progress were drafted.

Early this year, a bipartisan group of Minnesota Senate lawmakers backed a bill that would direct the state's Department of Commerce to conduct a study exploring the feasibility of SMRs (SF-1171). The Minnesota House and Senate also mulled allowing the Minnesota Public Utilities Commission to issue certificates of need to build new nuclear plants less than 300 MW in capacity (SF 2824). Both bills have been referred to the Climate and Energy Finance and Policy Committee.

Minnesota's nuclear moratorium is nearly three decades old, but some environmental organizations are rethinking their stance on new nuclear as a zero-carbon, baseload backstop to renewable power. Minnesota law mandates that the state reach 100% clean energy by 2040.

In general, SMRs are designed to yield anywhere from 50 to 300 MWs of electricity, as opposed to the typical 1 GW from traditional, large-scale reactors. They can be built indoors and then shipped to sites to be assembled. The U.S. doesn't have any SMRs in operation.

Meanwhile, Xcel Energy is exploring whether it wants to become operator of a NuScale VOYGR SMR under development at the Idaho National Laboratory. That plant isn't expected to be commercially operational until 2030.

NuScale's VOYGR is the first SMR design to win certification from the NRC.

Dairyland Power Cooperative, based in western Wisconsin, has partnered with NuScale Power to evaluate use of small-scale nuclear reactors in Wisconsin.

NuScale also is planning to build a dozen 77-MW pressurized water SMRs for Ohio and Pennsylvania in order to energize two Standard Power data centers by 2029.

If passed, Michigan's House Bill 4753 would create tax credits of 15% for qualified research and development expenses related to the "design, development or improvement" of SMRs and activities that will hasten them to market. The bill was referred to the House Committee on Tax Policy.

"Per capita, Michigan employs the highest number of engineers in the country," said state Rep. Pauline Wendzel (R), who introduced the bill. "We have the talent, and we have the capability. Now we need to put our foot on the gas to develop this safe, clean and reliable form of energy."

Efforts to resurrect the Palisades nuclear power station in southwest Michigan also involve SMRs. Last month, Wolverine Power Co-op signed an agreement with owner Holtec International to buy power, hoping Palisades reopens in 2025. That agreement includes a contract expansion provision to include up to two small modular reactors onsite.

Last year, Indiana Gov. Eric Holcomb (R) signed S271 into law, which mandated that the Indiana Utility Regulatory Commission work with the state's Department of Environmental Management to devise rules around granting of certificates of public convenience for the construction, purchase or lease of SMRs. Those rules were adopted at the end of June.

Purdue University and Duke Energy have recommended that Indiana consider public funding of studies dedicated to new nuclear and issuing state tax credits for advanced nuclear technology. Those recommendations were in an interim report of a joint study issued midyear.

Purdue and Duke are exploring the feasibility of using SMRs to meet the energy needs of Purdue's main campus.

Finally, the Missouri legislature this year weighed HB 225, which would have allowed utilities to file with FERC to raise rates to pay for SMRs. The bill, which cleared the house but failed to gain traction in the Senate after a public hearing, would have modified the state's 1976 law that prevents utilities from raising rates to pay for the construction of new projects.

Whether SMRs are economical enough to compete in the market remains untested. This month, researchers published a cost analysis of SMRs in the peer-reviewed international journal Energy. They analyzed the levelized cost of electricity among 19 SMR designs and said the costs to generate electricity from SMRs seems to be "non-competitive when compared to current costs for generating electricity from renewable energy sources," even when accounting for system integration costs that double renewable energy's price tag.

Researchers also concluded that manufacturers' cost estimates for SMRs "are mostly too optimistic compared to production theory" and that a Monte Carlo simulation showed "that no concept is profitable or competitive." ■

MISO News

MISO Likely to Pay $815K for 2 NERC Violations

By Amanda Durish Cook

MISO has agreed to pay an $815,000 penalty for a pair of NERC violations committed over the summer.

MISO Vice President of Operations Renuka Chatterjee said MISO addressed the issues quickly while self-reporting them to ReliabilityFirst's enforcement group. The grid operator agreed to ReliabilityFirst's non-negotiable settlement proposal in late August.

Chatterjee said *ReliabilityFirst* determined the severity of the violations, and *MISO* would have faced a higher penalty if it hadn't admitted the violations.

"MISO agreed to settle and admit the violations to minimize risk of increased penalty amount for MISO stakeholders," Chatterjee said at an Oct. 18 Advisory Committee teleconference.

MISO said both incidents violated standard *IRO-008-2*, which governs operational analyses and real-time assessments.

MISO reported it discovered missing data while it was updating models in its day-ahead analysis for an unspecified day. The data is tied to contingency scenarios the RTO runs to prepare for the next operating day.

The second breach came when MISO discovered it lapsed in monitoring a 115-kV tie-line because it had been erroneously marked as external to the grid operator. MISO said it corrected the issue and has since implemented a procedure to reflect a change in seasonal ownership of the constraint.

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

"An after-the-fact analysis with updated ratings also showed that this non monitoring did not represent a system operating limit violation," MISO added.

ReliabilityFirst has forwarded the penalty agreement to NERC for approval. The agreement then goes before FERC for authorization.

After FERC approval of the agreement, MISO will make a section 205 filing to recover the penalty from market participants. MISO said it anticipates FERC will issue an order on the settlement in late November or early December. In the anticipated timeline, MISO said it will recover the penalty sometime in the first half of 2024.

MISO said it maintained reliable operations throughout both events. The grid operator said, "at no time was there any harm to the bulk electric system." ■

NYISO: Costs of Mitigation Tool Bug Negligible

By John Norris

RENSSELAER, N.Y. — NYISO on Thursday said a market software problem identified this year in the day-ahead and real-time ancillary services markets had a negligible financial impact and did not result in any market manipulation.

In an *update* to the Installed Capacity/Market Issues Working Group, NYISO staff disclosed that an issue with the automated mitigation process (AMP), a mechanism that identifies and mitigates instances of market abuse to keep conditions competitive, led to a mere $893 of missed real-time mitigation over two hours and $41,729 in day-ahead mitigation over three days.

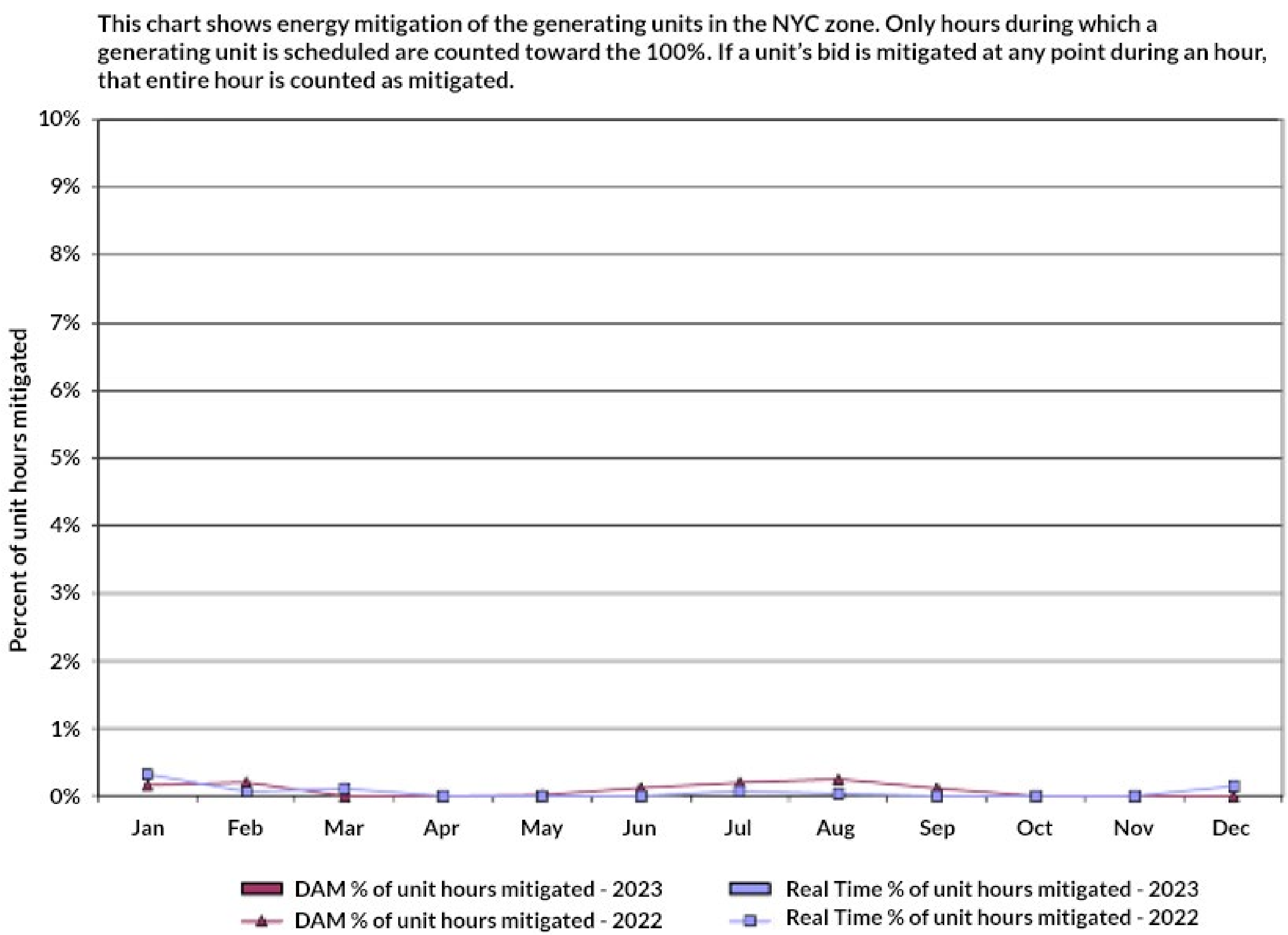
NYISO determined that the issue did not meet the threshold to be considered a significant market problem because the issue was quickly resolved and no unfair market behaviors were observed.

