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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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In this week's issue

Stakeholder Soapbox

The Cost of Inaction — An Outdated Grid, Overpriced Power

By Jason Stanek

Jason Stanek | *Maryland PSC*

The nation has a looming problem. The infrastructure upon which millions of Americans rely to power their daily lives is growing older while demand on regional power grids is breaking all-time records with increasing regularity. The country's regional grid operators lack sufficient access to generation in neighboring regions, resulting in preventable power outages and soaring electricity prices during extreme weather events. Even under normal operating conditions, a lack of import and export capability between various parts of the country can result in higher power costs.

The construction of high-voltage transmission lines between regions has been stymied over the years for various reasons, but it is clear we increasingly need new interregional lines, both now and in the future. One relatively simple way to accomplish this would be for Congress to direct FERC to establish a minimum interregional transfer capacity requirement to ensure that grid operators have enough capacity to export or import a certain amount of power to neighboring regions at all times. Doing so will strengthen the nation's resilience to extreme weather events, increase overall grid reliability and ultimately reduce the cost of delivered electricity to customers.

Fortunately, this policy option has recently been the focus of significant discussion by stakeholders. Late last year, FERC *discussed* such a minimum transfer standard. Notably, in its post-workshop comments, the U.S. Department of Energy *emphasized* that its draft *National Transmission Needs Study* finds a "pressing need for additional electric transmission infrastructure, including interregional transmission." Additionally, this topic has merited review by the Joint Federal-State Task Force on Electric Transmission, a collaborative dialogue between FERC commissioners and state utility regulators.

So, what's the "right" amount of transfer capacity? Some grid experts have called for a minimum interregional transfer capacity requirement ranging from 15 to 30% of peak load.

While there are benefits and costs associated with a higher or lower percentage, there is wisdom in setting a uniform minimum requirement. As I recently *testified* before the Senate Energy and Natural Resources Committee, it would be more expeditious if Congress were to define and set a reasonable threshold rather than tasking FERC with a multiyear stakeholder process to determine the requirement, a process that would surely further delay critical projects' buildout.

The need for new transmission lines also serves to mitigate the impact of extreme weather events, which are undeniably increasing in severity and frequency. In the first seven months of this year, 15 extreme weather events across the country — *several of which* caused *power outages* — each resulted in $1 billion or more in damages. These events accounted for the *most disasters over the period since 1980*. Extreme weather has also contributed significantly to congestion costs in recent years. While power outages during storms are never fully preventable, we can prepare our electric grid to better withstand them, as interregional transmission lines can transport available power from several states away to areas where local generators cannot meet demand.

Further, as I testified, long-distance wires connecting regions serve as an important insurance policy: While grid operators hope to avoid asking neighboring grids for electricity, it is important to have the ability to do so when a situation arises. For example, the addition of high-capacity interregional transmission lines from Texas to neighboring regions could have prevented the devastating storm-induced outages in February 2021, according to an analysis from power sector consulting firm Grid Strategies. Given the tremendous cost savings associated with additional interregional transmission capacity, a line could have *paid for itself in four days* during that cold snap.

More recently, some utilities could have saved upward of *nearly $100 million* per gigawatt of capacity in late 2022 if they were able to wheel more power in from the Midwest or New York. Instead, unplanned generation losses of all types *exceeded 70 GW*, and several balancing authorities ordered firm load shed of more than 5 GW over the Christmas holiday.

Moreover, increasing congestion on the regional power grids — when there is insufficient transmission capacity to deliver the most affordable power to customers, forcing more expensive generating units to run — cost the U.S. an *estimated $20.8 billion* in 2022, according to Grid Strategies. While this savings estimate can be debated, it is indisputable that customers pay more when they are unable to access cheaper supplies of electricity.

These facts are not lost on utility regulators. During the past year, members of the federal-state transmission task force reviewed the merits of a minimum transfer capacity standard and, more broadly, the need for more interregional transmission. In an op-ed published by *RTO Insider* in April, former Arkansas Public Service Commission Chair Ted Thomas touted the "significant reliability benefits" a standard would provide. (See *Stakeholder Soapbox: Transmission Keeps the Lights On*.)

At a task force meeting, former FERC Chair Richard Glick recognized that over the last decade, "there really hasn't been any interregional transmission built … so we're in a situation where I believe we need to consider, are there reforms that are necessary to move forward?"

Vermont Public Utility Commissioner Riley Allen found that there is a "growing body of evidence [that] interregional transmission can contribute to a significant degree on a triad of needs," including affordability, reliability and clean energy. And Dan Scripps, chair of the Michigan Public Service Commission, similarly emphasized that "there's no doubt that increased interregional transfers and interregional transmission can also offer additional benefits, particularly economic benefits, but ultimately the real value is ensuring that we have a grid that can support reliability and enhanced resilience, particularly in times when the grid operates in ways other than for which it is originally planned."

I agree with my colleagues on these points, but I also know that the *cost of developing new energy infrastructure projects* must be weighed against a number of competing considerations. That said, I am confident that building more interregional transmission lines is a good, near-term investment that will deliver benefits now and for future generations. The facts are clear; it's the political will that is needed. ■

Jason Stanek is the former Chairman of the Maryland Public Service Commission and previously served as a co-chair of the Joint Federal-State Task Force on Electric Transmission.

FERC/Federal News

9th Circuit Upholds FERC's Revisions to PURPA Regulations

Lack of Enviro Assessment 'Serious Violation' of NEPA, but Vacatur not Warranted, Court Says

By John Cropley

A federal appeals court last week rejected a challenge to FERC's 2020 revisions to how it enforces the Public Utility Regulatory Policies Act, though it concluded the commission committed a "serious violation" by not conducting a formal environmental assessment (EA) before issuing the order (*20-72788*).

Multiple renewable energy industry and environmental advocacy groups petitioned for review of Order 872, which they argued made it more difficult for independent, non-utility-owned energy generators to be designated qualifying facilities under PURPA (*RM19-15, AD16-16*). (See *FERC Rejects Challenges on PURPA Changes*.)

The 9th U.S. Circuit Court of Appeals, however, found that FERC holds broad rulemaking discretion and its interpretations of the law were not unreasonable. The court also rejected the petitioners' challenges to four specific provisions of the order.

The court did agree with the petitioners' contention that FERC violated the National Environmental Policy Act by not preparing an EA before issuing the order. It remanded the order to FERC to conduct an EA, but it declined to vacate it.

"Although FERC's failure to prepare an EA is a serious violation, Order 872 does not suffer from fundamental flaws, making it unlikely that FERC could adopt the same rule on remand, and the disruptive consequences of vacatur would be significant," the court said in its ruling, issued Sept. 5.

PURPA directed FERC in 1978 to promulgate rules to encourage development of two types of QFs: alternative energy sources such as renewables owned by the same person within 1 mile of each other that totaled no more than 80 MW generation capacity, or fossil-fired cogeneration facilities.

The law mandated that electric utilities buy the power generated by QFs under rate guidelines established by FERC and set by states. In response, FERC issued Orders 69 and 70 in 1980.

Congress changed the statutory language via the Energy Policy Act of 2005, and FERC responded with Order 688, which among other things established a rebuttable assumption that facilities with not more than 20 MW capacity do not have adequate, nondiscriminatory access to markets.

With Order 872, issued under then-Chair Neil Chatterjee (R), the commission explained that extensive technology advances and dramatic energy industry changes in the preceding 40 years made significant revisions necessary.

Among other things, FERC:

- expanded the 80-MW calculation radius to up to 10 miles and set a list of factors to establish whether facilities were "separate";
- allowed states to eliminate the fixed-rate option;
- gave states additional flexibility to calculate utilities' avoided costs; and
- reduced the 20-MW nondiscriminatory threshold to 5 MW.

| *Shutterstock*

Ruling

The 9th Circuit rejected the petitioners' contention that Order 872 discourages development of QFs, and therefore violates PURPA, which directed FERC to encourage such development.

The judges shot down various other arguments as well. They ruled that:

- FERC did not overstep the authority granted to it by PURPA, and Order 872 meets the test of the Chevron doctrine.
- FERC was not arbitrary or capricious in making the rules; it was reasonable and used discretion delegated to it by Congress.
- Order 872's rate-related provisions do not violate PURPA's nondiscrimination requirement.

The court did fault FERC for its reasoning for not preparing an environmental impact statement or an EA.

"FERC misunderstands NEPA's requirements," it wrote, adding that the commission's own regulations for implementing NEPA support its conclusions.

"It was eminently foreseeable that a regulatory change of this magnitude could produce significant environmental effects," it wrote. "It was a near certainty, for example, that at least some QFs could lose their status under the 2020 site rule, or that at least some states would eliminate the fixed-rate option for the calculation of avoided costs."

But the court concluded that vacatur would cause severe trouble, as several states have already initiated proceedings in response to the order and some utilities already have received relief from mandatory purchase obligations with facilities rated at 5 to 20 MW.

"Victory. Again," Chatterjee *posted* on X in response to the news. "The Chatterjee FERC record in the courts is quite strong." ■

FERC/Federal News

NERC: Coal, Natural Gas Stockpiles 'Adequate' Ahead of Winter Months

By Holden Mann

Supplies of coal and natural gas are likely to be less of a concern for the North American electric grid this winter, according to a member of the team developing NERC's 2023-2024 Winter Reliability Assessment (WRA).

Speaking at the ERO's Preparation for Severe Cold Weather webinar on Thursday, Stephen Coterillo, an engineer with NERC's Reliability Assessment department, previewed findings from this year's WRA. The team has been working on the report since July.

NERC's WRAs cover the months of December through February and are typically based on demand and generation availability forecasts provided by regional entities, utilities and other stakeholders. This year's assessment will also include information gathered as part of the ERO's first-ever Level 3 alert, which was issued this year after NERC's Board of Directors approved it at its meeting in May. (See "ERO to Issue First Level 3 Alert May 15," *NERC Board of Trustees/MRC Briefs: May 10-11, 2023*.)

Coterillo cautioned that the team has not finished processing the data, but he told webinar attendees he could share some preliminary findings. These include the rising stockpiles of coal, which are "trending toward an adequate level," and natural gas storage levels, which are above the five-year average for this point in the year. According to data from the Energy Information Administration, natural gas underground storage in the lower 48 states was more than 3,000 Bcf, higher than any year since 2017 except for 2019.

"This is definitely a welcome change from prior years, where supply chain issues, coupled with global supply concerns, caused lower inventory levels of stored coal and natural gas headed into the winter season," Coterillo said.

However, while the fuel levels are a welcome sign for the ERO overall, Coterillo also highlighted several areas of concern that will be featured in the upcoming report. First, several assessment areas — including Manitoba, SPP and British Columbia — reported that their anticipated reserve margins have fallen from the previous year's assessment.

In the case of British Columbia, the reduced reserve margin risks dropping below the area's reference margin level, which, as in many assessment areas, is higher than last year's. Coterillo attributed the declining reserve margins in SPP and other areas to increases in peak demand and generator retirements.

Coterillo also singled out MISO, which is projecting a significantly higher reference margin compared to last year, for comment. Noting that the RTO has "recently re-evaluated the reference margin for cold weather operations," Coterillo said MISO "opted for a higher [reference] margin to cover this impact for winters going forward."

Finally, the team previewed its extreme condition risk analysis for the upcoming winter. The risk analysis is based on data provided by each assessment area, including their anticipated resources for the winter and projected maintenance outages and forced outages. The analysis then factors in a potential extreme low-generation scenario, as well as projected peak demand under both normal and extreme conditions, to identify any areas where resources may not be sufficient at some point during the season.

NERC plans to publish this year's WRA in the middle of November. ■

A chart from the team developing NERC's upcoming Winter Reliability Assessment, showing anticipated reserve margins and reference margin levels from last winter and the upcoming season. | *NERC*

FERC/Federal News

Report Touts Value of Demand Response, Flags Challenges Facing It

Wood Mackenzie, CPower Say Pricing and Regulatory Reforms Needed

By John Cropley

A *new report* dives into the role demand response and distributed energy resources play in the reliability of the rapidly evolving North American power grid.

"Unlocking the Full Potential of DERs: Overcoming Capacity Pricing and Other Barriers to Ensure Grid Reliability" is a collaboration by energy consultant Wood Mackenzie and DER developer CPower.

The report notes what NERC and others have warned about: Large swaths of the U.S. face a growing risk of outages in peak demand periods or during emergencies as the nation moves from a centralized, predictable power flow to a distributed, dynamic grid.

The report continues:

While DR is not a baseload resource, it has proved highly reliable under severe conditions as traditional dispatchable power is supplanted by intermittent renewables.

DR, as the largest class of DER, is an increasingly important part of the resource stack in energy markets — the diverse sizes, locations and types of DR assets adds resilience and flexibility.

DR needs strong, consistent capacity price signals to promote enrollment and retention. These signals include ensuring that wholesale energy prices do not erode capacity prices; maintaining capacity pricing stability and predictability for customers who want to participate in DR programs, especially commercial/industrial customers; and addressing the common misconception that DR has zero costs and can stay in a capacity market as the price rides down to zero.

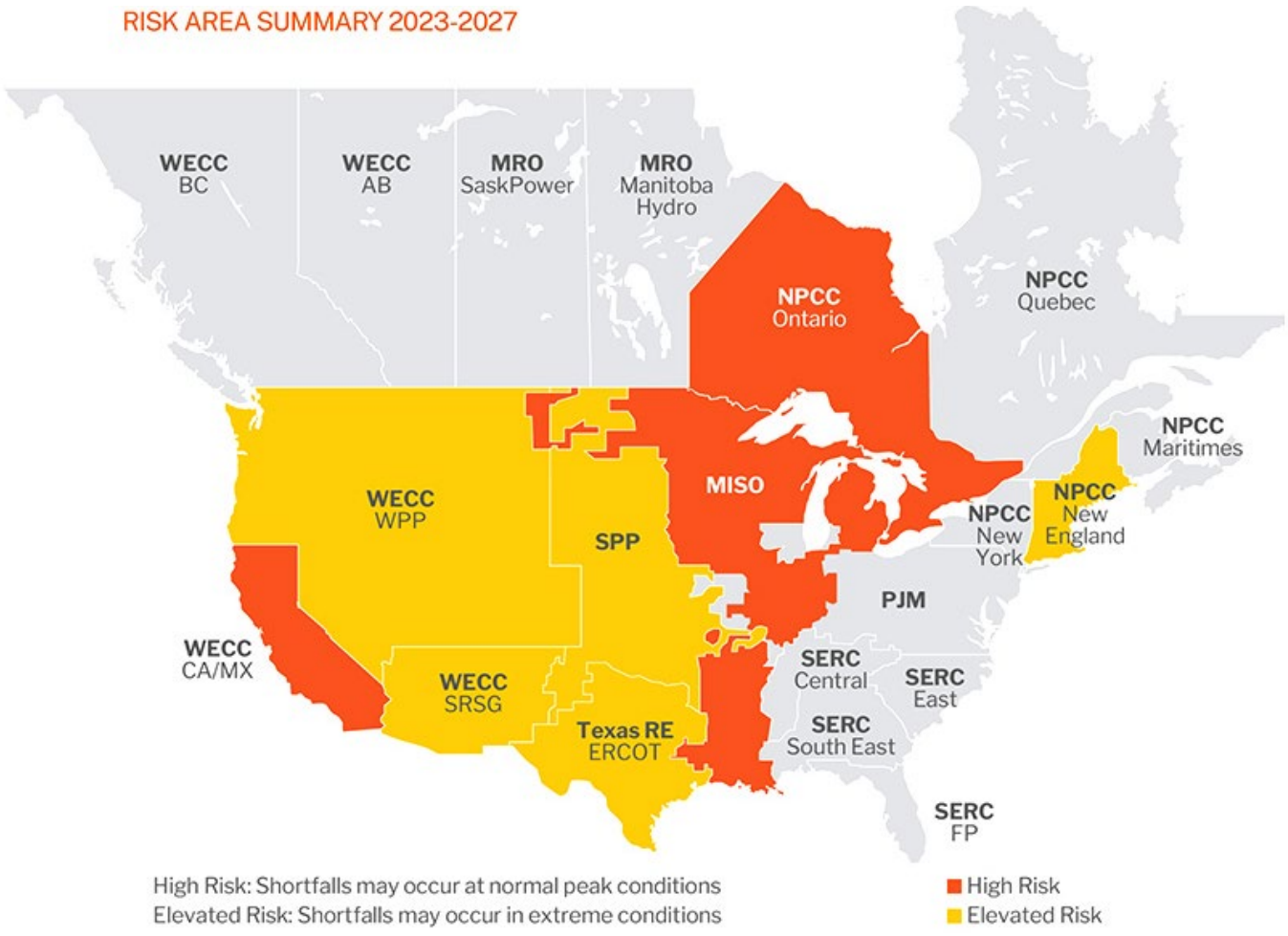
DR carries no capital costs but there are administrative and opportunity costs — so it is easy, even advantageous, for customers to stop participating when prices fall.

Adequate capacity pricing and capacity accreditation for DR are important.

The right price signals, such as a price floor, would reassure participants about the viability of the DR market.

CPower is developing what it calls the "Customer-Powered Grid" through DER monetization and virtual power plants — it has 6.3 GW of capacity at 20,000 sites across the U.S. It is owned by LS Power.

Wood Mackenzie provides global research, analysis and consulting in energy, renewables and natural resources. ■



A new report highlights the importance of demand response and distributed energy resources in ensuring grid reliability. | *NERC*

FERC/Federal News

NRDC Lays out Responsible Tx Expansion Recommendations

Council Touts Federal Authority and Coordination, Community Involvement

By James Downing

The U.S. must double the number of transmission projects permitted and built each year to meet its clean energy potential, the Natural Resources Defense Council said Wednesday in a *report* recommending ways to speed permitting rules to allow enough construction to meet midcentury climate goals.

"We also must double the rate at which we expand the transmission system and simultaneously shift to building large interstate transmission lines instead of the small local lines that are mostly added today," said NRDC Senior Advocate Nathanael Greene, the report's lead author.

The Inflation Reduction Act is a huge opportunity for the country to roll out renewable energy and make significant progress on cutting greenhouse gas emissions, while the heat and natural disasters this summer show that climate change is happening and must be addressed, Greene said in an interview.

"Those two things I think allowed people to put building things higher on their priority list," he added.

