ISSN 2377-8016 : Volume 2024/Issue 41 ▪ October 15, 2024

RTO Insider

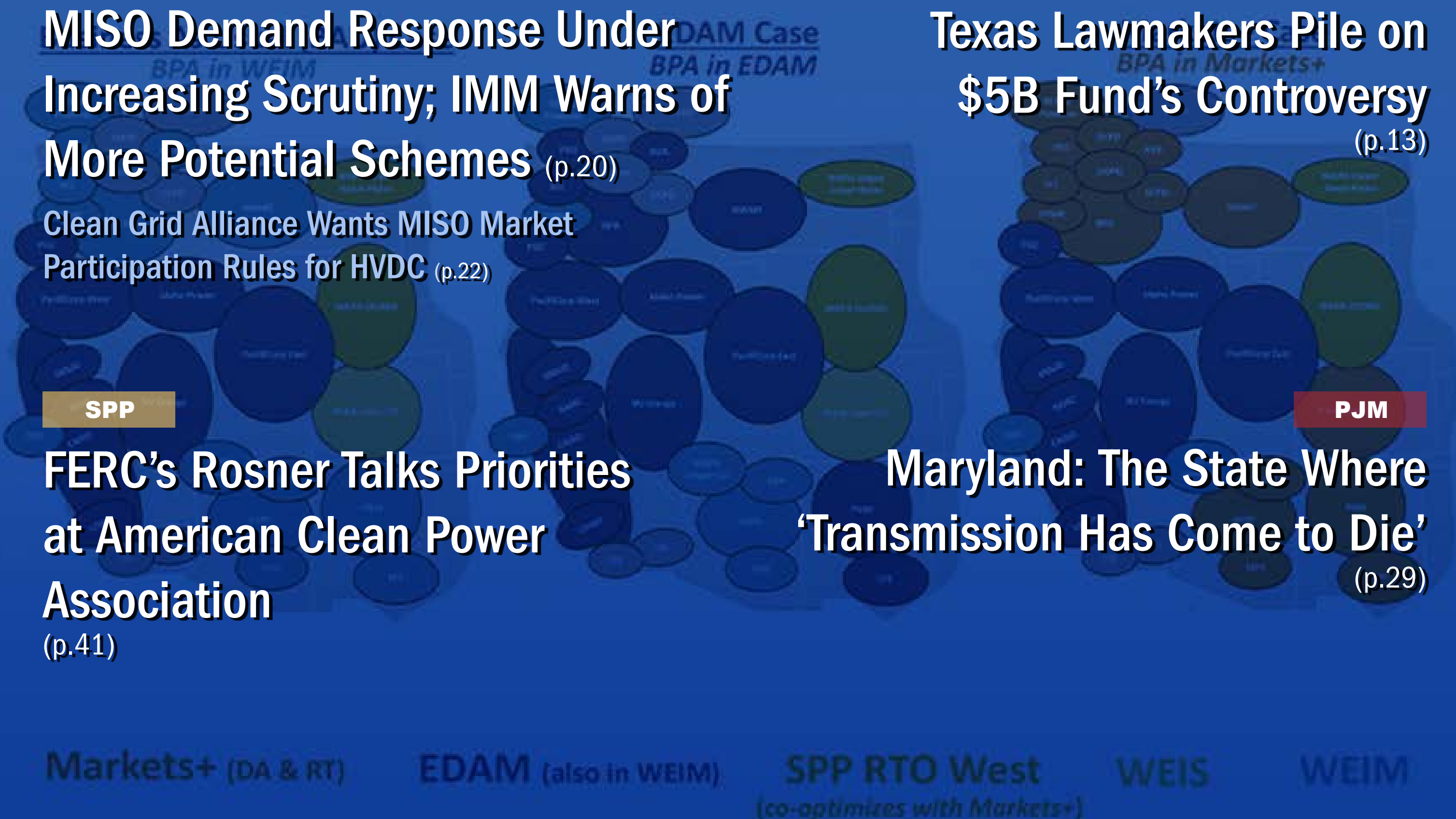
YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

SPP | CAISO/West

Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW (p.39)

Powerex Contests Brattle's EDAM/Markets+ Comparative Study (p.8)