The AMP validates and adjusts bids in the day-ahead market before settlement and conducts ongoing monitoring in the real-time market to ensure that market participants are not manipulating the market for their own gain. NYISO found that it was not working properly July 6 because of an April software deployment, which prevented the AMP from both effectively executing its mitigation procedures and evaluating start-up or minimum generation references correctly.

In response, NYISO issued a notice of a potential market problem July 11, initiating a confidential investigation in collaboration with its Market Monitoring Unit and FERC to determine whether the issue significantly disrupted the market or if any market participants were gaming it. (See *NYISO Discovers Market Problem, Opens Confidential Investigation*.) By July 18, the software issues were resolved for the day-ahead market.

Further investigation showed that the conditions for the AMP to "trigger" never materialized during the period it was malfunctioning, indicating that the impact was minimal. ISO staff noted how AMP activates infrequently to adjust bid offers, mitigating less than 0.5% of the unit hours throughout the previous year.

Mark Younger, president of Hudson Energy Economics, encapsulated stakeholders' reaction to the $893 cost in the real-time market, exclaiming sarcastically, "That is outrageous!" ■



Percentage of committed unit-hours mitigated by AMP in 2022 | *NYISO*

NYISO News

NYISO Management Committee OKs Budget, 5.6% Rate Increase

PJM JOA, Study Changes also Recommended

By John Norris

The NYISO Management Committee *recommended* Oct. 25 that the Board of Directors approve the ISO's *proposed* $194.8 million budget for next year, a $4.8 million (2.5%) increase. Because the spending will be allocated across a forecast throughput of 152.1 million MWh, a 2.9% drop from 2023, the Rate Schedule 1 charge/MWh will increase to $1.281/MWh, a 5.6% increase.

The spending plan adds 19 new positions, primarily in the planning and operations units. Other sources of the spending increase are hikes in consulting fees and staff salaries, which are proposed to increase by $7.1 million and $7.4 million, respectively. Much of the increase is offset by the $10 million increase in proceeds from debt.

The ISO said growth drivers, including new large loads, electric vehicles, heating electrification and economic growth, would be more than offset by growth in energy efficiency and behind-the-meter solar.

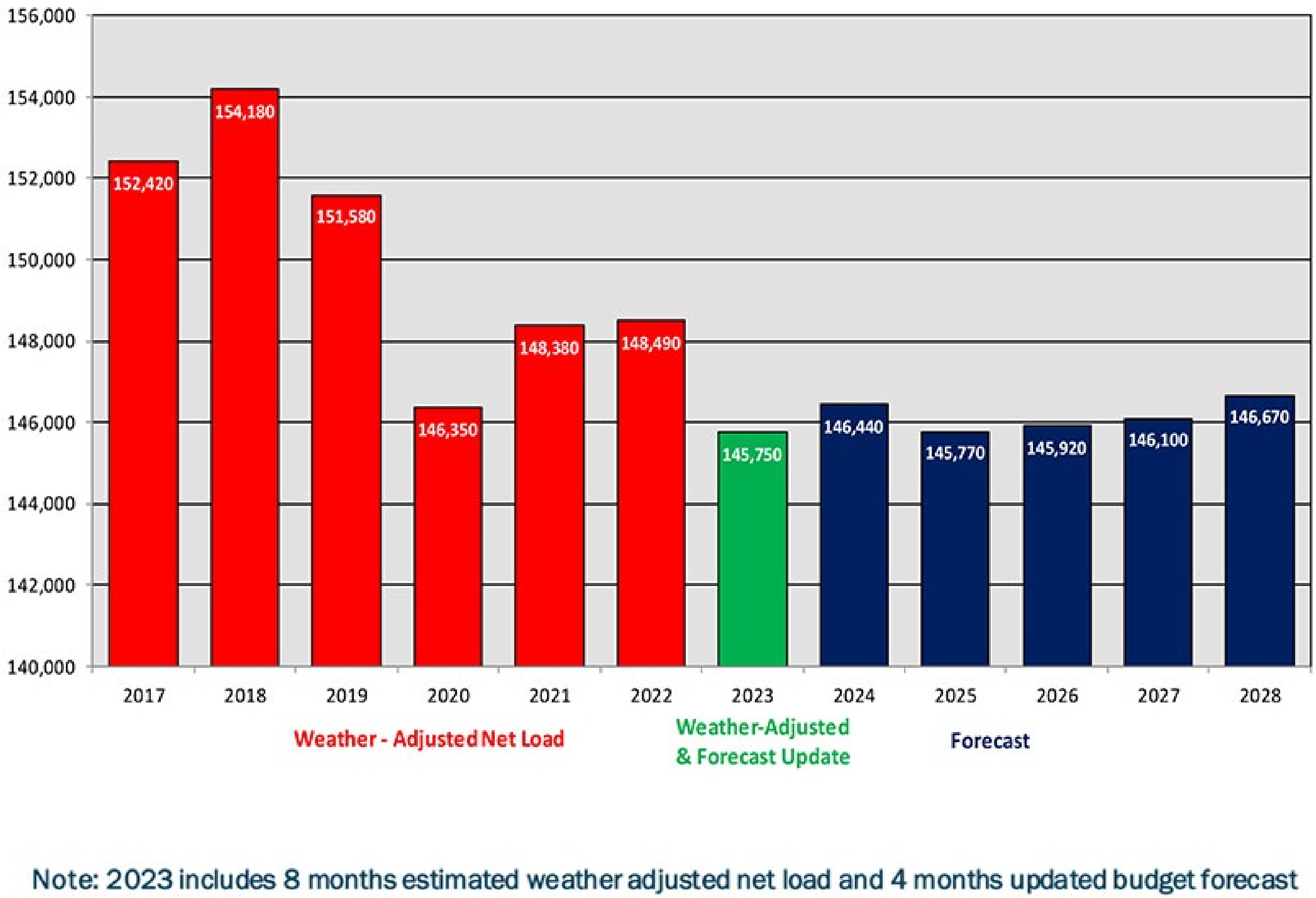
At the September MC meeting, some stakeholders were taken aback by the proposed staffing increases. (See "Draft Budget," *Emilie Nelson Named NYISO COO, Replacing Rick Gonzales*.) Alan Ackerman, director of NYISO regulatory affairs at Customized Energy Solutions, however, justified the ISO's draft budget, saying, "I think this does a great job of balancing the costs against the long list of items that need to get done next year."

The spending plan was approved unanimously by the MC on Wednesday. The board is expected to vote on the budget Nov. 14.

NYISO/PJM Joint Operating Agreement

The MC *recommended* that the board approve proposed *revisions* to the ISO's joint operating agreement with PJM, which governs coordination and data collection between the two grid operators.

The changes would migrate a *list* of interconnection tie facilities between NYISO and PJM from the JOA onto the web, add language clarifying that each operator adheres to its own procedures when developing and maintaining



Net load (GWh) | *NYISO*

NYISO News

interconnection reliability operating limits (IROL), and make clerical edits to facilitate cooperation in the resource adequacy and transmission planning areas. The IROL are the limits the ISO and PJM develop to ensure steady state and transient performance on the grid, such as voltage stability and transfer capability.

Howard Fromer, who represents Bayonne Energy Center, asked about PJM's status on this project and how the proposals would be filed with FERC.

Cameron McPherson, an associate market analyst with NYISO, responded, "we worked jointly with PJM to develop these revisions and they are in agreement on what we're submitting." He added, "[PJM] did present this information to their stakeholders earlier this month and did not receive any comments or questions."

These proposals were approved by the Business Issues Committee in September and are projected to be implemented in the first quarter of 2024, assuming approval by the ISO's board and FERC. (See "NYISO/PJM Joint Operating Agreement," *NYISO Business Issues Committee Briefs: Sept. 14, 2023*.)

Interconnection & Transmission

The MC *recommended* that the board approve tariff *revisions* intended to improve the coordination between NYISO's interconnection and transmission expansion studies.

The revisions would revise the criteria for including transmission projects in study assumptions, better capture generators outside NYISO's interconnection procedures for the purposes of future system planning and improve coordination among transmission projects moving through the ISO's interconnection processes.

The changes were recommended by the Operating Committee late last year, but the ISO delayed presenting them to the MC while it waited for FERC to rule on proposals by transmission owners concerning their right of first refusal for public policy transmission upgrades, which the commission approved in April of this year. (See "Interconnection & Transmission," *NYISO Operating Committee Briefs: Oct. 11, 2023*.)

The board will vote on the revisions in November. Assuming they are approved, NYISO will request its proposals become effective 60 days from when they are filed with FERC.

September Operations

NYISO's Emilie Nelson delivered her first monthly *market* and *operations* reports as chief operating officer, telling the MC that September experienced the summer's highest peak load (30,206 MW) and that year-to-date energy prices were down 57% compared to last year, declining from $92.27/MWh to $40.06/MWh due to continued decreases in gas prices.

Nelson was promoted to COO last month after Rick Gonzales announced his retirement from the industry. (See *Emilie Nelson Named NYISO COO, Replacing Rick Gonzales*.)

The peak load Sept. 6 happened during a multi-day heat wave in which temperatures exceeded 90 degrees Fahrenheit. NYISO examined how this summer's extreme weather events impacted grid operations and found that they currently pose little threat but will increasingly become a problem to the ISO's operations should the pace of fossil fuel retirements continue to outpace the addition of renewable generators. (See "Summer Operations," *NYISO Operating Committee Briefs: Oct. 11, 2023*.)

The ISO also added 20 MW of energy storage and 60 MW of behind-the-meter solar resources in September.

MC Election, Promotions

The MC voted to *elect* Glenn Haake, vice president of regulatory affairs at Invenergy, as new vice chair of the MC.

Haake reminded the MC that he was previously elected to be vice chair of the MC back in 2011, saying, "I'm excited at the prospect of being able to finish what I started a little more than a decade ago."