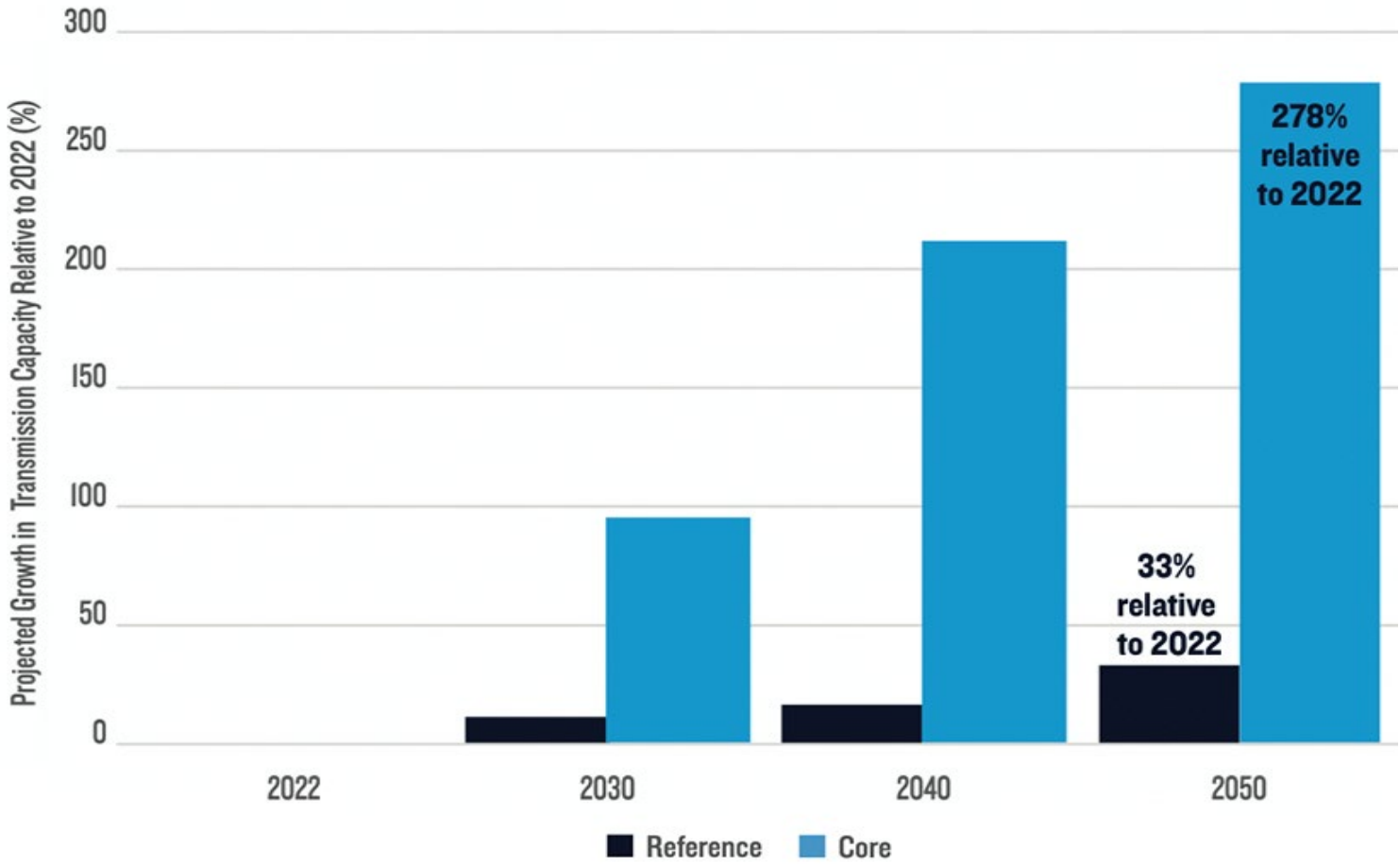
Issues around permitting have been a major focus for those working on federal energy policy all year, but so far, Congress has passed only a small package that largely ignored transmission. (See *Lawmakers, White House Promise More Work on Permitting After Debt Deal*.)

It is unclear whether lawmakers will be able to come up with another legislative package, but given the limited time due to the need to fund government operations and election season kicking into gear, NRDC wanted to express views on the subject to help inform any potential legislation, Greene said.

"This is an important conversation for Congress to be having because if a window opens, that's not going to be open for long, and people need to know what's important, what to do, what not to do," he said. "Because it'll have to happen quickly when it happens."

A deal could be attached to some kind of must-pass bill this year, which would leave little time for members to examine the legislation, he added.

The report identifies four major barriers to getting needed transmission built, the first being the need to obtain federal authority to site, permit and allocate costs for large interstate lines while increasing community engagement.



NRDC's chart showing how much transmission needs to be expanded in the coming decades to meet climate goals. | *NRDC*

FERC/Federal News

FERC and the Department of Energy should work quickly to implement their strengthened authority to designate new "national interest transmission corridors," the report said. (See *States, RTOs Caution DOE on Transmission Corridors*.)

NRDC is critical of FERC's "rubber stamping" of natural gas pipelines, so it wants the agency to do more robust environmental reviews and provide stronger landowner protections when it comes to expanding the electric grid under its limited siting authority. While NRDC has litigated some of FERC's implementation of the Natural Gas Act, that same kind of "bright line" siting authority would help expand the grid, Greene said.

"As long as it's a political question about whether they'll use that authority, it's always going to be harder for them to do that permitting," he added.

Ultimately, Congress should pass a law giving DOE authority to plan and FERC the ability to site large, interstate transmission lines, the report said.

Given that many of the projects NRDC wants to see built will cross state lines, having federal agencies planning and siting them makes sense, Greene said.

Another major recommendation is for FERC to "consider all the benefits of transmission" and then allocate them based on who benefits. The commission can implement rules to broadly allocate costs of new transmission to states, but if it fails to do so, then Congress should pass legislation requiring that, the NRDC said.

A pending notice of proposed rulemaking would update FERC's planning and cost allocation rules. And while Chairman Willie Phillips has called that a priority, it has yet to pass.

Dealing with NIMBY

The report's second recommendation is meant to deal with the opposition transmission projects often encounter because people do not want major infrastructure built near their homes, but that can be minimized by making community engagement a pre-requisite to siting rather than an afterthought.

"We know all the pieces of doing permitting better," Greene said. "We just need to integrate and hold people accountable."

The report suggests ensuring that communities gain benefits from hosting clean energy infrastructure. Specific benefits would vary by project, but they include jobs, environmental protections, financial contributions and energy benefits.

"Some developers already routinely negotiate community benefit packages for their projects," the report said. "States should incentivize or require this as a best practice."

The Inflation Reduction Act also earmarked money to help beef up permitting regulators in the states so they can adequately review the expanded pace of transmission development, Greene said.

The report's third recommendation is to improve federal coordination, accountability and staffing of clean energy permitting and environmental reviews. That can be done without undermining the purpose behind the National Environmental Policy Act, the report said.

"Environmental reviews can be made much more efficient through increased agency resources, greater use of programmatic reviews, and permitting solutions that are tailored specifically to clean energy projects," the report said.

The final recommendation is to embrace "smart from the start" planning to ensure that clean energy projects deliver conservation benefits and mitigate the impacts. That involves early and robust stakeholder engagement, planning at a landscape level, conservation of lands with important natural resources and cultural values, and moving projects to "low-conflict areas."

"'Smart from the start' is designed to make permitting more efficient and to protect high-value lands by strategically focusing on regional or landscape-level efforts to mitigate the impact of renewable energy resources," the report said. "These larger mitigation efforts often produce greater conservation outcomes than disparate project-level mitigation." ■

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CAISO/West News

CAISO Sheds Light on October Solar Eclipse Preparations

Growth in Solar Resources Means Oct. 14 Eclipse Should Have Greater Impact than 2017 Event

By Elaine Goodman

CAISO is planning ahead for a solar eclipse that will abruptly slash solar power across much of California the morning of Oct. 14.

The ISO successfully managed the drop in solar output during a total eclipse on Aug. 21, 2017. But since then, grid-scale solar within the CAISO footprint has increased from 10,000 MW to 16,500 MW, and behind-the-meter solar has grown from 5,700 MW to 14,350 MW. (See *Grid Operators Manage Solar Eclipse*.)

"The October 2023 eclipse will be more impactful than the 2017 eclipse because of the growth in solar capacity since 2017," CAISO said in a *technical bulletin* issued Aug. 31.

In response, CAISO has scheduled a series of meetings. Outreach to Western Energy Imbalance Market entities is also planned, as the ISO said coordination across the WEIM is critical to ensure optimal market dispatch during the eclipse.

CAISO is planning additional reserve procurement, a step it also took to *prepare* for the 2017 eclipse. The ISO will consider restricting maintenance operations around the time of the eclipse, to reduce the risk of an "inadvertent issue" occurring during maintenance work.

Another option would be to implement a Flex Alert or activate demand response programs during the eclipse. CAISO said it probably won't need to do that, "due to the eclipse occurring on a weekend when loads are typically lower."

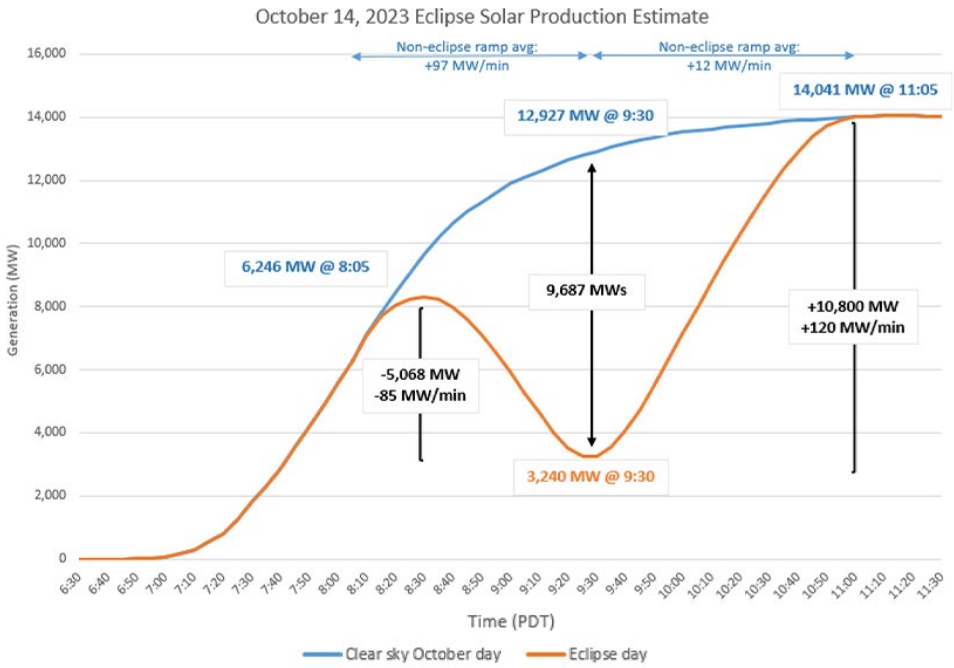
Blocking the Sun

During the so-called Great American Eclipse in August 2017, grid-connected solar generation in CAISO territory dropped by more than 3,500 MW in about an hour. CAISO replaced the lost solar power with electricity from imports, hydropower and natural gas power plants. Consumers conserved electricity during the eclipse to relieve stress on the grid.

The 2017 eclipse was on a Monday, from about 9 a.m. to noon PT in California.

In contrast to that eclipse, the event on Saturday, Oct. 14, will be an annular eclipse, in which the moon will block much of the sun but leave an outer ring.

Large parts of Oregon, Nevada, Utah and New Mexico, and small parts of California and Arizona, will see the maximum impact of next month's eclipse, with about 90% of the sun obscured. Much of California will see lesser amounts of sun obscuration, in the 70 to 80% range.



CAISO expects to experience a sharp drop-off in solar output during the the Oct. 14 eclipse, followed by an even sharper ramp-up as the sun comes back into view. | *CAISO*

The Oct. 14 eclipse will last from about 8:05 a.m. to 11 a.m. in CAISO territory. At the peak, around 9:30, grid-scale solar generation will drop to 12 to 23% of capacity, CAISO said. Solar production won't be completely cut off but will fall to a low of about 3,023 MW at 9:26 a.m.

Output will also be reduced for behind-the-meter rooftop solar, leading to increased load. The maximum impact to load will be a 4,843-MW increase at 9:15 a.m., compared with normal clear-sky conditions, according to CAISO's forecast.

Because the eclipse will occur on a Saturday, loads will be lighter than they would be on a weekday.

Ramp-up Concerns

One of CAISO's concerns is the steep ramp up in solar power after the eclipse peaks. The eclipse will end just as solar sites are reaching their midday production maximum, the ISO noted.

"The period after the eclipse maximum to the end of the eclipse … is the period of operational interest the CAISO will study to ensure adequate supplies of generation [reserves] are available to mitigate any adverse effects of the anticipated steep up-ramp in solar production," the ISO said in its technical bulletin.

CAISO said it will coordinate with hydro and battery resources to help with potentially large ramps.

The bulletin models eclipse impacts on a clear-sky day, which CAISO said represents a "high impact" scenario. Impacts will be less if Oct. 14 is a cloudy day.

CAISO plans to send out messages through its market notification system before and during the event.

"This message is to serve as a reminder that the solar eclipse will take place on Oct. 14, 2023, from 8:05 to 11:05 PDT," one sample message reads. "This is a unique event for the ISO [balancing authority], during which approximately 9,700 MW of solar generation will rapidly go away and then return within the span of less than three hours. Your cooperation and support throughout the event will help to ensure grid reliability." ■

ERCOT News

ERCOT Voltage Drop Leads to EEA Level 2

Emergency Operations 1st Since 2021 Winter Storm

By Tom Kleckner

DFW AIRPORT, Texas — A frequency drop Wednesday evening leading to a dip in operating reserves forced ERCOT to enter emergency operations for the first time since the disastrous February 2021 winter storm.

The EEA 2 was issued to maintain critical system frequency because of low power reserves. Grid frequency is the balancing of the flow of electricity between 60.1 and 59.9 Hz and must be maintained at that level on the entire ERCOT grid. On Thursday night, the frequency dipped to 59.77 Hz.

The grid operator issued a Level 2 energy emergency alert at 7:26 p.m. CT when operating reserves dropped below the 2,300-MW threshold as solar energy ramped down during near-record peak demand. It said frequency dipped to 59.77 Hz, below the 60.1- to 59.9-Hz critical system range; the EEA allowed ERCOT to use additional reserve resources.

"To protect the stability of the electric system, ERCOT has access to additional reserve sources only available during emergency conditions," CEO Pablo Vegas said in a *press release*.

In its first public acknowledgement of the event, ERCOT said in a Thursday evening email to the media that the event was triggered by a transmission limitation that restricted the flow of generation out of South Texas to the rest of the grid.

ERCOT exited the Level 2 EEA after about an hour and 15 minutes later, dropping down to Level 1. Operations returned to normal about 10 minutes after that.

Wholesale prices spiked at $5,070/kWh during the alert after having ranged from $20 to $60/kWh earlier in the day.

Speaking at SPP's Resource Adequacy Summit at Dallas/Fort Worth International Airport, Texas Public Utility Commissioner Will McAdams said the commission is compiling a report and it plans to publish this Wednesday. The report will then be discussed during the PUC's open meeting Thursday.

"Full debrief, for the public," McAdams said.

The event occurred during the normal evening period, when the sun sets and, along with it, solar production drops. ERCOT staff have met demand during that time period until Wednesday, when the drop was too precipitous. Solar energy regularly has been providing more than 12 GW this summer, with a peak of 13.73 GW in August.

ERCOT's operating reserves dwindled to critical low levels Wednesday. | *ERCOT*

"A key part of the story is that it's hotter at 8 p.m. than it used to be," *tweeted* Michael Webber, a professor at the University of Texas at Austin leading clean energy technology research. "After more than two months of high temperatures, the streets, sidewalks building materials and soil all become hotter and therefore keep the temps higher for longer after sundown."

Energy storage contributed a record 2.17 GW of energy during the EEA, according to *Grid Status*. Generation outages were within ERCOT's normal expectations of 5 to 6 GW.

"We need more dispatchable capacity to cover those time frames where our tightest timeframe isn't even in the peak demand time of the day anymore," Dan Woodfin, ERCOT's vice president of system operations, said during a panel discussion at the Resource Adequacy Summit. "We've got roughly 13 GW of solar online every day. It's when the sun goes down and so every day, it becomes an issue of whether the load is going to go down enough, and the wind comes up enough to make up for the solar going down. And it goes down really fast."

Dan Woodfin, ERCOT | *© RTO Insider LLC*

Demand peaked at 82.7 GW on Wednesday, enough to set a new high for September. However, that was far below ERCOT's still-unofficial peak demand record of 85.44 GW, recorded Aug. 10.

ERCOT issued a conservation appeal at 4:54 p.m. Wednesday for the hours between 6 and 9 p.m. The Texas grid already was operating under a weather watch through Friday.

It made another *call for voluntary conservation*, its 11th of the summer, for Thursday evening.

ERCOT has called for reductions by large electric customers and has worked with neighboring RTOs to deploy switchable resources. On Thursday, it also requested U.S. Department of Energy authorization to allow its generating units to operate up to their maximum output levels, if needed. The department *approved* the request that day.

"The system is really dependent on wind and solar to meet peak demand with just a normal level of thermal outages," Woodfin said. "We're using everything that's available almost every day. We're using the entire dispatchable fleet every day, so their performance is really important." ■

ERCOT News

Overheard at Infocast Texas Clean Energy Summit

Renewable Sector Responds to Close Call During Legislative Session

By Tom Kleckner

AUSTIN, Texas — The Infocast Texas Clean Energy Summit attracted several hundred developers, asset owners, financiers, investors and ERCOT stakeholders to discuss the booming opportunities and looming challenges in today's renewables environment.

Speakers and panels discussed large flexible loads, crypto mining, energy storage, Texas' continued reliance on renewable energy and the challenges facing ERCOT from the state's tremendous growth and insatiable demand for energy. Many of those solutions will be affected by the new laws and rules passed by the recent Texas Legislature.

Mark Stover, Apex Clean Energy | © RTO Insider LLC

Part of a panel addressing the new legislation, Mark Stover, director of state affairs for Apex Clean Energy, pointed to a projected slide that included images of a couple of news clippings.

"*Clean energy escapes the legislative session*," he said, referring to one of the headlines mentioned. "That's fairly accurate. Did we lose any limbs? We did not.

"I think there were about 50 bills that impacted our industry, but there were 19 bills that did not get across the finish line. Some were killed on the floor, some never got on a hearing, others kind of just got lost in the shuffle. But there were 19 bills that would have directly harmed the clean energy industry. Fortunately, those went away."

One of the bills that failed (*Senate Bill 624*) would have required wind and solar facilities to acquire special permits from the PUC, a requirement thermal generators wouldn't face.

"That was an industry killer that would have been absolutely devastating for the clean energy industry," Stover said. "Fortunately, we were able to get the recession and ensure that that bill did not pass, no trouble."

Still up in the air is the shape of the future ERCOT market. The grid operator and the state's regulators still are pushing forward with the performance credit mechanism (PCM), a market tool that would retroactively reward dispatchable generation that meets performance criteria during the tightest grid periods with incentive payments.

Attendees take notes during the Infocast Clean Energy Summit. | © RTO Insider LLC

Staff plans to draft a strawman proposal incorporating the Public Utility Commission's feedback and hold a series of workshops with stakeholders and PUC staff. ERCOT and the market monitor will perform a cost-benefit analysis before the legislature next meets in 2025. The ISO expects it will take another two years to implement the PCM.

Shell Energy's Resmi Surendran lays out the current state of the ERCOT market as moderator Matthew Boms listens. | © RTO Insider LLC

"So where do we go from here? There's a lot of details to be worked out," said Nate Miller, a director with Energy and Environmental Economics (E3). (The firm studied several market designs for the PUC but did not recommend the PCM.)