MISO

MISO Demand Response Under Increasing Scrutiny; IMM Warns of More Potential Schemes (p.20)

Clean Grid Alliance Wants MISO Market Participation Rules for HVDC (p.22)

ERCOT

Texas Lawmakers Pile on $5B Fund's Controversy (p.13)

SPP

FERC's Rosner Talks Priorities at American Clean Power Association (p.41)

PJM

Maryland: The State Where 'Transmission Has Come to Die' (p.29)

COVER: The Brattle Group's BPA day-ahead market benefits study examines three cases of market participation. *(Page 39)* | *The Brattle Group*

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885
See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

EIA: Colder Weather and Lower Fuel Prices Likely Mean Flat Bills This Winter

By James Downing

The U.S. Energy Information Administration expects consumers will spend roughly the same on winter heating this year as they did last year, according to its *Winter Fuels Outlook*.

"Overall, we expect that there's going to be, generally speaking, lower fuel prices that are going to be offset by higher consumption this winter," EIA Administrator Joseph DeCarolis said in an Oct. 9 webinar.

The two biggest sources of space heating across the country are natural gas and electricity, at 45 and 43% of all households. On average, bills for both sources should go up slightly this winter.

The Midwest is expected to see higher bills than last year, as consumers there are expected to spend 11% more on natural gas, compared to the 1% national average, and 6% more on electricity, compared to the 2% national average. The Midwest had an exceptionally mild winter last year, so the return to more normal temperatures in the region is expected to lead to a bigger jump in demand for heating, the outlook said.

While wholesale prices have fallen this year, weather forecasts call for more cold, with EIA expecting heating degree days to tick up 5% compared to last year. But it still is expected to be a generally mild winter, with the forecast calling for heating degree days to be 2% below the average of the previous decade, DeCarolis said.

For the first time, EIA broke out the share of the average bill for each fuel that goes toward space heating. While customers spend more on electric bills overall, the space heating portion of EIA's estimates are almost the same as those for natural gas, though the South has the biggest share of electric heating.

Temperatures can have a big effect on winter prices, though when it comes to electricity and natural gas, the effect is felt more in the wholesale markets. The impact lags on retail prices because, for the most part, they are overseen by state regulators, EIA analysts said in the webinar.

The prices for propane, which is used by 5% of households concentrated in the Midwest, and heating oil, used by 3% of total households almost entirely in the Northeast, vary more significantly with temperature because wholesale prices are more closely linked to residential prices.

Some five major storms have led to major effects on natural gas and power systems over the past 15 years, but those are difficult for EIA to predict. (See *Déjà Vu as FERC, NERC Issue Recommendations over Holiday Outages*.)

"Something like a major winter storm or an acute weather event is difficult to build into our forecast because the impact on price is of something like that would be highly dependent on where the storm hits," EIA's Corrina Ricker said. "For example, if it were to impact production, or if it's close to large demand centers, those types of factors would really play into how the natural gas price would be impacted."

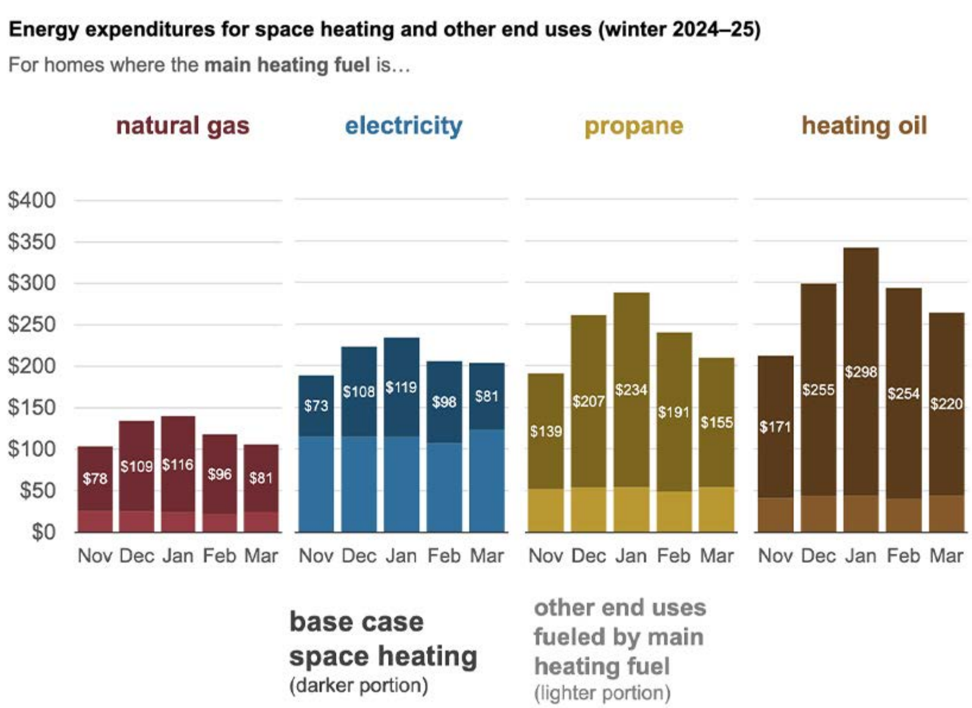
Winter storms can cause major price spikes, but those are short-lived, and their effect on residential prices usually is felt later when regulators allow utilities to recover costs from such events, she added.