He will work with MC Chair Julia Popova, NRG Energy's manager of regulatory affairs, in his new role next year.

Nelson also told the MC that Shaun Johnson has been promoted to the ISO's director of market design and Joshua Boles promoted to director of market mitigation and analysis. ■

($ in millions)							
	Revenue Requirement *			Other Information *		% Increase over Prior Year	
ISO/ RTO	2024 Revenue Req. (In $$)	Estimated 2024 MWh throughput (In millions of MWh)	2024 revenue req. (In $/MWh)	Debt outstanding at 12/31/24	Authorized FTEs at 12/31/24	Revenue Requirement	FTE's
MISO	$340.1M	716.5	0.47	$275.0M	1159	3.9%	13.2%
PJM	$365.0M	828.0 TWH	0.44	$138.0M	850	13.4%	11.1%
SPP	Data Not Available at this time						
ERCOT	$348.1M	465.0 TWH	0.71	$31.0M	1014	44.5%	20.3%
CAISO	Data Not Available at this time						
ISO-NE	$274.1M	140.7	1.95	$108.6M	644.5	21.3%	4.9%
IESO	$170.94M	154.9	1.104	$141.5M	963	7.9%	4.3%
NYISO	$194.8M	152.1	1.281	$85.4M	647	2.5%	3.0%
*All amounts are DRAFT, and may be subject to change as each ISO/RTO completes its 2024 budget approval process							

Peer comparison | *NYISO*

NYISO News

Providers See ‘Mixed Signals’ on Demand Response in NYISO

Fear ISO and MMU Market Proposals Could Jeopardize SCR Program

By John Norris

RENSSELAER, N.Y. — Demand response providers in NYISO last week expressed concern that proposed market rule changes will harm the economics of special case resources (SCRs).

“This has not been a good week for demand response,” said Aaron Breidenbaugh, senior director of regulatory affairs at CPower Energy Management, which aggregates demand response and distributed energy resources (DERs).

Breidenbaugh’s comment came at the Oct. 26 Installed Capacity/Market Issues Working Groups meeting, where the ISO *presented* proposed modeling changes that could significantly cut capacity accreditations for SCRs. It followed the Oct. 25 Management Committee meeting, where Potomac Economics, the ISO’s market monitoring unit, *proposed* that the ISO compensate some capacity suppliers based on their contribution to transmission security, which could also reduce payments to SCRs.

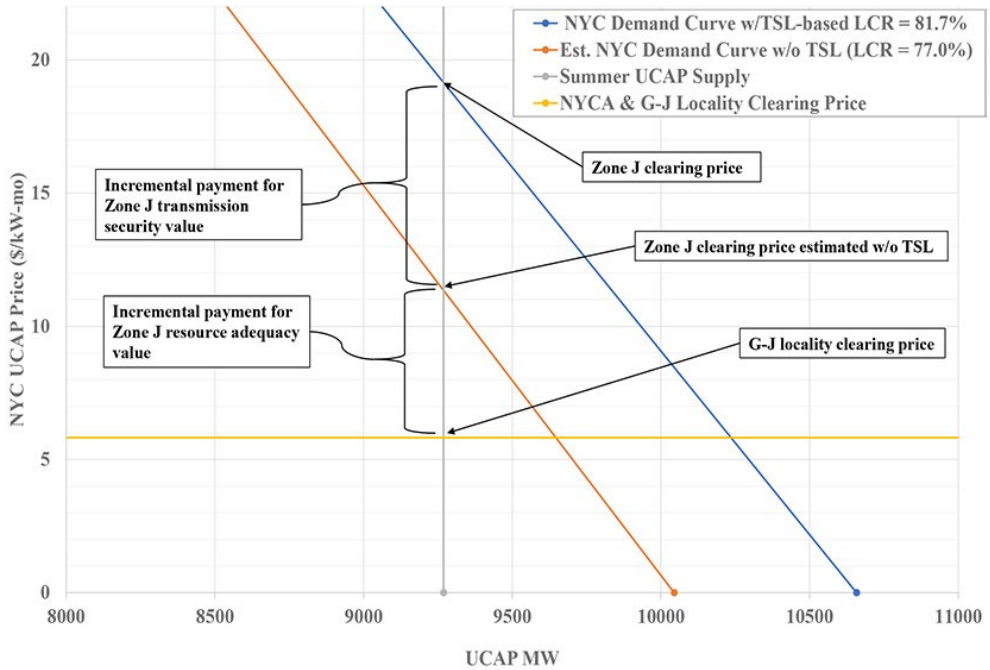
SCRs are demand-side resources whose load can be interrupted at the ISO’s direction or behind-the-meter generators rated 100 kW or higher that can reduce load on the transmission or distribution system.

The ISO says its current modeling of SCRs in the installed reserve margin (IRM), locational capacity requirement (LCR) and capacity accreditation studies is not aligned with SCRs’ actual performance.

It proposes to model SCRs as duration-limited resources with hourly response rates based on historical performance beginning in the 2025/26 capability year. In the interim, the ISO said it will treat SCRs as part of the four-hour energy duration limited capacity accreditation resource class. (See *NYISO Previews Capacity Accreditation Modeling Work*.)

Breidenbaugh said the ISO’s proposed changes could cut capacity accreditation of SCRs by 20%. He said his company will seek a change in the SCR program “to move from four hours to some other number ... in order to avoid gutting the SCR program.”

Breidenbaugh said Potomac’s proposed changes would reduce the payments to SCRs even more than is being contemplated by changes to accreditation rules, saying, “I’d prefer having my revenues reduced by 50% as opposed to 75%, but neither one of them is terribly attractive.”



Theoretical example of Potomac’s recommended approach to accreditation considering transmission security | *Potomac Economics*

Breidenbaugh said he’s received “mixed signals,” from the ISO on potential changes to the SCR program, citing NYISO CEO Rich Dewey’s comments at the Multiple Intervenors annual meeting about being willing to make SCR programs more flexible when previous NYISO presentations had suggested no such flexibility. He also cited statements by officials of the New York State Energy Research and Development Authority at the Alliance for Clean Energy New York annual meeting about “how important demand response is and how we aren’t going to meet the requirements in the CLCPA [Climate Leadership and Community Protection Act] without significantly greater demand-side flexibility.” (See *Mood Anxious as Renewable Energy Industry Gathers in NY*.)

He added that the ISO has made clear “that the future of demand response is the *DER participation model* — not getting rid of [the SCR program] but [NYISO is] making it so unattractive that the only alternative is to go into the DER participation model.”

The ISO’s DER and aggregation participation model, which will allow heterogenous groups of technologies to be compensated for services that they can provide collectively, was approved by FERC in January 2020 (ER19-2276). (See *NYISO DER Participation Model Gets FERC OK*.) On Oct. 19, the ISO *informed* FERC that it would not be implementing the DER participation model until the commission acts on companion tariff changes in docket ER23-2040.

Engaging the Demand Side

Adam Evans, a staffer at the New York Department of Public Service, also expressed concern. Although the ISO’s *Short-Term Assessment of Reliability* report for the third quarter identified a need to respond to new loads and shrinking margins, he said, “there’s really not much coming out of the Engaging the Demand Side effort,” an initiative to identify problems or gaps in the ISO’s existing demand side programs.

NYISO News

"I am really concerned about the long-term viability of the SCR program," said Jay Goodman, an attorney with Couch White, which represents large consumer stakeholders. "It seems that with every change layered onto the modeling, the impact generally seems to be in the direction of decreasing [SCRs'] capacity value.

"Our expectation is that SCRs being available is increasingly important, and so it doesn't make sense to have a … market rule change at a time when we think we need to be able to rely on them more," Goodman said.

In a *presentation* in September on the Engaging the Demand Side initiative, the ISO said it was not seeking to eliminate the SCR program but to respond to stakeholders' requests to modify SCR rules so that resources are compensated for their true operating capabilities.

The ISO said some SCRs can respond to events more frequently than others, and with less than the current 21-hour advance notification requirement. Some also can operate for up to eight hours. "In short, some resources have expressed that they are more flexible than the SCR program allows, but not flexible enough to fully participate in the DER program on dispatch," the ISO said.

The ISO said it would prefer to modify the DER participation model to tailor it to SCR operating characteristics rather than expanding the SCR program. Unlike the SCR program, which relies on manual actions by NYISO operators, demand-side resources in the DER model are automatically scheduled and dispatched based on the economics of their bids.

Maddy Mohrman, NYISO capacity market design specialist, told the ICAP/MIWG that "the goal of this project really is to come up with a modeling that just better represents the [SCR] program today."

NYISO will bring the results from its enhanced SCR modeling to the Nov. 1 meeting of the New York State Reliability Council Installed Capacity Subcommittee, which may vote to recommend changes be implemented into future IRM/LCR modeling.

MMU Recommendation

Breidenbaugh said SCRs could also lose revenues under Potomac Economic's suggestion to the Oct. 25 MC meeting that NYISO implement proposal No. 2022-1 from the MMU's May State of the Market *report*.

Potomac's Pallas LeeVanSchaick reiterated the monitor's recommendation during a discussion of NYISO's *draft* annual Comprehensive Reliability Plan, which the MC recommended be approved by the Board of Directors.

The CRP said that although the probabilistic resource adequacy analysis did not identify any reliability needs, the deterministic transmission security analysis predicts a deficiency for New York city starting in 2031 if the New York Power Authority's small gas plants, totaling 517 MW, retire without replacement resources.

The MMU's *memorandum* summarizing its comments on the CRP's resource adequacy assessment assumes that up to 1,180 MW of "emergency" resources in New York City for 2025, including 219 MW of SCRs. The transmission security assessment does not include emergency actions.

The MMU's State of the Market report found that SCRs and large resources whose size causes the transmission security planning contingency to increase "provide limited value towards satisfying reliability requirements based on transmission security criteria."