He said a reliability standard first must be determined, as it will set the PCM's performance credits awarded to generators. Then comes the question of dispatch requirements, hybrid resources only being part of the equation.

"There's a lot of details in the PCM that could significantly weigh the impact of PCM on the market," said Resmi Surendran, vice president of regulatory policy for Shell Energy North America. "The PCM, based on some studies, could have been a one-third reduction in the energy price, which is the revenue stream for renewables. Hopefully, it can be implemented as an additional revenue stream ... without reducing the revenue stream for everyone else."

Investors Cautious After New Laws

While the renewable sector may have escaped more severe legislation this year, it may have been enough to scare off some potential investors.

ERCOT News

"Investors saw what happened in that last Texas session and are sort of unsure about what's going to happen in the next session for understandable reasons," said Frank Swigonski, director of market design for Pine Gate Renewables. "I've heard people say that there's always been anti-renewable sentiment in Texas and this was just another day at the office. The difference last session was it was a little bit more pronounced and it got a little bit more national attention. I think that's something that we're going to be dealing with as we're trying to get investment projects long term."

Frank Swigonski, Pine Gate Renewables | © RTO Insider LLC

Swigonski said the PCM remains the biggest question mark with how costs will be allocated and its effect on the energy market.

"That uncertainty itself is a challenge because other developers can probably feel the same way and we can execute around new interconnections, cost allowances and new firming requirements, as long as we know what those requirements are," he said. "But as long as there's a big question mark in your financial spreadsheet, it's really hard to close on them right."

That said, Swigonski still says the Texas energy market is a great place to invest.

"The interconnection process in Texas is the fastest, the easiest and cheapest anywhere in the country. None of that changed," he said." Texas is a big state. It's got a dynamic, dynamic economy, there's low growth in taxes and there's a lot of sunshine and wind."

"We're pretty invested in Texas, and we think that the policy risk is very manageable," said Allan Schurr, chief commercial officer of storage developer Enchanted Rock. "I can tell you that having lived a former life in California that it is a wild card. Texas is a lot more predictable. It's undergoing a lot of changes with the market redesign. I don't know about the fundamentals but somehow, through the noise and the fog, there's still opportunity for us."

Living with Large Flexible Loads

When Bitcoin miners — having been shoved out of China because of their insatiable demand for power — began flocking to Texas in 2021, Gov. Greg Abbott (R) welcomed them in a *tweet* proclaiming the state "will be the crypto leader."

Agee Springer, ERCOT | © RTO Insider LLC

Two years later, Bitcoin mining consumes about 2.2 GW of power. That consumption could triple should the additional 4 GW of mining operations approved by ERCOT's interconnection process become energized. And while the mining loads gobble power, their ability to shut down quickly during tight operations is what makes them appealing to grid operators.

ERCOT has adapted quickly to Bitcoin, data centers and other large, flexible loads (LFLs). It has created a working group dedicated to the loads and hired an LFL interconnection manager, Agee Springer. It also has proposed new LFL classifications as either curtailable load resources or registered curtailable loads; the former would participate in economic dispatch; the latter would operate outside SCED.

"The optimal solution for reliability would be for as many of these loads as possible to participate in the economic dispatch," Springer said. "What this really does is it allows their behavior to be factored into the economic dispatch and accounted for when generation is instructed on how much power to produce. We see this as kind of a benefit to both loads and to ERCOT. It takes the guesswork out of being price responsive. You feed your desired behavior and your strike prices into the economic dispatch and then your behavior is coordinated with the rest of the grid."

He said the proposed concepts, which could be ready next year, would provide more data from load resources and improve the accuracy of ERCOT's forecasts. That would create a bigger pool of ancillary services, Springer said, "so that's a benefit for everyone."

The Clean Energy Buyers Association's Bryn Baker, senior director of market and policy Innovation, stressed the need to be able to run a 21st-century grid that keeps the lights on in 21st-century weather.

"That requires thinking more expansively about what is dispatchable versus non-dispatchable. Certainly, renewables are not always reliable and the dispatchable energy is not always reliable," she said.

Bryn Baker, Clean Energy Buyers Association | © RTO Insider LLC

"A big success story, besides demand response, is wind, solar and storage holding up the grid when its groaning at the edges," Baker added. "It is going to require thinking about things differently. We're going to need new technologies and new approaches ... but most important is that we're building [an ERCOT] market where that innovation happened, where testing those new technologies and approaches is possible."

IRA Could Be Boon to Texas

Several panelists marked the one-year anniversary of the Inflation Reduction Act, which provides billions of dollars in incentives, grants and loans to support new investments in clean energy and other areas.

"When you look at it at first blush, you see a lot of positive things that are more long term," said Matt Pawlowski, vice president of development for NextEra Energy Transmission. "We've gone from the years of three to five years [of tax credit deadlines], etc., where you're kind of rushing into everything because you think it's going to expire. Now, we have a much longer runway ... the IRA has been a longer-term view of things that we've wanted for years, instead of three-, four- and five-year chunks."

Matt Pawlowski, NextEra Energy Transmission | © RTO Insider LLC

George Hardie, vice president of business development for Pattern Energy Group, agreed the IRA will spur new development in Texas.

"It's a mixed bag of theories and it's certainly ample ammunition for issues in some of the congested areas in the Texas Panhandle, where there's more power than can get to some of the load centers," he said, noting the demand placed on the grid by oil and gas production in the Permian Basin. "We're seeing astounding load growth ... all that oil and gas is being electrified, so there's going to be a significant amount of renewables and weather, as well solar, needed for that density." ■

ISO-NE News

Environmental Orgs Request Rehearing on ISO-NE Reliability Program

Sierra Club Lawyer Says FERC's Lack of Scrutiny Sets Bad Precedent

By Jon Lamson

The Sierra Club, the Union of Concerned Scientists and the Conservation Law Foundation jointly filed for rehearing last week over FERC's approval of changes to ISO-NE's Inventoried Energy Program (IEP) (*ER23-1588*), arguing that the RTO failed to adequately justify the program and that it likely would increase costs for consumers.

The groups wrote that FERC's approval of the program "errs in failing to examine whether tripling the costs of the [IEP] is just and reasonable in light of the lack of evidence that IEP payments would incent oil and gas generators to procure more fuel than they would otherwise."

The nonprofits added that the commission's decision also "errs in failing to consider new information about winter energy adequacy that is relevant to the need for the IEP, and thus to whether consumers would receive benefits proportionate to the enormous additional cost proposed."

ISO-NE's IEP is intended to compensate generators for keeping stored fuel onsite to ensure the region's winter grid reliability, while the disputed changes to the program include the introduction of indexed rates meant to reflect changes in natural gas prices.

In ISO-NE's original filing of the IEP changes, the RTO argued the changes "are designed to align key parameters of the IEP rates, terms and conditions with current market conditions and to make other improvements necessary to attract sufficient investment in incremental inventoried energy to support winter reliability."

FERC unanimously approved ISO-NE's proposed changes in an August ruling. (See *FERC Approves Updates to ISO-NE Inventoried Energy Program.*) In the order, FERC dismissed a range of complaints from the organizations and state consumer advocates related to the cost and justification of the program.

"The purpose of the Inventoried Energy Program is to incentivize resources to maintain inventoried energy to support winter reliability, and ISO-NE's proposed revisions are designed to improve the program's ability to achieve this goal," FERC wrote.

In the rehearing request, the environmental organizations called FERC's ruling "arbitrary and capricious."

The groups wrote that FERC did not adequately consider the effect of changes to the region's winter risk profile since the creation of the IEP, or whether the program actually would spur changes in behavior of generators. (See *Study: Limited Exposure to Supply Shortfall for ISO-NE During Extreme Weather.*)

"Most of the generators who receive a payment under the IEP, they're already obligated to perform as capacity resources," Casey Roberts, senior attorney with the Sierra Club Environmental Law Program, told *RTO Insider*. "In order to do that, they have to have fuel, otherwise they can't run."

Salem Harbor Power Station, a gas-fired generating plant in Salem, Mass. | *Fletcher, CC-BY-SA-4.0, via Wikipedia*

Roberts argued FERC's lack of scrutiny of the program's justification and benefits sets a bad precedent for the approval of reliability programs.

"This really goes down to FERC's core responsibility of protecting consumers from paying excessive rates," Roberts said.

If FERC stands by its ruling, the environmental organizations could appeal FERC's decision in court.

In June 2022, the U.S. Court of Appeals ruled the IEP could not compensate coal, hydro, biomass and nuclear generators because the incentive would not change their inventory operations. However, the court left the rest of the IEP in place, ruling that oil, natural gas and refuse generators are eligible for payments. (See *Court Strikes a Blow to ISO-NE Winter Plan.*) ■

ISO-NE News

Mass. Utilities Submit Grid Modernization Drafts

Expected Doubling of Peak Load by 2050 Prompts Shift in Approach

By Jon Lamson

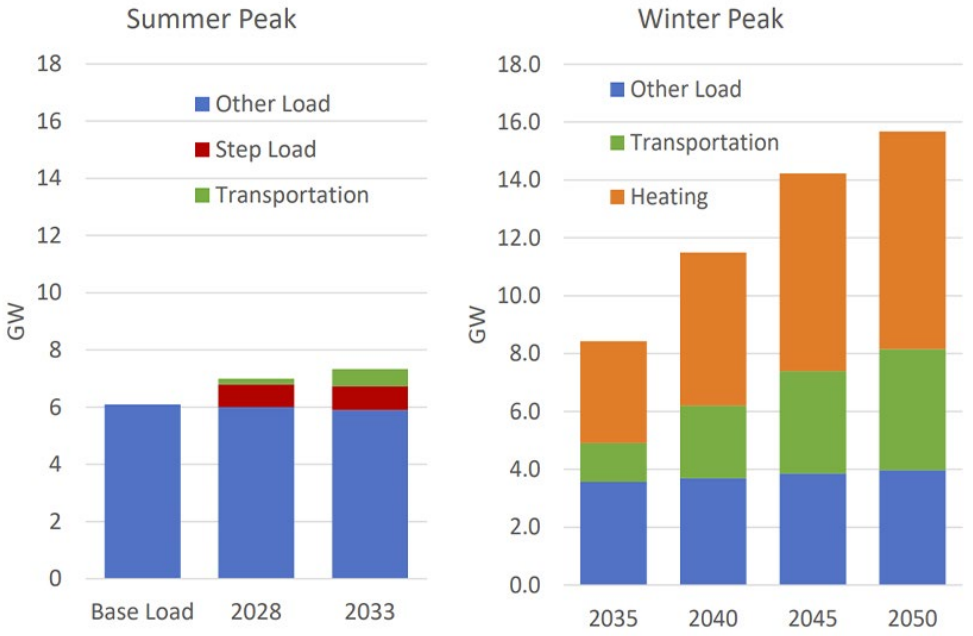
Eversource Energy and National Grid expect their annual peak electricity load in Massachusetts to more than double by 2050, the utilities told the state's Department of Energy Resources (DOER) on Sept. 1.

The projections are part of the draft electric sector modernization plans (ESMPs) submitted to DOER by Massachusetts' investor-owned electric utilities, which detail the electric distribution companies' plans to meet the massive increase in electricity demand associated with the electrification transportation and heating in the state.

The wide-ranging drafts also include near-term investment proposals, five- and 10-year demand forecasts and solutions planning, and they mark a major change in how the state conducts grid planning.

The Grid Modernization Advisory Council (GMAC), a stakeholder committee created by the state's 2022 *Act Driving Clean Energy and Offshore Wind* and convened by DOER, will review the filings, solicit public feedback and provide comments on the utilities' drafts.

"It's really taking a forward-looking approach for the first time in Massachusetts' history," said Kyle Murray, Massachusetts program director for the Acadia Center and GMAC voting member. Murray said grid planning in the state historically has happened in an "ad hoc manner."



Eversource peak load forecasts | *Eversource*

Murray added that one of the council's goals is to engage the public in the grid modernization process and include voices that historically have been absent from these proceedings.

The draft ESMPs outline the large infrastructure investments that will be needed to enable the clean energy transition, including huge increases in peak electrical loads. National Grid expects its annual peak to increase from about 4.6 GW to 10.7 GW.

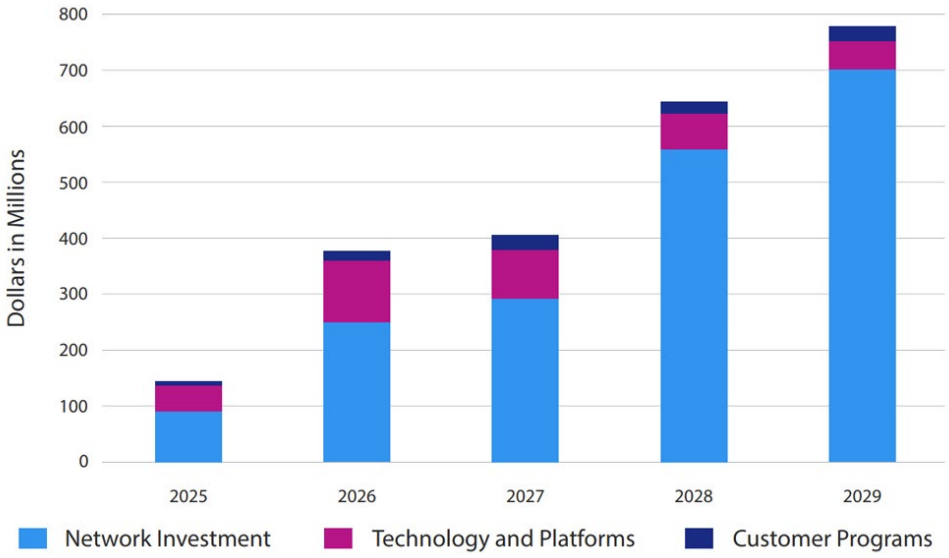
"Annual peak load, which is the maximum demand on the system in a given year, is expected to grow across our network 7% by 2029 and 21% by 2034 relative to 2022 levels, and more than double by 2050," National Grid wrote in its 726-page *report*.

Eversource expects an even larger increase for its system, anticipating its peak to rise from about 6.1 GW to 15.3 GW.

"The majority of this 150% increase in electric demand by 2050 is driven by electrification of heating needs (about 50%) with the remaining driven primarily by electrification of transportation needs (25%) and normal load (25%)," Eversource *wrote*.

The utilities also noted that the increasing reliance on distributed energy resources (DERs) will further strain the grid and necessitate additional upgrades.

To meet the expected demand increases, Eversource proposed building 14 new substations and upgrading 12 existing substations. The company also proposed three new substations and 14 upgrades to accommodate additional solar resources. National Grid proposed upgrading or expanding 18 existing substations



National Grid 2025-2029 proposed ESMP investments | *National Grid*

ISO-NE News

and building 28 new substations by 2034.

"Absent making these system investments in advance of these new peak demand levels, the expected load growth will result in overloads of existing equipment, which would impact the safety and reliability of our network operation," National Grid wrote.

Murray said one of his main hopes for the process is to help clear out the interconnection backlog of renewable energy projects.

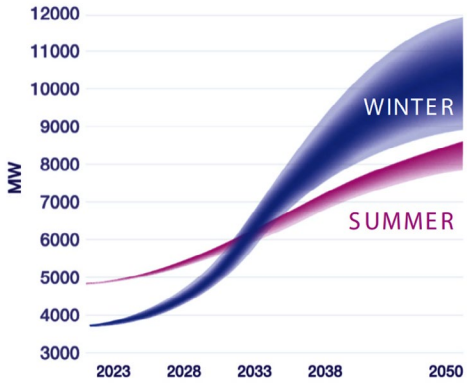
"We know we need as many renewables on the market as possible, and yet they're coming on at a pace that's kind of like a trickle," Murray said.

"Building system capacity with substations and battery storage systems will provide a critical foundation for enabling electrification and reliable interconnection of DERs," Eversource wrote.

The utilities emphasized the importance of early public engagement while making these investments, and jointly proposed the creation of a Community Engagement Stakeholder Advisory Group (CESAG) to help boost engagement with potentially impacted communities. Under the utilities' proposal, the group would be led by the utilities, with members agreed upon by the GMAC.

In an August *letter* to the GMAC, María Belén Power, undersecretary of environmental justice and equity at the Office of Energy and Environmental Affairs, stressed the importance of including environmental justice communities in the infrastructure siting process.

"[Environmental justice] populations should



National Grid peak load forecasts | *National Grid*

be engaged in public processes from the very beginning, not as an after-thought, and the engagement must be coupled with meaningful outcomes and results," Power wrote. "Adding equity or community outreach as a final step in the process does not allow for a meaningful process. Successful community outreach happens when the voices and perspective of those most vulnerable are reflected in the outcome."

Power said all communities affected by new grid infrastructure should be given ample opportunity to participate in siting processes, with accommodation made for the different languages spoken by residents. The undersecretary also emphasized the importance of considering the cumulative effects of grid infrastructure.

"When planning for new energy infrastructure or enhancement of existing ones, we must ensure we are not causing additional harm to those who have historically been overburdened," Power said. "When possible and if feasible, if a project may cause additional harm or burden on EJ populations, an alternative site should be identified."

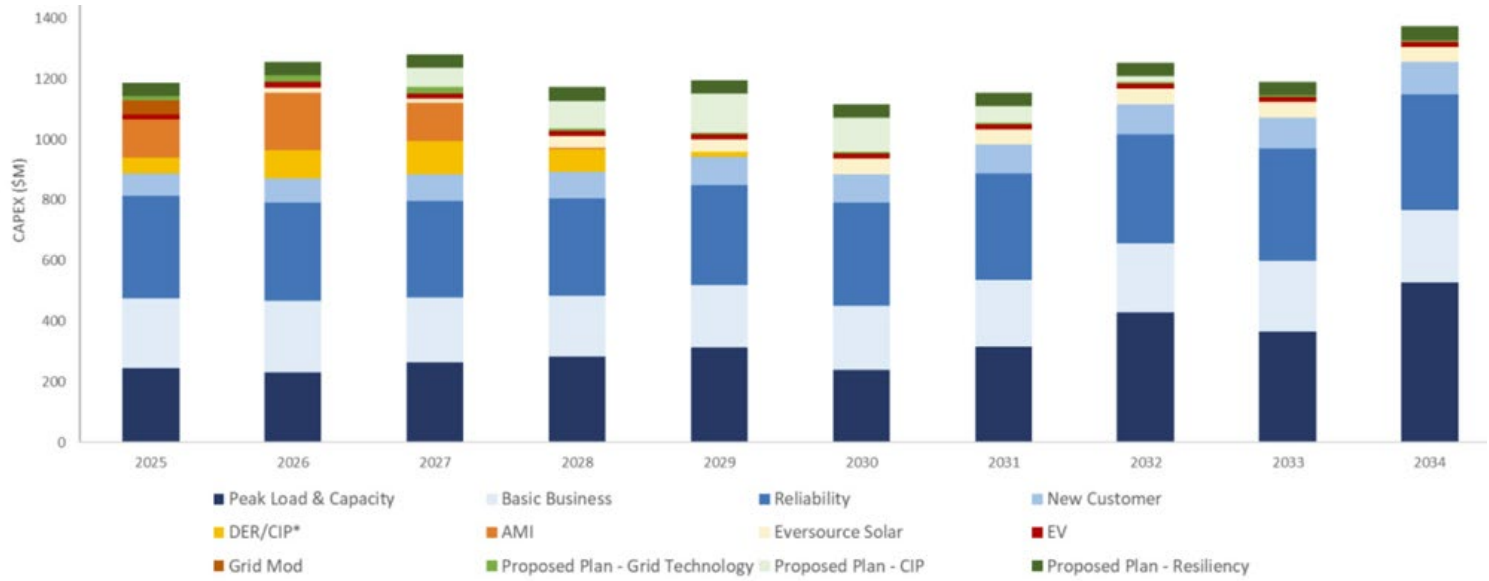
The utilities also outlined some mechanisms to reduce future demand, including energy efficiency, advanced metering infrastructure, managed charging and time varying rates.