A major trend in home heating is the adoption of heat pumps. But given how many other factors beyond the equipment can affect a home heating bill, EIA wasn't able to tease out any differences between that technology and traditional electric heating. EIA said it was working on how to isolate the effect of different heating equipment on consumer utility bills.

"The consumption and expenditures associated with these technologies depend to a large extent on household characteristics and the climate in which they are located," the winter outlook said. "For example, an electric resistance heater used in a small, well-insulated home in the South could result in lower expenditures than an air source heat pump placed in a larger, drafty home in the Northeast." ■

Looking Ahead

Winter storms can cause major price spikes, but those are short-lived and their effect on residential prices usually is felt later when regulators allow utilities to recover costs from such events.



An EIA graph showing its forecasts for average residential utility bills this winter by fuel type; the darker color represents the portion of the bill paying for space heating. | *EIA*

FERC/Federal News

Report Examines Grid Planning for Building Electrification

ESIG Paper Seeks to Start Conversation About Impact of Electrifying Heating

By James Downing

A new report argues that discussions about building electrification largely leave out one key issue: how to prepare the grid for the higher demand and new consumption patterns associated with the shift.

The Energy Systems Integration Group's (ESIG) "Grid Planning for Building Electrification" *report* seeks to start that conversation, with a focus on the increasing share of home heating being served by the grid, which has the biggest impact on overall demand patterns.