"Transmission security requirements are increasingly likely to cause higher [locational capacity requirements], especially in New York city. When this occurs, SCRs and large resources will be overcompensated and have inadequate incentives to take actions that would improve system reliability. In the upcoming 2023-24 capability year, we estimate that large resources and SCRs in New York City could be over-compensated by up to $52 million. (See *NYISO MMU Calls for Improved Shortage Pricing, More Capacity Zones*.)

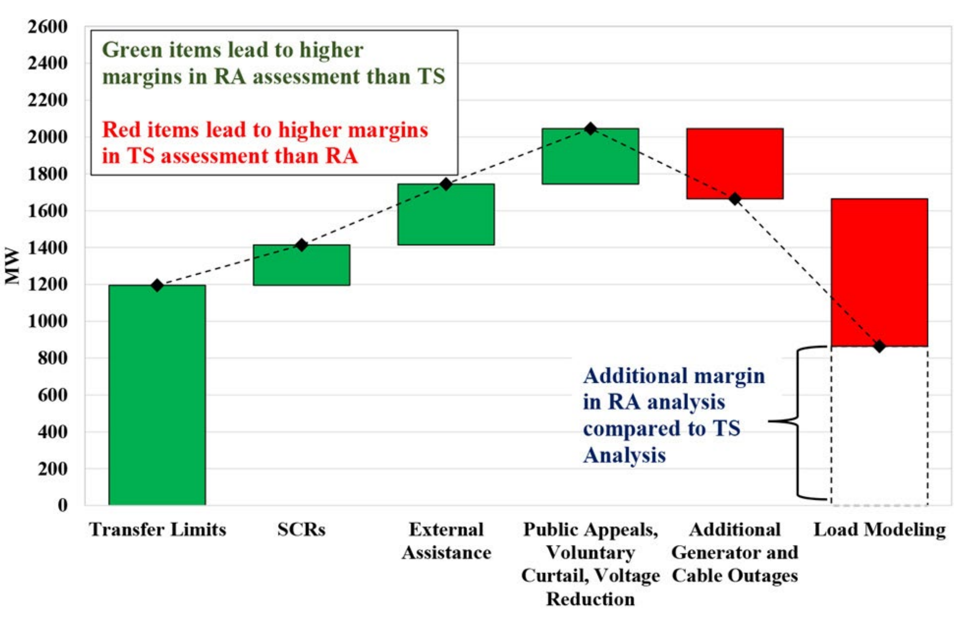
LeeVanSchaick said the MMU proposes a two-part pricing mechanism that separates resource adequacy and transmission security when transmission security criteria determine the LCR, ensuring SCRs, large contingency resources and intermittent renewables are appropriately compensated based on their contributions to the planning reliability requirements.

LeeVanSchaick pointed to a chart in Potomac's *presentation* to the MC that showed a roughly 800-MW difference in the marginal requirement needs for New York city projected by the two assessments. "If you calculate the margins [for New York city] using a transmission security assessment, there's a deficit in 2025, while a resource adequacy assessment would tell you there's a surplus," LeeVanSchaick said.

Breidenbaugh said that under the MMU's proposal, "you pretty much wouldn't have any SCRs in New York city."

Both NYSIO and Potomac acknowledged stakeholders' concerns but stressed more discussion is forthcoming.

LeeVanSchaick emphasized that Potomac "wanted only to highlight these differences to increase people's understanding of how the emergence of transmission-security-based capacity requirements are likely to affect investment incentives." ■



Overview of factors causing higher resource-adequacy-based New York City margin in 2025 | *Potomac Economics*

PJM News

NJ Revamps Third Solicitation OSW Connection Plans

BPU to Prepare Separate Coastal Infrastructure Solicitation

By Hugh R. Morley

| Shutterstock

New Jersey has revised its strategy for building the infrastructure to link offshore wind (OSW) projects to the grid onshore, abandoning a plan to have the developers in the state's third solicitation submit connection proposals along with their wind farm plans.

Instead, the New Jersey Board of Public Utilities (BPU) on Oct. 19 agreed to split off the connection infrastructure part of the project from wind farm development and hold a separate solicitation for the infrastructure work. The wind farm solicitation, which is expected to be concluded with project selection in early 2024, will continue as planned.

Jim Ferris, deputy director of the agency's division of clean energy, said that after reviewing the infrastructure component of the four bids submitted in the OSW solicitation, his staff concluded the original plan "imposes an unreasonable burden" on ratepayers. Splitting the two would increase competition by allowing infrastructure proposals from developers who had not submitted an OSW generation project, he said.

The BPU's 4-0 vote — one seat is vacant — was one of two decisions at the meeting triggered by implementation challenges involved in creating infrastructure that can handle the massive escalation in electricity generated that's expected as the state's clean energy policies unfold.

Separate from the OSW decision, the BPU agreed to extend the development deadline of five community solar projects after the developers filed petitions stating the utility to which they would connect their projects, Atlantic City Electricity, would take between 20 and 32 months to connect them to the grid. That delay effectively would prevent them from meeting program-imposed deadlines, the developers said.

BPU Commissioner Zenon Christodoulou acknowledged the OSW decision would not please some stakeholders but was necessary.

"I understand the frustration that this must cause on behalf of some of the developers that solicited [projects] in good faith," he said. "But we appreciate their partnership and look forward to working with them in the future to provide and promote a better product that will serve them the projects and the ratepayers.

Commissioner Mary-Anna Holden echoed the sentiment but said she was "very comfortable" with the decision.

"It is frustrating, but we're moving ahead," she said, adding that she backed the "approach that you're going to take with the pre-build, and soliciting people that really have an expertise in this transmission building."

New Solicitation

The state's third OSW solicitation, which could add capacity of between 1.2 GW and 4 GW and perhaps more, follows a 2019 solicitation in which the BPU backed the state's first OSW project, Danish developer Ørsted's 1,100-MW Ocean Wind 1. In the second solicitation, the state backed Ørsted's 1,148-MW Ocean Wind 2 project and the 1,510-MW Atlantic Shores project.

Gov. Phil Murphy (D) has set a state wind capacity target of 11 GW, of which the BPU so far has awarded 3,758 MW. Four bidders have submitted plans in the third solicitation (See *NJ's 3rd OSW Solicitation Attracts 4 Bidders*.)

The BPU on Oct. 27, 2022, approved onshore transmission upgrades totaling $1.07 billion that were submitted under a groundbreaking use of FERC Order 1000's State Agreement Approach. The approved projects would create a new substation to accept OSW electricity, known as Larrabee Collector Station. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

The BPU acknowledged at the time that the projects' selection under the SAA would not prevent future OSW generators from proposing different landing points or different routes to connect their offshore projects with the grid. In response, the board said it would require a successful bidder in its third OSW solicitation to "prebuild" offshore ducts and cabling to connect projects to the grid, known as PBI — creating a single corridor from the shore crossing to the Larrabee collector.

Ferris told board members Wednesday that

PJM News

the BPU planned for the offshore connection to link four OSW projects and land at the New Jersey National Guard Training Center in Sea Girt, from where it would connect to the Larrabee station. That "would minimize environmental and community impacts by resulting in a single short crossing and a single or limited onshore corridor to the point of interconnection," he said. The BPU planned to recover the cost of the infrastructure through the state's Offshore Wind Renewable Energy Certificate (OREC) system, which also would fund the OSW projects, he said.

However, Ferris said, the agency now believes the use of the "OREC funding mechanism" and the "requirement that the PBI could only be awarded to a developer who also receives an award as a qualified offshore wind project imposes an unreasonable burden on New Jersey's ratepayers."

"Staff has determined that a separate solicitation for the PBI open to transmission developers, transmission owners, offshore wind generation developers and other qualified firms."

A separate solicitation would "would increase competition and lead to ratepayers' savings," he added. He said the BPU staff believed the move would "not affect the generation project component of the third offshore wind solicitation applications."

Deadline Extension

In a separate case, the board approval of five deadline extensions in the state community solar program highlighted the difficulties faced by solar projects in some parts of the state in connecting projects to the grid.

Solar developers have for a while expressed concern about the challenges, and delays involved in getting projects connected, and cited the area served by Atlantic City Electric (ACE) in South Jersey as the worst. (See *Solar Developers: NJ's Aging Grid Can't Accept New Projects*.)

In outlining the case for an extension, Sawyer Morgan, clean energy representative for the BPU, noted that only 3 MW out of 33 MW of community solar project capacity that was approved by the BPU in the ACE area was expected to open within the program deadline.

The board's unanimous vote comes as the state prepares to transition to a permanent program — the Community Solar Energy Program (CSEP) — after two heavily oversubscribed community solar pilot programs that resulted in the approval of 150 projects totaling 235 MW. (See *NJ Opens Community Solar and Nuclear Support Programs*.)

The BPU approved the five projects seeking extensions in the second pilot program. They include two rooftop solar projects developed by Solar Landscape in Millville; two by Trina Solar Development on a Pennsville landfill; and a landfill project created by Greenpower Developers in Stafford Township. The projects had an initial 18-month deadline requiring them to become operational by May 4, 2023, which the BPU subsequently extended to Nov. 4, 2023, Morgan said.

"The petitioners each separately engaged in discussion of alternative interconnection options, but ACE's construction timelines still extended beyond the deadlines," the BPU representative said. "All three indicated that they would have been able to fully complete project construction by the deadline were it not for the upgrades required for interconnection."

The BPU representative said the difficulty of getting community solar projects online in areas served by ACE "may raise equity concerns for potential subscribers, as substantially more projects in other parts of the state have been able to become operational."

A deadline extension is warranted, he said, because the problems they face "were systemic, unforeseen and unforeseeable by petitioners, and wholly outside of their control."

Asked about the comments, Francis Tedesco, ACE spokesman, said in an email to *RTO Insider* that the company is "committed to continuing to work with local and state partners to accelerate the clean energy transition, including community solar, for the communities we serve."