"Regulatory and tariff changes that enable time-varying rates and recognize the shift toward greater electrification are required to support more impactful offerings to offset peak demand growth with increasingly flexible loads and expanded deployment of distributed resources," National Grid wrote.

Larry Chretien, executive director of the Green Energy Consumers Alliance and a GMAC member, told *RTO Insider* he still is reviewing the drafts, but agreed on the need to develop programs like time-varying rates and managed charging focused on reducing peak demand. High demand peaks lead to both higher costs for consumers and increased fossil fuel combustion.

"We think it's sacred that we've got to reach our climate goals, but we also want to make sure that it can be afforded by folks who are economically vulnerable," Chretien said. "I want to push the utilities on trying to bend the demand."

The GMAC will hold public listening sessions Oct. 30 and Nov. 1, with final feedback and recommendations from the GMAC due Nov. 20. The utilities then must file their final ESMPs with the Department of Public Utilities in January. ■



Eversource 2025-2034 proposed capital investments | *Eversource*

ISO-NE News

NEPOOL Participants Committee Briefs

COO Report

ISO-NE's energy market value was about $300 million in August, down from $580 million in July and $1.1 billion in August of 2022, COO Vamsi Chadalavada told the NEPOOL Participants Committee on Thursday.

Chadalavada noted that natural gas prices were 83% lower than the August 2022 average. Net commitment period compensation payments were about $800,000 lower than the previous month and $4.4 million lower than August 2022.

The peak load for the month occurred Aug. 21, which triggered an *abnormal conditions alert*. Overall, monthly temperatures were lower than historical August averages.

Chadalavada's *report* noted that annual 2023 emissions are down from 2022 levels through early August, with the biggest reductions coming from decreased oil combustion.

Budget Clarifications

Prior to the meeting, ISO-NE published a set of *responses* to questions from the states regarding the organization's draft 2024 budget. The RTO has proposed a 21.5% budget increase for the coming year. (See *ISO-NE Proposes 21.5% Budget Increase for 2024*.)

"The budget reflects increases necessary to successfully transition to the clean energy future, as well as catch up on inflation costs that were higher than previously budgeted," ISO-NE wrote. "While the inflationary pressures will subside, there will still be a need to increase resources in the foreseeable future. At this point, we are still assessing what may be needed for a post-transition paradigm."

ISO-NE told states that managing the grid amid the energy transition will require increased resources and personnel.

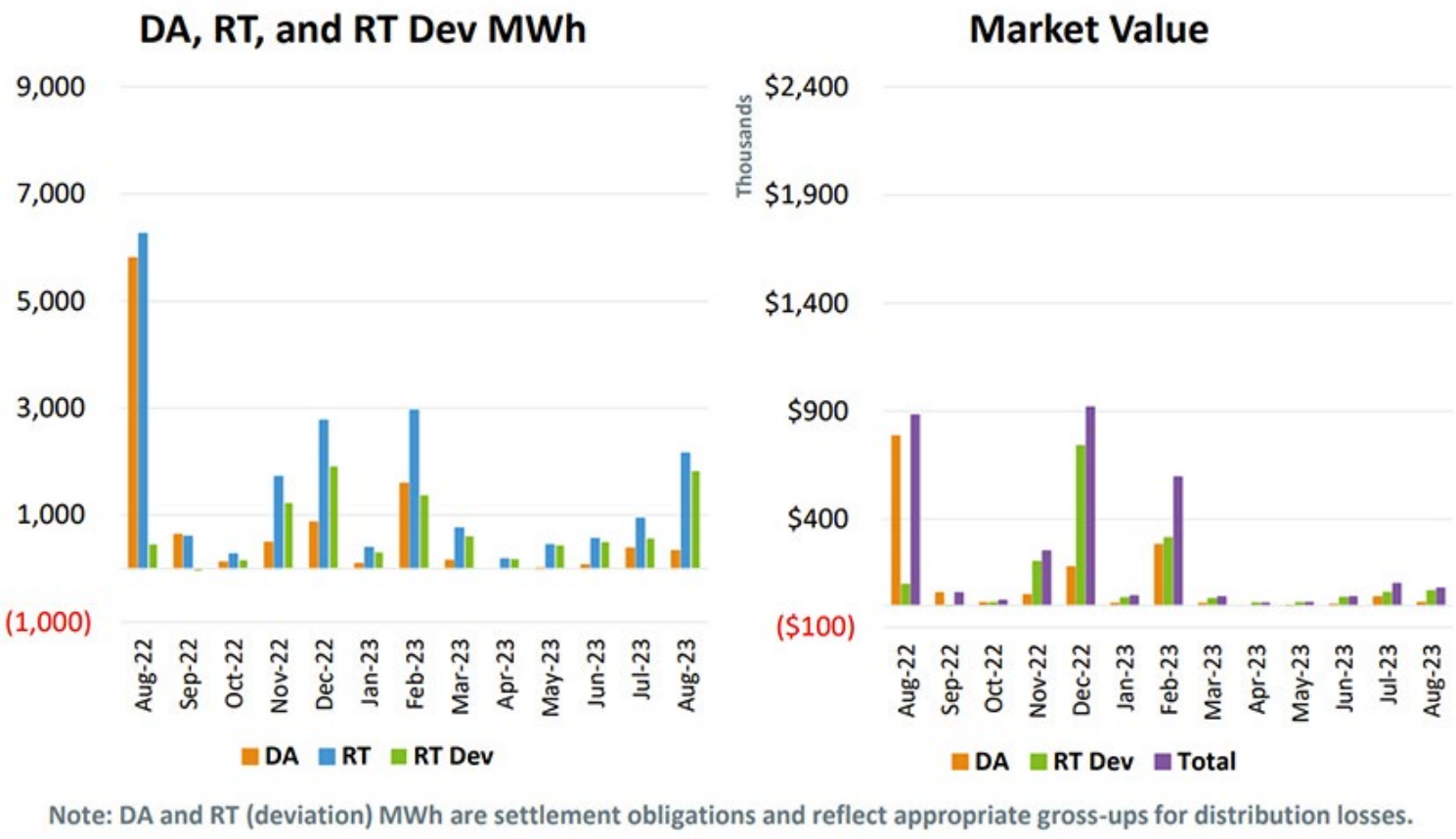
"The number of assets in New England will grow to hundreds of thousands/1 million-plus in number," ISO-NE wrote, adding that the complexity of its system will increase as it manages more behind-the-meter resources and non-dispatchable weather-dependent resources, as well as shifting load patterns.

"This complexity will increase the workload in ways that are straightforward (e.g., higher volume of asset registrations and transmission interconnections to study and manage) and less straightforward (e.g., changes to adapt the markets and operating procedures, including forecasting, to the aforementioned growth in complexity)," the RTO said.

ISO-NE also elaborated on the portion of the budget increase allocated to existing employee salaries, noting that an ongoing analysis led by an independent consulting firm has indicated that the RTO's base salaries are below market. The organization said that the unfinished aspects of this analysis will inform future budget decisions and "affect both the 2024 and 2025 salary budgets."

The PC will vote on the budget at the Oct. 5 meeting, which will be followed by a vote by the ISO-NE Board of Directors. The RTO said it hopes to file the budget with FERC in mid-October. ■

— Jon Lamson



ISO-NE price-responsive demand energy market activity by month | *ISO-NE*

MISO News

MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects

MISO to Revisit Expedited Review Process; Proposal Expected in Coming Months

By Amanda Durish Cook

MISO said it will seek approval from its board of directors for 578 transmission projects totaling $9.4 billion in December.

The RTO's 2023 Transmission Expansion Plan (MTEP 23) makes for MISO's largest-ever annual planning cycle and includes a substitution for two MISO South reliability projects. That's according to MISO's final round of subregional planning meetings for the year held Sept. 5-8.

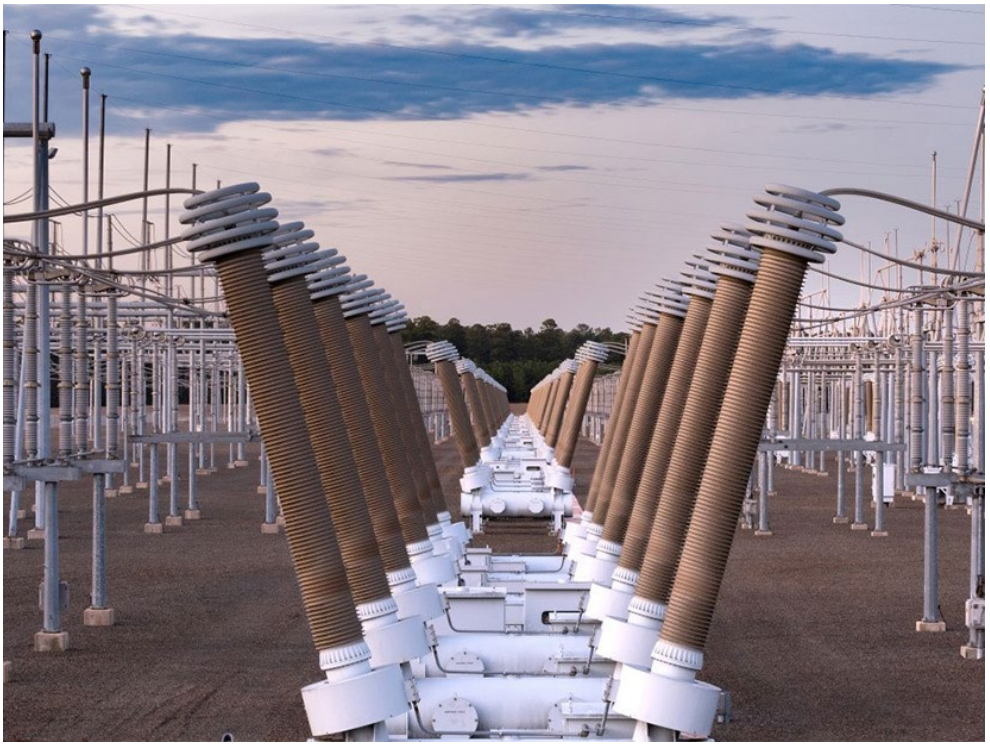
MISO South transmission owners plan to build 76 new projects at $4.3 billion, most of them to meet their own reliability planning criteria or NERC's reliability standards. The dramatic jump in proposed spending led some stakeholders this year to allege Entergy was circumventing more comprehensive and cost-shared regional projects. (See *Initial MTEP 23 Ignites Familiar Arguments over MISO South's Reliability Spending*.)

By comparison, MTEP 22 yielded a total $4.3 billion investment package. MISO's first long-range transmission plan (LRTP) portfolio approved last year — considered separate from the annual MTEP planning — produced a $10 billion investment.

MISO this year tested alternative designs for 11 proposed projects that represented 40% of MTEP 23 spending. Planning staff previously said multiple MISO South reliability projects, particularly substation work, might benefit from substitute projects. (See *MISO Weighs MTEP 23 Alternatives to South Reliability Projects*.)

Now, MISO said it's pursuing an alternative for the first phase of the three-part, nearly $2 billion Amite South line and substation work in Entergy Louisiana's southern territory. MISO said its selected alternative, the 500-kV Commodore-Waterford-Churchill loop *project*, will tie the area's 230- and 500-kV systems together at three points instead of two and better equip the system for future load growth in both the Amite South and Downstream of Gypsy load pockets in Louisiana. The extended 500-kV line will negate the need for another MTEP 23 project proposed by Entergy Louisiana, the 27-mile, 230-kV Downstream of Gypsy reliability project.

The project alternative is pricier than the original two projects combined, at $1.7 billion instead of the originally proposed $1.4 billion for Amite South Phase 1 and the $164 million for the Downstream of Gypsy project. The project involves building a new 500/230-kV substation; stringing a new 60-mile, 230-kV line and a new 85-mile, 500-kV line; upgrading an existing substation; and upgrading an existing nearby 230-kV line to 500 kV.



Circuit breakers at Entergy's Union Station in Arkansas | *Entergy*

"So, we chose one project alternative to replace two proposed projects," Manager of MISO South Expansion Planning Trevor Armstrong said during a Sept. 6 South Subregional Planning Meeting. "The alternative is more expensive, but it provided more load-serving opportunity for growth."

Entergy expects 2 GW of new load across the Amite South load pocket soon.

MISO also said the larger project will improve system resilience when extreme events strike and will address coming generation retirements in Amite South by allowing the option to cut multiple sources into existing stations.

The project still will have a 100% local allocation to load. MISO South's first regionally cost-shared, market efficiency project remains elusive.

Southern Renewable Energy Association's Andy Kowalczyk asked if Entergy pitched the idea for the substitution.

Armstrong said the design was on Entergy's list of alternative project suggestions, but it resembled a project idea MISO independently devised. He said the alternative ultimately was developed in conjunction with Entergy.

"This was the only one we felt needed to be selected in place of the original projects," Armstrong said.

Kowalczyk asked whether MISO planners will develop load growth projections for its planning modeling. MISO was forced to perform a separate sensitivity outside of its usual modeling to test for alternatives because it doesn't account for forward-looking load additions and generation retirements in modeling.

"I think they're credible inputs that need to be considered. I think it'll be a bit of a shock every year to have projects this size, and you have to perform a separate sensitivity," Kowalczyk said. "Maybe we're not accounting for future needs in the most cost-efficient way."

MISO planners said they don't have definite plans to include load growth estimates in planning modeling.

MISO News

Armstrong said the majority of the South region's MTEP 23 projects will be placed into service within the next three years.

Armstrong added that MISO still is working to develop possible alternatives to the third phase of Entergy Louisiana's Amite South reliability project. He said MISO likely will delay project approval into 2024; MISO planners said they didn't know whether the project will be included as a late addition to MTEP 23 or be deferred into the 2024 planning cycle.

However, MISO left standing the controversial $1.1 billion, 150-mile 500-kV line and substation project Entergy proposed for Southeast Texas. Planners said they couldn't find a better alternative in terms of economics or reliability to the baseline reliability project consisting of a 150-mile, 500-kV line, 500-kV substation and 500-230-138-kV substation.

Entergy said the Southeast Texas project will help meet its local planning criteria, reduce dependence on aging and increasingly unavailable resources, and be useful when restoring the grid from extremes wrought by winter storms and hurricanes.

During the Planning Advisory Committee last week, MISO Director of Cost Allocation Jeremiah Doner said load growth and reliability issues are driving the need for more transmission investment.

Because of the size of this year's MTEP, MISO will add another meeting of the System Planning Committee of the Board of Directors in mid-October to give MISO board members more time to understand the package's contents.

Sustainable FERC Project's Natalie McIntire asked MISO to revisit its definition of "other" projects because most of the spending is classed under the category this year. MISO's other project category includes reliability projects based on TOs' self-imposed criteria separate from NERC standards, projects needed for load growth and projects to address the age and condition of existing facilities. Other projects have become the lion's share of MTEP spending since the 2018 cycle.

MISO is accepting stakeholder suggestions and considering what additional planning studies it may undertake as part of MTEP 24. However, planning staff warned that MISO is limited next year in what it can accomplish because it's performing extensive analysis under its ongoing LRTP.

MISO will hold stakeholder workshops on the nascent, second LRTP portfolio again Dec. 1 and at the end of January.

MISO: Expedited Review Process Needs Revamp

Lastly, MISO said the MTEP 23 planning cycle has made it clear it should rethink its expedited project review process for projects that can't wait until the usual December MTEP approval to begin construction. MISO said it fielded more than 30 expedited project review requests — double the number it received in 2022 — predominantly because of new load interconnections.

Armstrong said some expedited requests were "simple, while others have become quite complex." He said MISO planning staff is struggling to complete on-time studies on the out-of-cycle requests. MISO likely will need to overhaul its expedited processing to make the ever-increasing analyses manageable, he said.

"We have seen some ones that cause harm to the system and require some back and forth. At this volume, it's not sustainable," Senior Manager of Expansion Planning Amanda Schiro added during a Sept. 8 East Subregional Planning Meeting.

Schiro told stakeholders MISO staff is discussing internally how to best modify its process and said stakeholders should expect a proposal in coming months. ■

MISO News

MISO to Assess Extending Queue's COD Grace Period

By Amanda Durish Cook

In light of stressed-out supply chains and a bogged-down study process, MISO has agreed to re-evaluate its rules around commercial operation dates in its interconnection queue.

Stakeholders and staff plan to discuss extending the grace periods around commercial operation dates at upcoming meetings of the Interconnection Process Working Group (IPWG).

MISO policy requires its interconnection customers' generator interconnection agreements (GIAs) contain a commercial operation date that's within three years of the date originally requested in their queue applications. MISO additionally allows an up to three-year extension of the commercial operation date in the initial GIA. When customers can't meet either, MISO can terminate the GIA and generator developers lose their place in line unless they can secure a waiver of their commercial operation dates from FERC.

Last month, EDP Renewables' David Mindham said supply chain troubles and delays in MISO's studies of generation projects mean that projects regularly take longer than the allotted six years from originally planned commercial operations and often require FERC waivers, which create uncertainty.

Mindham raised the issue at the Aug. 30 meeting of the Planning Advisory Committee, which ultimately assigned the issue to the IPWG for consideration.

Mindham said MISO should consider extending its COD deadlines in its tariff so they're feasible. He said transmission owners often don't have network upgrades ready until well into the second extension. Mindham said current wait times for equipment like breakers can last three and a half years and "eat away at the three-year grace period."

Construction of EDP Renewables' Harvest Ridge wind farm in Illinois | *The Boldt Co.*

"There are dozens of these projects that will require FERC waivers. This problem doesn't seem to be going away. If anything, it seems to be getting worse on the transmission owners' end, and it's going to take several years for that to get caught up," he said. "The commercial operation date should have some meaning. It should be a date that developers can reasonably meet."

Multiple MISO interconnection customers have sought commercial operation date waivers with FERC since the pandemic began and strained supply chains. Mindham said an extension could cut down on the need for developers to seek future waivers. ■

MISO News

Market Monitor Questions MISO Fleet Assumptions in Long-term Tx Planning

Stakeholders Mixed on Assumptions, Renewables, Approach

By Amanda Durish Cook

MISO's Independent Market Monitor took his concerns to stakeholders last month over what he deems unrealistic fleet assumptions in MISO's long-range transmission planning.

MISO Independent Market Monitor David Patton delivered a presentation at an Aug. 31 long-range transmission plan (LRTP) teleconference to let stakeholders know he's concerned MISO's long-range transmission planning could upend market functions. He said the issue is serious enough for him to delve into MISO's transmission planning matters when usually he's confined to market matters.