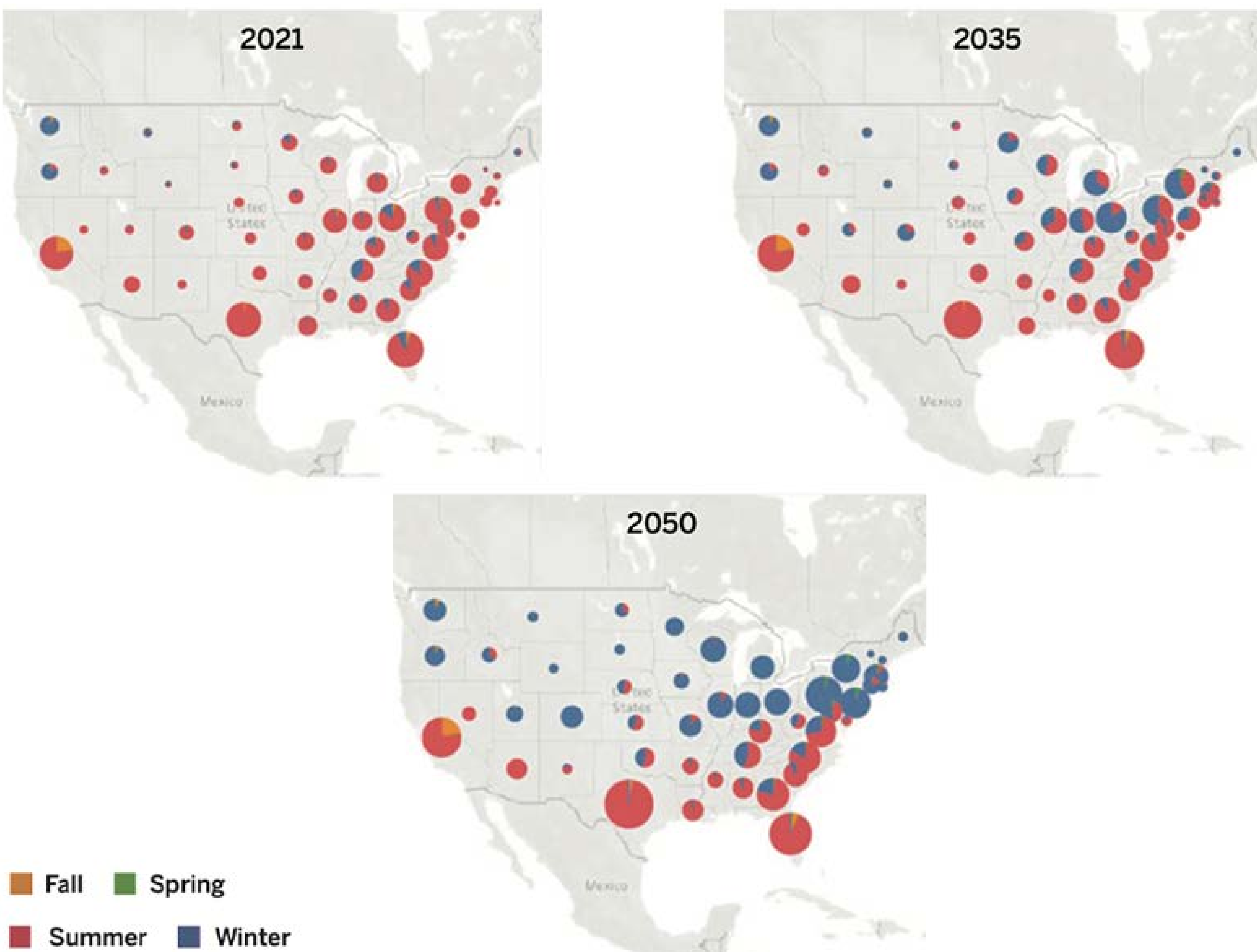
"Building electrification gets a lot of attention in the industry, but little information is available about what grid planners should do about it today," said Sean Morash, chair of ESIG's Grid Planning for Building Electrification Task Force. "This report bridges the gap between building energy modelers and grid planners, providing insights that will shape the distribution and bulk power systems that support our energy transition."

The effects of load growth on the distribution system are often only a minor consideration, but the long lead time and extended life of power infrastructure means that decisions today will support society into the 2060s, the report said.

Why This Matters

The ESIG report argues that building electrification should cause grid planners to shift the way they think about system risk.

"Load impacts from building electrification will increase the seasonality and weather dependence of loads, as well as increase the vulnerability of the power system to extreme weather, largely due to heating demand," the report said.



A map ESIG included in the report showing how electrification will cause some regions to shift peak demands to the winter in the coming decades. | *ESIG*

FERC/Federal News

Building electrification promises one major shift for the grid: as electricity is increasingly used for heating, many regions will shift from summer to winter peaks. Increased adoption of heat pumps, which tend to be more efficient than air conditioners, mean that summer peaks could decline in some regions. And while solar output aligns with gross peaks in the summer, winter peaks happen just before the sun comes up.

The report cites priority areas to improve distribution system planning in the face of growing electrification.

The first is to improve forecasting because the load shape impacts of building electrification will vary by location.

Areas such as the Southeast and Texas, where a lot of heating is already electrified, could see overall use decline as more energy-efficient heat pumps replace less efficient older units, or resistance heaters. But when it comes to winter peak demands for those states, cold snaps plus even more electrified homes could cause them to be higher.

"On the other hand, the adoption of electric heating in areas predominantly served with fossil fuels could result in a doubling of electricity use, affecting both peak power and total electricity needs," the report said.

Distribution system planners will need a more granular understanding of technology adoption, such as the rates of electrification, what kinds of heat pumps are being adopted, and what that means for the local climate zone. Planners should also develop a solid baseline of current building demand broken down by end use because electrification will impact some significantly and others not at all.

Increased Winter Risk

Because electrification will make the grid more vulnerable to extreme temperatures, planners must consider extreme events, which includes factoring how climate change can impact those events over time, according to the report.