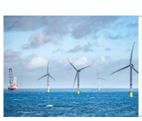
"We continue engaging with state electric utility companies, solar developers, the NJ Board of Public Utilities and other stakeholders and are actively working toward performing necessary energy grid upgrades to help accommodate community solar projects in our service area," he said. ■

Northeast news from our other channels

Conn. Seeks Proposals for Onshore, Offshore Renewables

Mass. Climate Chief Issues Wide-Ranging Recommendations

Mood Anxious as Renewable Energy Industry Gathers in NY



Vineyard Wind 1 on Track to Produce Power by Year's End

NY Announces Renewable Energy Projects Totaling 6.4 GW

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PJM News

PJM Stakeholders Approve New CONE Area for ComEd over Consumer Opposition

By Devin Leith-Yessian

The Markets and Reliability Committee (MRC) voted Oct. 25 to approve the *creation* of a fifth cost of new entry (CONE) area for the Commonwealth Edison (ComEd) zone to reflect an expectation that the Illinois Climate and Equitable Jobs Act (CEJA) will shorten the lifespan for combined cycle generators — the current reference resource CONE values are based on.

The vote capped months of discussions of how to reflect particularities at the local and state level that could affect the inputs in calculating the cost to build the reference resource, a subject broached by J-Power USA in a protest to PJM's 2022 quadrennial review filing. The company argued that new combined cycle resources would be forced into retirement within the 20-year amortization period included in the CONE calculation due to the legislation's requirement that generators have zero carbon emissions by 2045. (See "J-Power Critiques Amortization Period," *PJM Defends Quadrennial Review Parameters from Generator Protests*.)

The vote, which carried 80% support, came after a motion from the Illinois Citizens Utility Board (CUB) to defer the vote by a month failed after receiving 46.7% support against the two-thirds sector-weighted threshold needed to pass. Clara Summers of the Illinois CUB said that the delay would have provided more time to evaluate the effect of the proposal and potentially develop an alternative or amendments to the package. In particular, she expressed concern the proposal had no mechanism for reevaluating whether the ComEd-specific net CONE zone is providing relevant price signals as we near 2045, the expected end date for the combined cycle reference resource.

The proposal was endorsed by the Members Committee following the Oct. 25 MRC vote. A motion to defer the vote made by Summers was rejected by the MC as well.

She argued the legislation could affect inputs used to calculate CONE beyond the reference resource asset life, including the energy and ancillary service (E&AS) revenue offset.

"This proposal focuses on one factor in setting net CONE, asset life, because of CEJA ... but CEJA also has an impact on things like the E&AS offsets," Summers said before motioning to defer the vote.

She also pointed to comments PJM made in support of its quadrennial review filing at FERC stating there hasn't been a holistic analysis of CEJA's impact on CONE and that creating a region to account for legislation in Illinois could establish a precedent for creating CONE areas across several states and localities to account for various policies. Instead of establishing a new CONE area to account for specific legislation in one state, she said creating a clear standard for when a new area is warranted would be preferable.

Zachary Callen of the Illinois Commerce Commission said commission staff are not opposed to creating a new CONE area on principal, but he believes it's a complicated subject that hasn't had enough stakeholder discussion.

"It does give us pause that this is a really Illinois- and CEJA-specific policy and what we'd like to see more is something more rules-based," he said.

He said the tightened Base Residual Auction schedule over the next few years would provide little time for policy makers, load and generation to respond to price signals based on a new CONE area. Given PJM's analysis that the effect would be minimal at first, Callen suggested it may be better to wait until the next quadrennial review to make the change and to use the additional time to conduct more research.

Paul Sotkiewicz, president of E-cubed Policy Associates, said he had brought an alternative proposal that would have automatically created a new CONE area when policies affecting a region affected CONE inputs. He withdrew the package out of a desire to have the reduced asset life implemented in time for the 2025/26 auction. The further in advance the change is made, the less sharp any change in CONE values would be, he said.

"It's important to send those signals about reliability sooner rather than later, rather than have everything fall off a cliff" and risk a larger rate shock, Sotkiewicz said.

PJM's Gary Helm said the new area would have a CONE value of $201,714/MW-year, higher than any of the existing four areas. CONE Area 3, which ComEd is a part of, has a value of $197,800/MW-year. The proposal would affect only the reference resource asset life factor, based on the assumption that natural gas resources will retire based on CEJA's requirement that those generators reduce their emissions to zero by 2045.

Helm said waiting until the next quadrennial review would mean any changes would not be implemented until the 2030/31 delivery year, well into the period that PJM has stated it's concerned about resource adequacy as loads increase and fossil generation retires. He said that the proposal is part of a larger strategy for maintaining resource adequacy and that making the changes at this time would avoid a sudden change in capacity prices.

Paul Sotkiewicz, president of E-Cubed Policy Associates, speaks during the Organization of PJM States Inc. (OPSI) annual meeting on Oct. 16. | *© RTO Insider LLC*

The motion to defer was supported predominantly by the electric distributor and end-use customer sectors, with about 90% support in both categories. The other supplier and generation owner sectors were strongly opposed and transmission owners more mixed about the proposal, with 40% support. When the vote shifted to the actual proposal to create a fifth cone area, the transmission owner, other supplier and generation owner sectors were unanimous in their support, while 70% of the electric distributor sector and 46.2% of end-use customers voted in support at the MRC. ■

PJM News

PJM MRC Briefs

Markets and Reliability Committee

Proposed Rules for Generation with Co-located Load Rejected

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee rejected a *proposal* to modify how generators with co-located load not interconnected with the RTO's grid may participate in its capacity market.

The package, which was sponsored by Exelon in the Market Implementation Committee, received 19.5% support during the Oct. 25 vote. (See "Stakeholders Endorse Proposal on Co-located Load," *PJM MIC Briefs: Aug. 9, 2023*.)

The proposal would have required that the generation and load each be separately metered, with the generator being designated as a load-serving entity for the load. The generator would have been billed for the energy consumed by the co-located load as an LSE in settlement.

Exelon Vice President of Federal Regulatory Affairs Sharon Midgley said the proposal would allow the generator to offer its full accredited capability as capacity and require the load to pay for a capacity commitment through LSE charges. She said the proposal would effectively be a net financial derate for capacity market participation.

Constellation Director of Wholesale Market Development Adrien Ford urged the committee to vote against the proposal, referring to her comments during the package's first read in September arguing, in which she argued that it would violate the Federal Power Act by considering load not receiving energy from PJM's grid to be FERC jurisdictional.

Midgley responded that the load under the proposal would be retail and end-use.

Independent Market Monitor Joe Bowring said that the IMM opposed the proposal because, despite its designation of the generator as an LSE, it would permit the same capacity to be sold twice.

PJM's Tim Horger said that several proposed amendments were dropped based on stakeholder feedback in September and a determination that they were not necessary. He offered a friendly amendment, which the commission accepted, to adjust the cost-based offer definition to be in line with changes made throughout the manuals following the shift to cost- and market-based offers. In the event that the larger proposal did not pass, he said that PJM would seek to make the revisions as a standalone manual change.

Deputy Independent Market Monitor Catherine Tyler speaks at the Oct. 25 PJM Markets and Reliability Committee meeting. | *© RTO Insider LLC*

Stakeholders have been discussing how to account for generators with co-located load, both in configurations where the load is interconnected to the wider PJM grid or only capable of receiving energy from the generator. Several proposals addressing both were voted on by the MIC in August, but none regarding grid-connected load were endorsed, and Exelon's was the only one for unconnected load to pass.

Stakeholders Mixed on Sunsetting Clean Attribute Procurement STF

Stakeholders are considering terminating the work of the Clean Attribute Procurement Senior Task Force (CAPSTF) following several states opting to form a working group outside the PJM process to explore the creation of a voluntary market for trading clean energy attributes that is not under FERC jurisdiction.

The CAPSTF's work culminated in three proposals being polled in May, but none received the majority support needed to advance to the MRC. The poll did show overwhelming support for putting the task force on hiatus while the Critical Issue Fast Path (CIFP) process on the capacity market that, initiated in February, ran its course.

The effort is being spearheaded by Ryann Reagan, of the New Jersey Board of Public Utilities, who told *RTO Insider* that the state working group is primarily focused on a forward clean energy market (FCEM) design, which she said is a process similar to the proposal that received the largest share of support in the poll at 41%.

The concept would allow the trading of products representing clean energy attributes, as well as existing renewable energy credits (RECs). PJM currently administers a registry of RECs through the subsidiary PJM EIS (Environmental Information Services), but it does not facilitate the trading of credits.

PJM News

The FCEM design would not involve the procurement of capacity outside the Base Residual Auction (BRA); that would be more along the lines of an Integrated Clean Capacity Market, a variant of which received 33% in the poll.

The working group is open to the public, with those interested in participating welcome to reach out to Reagan; PJM and the Brattle Group are participating in addition to the states. The working group has a goal of reaching a general framework for a market design by the end of the year.

Whatever form any market created by the working group takes, Reagan said it's intended for state participation to be voluntary and also be open for nonstate entities, such as companies with clean energy goals. She said she has heard frustration about the lack of a centralized way to purchase credits, particularly for smaller REC buyers.

The desire to move out of the PJM stakeholder process is partly borne of not wanting to lose momentum at a time that the RTO is beginning work on several significant issues, such as the rules around reserve resources and generation deactivation. She noted that the topic had been discussed at PJM for three years and the CAPSTF has been on hiatus for five months.

Katharine McCormick, of the Illinois Commerce Commission, said the working group is also building on discussions held at the Organization of PJM States Inc. (OPSI) that concluded over the summer. She highlighted a few priorities in the analyses at PJM and OPSI, including that all of Illinois be modeled, so that the impact of any resource deactivations to the southern, MISO-covered portion of the state are considered.

McCormick said Illinois is participating in the working group, but it has not committed to being involved in any final market design that may come out of it. In addition to being able to procure capacity that meets the state's future clean energy requirements, she said it is also interested in ways of satisfying its capacity needs outside of PJM's Reliability Pricing Model (RPM).