"The performance of the market is greatly impacted by out-of-market investments … coordinated by MISO," Patton said. He said overblown transmission investments can "fundamentally" affect locational marginal prices and ancillary services.

Patton said the capacity expansion prediction MISO is using to develop its second LRTP portfolio contains an overestimated amount of intermittent, renewable generation and an exaggerated amount of dispatchable generation retirements.

"Planning to that future, I think is highly problematic," Patton said.

MISO would come up with a "very different set of future transmission needs" if it includes a more realistic fleet projection that includes battery storage, hybrid storage, and renewable resources and new natural gas generation, he said.

Patton's criticisms are contained in this year's State of the Market report. He also appeared in front of MISO board members to critique MISO's transmission planning future. Board members have questioned Patton's departure from markets into transmission planning. (See "LRTP Doubts," *MISO IMM Zeroes in on Tx Congestion in State of the Market Report*.)

Minnesota Public Utilities Commission staff member Hwikwom Ham said he had serious concerns with Patton's critique of transmission planning. He asked what's keeping the IMM from weighing in on states' integrated resource planning, because that also affects MISO markets.

Ham said MISO's second LTRP portfolio's assumptions are based directly on states' emissions reductions plans.

The Cardinal-Hickory Creek line under construction | *ATC and ITC Midwest*

"You are directly defying that outcome," he said.

American Transmission Co.'s Bob McKee agreed MISO's futures use "actual" state plans and planned retirements.

Patton said he wasn't trying to question state directives. But he said his analysis shows a 2040 fleet mix that contains 108 GW less solar and wind resources than MISO is planning for. He said MISO states still could achieve their official emissions reduction targets even with the absent, hypothetical intermittent resources. Patton said he didn't account for "announcements made by governors that may or may not make their way into legislation."

MISO expects it will add 369 GW of new, mostly renewable resources by 2042, bringing its total installed capacity to 466 GW. However, only 202 GW of that capacity is accredited; staff assumes a declining effective load-carrying capability for the renewable additions. (See *MISO: Long-range Tx Needed for 369 GW in Interconnections*.)

Patton also said he found MISO's forecast that it will have 29 GW of flexible resources — including green hydrogen, long-duration battery storage, small modular nuclear reactors and reciprocating internal combustion engines — highly unrealistic. He questioned whether those technologies will be commercially available by the 2040s.

Patton also said half of MISO's 13 states don't have definitive decarbonization mandates. He said MISO shouldn't assume members don't build dispatchable gas resources between now and 2030.

But some stakeholders said they viewed Patton's view as more environmentally harmful and more expensive to ratepayers, because of an expansion of gas infrastructure. Some also said it was disrespectful for Patton to show up to a planning meeting so late in the game to advocate for a rethink of MISO's transmission planning future.

Patton said he will make a point to participate in MISO's LRTP benefit analysis going forward.

Sustainable FERC Project attorney Lauren Azar said she worried Patton's transmission analysis based on a concern for the market is shortsighted because the market only sends short-term signal and doesn't indicate "the type of grid we're going to need in 2042, or

MISO News

even 2035."

"MISO is [a] leader in the nation in building 20 years out," Azar said.

But Patton warned about the dangers of overbuilding transmission based on a flawed view of future capacity.

"If we adopt a future that's not realistic, I don't think we can be confident in that," he responded.

Southern Renewable Energy Association's Andy Kowalczyk asked Patton to consider MISO may be running the risk of underbuilding the transmission system, which also would raise costs for ratepayers. He said he didn't think battery storage would "absorb" the need for new transmission because it still needs to charge from and dispatch to the system.

Sustainable FERC Project's Natalie McIntire said she was skeptical of Patton's analysis that MISO states could achieve a dramatic, more-than-90% carbon reduction by 2042 while removing 108 GW of renewable energy from the equation.

But North Dakota Public Service Commissioner Julie Fedorchak said she thought it was worthwhile for Patton to question MISO's fleet assumptions when the second LRTP portfolio could cost as much as $30 billion.

"We absolutely need more analysis instead of less," she said.

Mississippi Public Service Commission consultant Bill Booth called for MISO to take a fresh look at its battery storage addition assumptions.

"This is an expensive endeavor. We cannot afford to build wasteful transmission. … These are costs that are going to be borne by ratepayers, and we need to make sure they're necessary and needed and the best thing for the footprint," said Kavita Maini, an energy consultant representing MISO end-use customers.

MISO Responds

MISO Vice President of System Planning Aubrey Johnson said MISO in the past has been accused of not "being big or bold enough in transmission planning," especially in its 2011 multivalue transmission portfolio. He said MISO is embarking on "least regrets" long-range transmission planning.

Johnson reminded stakeholders that the LRTP portfolios are being developed to resolve major regional system issues, not ensure the interconnection of an additional 369 GW, or ensure a certain generation mix. He said MISO's planning future is meant to reflect members' resource planning.

"It's not the goal to maximize transmission building, but to maximize the value of the transmission we recommend," Johnson said. He added he's confident MISO will advance the most valuable second LRTP possible.

Johnson also said MISO operators found MISO's multivalue projects helped it better navigate mid-August's heat wave. (See *MISO Calls 1st Summertime Emergency amid Systemwide Heat Wave*.)

"So those things matter," Johnson said.

MISO hopes to recommend a second, multibillion dollar LRTP portfolio to its Board of Directors in the first half of 2024. ■

MISO News

FERC Blocks Solar Group's Contest of MISO Ban on Renewable Ancillary Services

FERC: SEIA Didn't Demonstrate that Renewables are Reliably Comparable

By Amanda Durish Cook

FERC has ruled it's appropriate for MISO to continue to preclude renewable resources from providing ancillary services in its markets, countering a solar trade group's complaint.

FERC said the Solar Energy Industries Association (SEIA) didn't present evidence that MISO's policy of barring renewable output from ancillary services was producing unfair rates (*EL23-28*).

In an Aug. 31 order, the commission said much like its recent order authorizing MISO's ban on wind and solar generation from supplying ramping capability, it remains the case that renewables rarely are the most economic choice to supply operating reserves because their locations exacerbate already binding transmission constraints. (See related story, *FERC: MISO Can Ban Intermittent Resources from Providing Ramp*.)

SEIA lodged the complaint early this year in part because of MISO's effort to bar renewables from furnishing ramping. (See *Solar Trade Group Challenges MISO Ban on Renewable Ancillary Services*.) The group argued that MISO's dispatchable intermittent resources are operationally capable of providing regulation service, spinning reserves and supplemental reserves and that its current market rules discriminate against some resources because they're tailored to the large, centralized power plants of the past. It also said instating renewables' eligibility for such services would foster competition.

But FERC said SEIA didn't demonstrate that renewables "can reliably deliver the ancillary services they are cleared to provide to the MISO market in a manner comparable" with other resources.

| *Solar Energy Industries Association*

The commission acknowledged MISO's current market clearing software isn't sophisticated enough to consider locations of resources and nearby congestion rendering them non-deliverable. It said if MISO were to clear operating reserves from renewable sources, congestion would prevent them from making it to market in most cases. Thus, allowing procurement would create a reliability issue and payments to unhelpful resources, FERC decided.

The commission also agreed with MISO that it's far more lucrative for renewable resources to provide energy over ancillary services.

Lastly, FERC said SEIA's arguments differed from the commission's previous regulations requiring open access transmission service and establishing separate performance and capacity payments for frequency regulation service, and its ruling against the undue discrimination of electric storage resources.

"Those orders did not require that every resource type must be allowed to provide such services," FERC said.

FERC said though it's "undisputed" MISO's tariff treats renewable and nonrenewable resources differently with respect to ancillary services, SEIA didn't prove that renewable and nonrenewable resources are "similarly situated" because when renewables are cleared to provide ancillary services, they're trapped behind a transmission constraint.

As with their order blocking MISO renewables from providing ramp capability, Chairman Willie Phillips and Commissioner Allison Clements issued a joint statement to emphasize that the order was limited. The two said MISO's market dynamics are set to change — and the snub likely will be temporary — as renewable energy becomes more prevalent.

"We strongly urge MISO to continue to improve and enhance the software on which its markets rely. Both MISO and the commission recognize the limitations of MISO's current software, and the record suggests that these shortcomings are contributing to problems that go beyond [renewable] integration alone," Phillips and Clements wrote. "We anticipate the continued development of these resources and encourage MISO to be ready for them as they come online." They said MISO should devise ways to account for locational congestion in its software when selecting resources. ■

NYISO News

Clean Energy Groups Protest NYISO DER Proposal

AEU, AEMA Claim ISO's Rules Could Stifle DER Aggregation Market Entry

By John Norris

Renewable energy advocates filed a protest with FERC on Thursday arguing that NYISO's proposal to facilitate participation of distributed energy resource aggregations in its market would discriminate against smaller aggregations (*ER23-2040*).

The protest by Advanced Energy United (AEU) and the Advanced Energy Management Alliance (AEMA) comes after NYISO's response to a FERC deficiency notice asking the ISO to clarify several aspects of its proposals to comply with Order 2222, which requires RTOs and ISOs to design rules giving aggregations market access. The complaints closely align with previous protests by the two groups.

In the protest, the groups argued that NYISO failed to justify its 10-kW minimum requirement for DER aggregation participation. They also contended that the ISO's plan to restrict single resource type aggregations from using metering service entities is illogical and that its requirement that demand response resources submit cost-basis data is impossible to fulfill since that data does not exist.

AEU and AEMA particularly focused on the 10-kW rule, maintaining that the requirement does not "withstand scrutiny" and that basing the DER aggregation minimum participation model on historical emergency demand response and special case resource programs is inappropriate because the "resource types and sizes are different."

| © RTO Insider LLC

The two organizations also questioned NYISO's administrative reasons for limiting DER participation, arguing that if the ISO thought it would be burdensome to register all types of DERs then it should either hire more staff or ask FERC for a limited waiver to give it more time to review smaller DER aggregations.

AEU and AEMA also criticized NYISO's failure to propose an end date for its 10-kW requirement, which they said violates the objectives of Order 2222.

The groups asked the commission to reject NYISO's proposals, saying the ISO's *response* to FERC's deficiency notice fails to adequately explain or justify the shortcomings the commission had identified.

In addressing FERC's letter last month, the ISO stuck to its previous arguments, claiming it did not have the bandwidth to allow all resources to immediately participate and saying that any further delays would hinder implementation of its DER aggregation plans and potentially disrupt its demand response programs. (See *FERC Seeks More Info on NYISO DER Aggregation Proposal*.)

FERC must respond to NYISO's deficiency letter within 60 days. ■

NYISO News

NYISO to Ask FERC for Order 2023 Compliance Extension

TPAS/ESPWG Also Briefed on CRP Revisions, Class Year Projects

By John Norris

RENSSELAER, N.Y. — NYISO on Wednesday said it plans to file a motion with FERC for an extension on the compliance deadline for Order 2023, according to a *presentation* given to stakeholders.

Thinh Nguyen, NYISO senior manager of interconnection projects, told the Transmission Planning Advisory Subcommittee (TPAS) and Electric System Planning Working Group (ESPWG) meeting that the ISO has 90 days to make its request to the commission, following the order's *publication* in the *Federal Register* that day.

Nguyen added that NYISO plans to hold meetings focused on the interconnection queue and Order 2023 compliance that will be held after regular TPAS sessions and be potentially named the Interconnection Issues Task Force.

NYISO's presentation also noted how, though it and several other RTOs have already asked FERC for a rehearing on Order 2023, the ISO might still comply with the order, as it is unclear if the commission will grant a rehearing (*RM22-14*). (See *FERC Order 2023 Gets Rehearing Requests from Around the Industry*.)

The ISO has been actively working to streamline its congested interconnection queue, and while it believes Order 2023 could improve efficiencies, it also cautioned stakeholders that it believes some of FERC's directives may be legally inconsistent or counterproductive to the order's goals.

Stakeholders probed NYISO staff for detailed information about the transition process and its potential implications.

Doreen Saia, an attorney with Greenberg Traurig, asked whether much of the transition was still to be determined or if the ISO could share some specifics.

Nguyen acknowledged that many of the specific details are to be determined but added that "for us to make a meaningful transition, we may need to sit down and figure out what this new process will look like and come up with a transition rule that will complement our own study process."

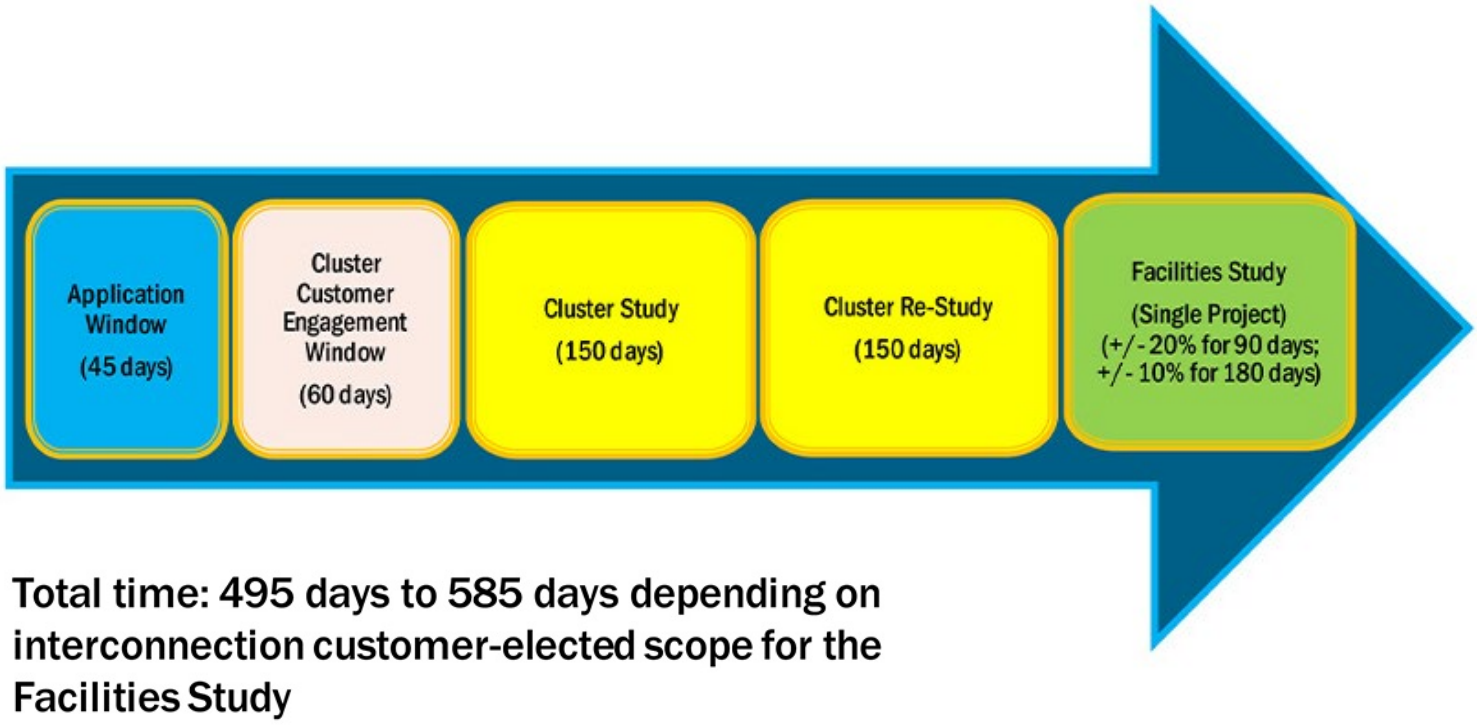
Mark Reeder, representing the Alliance for Clean Energy New York, asked about the frequency of the newly proposed task force's meetings and the expected outcomes.

"It's too early to decide whether these will be biweekly or monthly meetings, but we want to make sure that when we host these meetings that we are coming to stakeholders with meaningful information rather than just general updates," Nguyen said.

NYISO promised to return to stakeholders with more details on how it proposes to comply with Order 2023 and how proposed revisions might impact current interconnection processes.

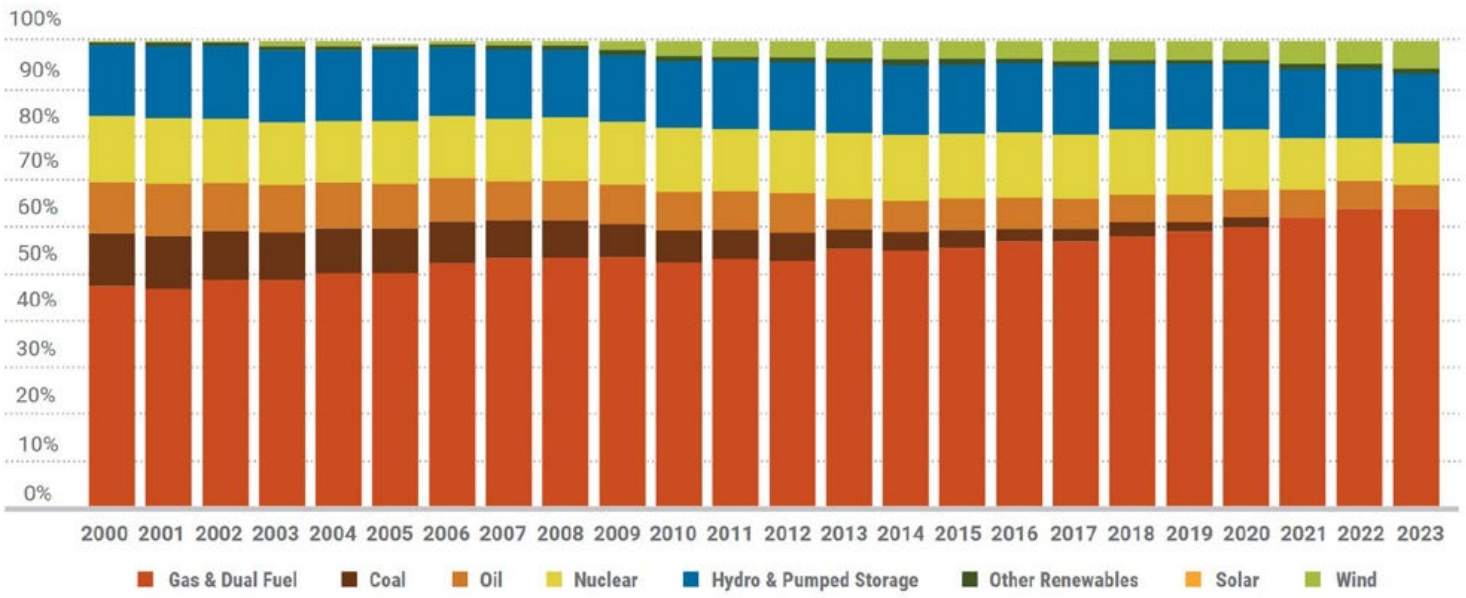
Comprehensive Reliability Plan

NYISO also *presented* an updated draft of the Comprehensive Reliability Plan, with additional sections for dispatchable emission-free resources (DEFRs) and other developing tech-



Overview of theoretical Order 2023 cluster study timeline | *NYISO*

NYISO News



Historical generating capacity fuel mix in New York (2000-2023) | | *NYISO*

nologies, as well as the short-term reliability needs recently identified in New York City.