Traditional planning has centered around one peak demand event, but severe weather — especially in winter — can cause longer-duration stress by increasing loads for prolonged periods. Electrification of heating will exacerbate that stress, but it can be planned for by switching to a "time-series analysis" that assesses risk across multiple hours of the year and the efficacy of solutions for those intervals.

Distribution system equipment has some universal engineering standards, but local utilities embed their own assumptions about system conditions, demand diversity and load growth.

"However, past practices may not be well suited for electrification-driven load growth, which may have different hourly load impacts," the report said. "Distribution system planners will need to reevaluate the underlying assumptions that drive equipment standards."

The shift to longer-duration winter peaks can impact grid-edge equipment, which is typically designed to serve peak demands for short durations and can lead to component failures.

"Overload failures can occur throughout the grid, including in distribution systems, where equipment is often unmonitored," the report said. "Grid failures during extreme winter weather events pose much more risk to human health and wellbeing than do summer peaks."

The industry could avoid the largest impacts from electrification by relying more heavily on energy efficiency and demand management practices, the report said.

"In the context of building electrification, the most important energy efficiency measures are those that maintain building temperature with minimal input from the grid, because of the long duration of winter reliability events," the report said.

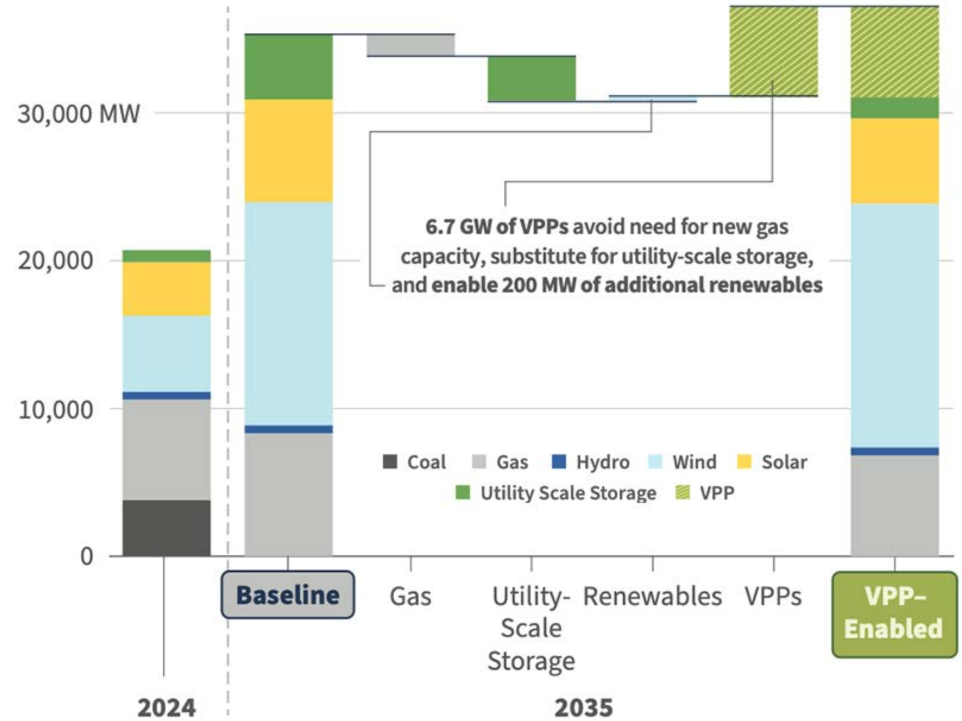
Thirty percent of thermostats are "smart," and actively tapping those and other demand resources can greatly help in reliably electrifying buildings, the report said.

To some extent, utilities can predict when some areas in their service territories are going to electrify because some programs target specific neighborhoods or are focused on low-income customers. They should then plan ahead and upgrade infrastructure with an eye to growing future demand. ■

FERC/Federal News

RMI, VP3 Report Lays out Growth Case for Virtual Power Plants

By James Downing



| RMI, VP3

Virtual power plants can help the power grid deal with some of its most pressing issues, such as meeting rising demand and helping to integrate more renewables affordably, according to a recent report from RMI and the Virtual Power Plant Partnership (VP3).