If the end result of the working group does turn out to be a FERC-jurisdictional market, PJM's Scott Baker, facilitator of the CAPSTF, said a new forum can be found to hold those discussions.

Vistra's Erik Heinle said the possibility of the working group yielding a product that is either FERC jurisdictional or has an impact on PJM's markets that requires stakeholder attention could warrant leaving the task force open for at least a few additional months, especially considering the group's goal for a framework.

Baker responded that PJM staff considered leaving the task force open but are generally averse to having task forces not actively engaged in work.

Multiple Proposals Considered for Incorporation of Multi-schedule Modeling

The committee discussed two *proposals* intended to allow modeling of combined cycle and storage resources to be incorporated in the market clearing engine (MCE) without causing computation times to increase to an untenable degree.

Both proposals were endorsed by the MIC at its Oct. 4 meeting and are slated to be considered for MRC endorsement on Nov. 15. (See "Multi-schedule Modeling in Market Clearing Engine," *PJM MIC Briefs: Oct. 4, 2023*.)

The main motion, sponsored by PJM, would create a formula to select the offer expected to produce the lowest total dispatch cost and forward only that offer to the MCE. An alternative, jointly sponsored by PJM and GT Power Group, would select resources' cost-based offers when they fail the three-pivotal-supplier (TPS) market power test and their parameter-limited offers during emergency conditions.

The issue stems from an expectation that the number of schedules that the MCE would have to consider would exponentially increase because of the number of configurations that combined cycle and storage resources can reflect in their offers. The changes are being considered as part of a larger overhaul of the MCE through PJM's Next Generation Markets (nGEM) project.

GT Power's Tom Hyzinski said the rationale behind the joint proposal was to find a middle ground between PJM's proposal to pick a single generator's offer using a formula, and another proposal that GT Power put forward with the Monitor that would have constructed a single offer using parameters from one offer and incremental costs from another. He said the joint PJM proposal uses the formulaic approach to pick a single offer from among multiple cost-based offers, while the IMM proposal would require the resource owner to select the single cost-based offer.

"The intent here was to move this thing towards the middle," he said.

Deputy Monitor Catherine Tyler *presented* an issue with each proposal that she argued would create new ways for generators to avoid market power mitigation without resolving existing issues.

Tyler said PJM's proposal would result in the RTO only considering offers at their economic minimum (EcoMin) value, even if that offer becomes much more expensive at higher outputs. She gave an example of a resource where the price-based offer is cheapest at its 100-MW EcoMin but which jumps to the $1,000/MWh offer cap when the resource is dispatched above 120 MW. In such a case, she said the cost-based offer should be selected even if it's more expensive at EcoMin.

The PJM/GT Power proposal and the IMM/GT Power proposal, which was not endorsed by the MIC, would resolve the market power mitigation issue, Tyler said.

Both proposals would also use the PJM total dispatch cost formula to select among multiple cost-based offers, creating a possibility of a dual-fuel resource being dispatched on a fuel that is not the most economical for a portion of the day. Tyler said that could create a dilemma for generators because of the requirement that they base cost-based offers on the most economical fuel or risk being in violation of market manipulation rules.

PJM's Keyur Patel said that some tradeoffs will have to be accepted to realize the benefits of combined cycle modeling.

"We know that this is not optimal," he said.

Tyler said that the MRC should endorse the IMM/GT Power proposal, arguing that neither PJM nor GT Power had explained why it would be not the best solution.

Recommended Values for 2023 Reserve Requirement Study

The committee endorsed PJM's recommended *values* for the installed reserve margin (IRM) and forecast pool requirement (FPR) components of the annual Reserve Requirement Study (RRS), which would have the effect of increasing the amount of capacity the RTO aims to procure through future BRAs.

The parameters are set to go before the Members Committee in November and to the Board of Managers for final approval in December. (See "Stakeholders Endorse Reserve Requirement Study Values," *PJM PC/TEAC Briefs: Oct. 3, 2023*.)

The IRM, which sets the targeted capacity level above expected loads, would rise from 14.7% for the 2026/27 delivery year in the 2022 study to 17.6% for the 2027/28 delivery year. The FPR, which includes forced outage

PJM News

rates, also would increase from 9.18% to 11.65% for the corresponding delivery years.

PJM made a handful of changes to how the study is conducted in the wake of December 2022's Winter Storm Elliott and the changes to the capacity market being considered by FERC through the RTO's filing resulting from the CIFP. Load models were developed using both the PRISM software PJM has historically used, as well as an hourly loss-of-load model developed from the effective load-carrying capability accreditation studies. PJM also included data from the 2014 polar vortex and Elliott, reversing a historical practice to not include extreme winter storms in the study's modeling based on the impact of Elliott.

Minimal coincidence between the PJM peak load period and the "world" peak — which is defined as MISO, NYISO, TVA and VACAR — led to the capacity benefit of ties (CBOT) value more than doubling to 2.2% from the 1% value in the 2022 study. To reduce volatility, PJM elected to average the CBOT values from 2017-2022 and use that figure, which landed at 1.5%, instead.

The load model, which included data from 2013-2019, contributed to a 2.1-percentage-point increase in the IRM, while the winter peak week caused a 1.1-point increase. The values were slightly lower for the FPR drivers. The 1.5% CBOT contributed to a 0.5-point decline in the IRM value and a 0.58-point-lower FPR.

During a Resource Adequacy Analysis Subcommittee (RAAS) meeting in August, James Wilson, a consultant to state consumer advocates, calculated that the recommended values would constitute an approximate 3,700-MW increase in the summer reserve margin.

New Transmission Outage Coordination Rules

The committee signed off on revisions to Manual 38, which pertains to operations planning, to increase coordination between PJM and transmission owners to capture any potential extended transmission outages not identified by existing processes.

The proposal would add a step after board approval of Regional Transmission Expansion Plan (RTEP) windows for RTO staff and TOs to coordinate the sequencing of their outages and evaluate if any mitigation is needed, such as short-term emergency ratings or upgrades to limiting facilities. (See "Stakeholders Endorse Outage Coordination Manual Revisions," *PJM OC Briefs: Oct. 5, 2023*.)

The overall outage coordination package approved by the Operating Committee in June also adds information about outage requests and transmission ratings to PJM's website to increase transparency. (See *PJM OC Briefs: June 8, 2023*.)

Members Committee

3 Changes to Stakeholder Process Proposed

The Members Committee discussed first reads on three proposed changes to Manual 34, which sets the structure of the Consensus Based Issue Resolution (CBIR) stakeholder process.

Dayton Light and Power presented a change to the voting structure so that if a main motion fails, any alternative proposals submitted during the period for posting meeting materials would be voted on simultaneously.

Exelon's Alex Stern presented a proposal that would specify that requests to add an item to a standing committee meeting agenda is considered to be timely when it is made at least seven days in advance. Requests should include a summary of the action that the committee will be asked to consider.

The language would provide committee chairs with discretion to consider agenda items posted within seven days of a meeting in the event of the subject being time sensitive or of unforeseen disruptions, such as PJM website or internet outages.

Chairs may also consider waiving the deadline for non-voting items, such as informational reports, with the suggestion that members instead provide enough time for PJM staff to review for formatting and agenda conformity.

Monitor Bowring asked for clarification on whether the flexibility around informational items would apply to the reports delivered to the MC webinar, which Stern confirmed would be the case.

Stern also presented a second proposed change aiming to clarify that senior standing committees hold final authority over issues considered by task forces and that the lower committees set the order that proposals will be voted on at the MRC and MC. ■

— Devin Leith-Yessian

PJM News

FERC Approves Extension of Comment Period in PJM CIFP Filings

By Devin Leith-Yessian

FERC has approved a nearly one-week extension of the comment period on PJM's two filings to rework several areas of its capacity market following the conclusion of the Critical Issue Fast Path (CIFP) process in October (*ER24-98, ER24-99*).

The extension, issued Oct. 27, allows comments to be submitted through the end of Nov. 9, rather than the Nov. 3 deadline PJM sought. PJM Chief Communications Officer Susan Buehler said the extension does not impact the Dec. 12 effective date PJM requested in its filing and therefore would not impact its target to have changes in place for the 2025/26 Base Residual Auction, scheduled to be run in June 2024. (See *PJM Files Capacity Market Revamp with FERC*.)

The commission did not go as far as the Independent Market Monitor *asked* when it filed a request for comments to be permitted until Nov. 17, arguing that the intricacy of the filing warrants additional time. The request was supported by American Electric Power, American Municipal Power (AMP), Old Dominion Electric Cooperative, the PJM Industrial Customer Coalition and the Office of the Ohio Consumers' Counsel.

"The Market Monitor requests an extension of time of 14 days because the filings in these dockets raise important, complex and intricate issues about the design of the PJM capacity markets. More time is required for preparation of an adequate response than the current deadline affords," the Monitor wrote.

PJM *responded* that the Monitor and stakeholders should be aware of the changes being proposed in the filing through the months of discussion throughout the CIFP process. Extending the comment period would reduce the amount of time for the commission to evaluate the filing and comments to make a reasoned decision by Dec. 12.

"Specifically, PJM thoroughly discussed the proposed enhancements with all stakeholders, including the Market Monitor, through the Critical Issue Fast Path stakeholder process over a six-month period before the actual filing. Further, the PJM board issued a public letter to all stakeholders detailing the very proposals contained within the underlying dockets nearly one month ago on Sept. 27, 2023," PJM wrote.

In its *comments* supporting the Monitor's request, AMP wrote that the changes being considered could have substantial impacts on the capacity market that should be fully thought out. If full consideration of the proposals leads to the commission not issuing an order prior to the commencement of pre-auction activities, AMP recommended that the commission delay the auction schedule or order it to be run it under the status quo rules.