The newly added "Beyond the CRP — Road to 2040" section, featuring DEFRs, was included in response to stakeholder requests. (See "Comprehensive Reliability Plan," *NYISO Proposes 48 Market Projects for 2024*.) The CRP, which is the last part of the *reliability planning process*, is conducted every two years and evaluates the future risks to reliability and the viability of proposed solutions identified in earlier Reliability Needs Assessments.

Mark Younger, president of Hudson Energy Economics, and Kevin Lang, partner at Couch White, questioned NYISO's reliance on NERC data for reliability assessments, rather than using New York-specific data. Younger said New York City certainly has a reliability need in the short term but argued that using state data might lead to a more accurate accounting of potential shortfalls.

ISO staff said they are discussing the subject internally, though they emphasized that confidentiality concerns are a main reason New York data is not used.

NYISO aims to release its final CRP draft by late September and will seek committee approval in October.

Class Year & Expedited Deliverability Study Update

NYISO *reported* that 84 projects are officially part of Class Year 2023 and *released* a list of the 16 projects that have executed their expedited deliverability study (EDS) agreements.

The CY study assesses the feasibility of new projects looking to enter NYISO's grid, while the EDS process is a more fast-tracked grid feasibility assessment for prioritized energy projects.

NYISO Manager of Facility Studies Wenjin Yan said the ISO must first finalize the EDS base case and estimated the study would finish next January.

Reeder suggested the ISO should consider tariff changes to allow for later entry into the EDS and consider starting another study after the current one is completed in early 2024 to enable projects to move ahead more quickly.

Yan said NYISO anticipates presenting CY23 for committee approval in July and August 2024.

NYC PPTN

NYISO gave a quick update on the New York City public policy transmission needs assessment, stating that the ISO is finalizing the baseline case and will share the data with developers upon completion.

The ISO reminded stakeholders, however, that the information would only be given to developers who have completed the requisite *Critical Energy Infrastructure Information Non-Disclosure Agreement*. According to both staff and stakeholders present, there is no set deadline for completing a CEII agreement. ■

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NYISO News

NY State Reliability Council Executive Committee Briefs

Emergency Operating Procedures

ALBANY, N.Y. — The New York State Reliability Council Executive Committee on Friday approved the *preliminary* base case for the upcoming capability year and new emergency operating *procedures* aimed at enhancing grid reliability.

NYISO COO Rick Gonzales | *NYISO*

The base case was approved after it received approval from both the NYSRC's Installed Capacity Subcommittee, other committee members and NYISO, with the ISO's COO, Rick Gonzales, saying during the meeting, "This is a step in the right direction, and the ISO supports this change," in reference to the proposed revisions.

The base case is particularly crucial for resource adequacy modeling, as it sets the foundation for assessing the reliability of the power system by establishing assumptions concerning load forecasts, generator availability, transmission constraints and other factors that influence the modeling.

Previously, the ICS reported how conditions are tightening in the New York Control Area and that conservatively adjusting the ISO's emergency operating modeling and its base case is necessary as the state relies on neighboring systems, particularly in the winter, to support reliability during emergencies. (See "Emergency Operating Procedures," *NY State Reliability Council Executive Committee Briefs: June 9, 2023*.)

The ICS and NYISO staff will continue to conduct sensitivity analyses using these new assumptions to better understand the impact they will have on the state's installed reserve margins and then report back to the committee.

Stakeholders were asked to share input before anything is finalized at the ICS meeting on Oct. 4.

Inverter-based Resources Standard

The committee discussed NERC's new risk priorities list in light of a recent inverter-based resource (IBR) event in Utah that caused grid instability.

NERC for the first time updated its risk priorities list to include energy policy as a risk profile after it determined that policymakers' decisions are becoming increasingly crucial to ensure the reliability of the grid. (See *ERO Adds Energy Policy to Risk Priorities List*.) New York has been working to finalize rule requirements and comply with NERC standards for IBRs.

The New York State State Reliability Council meets at Wolfert's Roost Country Club in Albany. | | *© RTO Insider LLC*

Last month a solar disturbance in southwest Utah raised further questions about the reliability of IBRs and prompted NERC to reiterate the importance that generators and developers follow its *Level 2 alert*, which set out IBR guidelines. (See *NERC Utah Event Report Underlines Ongoing IBR Issues*.)

Mayer Sasson, former chair of the Executive Committee, commented that when reading NERC's report on the incident, he felt like its authors were "angry and upset," as utilities and the wider industry were "not taking [NERC's] event analysis and recommendations seriously."

Roger Clayton, chair of the NYSRC's Reliability Rules Subcommittee, who has been leading the charge of implementing IBRs, said that the incident "is more evidence that we need to get this right," adding that the state "must learn the lessons from these incidents and avoid such incidents from happening in New York."

NYISO Updates and Eclipse Prep

NYISO informed the EC that it has made notable progress on several market development projects, such as its dynamic reserves, duct firing model improvements and four-year demand curve reset, as well as begun preparing for an upcoming solar eclipse.

Aaron Markham, NYISO vice president of operations, also told the committee that August was a "pretty benign month" and experienced a peak load of 24,970 MW.

NYISO has begun preparing for an anticipated partial solar eclipse in October, which is expected to reduce solar energy by roughly 700 MW, though the ISO believes it will have enough resources available to meet load at the time.

The ISO is also looking ahead to a total solar eclipse expected in April 2024 that will pass through the state. ■

— John Norris

PJM News

New Jersey BPU President Fiordaliso Dies

17-year Agency Veteran Spoke Frequently of the Need to Protect State's Climate Future

By Hugh R. Morley

Joseph L. Fiordaliso, who led the New Jersey Board of Public Utilities as it embraced an aggressive and sweeping clean energy agenda marked by a major investment in offshore wind, has died, Gov. Phil Murphy (D) said Thursday.

Fiordaliso, 78, a BPU commissioner since 2005 and a former deputy chief of staff to former Gov. Richard Codey, spoke frequently about the need to adopt aggressive policies to combat climate change, saying he did not want future generations to look back at the agency's efforts and question why it didn't do more.

"Climate is changing," he said at the board's most recent meeting, on Aug. 16, shortly before it voted to enact a permanent community solar program after two well-received pilot programs. "And we all better be adults about the fact that we have to do something about it, not hide our heads in the sand. Because it's not going to get any better; it's only going to get worse."

Fiordaliso's death leaves the agency leaderless as it confronts increasing challenges to the state's clean energy investment and especially the OSW program, which is facing community and special interest opposition and several lawsuits, as well as developer concerns about increasing costs that have raised questions about project viability.

The passing of the president removes a key font of experience on the board. Three of the four remaining BPU commissioners — Democrats Christine Guhl-Sadovy and Zenon Christodoulou, and Republican Marian Abdou — joined the board in the past year. The fourth, Republican Mary-Anna Holden, was appointed in 2012.

Under New Jersey law, the governor picks the BPU president, and the Senate can either confirm or reject the candidate.

Murphy, in a statement announcing Fiordaliso's death, called Fiordaliso a "consummate public servant, a trusted colleague and a good friend." The governor's office did not say how or when Fiordaliso died, but the *Associated Press* said he died Wednesday.

"As president of the BPU since the beginning of my administration, Joe skillfully led our work to responsibly transition to a clean energy economy while always putting the needs of consumers first," Murphy said. "Every time you saw Joe he was wearing his signature offshore wind pin or handing one out to anyone and everyone he met."

Joseph L. Fiordaliso, president of the New Jersey Public Utilities Commission, died Wednesday night. He was a strong supporter of the state's clean energy policies. | *NJ BPU*

To Fiordaliso, the pin — fashioned in the shape of a wind turbine — demonstrated support for the OSW program. But it drew criticism from opponents who saw in it a sign that he was too closely aligned with the OSW sector. The pin even drew the attention of a Republican lawmaker who quizzed Fiordaliso about it at a recent budget hearing.

Fiordaliso, however, said his interest was in doing what was best for the state and for ratepayers. In fact, at the board's June meeting, he lashed out at the state's two offshore wind developers who he said had created "delay after delay after delay … almost since Day 1.

"So I'm issuing a recommendation to those developers: Put your nose to the grindstone, and let's get this going again," he warned them. "Because my patience is short, and your delays are intolerable. And if you can't do that, we have to have a very intense discussion." (See *NJ BPU Pulls Offshore Tx Project Mod from Agenda After Complaint*.)

Top Priority

Murphy, who appointed Fiordaliso as BPU president on Jan. 15, 2018, has set a target for the state to develop 11 GW of OSW capacity by 2040. The BPU has approved three projects, totaling 3.758 GW, in two solicitations and is expected to announce the winners of a third round early in 2024, which could add 4 GW. In addition, the state has moved aggressively to jump-start a logistics sector to support the OSW projects, along with those of other states, which include the development of the New Jersey Wind Port to handle material and equipment for use in the projects. (See *NJ Opens Third OSW Solicitation Seeking 4 GW+*.)

Doug O'Malley, executive director of Environment New Jersey, an environmental group, said that Fiordaliso's lengthy tenure as a BPU commissioner meant he was present in, and accrued a great depth knowledge of, the early years of the solar sector in the early 2000s. The BPU's support helped put the state in the forefront of solar capacity development.

Fiordaliso also saw the inactivity on OSW during the tenure of Republican Gov. Chris Christie, from 2010 to 2018, and the BPU's

PJM News

aggressive embrace of OSW when Murphy appointed Fiordaliso as the agency's president will be a key plank of his legacy, O'Malley said.

"Wind was arguably the top priority for President Fiordaliso," he said. "He cared deeply about offshore wind as kind of a new technology that you can harness."

"Obviously, offshore wind has had choppy waters this year," he said. "But we would not be in the position we are in without President Fiordaliso's leadership."

Other parts of the BPU's aggressive agenda under Fiordaliso also have ruffled feathers. The agency is facing criticism from Republicans and business groups over the expense of the clean energy programs, including the lack of clarity on how much it will cost ratepayers. The programs include extensive subsidies for the purchase of electric vehicles (EVs) and trucks and the development of charging sites, proposals for subsidies of energy storage systems and plans to promote the use of electric heat and water systems in buildings and reduce the use of fossil fuels.

The New Jersey Business and Industry Association (NJBIA), which frequently disagreed with the BPU over cost concerns and the focus on electricity instead of other alternative energy forms, said in a statement prompted by his death that Fiordaliso was "truly and passionately committed to his job and its many missions."

"Even when we didn't agree on policy issues, President Fiordaliso always had an open door, took part in many NJBIA events and had receptive ears to our concerns," said the statement from CEO Michele Siekerka.

Anjuli Ramos-Busot, director of the Sierra Club of New Jersey, released a statement that called Fiordaliso a "fighter for renewables and a proud supporter of offshore wind.

"He understood the severity of climate change and had a vision for the BPU to combat it," she said.

Tough Upbringing

Fiordaliso grew up in a cold-water apartment in Newark, and he never forgot his roots as he was putting together policy, O'Malley said. That was particularly evident in Fiordaliso's support for the state community solar program, which provides discounted clean energy to low- and moderate-income ratepayers, O'Malley said. (See *NJ Opens Community Solar and Nuclear Support Programs*.)

"He was a big supporter of making clean energy, especially solar, more accessible for more people," O'Malley said. "He wanted to make sure the clean energy could reach every New Jersey resident."

Fiordaliso graduated with a degree in business education from Montclair State University and was a teacher from 1967 to 1986, according to the *university's website*. He was director of government relations for the Saint Barnabas Health Care System and served three terms as mayor of Livingston, N.J.

He was a member of the National Association of Regulatory Utility Commissioners' Committee on Critical Infrastructure and Committee on Energy Resources and the Environment and also sat on the Executive Committee for the Regional Greenhouse Gas Initiative. (RGGI) and RGGI's Strategic Communications Team, according to the *BPU website.*

He also was board member of the Organization of PJM States Inc. and of the advisory council to the board of directors of the Electric Power Research Institute. In May 2023, FERC appointed Fiordaliso to the Joint Federal-State Task Force on Electric Transmission.

At the BPU's meeting last month, Fiordaliso introduced several interns and spoke about the role of the board.

"We are doing work that's going to help, hopefully save future generations," he said. "It's not many times in one's career, and I've been working a long time, that you can actually say that I'm doing something that is going to affect future generations in a positive way."

He noted that he had spent all but five years of his working life in the public sector.

"It is one of the most gratifying experiences I think a human being can have," he said. "You may not make a million dollars but the satisfaction that you get from doing what you do is certainly worth a million dollars." ■

PJM News

Settlement Possible Between PJM and Generation Owners over Winter Storm Complaints

'Settlement in Principle' Could Lead to Settlement Package Late this Month

By Devin Leith-Yessian

Several generation owners and PJM are progressing toward an agreement regarding the non-performance charges the RTO assessed in its allegation the generators failed to meet their capacity obligations during the December 2022 winter storm, according to the settlement judge mediating the deliberations (*EL23-53, et al.*).

Judge Matthew J. Vlissides Jr. wrote in a Sept. 1 status report that a "majority of the participants indicated that they reached a settlement in principle" as of the previous day's conference and he recommended terminating the process without holding further meetings. (See *FERC Sends Elliott Complaints Against PJM to Settlement Judge*.)

"These participants represent that they are finalizing the settlement materials and anticipate filing the settlement package by late September 2023," he said.

East Kentucky Power Cooperative spokesperson Nick Comer said EKPC is pleased the parties have reached a settlement in principle but wouldn't comment further until the terms have been filed with the commission. PJM declined to comment.

The companies involved in the settlement procedures include Essential Power (EL23-53), Aurora Generation (EL23-54), the Coalition of PJM Capacity Resources (EL23-55), Talen Energy (EL23-56), Lee County Generating Station (EL23-57), SunEnergy1 (EL23-58), Lincoln Generating Facility (EL23-59), Parkway Generation Keys (EL23-60), Old Dominion Electric Cooperative (EL23-61), Energy Harbor (EL23-63), Calpine (EL23-66), Invenergy (EL23-67) and EKPC (EL23-74).

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PJM stated the penalties from Winter Storm Elliott total about $1.8 billion, though during stakeholder meetings it has said it's likely some percentage of generators will default on the penalties. To reduce the impact to those companies, PJM filed to extend the payment period for non-performance charges to nine months, which FERC approved in April. (See "FERC Approves Alternative Billing Schedule," *PJM: Elliott Nonperformance Penalties Total More Than $1.8B*.)

The commission established the settlement judge procedure June 5 to see if the parties involved in a dozen complaints could reach an agreement within 60 days and extended the process an additional month on Aug. 14 after Vlissides wrote a progress report finding the parties were "significantly progressing" toward settlement.

PJM asked the commission to establish a settlement judge in April, arguing that while it maintains the penalties are valid, a faster resolution could support the long-term health of the capacity market and result in more consistent settlement outcomes.

"The capacity market also is designed in large measure to signal the need for new capacity resource investment, and the expectations of the financial and investment community accordingly are an important backdrop to the operation of this market," PJM said in its earlier filings. "Timely, consensual resolution of these disputes thus could, potentially, help support the long-term health of the resource adequacy construct in the PJM region."

The complaints argued PJM improperly declared emergencies in regions where it was not warranted and continued to export to other balancing authorities in contravention of its tariff and the RTO had not provided generators with the required notifications they were expected to be available to allow them to procure fuel. ■

PJM News

Va. SCC Orders Dominion to Suspend Unapproved DER Interconnection Rules

By James Downing

The Virginia State Corporation Commission last month ruled that Dominion Energy overstepped its authority in requiring distributed solar for large customers to go through new processes that led to spikes in the cost of installation.

The Virginia Distributed Solar Alliance filed a complaint against the new procedures in June, alleging they overstepped the regulated utility's authority, as the SCC has been looking into the issues around interconnection of distributed sources in other cases. The SCC last approved interconnection rules back in 2020 and it is now looking at additional changes.

The commission on Aug. 30 agreed to suspend the parameters and interconnection agreements until it wraps up its open proceedings looking into the issues, but it declined to "address the myriad of additional relief" sought by the solar group.

The group's other requests can be taken up in other proceedings, the SCC said. It also noted that it was not taking lightly Dominion's claims about safety and reliability, but that it lacked authority to implement the new processes without a prior order.

"Dominion should continue to take the actions necessary to maintain the immediate safety and reliability of its system; this may include, but need not be limited to, seeking specific authority from this commission in one or more formal proceedings," the commission said.

The utility adopted new parameters for projects between 250 kW and 1 MW and projects that range from 1 to 3 MW in December 2022, but the solar group's complaint focused on their impact on projects below 1 MW, which are midsized, nonresidential projects. The complaint alleged that the new rules have led to costs, delays and barriers to adding such distributed generation around Virginia.

The rules that were suspended by the SCC led to "unprecedented" costs and delays by potentially requiring distributed solar to pay for substation upgrades and dark fiber cable and relay panel equipment. Dark fiber costs between $150,000 and $200,000/mile; relay panels can cost $250,000 for equipment and potentially more than double that for engineering, mobilization and construction management.

The complaint listed a number of anecdotes, including one at the James River Juvenile Detention Center for Henrico County, where Dominion estimated $2.25 million in preliminary costs for a 686-kW system. Prince William County Schools faced similar costs on a 987-kW array it was planning. Both projects, and others owned by private firms, proved too expensive with the extra costs that Dominion assessed under the now-suspended rules.

Dominion had argued in a filing last month that it needs to update the rules as distributed generation has grown rapidly in Virginia since a law passed expanding its net energy metering program.

"As a result of these changes, more net metering generation, with higher capacity ratings, are now rapidly developing and penetrating the company's electric power system," the firm said. "The company has been tasked with integrating more net metering distributed energy resources, with higher capacity ratings, that are now permitted to produce up to 150% of the customer's expected annual energy consumption."

The parameters suspended by the SCC were meant to ensure Dominion's ability to specify the equipment and technical specifications needed to establish safe and reliable interconnection, the company said. ■

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PJM News

NJ Gov Appoints Clean Energy Advocate to Head BPU

Christine Guhl-Sadovy Will Replace Fiordaliso, Her Former Boss

By Hugh R. Morley

Christine Guhl-Sadovy | *New Jersey Chamber of Commerce*

New Jersey's Board of Public Utilities, the leading edge of the state's aggressive push into renewable energy, will be led by Christine Guhl-Sadovy, a former organizer for the Sierra Club in the campaign against coal, Gov. Phil Murphy (D) said Monday.

Guhl-Sadovy, who joined the board in May, will replace Joseph L. Fiordaliso, who died Sept. 6th and had served for 17 years as a BPU commissioner, including five as the agency's president. Guhl-Sadovy worked as Fiordaliso's chief of staff at the BPU before moving to become Murphy's cabinet secretary in October 2021.

While chief of staff, Guhl-Sadovy worked on the state's 2019 Energy Master Plan, the 2018 Clean Energy Act and the state's Electric Vehicle Incentive program, all of which helped shape the state's commitment to a vigorous transition away from fossil fuels and toward renewable energy.