The *report*, "Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems," lays out a path to expand VPPs, in line with the Department of Energy's VPP Liftoff report from last fall. (See *DOE Report Lays out Commercialization Path for VPPs*.)

About 500 VPP programs already are in operation, providing between 30 GW and 60 GW of peak-coincident capacity in the country. With hundreds of gigawatts of new distributed energy resources coming online, the report says VPPs could serve much of the emerging need for 160 GW by 2030.

While the technology is being used today, it's important that it's part of any planning processes, said the report's co-author, RMI's Tyler Fitch.

"The key is going to be changing our operations and planning processes such that VPPs are visible to them and making it such that VPPs can respond to signals in ways that make sense for the grid," Fitch said.

Current planning practices can silo the distribution system, where VPPs are located, off from the bulk transmission system, so ensuring they can be procured and dispatched like any other is going to be important to fulfilling their potential, Fitch said.

Ben Brown, CEO of VP3 member Renew Home, said VPPs offer the kind of dispatchable, clean resource the grid needs.

"I think there tends to be a lot of focus on newer technology; technology that can go after solving some problems," Brown said. "And I think for us, it was really important to highlight that, hey, there's a lot of existing latent resources out there."

Why This Matters

Virtual power plants can be quickly stood up to help balance the grid in a time of growing demand when connecting grid-scale resources often proves difficult.

Renew Home was created by the merger of Google Nest Renew and OhmConnect, and it now runs the largest residential VPP in the country. More than 80 million households have installed electric heating and cooling systems, and water heating increasingly is done with electricity, Brown said.

"Those represent ... an existing growing resource that, if tapped into correctly, really can provide a meaningful, very low-cost way to support decarbonization and some of the load growth that we're seeing on the grid," Brown said.

VPPs offer benefits over the grid-scale resources they compete with in that they are rapidly deployable, meet load where it exists and offer local economic, reliability and resilience benefits, the report says.

"We believe we could bring together about 50 GW of VPP capacity online by 2030 just through kind of the current funnels," Brown said.

VPPs do not require new technology, and there's no need to build new infrastructure, with customers installing smart thermostats, distributed solar and storage, and electric vehicles into their existing homes, Brown said.

"Being able to engage directly with households around ways in which their home can add value to the grid and therefore actually them get paid for it, and then being able to reduce their energy costs, is such a huge component of this," he added.

Getting residential customers signed up in VPPs will be increasingly important to help balance the grid, Brown said. ERCOT, where Renew Home is active as a retail electric provider, already sees its demand peak in the summer, and its winters are driven by residential demand. That will be more common across the country.

"Most of the rest of the country, over the next 10 to 15 years, will probably go through updates with using heat pumps, and that will actually drive more and more heating-related electric peaks versus what's just happening in certain regions of the country where electric heating is already pretty high," Brown said.

Heat pumps are efficient, but modeling in the Northeast shows their adoption could greatly increase the peak demands of residential and commercial customers in coming decades.

FERC/Federal News

The adoption of EVs by consumers will add many new DERs to the grid, Fitch said.

"I think we're sort of at an inflection point here, where a lot of the operational questions are being answered, and lots of the business models are being figured out," Fitch said. "And ... especially with the [Inflation Reduction Act], there's a whole asset turnover, in terms of internal combustion vehicles to EVs, that will really facilitate a greater role for VPPs."

Coordinated EV charging so the vehicles on a block are not all charging at once and overloading the local system is part of it, but utilities are realizing that more subtle, minute-by-minute shifts in that demand can help integrate those new loads cost effectively and reliably, Brown said.

"Otherwise, you're dealing with a problem where you're just overbuilding infrastructure and passing on that cost to consumers in a way that is not necessarily healthy for where we need to go," he added.

DERs represent a growing base for VPP, just as the power grid's need for additional supply as demand grows.

"In the context where interconnecting grid-scale resources is hard, there's this unique window for VPPs to play this capacity role," Fitch said.

Some VPPs already are, with Fitch pointing to SunRun's aggregation of solar-plus-storage systems in California, which provided the grid with an average of 48 MW of dispatchable capacity during a heat wave this July, the company said.

FERC Order 2222, which required RTOs and ISOs to integrate DER aggregations into their markets, also helps integrate DERs into VPPs, Brown said. But some of the rules could be changed to encourage more participation from residential consumers, as the minimum thresholds to participate in some of the markets are too high.