"If a delay becomes necessary, PJM should seek a revised date for that auction or run it under the existing rules, which have not been found to be unjust, unreasonable or unduly discriminatory. Neither the stakeholders' nor the commission's review of PJM's complex filings should be cramped by PJM's assertions that allowing two more weeks for comments will materially affect the auction schedule," AMP said. ■

PJM CEO Manu Asthana | © *RTO Insider LLC*

Company News

CenterPoint Names New CEO to Replace Lesar

Houston Utility Reports 14th Straight Strong Quarter

By Tom Kleckner

CenterPoint Energy on Thursday *announced* a leadership change atop the organization, with COO Jason Wells replacing the retiring David Lesar as CEO.

Wells will become CenterPoint's CEO on Jan. 5. Lesar will work closely with his successor in the meantime to ensure a seamless transition, the Houston-based company said.

"I have full confidence that Jason is the right person to take the helm," Lesar told financial analysts during the company's third-quarter earnings conference call. "Now is the right time to advance this transition as our very strong third-quarter results demonstrate. We have great momentum and a solid foundation in place. Making this change at the beginning of 2024 allows Jason and the team to hit the ground running."

Jason Wells (left) will replace David Lesar as CenterPoint Energy's CEO in January. | *CenterPoint Energy*

Lesar, a former CEO with Haliburton, was brought out of retirement in 2020 to provide leadership after the Texas Public Utility Commission reduced a $161 million rate case settlement to $13 million. Scott Prochazka resigned as CEO shortly after the decision. (See *New CenterPoint CEO Promises to 'Simplify the Story.'*)

Wells joined CenterPoint as its CFO in 2020, shortly after Lesar was appointed CEO. The two have worked together to "reshape and launch our utility-focused strategy," he said.

Wells previously spent 13 years with PG&E Corp., where he worked his way up the ladder before eventually serving as CFO. He holds bachelor's and master's degrees in accounting from the University of Florida.

He thanked Lesar for his "tireless" leadership, mentorship and friendship and said he has "incredibly big shoes to fill."

CenterPoint *reported* earnings of $256 million ($0.40/diluted share), compared to $189 million ($0.30/diluted share) for the same period a year ago. The company said the results primarily were driven by growth, regulatory recovery and favorable weather.

It was the 14th straight quarter CenterPoint has met or exceeded expectations, Lesar said. Zacks Investment Research had projected earnings of $0.37/share.

Commiserating with CenterPoint's executive team over the Houston Astros' recent elimination from the MLB playoffs, one analyst said, "You can win every year in the utility business, but you can't in baseball."

"So true," Lesar responded. He closed the conference call by saying, "Just stick with us, because the best is yet to come."

CenterPoint's share price closed at $27.60 Thursday, a gain of 13 cents for the day. ■

Company News

NextEra's Renewables Unit, FPL Key Performance

NextEra Energy said last week that its renewables subsidiary had its best origination quarter in its history, adding about 3.25 GW to its backlog.

NextEra Energy Resources' (NEER) backlog now exceeds 21 GW, net of projects placed in service. The clean-energy unit placed a little over 1 GW of resources into service.

NEER and *Florida Power & Light*, the nation's largest electric utility, added 65,000 more customers from a year earlier, helping NextEra beat Wall Street estimates.

NextEra *reported* third-quarter earnings of $1.219 billion ($0.60/share), compared to $1.696 billion ($0.86/share) for the same period a year ago.

"We will be disappointed if we are not able to deliver financial results at, or near the top of, our adjusted earnings per share expectations ranges in each year through 2026," CEO John Ketchum told financial analysts during the company's third-quarter conference call.

"The strength of both businesses ... combined with our competitive advantages and strong balance sheet, positions us to continue creating long-term value," he said. ■

— Tom Kleckner

NextEra Energy's "Dr. Seuss" solar panels at its headquarters. | *© RTO Insider LLC*

Company News

Xcel Energy Touts Steel for Fuel 2.0 Plan

Capital Investments Projected to Reach $34B by 2028

By Tom Kleckner

Xcel Energy management told financial analysts last week that it has made "significant progress" on what it calls "industry-leading clean energy transition plans."

"Given that the regions where we serve customers are the most resource rich in wind and solar," CEO Bob Frenzel said during the company's third-quarter earnings call Friday, "we believe that we can lead this clean energy transition for our customers more cost-effectively than almost any other company."

The Minneapolis-headquartered company is relying on its Steel for Fuel 2.0 program, which builds on its plan to swap fossil generation for fuel-free wind and solar that the company rolled out seven years ago. Xcel has increased its capital investment plan through 2028 to $34 billion, with another $10 billion potentially necessary after state regulatory approval of clean energy projects. (See *Earnings Up, Xcel Touts 'Steel-for-Fuel' Strategy*.)

In September, Xcel's Colorado subsidiary filed what it called the largest clean energy transition effort in the state's history. The plan includes shutting down its remaining Colorado coal plants with approximately 6.5 GW of renewable energy and battery storage, doubling the state's renewables, and about 600 MW of natural gas resources to ensure reliability during times of low wind or solar conditions.

Including about $3 billion in required transmission investments, Xcel will invest nearly $11 billion in the state. The company expects Colorado's regulatory commission to rule on the proposal early next year.

In Minnesota, Xcel has received regulatory approval to add 250 MW of new generation at its *Sherco Solar project*, bringing the facility's capacity to over 700 MW. The project will use existing interconnections from the Sherco coal plant, which is retiring by 2030.

Its Southwestern Public Service Co. (SPS) subsidiary filed a resource plan in New Mexico earlier this month that lays out a need for between 5 GW and 10 GW of new generation by the end of this decade. SPS already has proposed 418 MW of company-owned solar and battery projects that are pending commission approval.

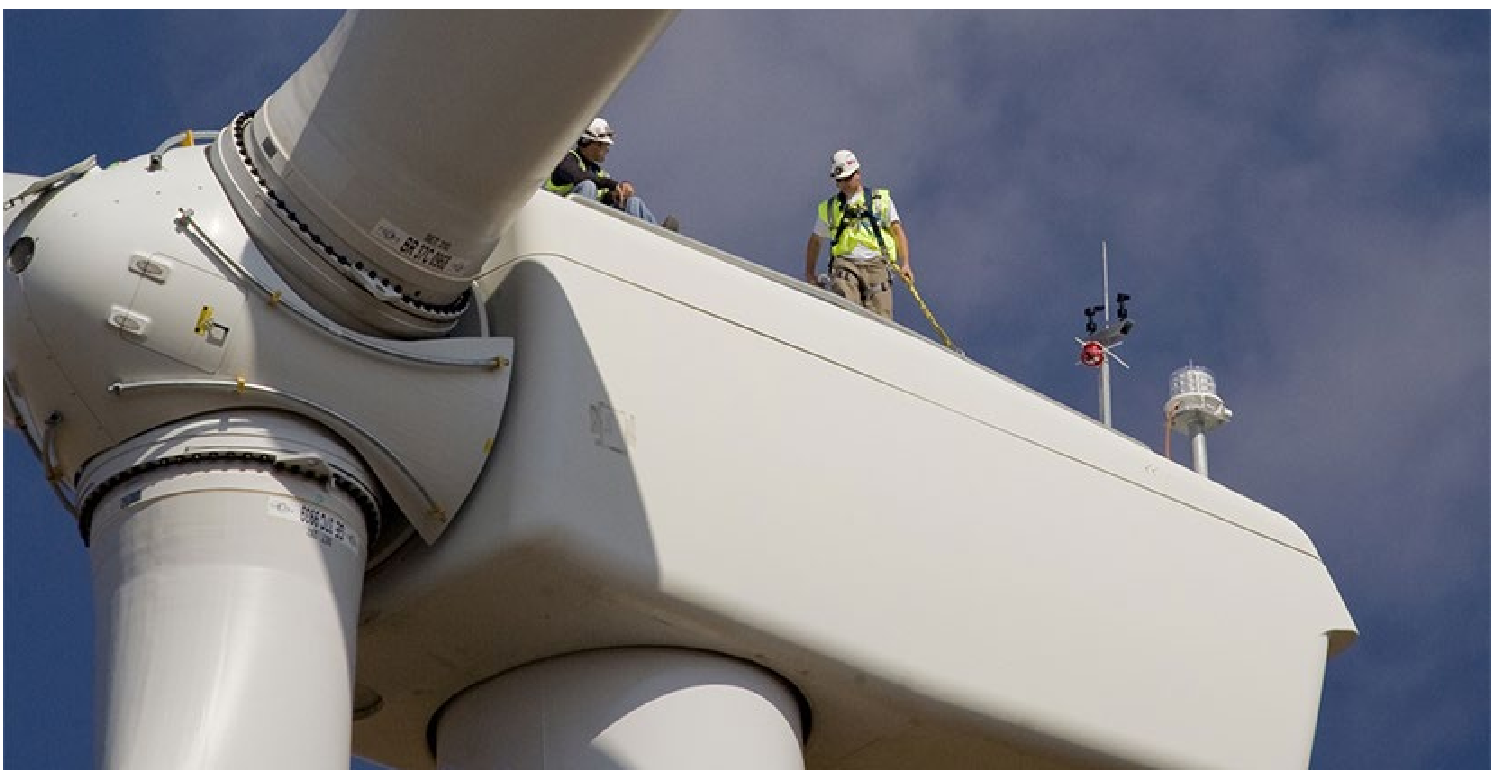
"We have the potential to deploy [15 GW] to [20 GW] of new clean generation on our systems by 2030, dramatically lowering our emissions profile," Frenzel said.

The company said it will appeal a *Colorado district court decision* Wednesday that awarded CORE Energy $26.5 million in damages for a breach of contract and mismanagement of Xcel's Comanche 3 unit. CORE owns a 25% share of the plant, which has averaged 91 days of unplanned shutdowns a year since the unit went online in 2010.

"We have a strong legal basis for challenging that $26 million award," Xcel CFO Brian Van Abel said.