Murphy said he believed Guhl-Sadovy would continue what he called Fiordaliso's "steadfast … unwavering belief that we not only can — but must — cultivate a healthier and more sustainable planet for our children and grandchildren."

(See related story: *NJ BPU President Fiordaliso Dies*.)

"I'm confident that Christine, who has demonstrated her commitment to these same values time and time again throughout her invaluable service in my administration, will continue to build upon Joe's lasting legacy," he said. He added he expects her to "responsibly transition New Jersey to a clean energy economy, while putting the needs of consumers and New Jerseyans first."

Guhl-Sadovy's appointment takes effect immediately. New Jersey law requires the governor to nominate BPU commissioner candidates subject to confirmation by the state Senate. But Murphy can appoint the president from commissioners who already gained Senate approval. (See *NJ Senate Approves Two BPU Commissioners*.)

She takes the helm as the board faces a growing pushback against Murphy's clean energy policies, with vigorous opposition to the state's offshore wind plans from shore residents and tourism advocates, and concerns from offshore wind developers that approved projects no longer may be economically viable because of rising costs.

Murphy expects to nominate *Stephanie Lagos*, deputy chief of staff to the governor and his wife's chief of staff, to fill the open seat on the five-member board, according to a source close to the governor. She would go for confirmation by the Senate in the fall.

The BPU has canceled its next meeting, which was scheduled for Thursday.

Beyond Coal, Planned Parenthood

Guhl-Sadovy, in a statement released by Murphy, said she's looking forward to "continuing to serve the people of New Jersey in this role, and making the planet healthier."

A graduate in psychology from Rutgers University, Guhl-Sadovy also gained a certificate in leadership, organizing and action from the Harvard Kennedy School, according to her *LinkedIn page*. She worked on energy and environmental issues with the national Sierra Club as a representative of the Beyond Coal campaign and while at Planned Parenthood she worked to ensure the election of pro-women's health candidates and on the successful effort to pass legislation to restore funding in New Jersey for family planning.

Guhl-Sadovy drew support from the environmental community during her confirmation as commissioner, and Doug O'Malley, director of Environment New Jersey, welcomed her appointment as BPU head.

"Christine started her career working to fight climate change, and now she's in the bully pulpit," he said. "She'll clearly continue the legacy of President Fiordaliso, and she's a force in her own right."

He called her an "an incredibly strong pick to lead the board," in part because of the wealth of knowledge she brings to the position from having worked as Fiordaliso's chief of staff. ■

PJM News

PJM OC Briefs

PJM Delays Vote on Quick Fix to Information Sharing Requirements

VALLEY FORGE, Pa. — PJM on Thursday opted to hold off from seeking stakeholder endorsement of a quick-fix *issue charge* and proposed *manual revisions* aimed at reducing the circumstances under which the RTO would be compelled to provide advance notice of when it will be sharing confidential member information with third parties. (See "PJM Brings Quick Fix Issue on Data Sharing," *PJM OC Briefs: Aug. 10, 2023*.)

PJM's Becky Davis told the Operating Committee that confidential information is regularly shared with reliability coordinators, transmission owners and NERC in the course of normal business, and a notification five days before the information is shared has become "inefficient and impractical" and slowed down coordination with those parties.

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned why the change was being sought as a quick-fix change to Manual 33, rather than as a change to the Operating Agreement with a corresponding FERC filing, which he believes would be a "slam dunk" before the commission.

PJM Assistant General Counsel Thomas DeVita said the RTO considered removing the notification entirely through changes to the OA but came to the conclusion that members may prefer notification in some circumstances, such as the NERC inquiry into the December 2022 winter storm.

East Kentucky Power Cooperative's Denise Foster Cronin suggested explicitly including the advance notice exceptions envisioned by the draft manual revisions in the OA (rather than the manual) and including a retroactive notification requirement when advance notice is not provided to allow members to remain informed about when their information has been shared without slowing down PJM's coordination with third parties.

PJM said it will defer seeking a vote on the quick fix until the October OC meeting to work with stakeholders to incorporate their feedback into the proposal.

Stakeholders Endorse Quick Fix on Synchronized Reserve Dispatch

The OC unanimously endorsed a quick fix *issue charge* and *manual revisions* to clarify that generation owners should respond to a synchronized reserve deployment when they receive notification through any of the existing Energy Management System (EMS) datalinks. (See "PJM Proposes Synchronized Reserve Deployment Language," *PJM OC Briefs: Aug. 10, 2023*.)

PJM's Frank Hartman said the status quo language has resulted in many reserve resources waiting until they have received the all-call message from dispatchers, which takes longer to reach generators. When reserve resources receive a signal to respond, Hartman said their default is to provide the full amount they're committed to in the market. For a resource with a 50-MW reserve obligation, he said that is the amount it should provide unless it receives instructions otherwise from dispatchers.

The quick fix is one of several solutions PJM has proposed to address a decline in response rate since the reserve market was overhauled in October. (See "PJM Seeks Stakeholder Process on Reserve Certainty," *PJM MRC/MC Briefs: July 26, 2023*.)

Sotkiewicz said he finds the issue charge problematic as it does not address the possibility that there may be underlying issues with the reserve market structure that may be leading to the decline in response rates.

PJM's Donnie Bielak said the quick fix is meant to clarify existing instructions to generators, and there are other forums where the RTO intends to address the issues that Sotkiewicz raised.

"All of your comments are well taken; it is on our radar, and it is something we collectively want to address as well," Bielak said.

Stakeholders Endorse Manual Revisions Related to Communication Failures

The OC unanimously endorsed *revisions* to Manual 1 that detail when TOs would be required to notify PJM that interpersonal communication capabilities have been disrupted.

The revisions state that PJM is required to be notified when only alternative communication systems are available and a loss of portions of a TO's interpersonal communication capability, such as a radio failure, does not require a notification so long as other voice communications detailed within the TO's communication capability remain available. (See "PJM Proposes Manual Revisions Related to Communication Failures," *PJM OC Briefs: Aug. 10, 2023*.) ■

— Devin Leith-Yessian

Donnie Bielak, PJM | © *RTO Insider LLC*

PJM News

PJM MIC Briefs

Voltus Withdraws Issue Charge on DR Offer Parameters

VALLEY FORGE, Pa. — Voltus on Wednesday withdrew an *issue charge* at the PJM Market Issues Committee addressing the parameters that demand response resources can include in their energy market offers after several stakeholders stated their opposition to using the "CBIR Lite" (Consensus Based Issue Resolution) process.

The MIC was to vote on adopting the issue charge during Wednesday's meeting. (See "Voltus Brings Economic Demand Response Parameter Issue Charge," *PJM MIC Briefs: Aug. 9, 2023*.)

David Aitoro, Voltus senior energy markets manager, said the company would further consider whether it wanted to continue to seek the CBIR Lite pathway or switch to the standard CBIR process before bringing the subject before the committee again.

Paul Sotkiewicz, representing J-Power, said the use of the CBIR Lite process prevents him from being able to support the issue charge, which he would otherwise likely support in concept.

The *problem statement* and issue charge say DR providers lack the ability to automatically specify a maximum run time or to set a minimum amount of time between being dispatched.

Because the documents were first brought for a first read in August, Aitoro *said* they were revised to make clear that the issue charge would preclude discussion of capacity market offers and is instead intended to focus on the two parameters outlined.

"We're not touching any broad status quo rules; we're not touching load management," he said. DR participating in the capacity market is referred to as load management.

Monitoring Analytics President Joe Bowring | © RTO Insider LLC

Independent Market Monitor Joe Bowring said the narrow scope of the issue charge would prevent stakeholders from engaging in discussions about DR that need to be had, including interactions between DR's participation in the capacity and energy markets. He also opposed using CBIR Lite, saying the potential impacts warrant the full stakeholder process.


Paul Sotkiewicz, E-Cubed Policy Associates | © RTO Insider LLC

"This is not a trivial thing; it has potentially significant impacts on how DR works," he said.

AEP Energy's Brock Ondayko raised the possibility of requiring DR resources to document when they make a change to their parameters.

Aitoro said he intends to keep the scope of the issue charge narrow, and if a broader discussion is sought by stakeholders, an additional issue charge would be the best way to initiate that.

Providing education on the status quo rules for DR, PJM's Peter Langbein said there is about 8,451 MW of DR participating in the capacity market, the "vast majority" of which does not have an energy market offer. About 2,449 MW of DR is in the energy market.

A DR resource can participate both as load management, with a capacity and energy market offer, as well as a separate economic DR resource, with an energy-only offer. Langbein said the parameters included in the capacity offer would override any energy offer parameters.

There are numerous ways in which the energy market rules differ for DR resources, including their ability to manually change the availability of their offer into the market, which Langbein said is because of the lack of market power concerns.

Sotkiewicz said the differences, particularly the ability to switch availability on and off, have the potential to be discriminatory treatment.

"Why do we have different rules for economic DR than generation?" he asked.

AEP, Dominion Proposal on Capacity Obligations for Concentrated Loads

An *issue charge* and *problem statement proposed* by American Electric Power and Dominion Energy would address how capacity obligations are assigned to load-serving entities when large amounts of load are added to concentrated areas.

AEP's Josh Burkholder said that when a large amount of load is added to a single zone, such as clusters of data centers, it can lead to the capacity obligation being dispersed broadly across the zone. For fixed resources requirement (FRR) entities, he said that can also result in the amount of capacity they're required to procure being above what's needed to serve their internal demand.

The issue charge also ran into questions about whether it should progress under CBIR Lite, as is currently proposed, or if it should instead use the standard CBIR process.

Discussion Continues on Multischedule Clearing in the Market Clearing Engine

Deputy Monitor Catherine Tyler *presented* a

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Catherine Tyler, IMM | © RTO Insider LLC

new joint proposal with the GT Power Group to address the computational barriers to introducing multischedule clearing in the market clearing engine (MCE). (See "First Reads on Proposals Addressing Multi-schedule Modeling in MCE," *PJM MIC Briefs: Aug. 9, 2023*.)

The package is an alternative to GT Power Group's original joint proposal with PJM, which would select resources' cost-based offers when they fail the three-pivotal-supplier (TPS) test and their parameter-limited offers during emergency conditions, but would allow resources to choose the most cost-effective offer to send to the MCE when they have multiple valid offers, such as in the case of dual-fuel generators.

Tyler said a shortfall of the previous proposals was that dual-fuel generators may be dispatched based on schedules that would not match the most efficient fuel.

"We don't want to commit a unit to run on a more expensive oil offer when [gas] fuel is more efficient," she said.

Under the new proposal, if a unit with multiple offers fails the TPS test, PJM will commit the unit to operate based on the fuel the generation owner expects to use in each hour of the day. The PJM solutions would also not resolve issues that allow generators with market power to raise energy prices by using high markups and to extract uplift using inflexible parameters.

Tyler said any generators not submitting the most efficient offer may be considered to be engaging in market manipulation.

The joint package adds a *fifth option* to resolve an issue identified in the development of the Next Generation Markets (nGEM) overhaul of the MCE, where the number of offers the engine would have to analyze when clearing combined cycle and storage resources would cause an untenable increase in computational times. PJM's proposal would create a formula for selecting the offer that results in the lowest total dispatch cost, which would be entered into the engine.

The first Monitor proposal would combine the lowest offer points and most flexible parameters from resources price and cost-based offers under certain scenarios, impose offer capping and parameter limits to all resources that fail the TPS test and apply parameter limits to capacity resources during emergencies.

The Monitor's second package would do the same as above but would use the status quo rules for resources with multiple cost-based offers.

Sotkiewicz questioned if PJM would consider the proposal to be temporary until a technological solution that reduces computational times is found.

PJM's Keyur Patel said if the technology improves, staff would be open to reverting to the status quo. Tyler, however, said the Monitor's perspective is that the status quo would be improved by resolving the market power issues.

Competing Proposals Addressing Local Factors on Net CONE Merged

E-Cubed Policy Associates, PJM and the Monitor have merged competing *proposals* centered on how to account for local or state factors, such as climate legislation, which could affect the cost of new entry (CONE) for generators in that region. The new package would add a fifth CONE area for the Commonwealth Edison region but would not codify a new pathway for adding new areas in the future. (See "Stakeholders Discuss Proposals to Include Local Factors in Net CONE," *PJM MIC Briefs: Aug. 9, 2023*.)

Both the original PJM and E-Cubed packages would have broken ComEd out as a new CONE area, but the E-Cubed proposal also would have automatically created new areas when local factors shortened asset lifespans or would imply a different reference resource from what is used by PJM in its calculation of CONE. Sotkiewicz, president of E-Cubed, has argued that the impact of the Illinois Climate and Equitable Jobs Act (CEJA) would shorten the lifespan of many generators, including the reference resource, located in the state. The merged proposal would include an amortization period reflecting CEJA in the fifth CONE area.

Sotkiewicz said streamlining the process to create new CONE areas in the future was his primary rationale for creating a second proposal, but that he believes the existing tariff language has been demonstrated to be adequate. He said PJM was concerned about creating an automatic process for adding CONE areas, believing it should be done on a case-by-case basis with stakeholder consideration of the variability on the ground. ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

Planning Committee

PJM Presents Quick Fix on Load Forecast Guidelines

VALLEY FORGE, Pa. — The frequency and magnitude of load forecast adjustment requests PJM is receiving from electric distribution companies (EDCs) has led the RTO to bring a problem statement, issue charge and proposed manual revisions on the timeline those adjustments are approved on.

The changes are being sought through the quick-fix process, which allows an issue charge and proposed solution to be brought concurrently and voted on in an expedited manner.

PJM's proposal would move the Load Analysis Subcommittee's review of forecast adjustment requests to September and October to provide more time for consideration and EDCs would be requested to provide hourly data and a 15-year forecast of their adjusted load.

PJM's Molly Mooney told the Planning Committee on Sept. 5 that numerous factors are taken into account to avoid double-counting load during forecasting, and any types of industries reflected in federal employment figures wouldn't be counted as a discrete large load increase. Loads from data centers, however, are difficult to forecast because of their disproportionate demand and the fast turnaround between when an interconnection is requested and the in-service date.

Paul Sotkiewicz, president of E-Cubed Policy Associates, asked what PJM's lead time is between when it finds out about an expected load and that consumer going live on the grid.

PJM's Dave Souder said much of the load goes through the supplemental process at the Transmission Expansion Advisory Committee, providing a few years' notice. The issue charge seeks to obtain that information from EDCs further out so more analysis can be built into the planning process.

James Wilson, a consultant for state consumer advocates, said data centers are largely being constructed by a few major parties that are concerned about transmission constraints hindering their projects, leading them to investigate siting in multiple EDCs when only one project will come to fruition. If this is not accounted for, he said projects could be double-counted and transmission built to serve loads that are not built.

Patricio Rocha-Garrido, PJM | © *RTO Insider LLC*

Wilson urged PJM to hire an independent consultant to do along-term forecast of data center load and questioned what PJM's response would be if EDCs were unwilling to do a 15-year forecast of data center loads. He said that in the event that an EDC submits a total load adjustment request for load-serving entities within their territory, those entities should be required to verify the adjustment.

Mooney said increasing the horizon on the data that PJM is seeking also allows for more time to collaborate with EDCs and work through any issues distributors may have with the process.

First Read of 2023 Reserve Requirement Study

Load forecast uncertainty and increased winter risk are driving a significant increase in the reserve procurement levels recommended by the 2023 Reserve Requirement Study (RRS), which went before the PC for a first read. (See *PJM Presents Preliminary 2023 Reserve Requirement Study to Stakeholders*.)

The installed reserve margin (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 DY using PRISM modeling software. The forecast pool requirement, which considers forced outage rates, also would increase from 9.18% to 11.65% for the corresponding DYs.

Numerous changes were made to the study's processes this year, including two parallel analyses using the PRISM software historically used in the RRS, as well as using software developed to perform hourly loss-of-load modeling used in effective load-carrying capability (ELCC) and the inclusion of data from the 2014 polar vortex and the December 2022 winter storm. PJM has historically not included the 2014 storm in the RRS dataset, but experience from the storm led staff to revise that practice.

The hourly modeling largely led to higher figures, yielding an IRM of 18.3% for the 2027/28 DY and 12.31% FPR, with much of the difference between the PRISM values arising from the load model. Prior to stakeholders voting on endorsement, PJM plans to recommend use of either the PRISM or hourly results, which stakeholders will have the opportunity to chose between.

PJM's Patricio Rocha Garrido said 70% of the loss-of-load expectation (LOLE) is concentrated in the summer and 30% in the winter under the PRISM modeling, while the hourly modeling has an 80/20 balance between the summer and winter. Past modeling is now believed to have understated extreme loads, especially in the summer, he said.

"The previous load forecast model was producing values that were understated ... whereas

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the new model that is more granular looks at every hour of the year and the weather in that hour" and the corresponding intermittent output, Rocha Garrido said.

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 to 2022 and use that figure, which landed at 1.5% instead.

Transmission Expansion Advisory Committee

PJM Updates Stakeholders on RTEP Windows

Project proposals for the first window of PJM's 2023 Regional Transmission Expansion Plan (RTEP) are being accepted through Sept. 22, with the goal of resolving 266 flowgates, 130 of which are competitive. The window opened on July 24 and PJM is targeting receiving approval from the Board of Managers in February, PJM's Sami Abdulsalam *said* during last week's meeting.

PJM is also conducting scenario evaluations on the 72 proposals submitted in the third window of its 2022 RTEP, which opened in May to solicit solutions to load growth in centered on the northern Virginia region, which is experiencing high data center load growth. Staff plans to walk stakeholders through the window evaluation results during the Oct. 3 TEAC meeting, which will be followed by a first read on Oct. 31.

Several ratepayers expressed concerns about land use and cost allocation to regions they argued would not be benefited by the projects, and they urged PJM to consider historical opposition similar projects have received.

Supplemental Projects

FirstEnergy *presented* a project to replace a 230/34.5-kV transformer nearing its end of life and associated relays at its Windsor substation in the JCPL zone at a $6.3 million price tag. The replacement is currently underway and is expected to be completed in November.

FirstEnergy *presented* a $2.2 million project to replace circuit switcher and limiting substation conductor at its Damascus substation and a wave trap, disconnect switches and limiting substation conductor at its Mount Airy facility, which are connected by the 230-kV Damascus-Mount Airy line in its APS zone. The equipment at the two sites have a history of misoperation and cannot be repaired due to lacking spare parts and limited expertise in the technology.