The other big issue facing the industry is access to data, he said.

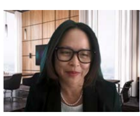
"It's not easy for households to be able to get access to and share utility meter data very easily and everywhere, and so that's an area that we believe there could be continued progress on," Brown said.

That would help utilities engage with their customers in new ways, such as setting up smart home platforms, apps and other kinds of communications beyond the monthly bill or occasional email, he added. ■

National/Federal news from our other channels

IEA Expects 5.5 TW of New Renewables by 2030 NetZero Insider

SERC Speaker Warns of Challenges in Cloud Transition ERO Insider



NERC Examining Lessons from IBR Standard Development ERO Insider

National/Federal news from our other channels

Maryland Building Emission Rules Face Owner Opposition NetZero Insider

National/Federal news from our other channels

NARUC Offers Guidance to States on Advanced Nuclear NetZero Insider

NYPA Enters Renewable Development with 3.5-GW Plan NetZero Insider

Vermont PUC Rejects Heating Fuel Credit Trading Concept NetZero Insider

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

CAISO/West News

Powerex Contests Brattle's EDAM/Markets+ Comparative Study

Company's Response Focuses Heavily on Debate Around Fast-start Pricing

By Robert Mullin

A Brattle Group study comparing key features of CAISO's Extended Day-Ahead Market and SPP's Markets+ contains "several material misstatements of facts" and overlooks evidence "directly contrary to its conclusions," Powerex contends in an Oct. 7 brief criticizing the study.

The *brief* from the energy trading arm of Canada-based BC Hydro comes in response to a white paper Brattle published Oct. 1 that sets out a point-by-point comparison of seven design features of the EDAM and Markets+, including transmission optimization, fast-start pricing, real-time unit commitment (RTUC), procurement of imbalance and flexibility reserves, seams optimization, greenhouse gas pricing and congestion revenue allocation. (See *Brattle Study Likely to Fuel Debate over EDAM, Markets+*.)

All those features have figured prominently in the often-contentious debate between supporters of each market, which is increasingly playing out in various back-and-forth studies and *presentations*, as well as a series of "*issue alerts*" published by a core group of Markets+ funders — which includes Powerex.

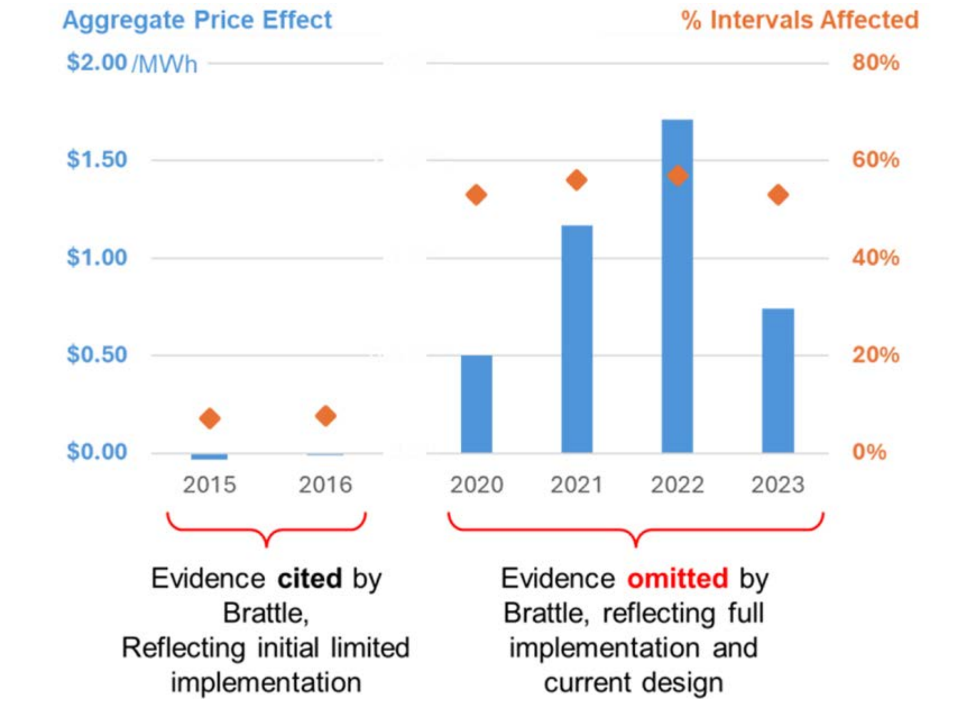
Fast-start Conflict

In its brief, Powerex contends "that the failure of the Brattle paper to provide a credible and fact-based examination of the market design differences is clearly evident in its discussion of fast-start pricing [FSP]."