The company *reported* earnings of $656 million ($1.19/share), compared with $649 million ($1.18/share) for the same period in 2022. The results reflect the effect of increased recovery from infrastructure investments, higher sales and demand, and lower operating and maintenance expenses, partially offset by increased interest charges and depreciation, the company said.

Its share price lost 2.4% Friday, closing down $1.46 at $58.31. ■



Xcel Energy is projecting up to $44 billion in investments, much of it for clean energy. | *Xcel Energy*

Company Briefs

Energy Executive Charged in Conspiracy to Steal GE Trade Secrets

Retired energy executive John Gibson was criminally charged in Virginia federal court for an alleged conspiracy to steal General Electric and Mitsubishi Heavy Industries trade secrets.

Gibson allegedly helped coordinate a 2019 scheme to help win a bid to build a gas turbine plant for Dominion Energy. An employee for Siemens and one for Dominion previously pled guilty in relation to the same matter.

Siemens, described in the indictment as "Company 1," convinced a Dominion employee to share trade secrets and other confidential information from GE and Mitsubishi's bids, and returned the favor with gifts, documents said. The information allowed Siemens to undercut the GE bid and secure the plant contract. Siemens isn't mentioned in the complaint, but Gibson's status as a Siemens executive is also alleged in a lawsuit brought by GE against the company involving the events.

More: *Bloomberg Law*

Tesla Discloses DOJ Probes Over Vehicle Range, Personal Benefits

Tesla last week disclosed that the Department of Justice has been investigating, and in some cases issued subpoenas, to the automaker regarding its driver assistance systems marketed as Autopilot and Full Self-Driving options, the range of its EVs, as well as "personal benefits, related parties" and "personnel decisions" at the company.

It was reported in August that federal prosecutors were investigating whether Tesla used company funds to design and build a "glass house project" for Musk. Last year, it was reported that a federal criminal investigation was underway concerning Tesla's claims that its cars were self-driving. Reports and research revealed that Tesla's cars frequently fail to achieve the mileage stated in range estimates.

Tesla also disclosed that a data breach has resulted in several individual and prospective class action lawsuits filed against it.

More: *CNBC*

American Battery Factory Breaks Ground in Ariz.

The American Battery Factory last week broke ground on a new $1.2 billion manufacturing facility in Tucson, Ariz.

The company said the facility will create 1,000 new jobs when it reaches full capacity, while the economic impact for Southern Arizona will reach $3.1 billion in 10 years.

More: *AZPM*

Federal Briefs

House Republicans Pass Energy, Funding Bill

House Republicans last week voted 210-199 to pass a sprawling partisan energy plan.

The bill cuts more than $5 billion in spending that was passed as part of the Inflation Reduction Act. The legislation is unlikely to become law, though, as the White House has threatened to veto it.

Among other provisions, the legislation targets a program that gives rebates to consumers who purchase electric appliances. It would also cut a program in the IRA aimed at helping state and local governments adopt climate-friendly building codes, as well as cut the DOE's Energy Efficiency and Renewable Energy Office by about $466 million.

More: *The Hill*

TVA Colbert Combustion Turbine Plant Adds 3 Turbines

The Tennessee Valley Authority last week announced that its additions at the Colbert Combustion Turbines are fully operational.

The three new turbines, which cost $500 million, produce around 750 MW.

TVA President and CEO Jeff Lyash said the additions have helped reduce strain on the grid and reduce fossil fuel emissions.

More: *WAFF*

BLM Backs Off Approval of Albany County Wind Tx Line

The Bureau of Land Management last week voluntarily backtracked on its approval of a transmission line in Southeast Wyoming.

The Albany County Conservancy and retired U.S. Fish and Wildlife biologist Mike Lockhart filed a lawsuit earlier this year challenging the BLM's approval process for the transmission line, which was proposed to connect the Rock Creek Wind project to two larger transmission lines that will carry wind energy out of Wyoming. The lawsuit claimed the approval process was improperly done, without required public notification and participation.

The BLM has agreed to go through the public process before issuing another decision.

More: *Cowboy State Daily*

State Briefs

GEORGIA

Georgia Power Asks for Permission to Burn More Natural Gas

Georgia Power last week asked the Public Service Commission to allow it to burn more fossil fuels to meet rising demand.

The company said it wants to build or contract for at least 3,365 MW of generating capacity. The utility projects increased demand is coming so quickly that it can't wait until 2026 to start increasing supply and does not have time to seek more power from outside providers.

Based on Energy Information Administration statistics, the investment could run into the billions of dollars, although the company repeatedly declined to provide an estimate. Customers would not fully pay for it until after 2026 under the plan the company proposed to the PSC.

More: *The Associated Press*

ILLINOIS

Lawmakers Will not Attempt to Override Pritzker's ROFR Veto

Rep. Larry Walsh (D) last week announced

he would not attempt to override Gov. **JB Pritzker**'s (D) partial veto that struck language from a bill giving utilities the right of first refusal (ROFR) for transmission lines.

In issuing the amendatory veto, Pritzker said opening up bidding for transmission lines would create competition, while giving existing utilities ROFR on future projects would create a monopoly and lead to higher energy costs.

Walsh said his plan is to bring a new bill granting ROFR next year instead of attempting to override Pritzker's veto.

More: *WGEM*

One Earth Energy Proposes CO2 Pipeline Project

One Earth Sequestration filed an Application for Certificate of Authority with the Commerce Commission on Oct. 18 to construct in a 7.34-mile One Earth Sequestration (OES) Pipeline.

The OES Pipeline would transport liquid carbon dioxide captured from the 150-million-gallon ethanol facility operated by One Earth Energy in Gibson City to an injection site in McLean County, according to the filing. About 420,000 metric tons of CO_2 is produced by the ethanol facility each year, but the pipeline would have the capacity to transport up to 4.5 million metric tons per year.

If approved, construction of the pipeline would start in 2024, with service expected in 2025.

More: *FarmWeekNow.com*

Piatt County Approves Wind Farm

The Piatt County Board last week voted 4-2 to approve Apex Energy's special use permit to allow the county's first wind farm.

The Prosperity Wind Farm, owned by Apex Clean Energy, will have 50 turbines with land use agreements covering more than 19,000 acres.

The county Zoning Board of Appeals approved findings of fact on Oct. 3 that stated that project standards were met. However, it still voted to not recommend the project to the board.

More: *Piatt County Journal-Republican*

MONTANA

PSC Approves NorthWestern Energy Rate Hike

The Public Service Commission last week unanimously approved a new NorthWestern Energy rate structure that will go into effect in November.

Residential customers will see a 28% increase on bills compared to August 2022, or an 8% increase since the commission approved an interim rate increase for the utility last fall. The changes are expected to increase NorthWestern's electricity-related revenue by $82 million and its natural gas revenue by $18 million.

The PSC said it leaned heavily on its staff, who have been reviewing the case over the past 14 months, when explaining its approval.

More: *Montana Free Press*

NEW MEXICO

County Opposes NM Gas Company's LNG Storage Facility

The Bernalillo County Commission and community members last week voiced their opposition to the New Mexico Gas Company's proposed liquified natural gas storage facility.

Residents referenced "numerous safety risks, health concerns and financial costs placed on New Mexicans," along with "further [worsening] the climate crisis."

The commission went on to create a resolution against the facility and passed it along to the Public Regulation Commission.

More: *KRQE*

NEW YORK

NYC Approves Requiring All Zero-emission Rideshare Vehicles by 2030

New York City Mayor **Eric Adams** (D) and the New York City Taxi and Limousine Commission last week announced the unanimous approval of new rules that will require all city rideshare vehicles to either be zero-emission or wheelchair accessible by 2030.

The requirements will be phased in over the course of the next several years, starting with 5% of all rideshare vehicles by 2024.

The adoption of the rules makes New York City the first city in the U.S. to commit to transitioning to an all zero-emission or accessible rideshare fleet.

More: *Staten Island Advance*

OHIO

Bill Would Declare Nuclear Power as 'Green Energy'

House lawmakers last week introduced legislation that would expand the state's legal definition of "green energy" to include nuclear power.

Last year, state lawmakers added a provision to state law that created a new legal definition for the term "green energy" that explicitly includes energy generated via natural gas. The new law also includes any energy resource that either releases "reduced" air pollutants or is more sustainable "relative to some fossil fuels."

More than half of the state's the power generated in 2022 came from natural gas, according to the EIA. Another 12% came from two nuclear plants, while renewables produced about 4%.

More: *Cleveland.com*

TEXAS

State Leads Nation in Installed Solar

Texas now has the most solar power installed on its grid in the country, according to data collected by *Bloomberg*.

ERCOT, the grid operator for 90% of Texas, had 18,364 MW of solar capacity installed as of Sept. 30. Meanwhile, CAISO had 17,277 MW of solar capacity installed by the end of September.

More: *Houston Chronicle*

VIRGINIA

Judges Deny Landowners' Emergency Request to Halt MVP

The D.C. Circuit Court of Appeals last week denied an emergency injunction request from six landowners to halt Mountain Valley Pipeline construction on their properties.

Three couples are suing FERC and Mountain Valley Pipeline and have argued that Congress improperly delegated the legislative power of eminent domain to the commission. A federal judge in the D.C. Circuit had previously dismissed the

landowners' case, citing a lack of jurisdiction, but the landowners appealed to the U.S. Supreme Court, which sent it back to the appellate court in April.

The court order did not offer details behind the decision.

More: *Cardinal News*

Prince William Adopts County's 1st Environmental Master Plan

Prince William County supervisors last week approved the county's first-ever plan that sets goals for reducing greenhouse gas emissions and transitioning to sustainable energy.

The plan focuses on five goals adopted in November 2020 and includes 25 actions that have been "prioritized for immediate execution" by the county government. Of the five goals, reducing greenhouse emissions by 2030 is a priority that can only be achieved by reducing emissions both in the community and the county government. Some priorities for reducing emissions include upgrading public transit infrastructure, promoting renewable energy incentive programs and improving pedestrian and bicycle infrastructure.

More: *Prince William Times*