The Public Service Enterprise Group *presented* two projects to add substations in the South Edison and Perth Amboy area to address rising loads and aging equipment at its existing local infrastructure. The 230/13-kV South Edison substation would be built at a $56.1 million cost adjacent to the existing Meadow Road facility, which has a contingency overload of 124%. A new 69-kV line would be built from South Edison to a new 69/13-kV substation, which would be built adjacent to the Keasby facility. The $220.9 million project would support the Keasby substation, which is nearing 100 years old and in need of repairs, and the Pierson Avenue substation, which has a contingency overload of 123.3%. ■

— Devin Leith-Yessian

2023 RRS Study results - PRISM:

RRS Year	Delivery Year Period	Calculated IRM	Average EFORd	Recommended FPR*
2023	2024 / 2025	**17.7%**	5.10%	**1.1170**
2023	2025 / 2026	**17.7%**	5.09%	**1.1171**
2023	2026 / 2027	**17.7%**	5.08%	**1.1172**
2023	2027 / 2028	**17.6%**	5.06%	**1.1165**

2023 RRS Study results - Hourly Model:

RRS Year	Delivery Year Period	Calculated IRM	Average EFORd	Recommended FPR*
2023	2024 / 2025	**18.5%**	5.10%	**1.1246**
2023	2025 / 2026	**18.4%**	5.09%	**1.1237**
2023	2026 / 2027	**18.4%**	5.08%	**1.1239**
2023	2027 / 2028	**18.3%**	5.06%	**1.1231**

The preliminary results of PJM's 2023 Reserve Requirement Study (RRS) would lead to higher reserve margins under both the PRISM and hourly models. | *PJM*

SPP News

Nation's Grid Faces 'Rendezvous with Reality'

SPP Resource Adequacy Summit's Participants Share Solutions

By Tom Kleckner

DFW AIRPORT, Texas — Keeping the lights on has long been a simple proposition for grid operators. Look at historical demand, add in growth expectations and ensure you have enough generation available to meet that demand.

No more. With older thermal plants retiring or breaking down and being replaced by a flood of more variable renewable resources, grid operators need a more comprehensive focus to ensure they have enough capacity and reserves to keep the system in balance.

SPP last week invited federal and state regulators, academics, market participants and other stakeholders to its inaugural Resource Adequacy Summit. There, they discussed the events that have led the industry to this juncture and the actions necessary to improve the grid's reliability in the face of enormous change.

"This is the first opportunity we've really had to kind of open up a stakeholder, customer and just simply interested party dialogue on a very important topic," SPP COO Lanny Nickell said in kicking off the Thursday summit.

FERC Commissioner Mark Christie likened the current state to that of the Great Depression, when President Franklin D. Roosevelt said the country was facing a *rendezvous with destiny*.

"We're at a very critical time ... reliability means, 'Are the lights going to stay on?' That's what it means to the general public," Christie said. "Are the lights going to stay on? We're really at a point where that's coming into serious question. Are the lights going to stay on?

FERC Commissioner Mark Christie (left) and NERC CEO Jim Robb listen to an audience question. | *© RTO Insider LLC*

SPP's Resource Adequacy Summit begins. | *© RTO Insider LLC*

"Right now, when it comes to the reliability of our grid, the United States is facing a rendezvous with reality. Reality is just around the corner. You may think you can avoid it for a while, but reality will track you down. And reality is tracking us down when it comes to the reliability of our grid," he added.

Testifying before the Senate's Energy and Natural Resources Committee in May, Christie told lawmakers the grid is facing "potentially catastrophic consequences." He said he was not trying to be melodramatic. (See *Senators Praise Phillips, FERC's Output at Oversight Hearing*.)

"We were not trying to get a sound bite out there into the media. I used the term 'catastrophic' because when we have multiple-day outages ... that's catastrophic by any definition. People die if it's a cold-weather outage, and so that is catastrophic."

The core reason, Christie said, is not necessarily the vast amount of wind and solar generation that is being added to the grid. It's the subtraction of coal, gas and other dispatchable thermal resources at a pace that is unsustainable, he said.

"The first rule of holes is if you're in one, stop digging," he said. "If the fundamental problem we're facing is we're shutting down dispatchable resources far too prematurely, then the answer is to stop shutting down dispatchable resources far too prematurely."

Christie brought receipts with him. He said PJM forecasts the *loss of 40 GW* of mostly dispatchable capacity by 2030. He said MISO expects to be *9 GW short* by 2028. He noted an earlier presentation from Nickell saying SPP has installed 24 GW of wind and solar in recent years but has lost 8 GW of dispatchable resources.

"And by the way, that is before the EPA came out with the power plant rule, which is going to make that number even worse, as every RTO knows," Christie said. "The numbers don't add up. You lose 8 gigs of dispatchable and you pick up 24 gigs of wind and solar, [you think] you're fine right now. You're not fine, because as we all know, a megawatt of nameplate wind and solar is not equal to a megawatt of nameplate coal or gas. It's just reality."

"There's really no reason why we should be retiring perfectly good resources in this country," said Zachary Ming, a director with San Francisco-based consulting firm Energy and Environmental Economics (the folks behind ERCOT's market redesign).

"We should be focusing on building as many

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Zachary Ming, E3 | © RTO Insider LLC

new resources, primarily renewables and storage, and keeping the firm dispatchable resources online that we have. That is both going to maximize affordability, and it's going to maximize environmental benefits as well," Ming said. "You reduce emissions by building renewable resources that come first in the dispatch order and will dispatch ahead of dispatchable resources. All building renewables will do is allow us to use the dispatchable resources less, but renewables have limited contributions to reliability. So, it doesn't mean we can retire the resources. It just means that we can use them less. They will have less emissions and they will have environmental benefits, and they'll still stay there for reliability."

"We're facing reality very, very simply. I think everybody knows that," Christie said. "The question is, is there going to be the political will to make a turn in policy and recognize that we're not going to get to where everybody wants to get, which is a lower-carbon grid, without reality being part of the equation, because reality will track you down. We're headed to some bad outcomes and none of us want to be around when those outcomes hit, because that's when the finger-pointing starts."

Sitting next to Christie, NERC CEO Jim Robb said the industry's ability to conduct resource planning with a "highly variable intermittent generating system" will define the industry's next 10 to 15 years.

"That's the challenge that's in front of us, and it's not our grandfathers' resource adequacy problem," he said, noting NERC would like to hold an event similar to SPP's. "I think we have to recognize that we take constructs that we all grew up with and we've been trying to modify them to adapt to a system that's just fundamentally very, very different than what we grew up with. Whatever [resource adequacy] construct you look at is a very important number, but it's no longer close to being a sufficient number for planning and operating the system."

Robb pointed out that the traditional resource adequacy constructs are based on meeting demand during peak hours with enough of a margin to account for the "random independent equipment failures."

"That doesn't work anymore," he said, pointing to what he called "common conditional failures" of the emerging generation fleet that is flush with renewables.

"A wind drought, solar drought, cloud cover, unexpected cloud cover, extreme cold weather affects the ability of large amounts of generation to operate, so this whole notion of kind of random failure being the driver of how much generation we need isn't sufficient," Robb said.

Policymakers need to "come to grips" with three questions, he said: how frequently they can tolerate loss-of-load events, how long an event are they willing to tolerate and how much are they willing to pay to prevent them.

"We know we can't afford a 100% reliable system," he said. "We're going to have to make important tradeoffs between reliability and those three parameters [frequency, duration and scale] and how much we will be paid to avoid that. Resilience and reliability is not free."

Robb said he's encouraged by recent research into what customers are willing to pay to avoid multiday outages. He said those numbers are "much, much higher" than what he's seen in the past.

"We've taken away the obligation to serve, and in these market areas, we rely on commercial constructs to try to recreate that," he said. "It's an imperfect substitute, but we have to figure out how to get the market rules to reward reliability with investments that aren't going to be naturally paid for during the 98% of the normal periods."

SPP is taking those steps with several recent changes. It increased its planning reserve margin from 12% to 15% last year and made several tariff changes for load-responsible entities' deficiency payments and a payment structure based on a sufficiency valuation cure.

Those changes were approved by FERC in April. (See *FERC Approves SPP's Resource Adequacy Changes*.)

Buddy Hasten, AECC | © RTO Insider LLC

Buddy Hasten, CEO of Arkansas Electric Cooperative Corp, one of SPP's LREs, called for fairness in meeting reliability commitments.

"We're propping up reliability, but we get paid nothing for it," he said. "When the wind blows hard enough or the sun shines bright enough, we have to pay the market to just keep our resources online to prop up the market to be there for reliability. So when [prices] go negative, I'm paying to keep that resource online.

"We like to play games. You create the rules of the game, and everyone plays it, and it's all about who can get the lowest cost because we've turned electricity into a commodity instead of an essential service," Hasten added. "At some point, there has to be a financial metric rule, some payments, something somewhere to pay for that reliability. Otherwise, everyone's going to keep playing the game and just chasing the cheapest electron."

A nuclear submariner for 20 years, Hasten said he's very aware of the importance of resource adequacy.

"If you don't have enough resources, you go to the bottom of the ocean," he said. "Resource adequacy is life or death. I'd hate to be the person that go to those folks' home and says, 'Hey, I'm sorry, you froze to death.' ... 2021 was the first time we sent linemen out and white bucket trucks to go open breakers and put people on the dark. That's called progress, I guess."

Several speakers pointed out the role natural gas played during that winter storm. Gas plants without firm fuel contracts — and some with firm contracts — were unable to get those supplies as heating homes took precedent. Other thermal generators simply weren't prepared for the extreme winter conditions.

Aubrey Johnson, MISO | © RTO Insider LLC

Aubrey Johnson, MISO's vice president of system planning and competitive transmission, said aging plants in the RTO's fleet also played a role in the 2021 and 2022 winter storms.

"It's actually a fleet that's not responsive when you actually need it," said Johnson, who has a background in power plants. "Working with Southern Co., we used to have real competition about how you showed up during peak season and how well your plants performed. When I look at some of the performance numbers today, I'm kind of shocked. You would spend a lot of time in the principal's office with those kinds of performance numbers.

"The No. 1 way to ensure resource adequacy is ensuring you have adequate resources," he added.

Given a chance to provide suggestions to the audience during a lightning Q&A round, Johnson's message was simple.

"Build. Just build," he said. ■

Company Briefs

Enbridge to Buy 3 Dominion Utilities for $14B

Enbridge last week announced it will purchase three utilities from Dominion Energy for $14 billion, including debt.

The deals for East Ohio Gas, Questar Gas and Public Service Co. of North Carolina will consist of $9.4 billion in cash and $4.6 billion of assumed debt.

The deal, which is subject to approvals, is expected to close in 2024.

More: *Reuters*

Standard Lithium Plant Plans Move Ahead for El Dorado

Standard Lithium last week announced it is moving forward with plans for Arkansas' first commercial lithium production facility after it released positive results from a definitive feasibility study for a $365 million battery-grade lithium operation just outside El Dorado.

The feasibility study foresaw average annual production of 5,400 tons of lithium carbonate over at least 25 years, and an internal rate of return of 24% assuming a discount rate of 8% and a long-term price of $30,000 per ton.

Standard's timeline is subject to ongoing engineering, its finalization of commercial agreements and approvals from the Arkansas Oil and Gas Commission.

More: *Arkansas Business*

Microsoft Funding Startup, New Approach for Carbon Removal

Microsoft agreed to fund a carbon capture technology that uses the natural properties of limestone to take carbon dioxide out of the atmosphere, startup firm Heirloom Carbon announced last week.

Microsoft will purchase about $200 million worth of carbon credits (equivalent to 315,000 tons of carbon) over 10 years from Heirloom to fund its carbon capture operations in Louisiana and elsewhere in the U.S.

Heirloom's direct air capture process uses processed limestone to draw carbon dioxide out of the air, where it is then removed from the stone and stored underground or in concrete.

More: *The Hill*

EV Maker Rivian Opens Chicago Showroom

Electric vehicle maker Rivian last week opened its first direct-to-consumer retail space in Chicago's Gold Coast neighborhood on Sept. 8.

"This allows us to bring it directly to where they spend their time. So, we're meeting the customer where they are. This is where people spend time after work. This is where families come on the weekends. And it's just a nice way for us to show up," said Tony Caravano, senior director of customer engagement for Rivian.

More: *WLS*

Federal Briefs

Solar Contributed 45% of Generation Capacity Additions in First Half of 2023

A report released by the Solar Energy Industries Association and Wood Mackenzie found that the U.S. solar market installed 5.6 GW in Q2 2023, a 20% jump over Q2 2022 totals.

The industry has installed nearly 12 GW in the first half of 2023, indicating volumes are set to grow year-over-year after experiencing contraction in 2022.

Florida topped all U.S. states for solar installations in the first half of the year, installing 2,499 MW. That total surpassed the 1,648 MW added by California and the 1,292 MW added by Texas.

More: *pv magazine*, *Tampa Bay Times*

E&C Republicans Press Ford for Info on Battery Plant Ties to China

A group of 26 Republicans on the House Energy and Commerce Committee are probing automaker Ford Motor Company over its partnership with Chinese battery firm Contemporary Amperex Technology.

"While Ford has labeled this project a 'commitment to American manufacturing' and asserts it will create 2,500 new American jobs, we are concerned that Ford's partnership with a Chinese company could aid China's efforts to expand its control over United States electric vehicle supply chains and jeopardize national security by furthering dependence on China," the Republicans stated in their letter.

In February, Ford announced it would invest $3.5 billion to build a lithium iron phosphate battery plant to supply its growing EV manufacturing. As part of the announcement, the Ford said it had reached an agreement with CATL to manufacture the battery cells at the plant using services provided by the Chinese company.

More: *Energy & Commerce Committee*

EPA Delays New Ozone Pollution Standards until after 2024 Election

EPA last week said it is delaying plans to tighten air quality standards for ground-level ozone, or smog, despite a recommendation by a scientific advisory panel to lower air pollution limits to protect public health.

The decision by Administrator Michael Regan means that the regulation will not be updated until after the 2024 presidential election.

The review, which will last at least two years, will "ensure that air quality standards reflect the latest science in order to best protect people from pollution," Regan said.

More: *The Associated Press*

Biden Admin Cancels Remaining Oil, Gas Leases in Arctic Refuge

The Department of Interior last week canceled the seven remaining oil and gas leases in Alaska's Arctic National Wildlife Refuge.

The administration also announced proposed rules aimed at providing stronger protections against new leasing and development in portions of the National Petroleum Reserve-Alaska that are designated as

special areas for their wildlife, subsistence, scenic or other values. The proposal must go through public comment.

More: *The Associated Press*

Sens. Moran, Marshall Seek Reversal of FERC Tx Ruling

U.S. Sens. Roger Marshall and Jerry Moran of Kansas last week objected to FERC's decision to reverse its approval of a plan to distribute electricity transmission facility costs more equitably from heavy wind-producing states such as Kansas to other member states in SPP.

FERC agreed in October 2022 to permit the multistate power pool to address unfair division of the cost for transferring electricity from zones with vast amounts of generation, including the wind-rich state of Kansas, to consumers in other SPP states. However, FERC reversed that decision in July in response to complaints from Southwestern Electric Power, Public Service Co. of Oklahoma and Oklahoma Gas & Electric Company, as well as city utilities in Springfield and Kansas City. Based on this secondary review, FERC unanimously agreed the cost-sharing plan gave SPP's board too much leeway in deciding whether to implement a more regional approach to allocation of transmission costs.

Moran and Marshall called for the reinstatement of the ruling favorable to Kansas customers who have been compelled to subsidize energy usage in neighboring states. The senators' letter highlighted development of the wind industry in Kansas and what the GOP lawmakers viewed as unfairness of regulations requiring families and businesses to pay inflated costs of moving electricity on the grid.

More: *Kansas Reflector*

State Briefs

IOWA

Judge Says Solar Supports Townspeople's "Health and Safety"

A judge last week ruled that zoning adjustments favoring solar power align with Linn County's stated objectives, specifically the "protection and enhancement of the health and safety of all residents through the use of renewable energy." The case revolved around objections to the 1,934-acre Duane Arnold Solar Project, under development by NextEra Energy.

The plaintiffs' complaints included zoning ordinance violations, illegal "spot zoning" and allegations that the project contravened both the county's comprehensive plan and state law by allowing the conversion of prime farmland. In the end, the judge dismissed all eight complaints.

More: *pv magazine*

Scott Co. Landfill to Convert Waste into Natural Gas

New technology from WAGA Energy will be installed at the Scott Area landfill to convert raw methane from waste into grid-compliant natural gas.

A series of wells and tubes are currently collecting methane from underneath the landfill site. The Linwood Mining and Minerals company holds the rights to this methane, but has not been using it since 2018. WAGA Energy reached out to the county waste commission to offer to install the WAGA Box. The device essentially cleans the raw methane produced at the landfill and reinjects into a local natural gas pipeline.

More: *KWQC*

LOUSIANA

Environmentalists Lose Latest Court Battle Against LNG Project

The 5th U.S. Circuit Court of Appeals last week rejected multiple arguments by the Sierra Club and the Healthy Gulf organization, who asked the court to review and vacate the permit granted by the U.S. Army Corps of Engineers for the Driftwood LNG project.

The judges said the Corps had complied with requirements of the federal Administrative Procedures Act and the Clean Water Act.

Tellurian Inc., which owns the project, said it hopes to begin LNG production by 2027.

More: *The Associated Press*

OHIO

Supreme Court Passes on Solar Farm Appeal

The Ohio Supreme Court last week dismissed a case asking the court to reverse the Power Siting Board's rejection of a permit to build a solar farm in Greene County.

The court didn't explain itself beyond noting the participating justices unanimously dismissed the case for lack of jurisdiction. Last December, the board rejected Kingwood Solar's application for a permit. While Kingwood met the technical and environmental requirements, the board found the facility will not "serve the public interest, convenience and necessity," as state law requires.

The ruling narrows the path to development for Kingwood, which originally hoped to break ground in June 2022. The board could also reverse its rejection of a permit.

More: *Cleveland.com*

SOUTH DAKOTA

PUC Denies Permit for Navigator CO2 Carbon Pipeline

The Public Utilities Commission last week unanimously rejected Navigator CO_2's application for a permit to construct the Heartland Greenway carbon capture pipeline.

Commissioner Kristie Fiegen listed several reasons for denying the permit, including what she described as a failure by the company to adequately disclose carbon dioxide plume modeling, and a failure to provide timely notices to some of the landowners along the proposed route.

The PUC also unanimously refused the company's request to preempt county pipeline setback ordinances.

More: *South Dakota Searchlight*

VIRGINIA

Amazon to Spend $11B Creating Data Centers in Louisa Co.

Amazon Web Services last week announced plans to spend nearly a third of its $35 billion data center expansion budget to create two data center campuses in Louisa County.

The data centers will be built in the county's Technology Overlay District, which was developed with "strict development standards" to attract technology businesses and

support economic growth.

More: *WRIC*

Commission on Electric Utility Regulation Reconvenes After 6 Years

The Commission on Electric Utility Regulation met for the first time in six years last week, following legislation during the last General Assembly session that requires it to now meet twice every year.

The commission is tasked with reviewing the impacts of legislation on electric utility regulation that can include complex provisions governing lawmakers' desires for electric generation and utility profit levels. Many lawmakers expressed an interest in reviving the commission because of the difficulty of navigating those complexities during the state's 45- or 60-day legislative sessions.

At the meeting, the commission elected Sen. Scott Surovell (D-Fairfax) as its new chair.

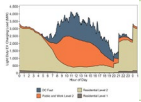
More: *Virginia Mercury*

National/Federal news from our other channels

Southeast Wash. Looks to Become Clean Tech Hub — NetZero Insider

Apple Supports Proposed Calif. Emissions Reporting Bill — NetZero Insider

Wash. Allowance Prices Surge Again in 3rd Cap-and-trade Auction — NetZero Insider



Report Shows Rapidly Growing Need for EV Chargers in Calif. — NetZero Insider

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