While Markets+ supporters have argued that FSP is an important benefit of the SPP market that's conspicuously absent from CAISO's markets, the Brattle paper played down the importance of the mechanism, saying that evidence from several RTOs in the East — including SPP — shows FSP has minimal impact on market prices or revenues for fast-start resources.

Why This Matters

Powerex's response to Brattle's study adds to the increasingly contentious debate as EDAM and Markets+ supporters both try to influence utility decisions on which market to join.



Powerex said MISO data show that fast-start pricing has had an increasing impact on prices overall in the RTO since it was implemented. | *Powerex*

Brattle also questioned the viability of a 2022 *study* conducted by consulting firm Energy GPS for Powerex and the Portland, Ore.-based Public Power Council (PPC), which analyzed potential impacts on CAISO markets if the ISO were to implement FSP.

In his initial reaction to the Brattle study, Jeff Spires, director of power at Powerex, told *RTO Insider* that Brattle misrepresented the results of Energy GPS' analysis and failed to include the most recent data from the Eastern RTOs showing the benefits of FSP.

The Powerex brief builds on Spires' points, for example asking why Brattle chose to present MISO's FSP analysis from 2015 and 2016 when more recent data are available online.

"This is a glaring omission, as later reports paint a very different picture," Powerex wrote. "In 2021, the MISO Independent Market Monitor explained that while the initial effect of fast-start pricing was very small (when fast-start pricing was a new market design feature), MISO subsequently made important changes to how it applies fast-start pricing that 'have significantly improved real-time price formation in MISO,'" according to the Monitor's 2021 State of the Market report.

Powerex said MISO data show that, from 2020 to 2023, the overall price impact from FSP was 50 to 100 times the 1- to 3-cents/MWh estimates for 2015 and 2016 cited by Brattle.

The brief said Brattle's study also omitted evidence that, in recent years, FSP in PJM added an average of $4/MWh to $8/MWh to the RTO's prices during morning and evening demand peaks.

Powerex said also that Brattle "briefly acknowledges" that New England system prices increased by 11% when ISO-NE implemented FSP, but at the same time cautions that the analysis identifying that increase was "limited to the first eight months after FSP came into effect."

"Brattle could easily have reviewed the annual reports for [ISO-NE] published since then," Powerex wrote, citing the ISO-NE Internal Market Monitor's conclusion in its *2023 Annual Markets Report* that "fast-start pricing rules in the real-time energy market continue to have notable impacts on pricing and market costs."

Powerex also castigates Brattle for saying Energy GPS' 2022 analysis suggested that FSP would have had an average price impact of $15/MWh to $23/MWh on CAISO's market over 2017-2020 if the ISO had implemented the practice.

"In fact, the [Energy GPS] report clearly states that 'for the evening peak hour from 6 p.m. and 7 p.m., this price impact averaged nearly $15/MWh in NP15, and nearly $23/MWh in SP15,'" Powerex wrote, referring to trading hubs on the CAISO system. "The Brattle paper takes the price impact of the single-highest hour and presents it as the price impact across all hours, which is simply false."

John Tsoukalis, a principal at Brattle and the lead author of the study, said his group "will take a close look at and consider the additional evidence [Powerex] put forward on fast-start pricing, but we note that the fast-start pricing section of our white paper is based on the analyses conducted by market monitors in other regions.

"For example, SPP's [Market Monitoring Unit] stated in May 2022 that 'there was very little change in the revenues to fast-start units due to the new fast-start pricing. The fast-start pricing appeared to have created [a] 1.5% increase in day-ahead revenues to fast-start resources and a 0.5% increase in real-time revenues. All else equal, the increase in revenue would cause a negligible reduction in make-whole payments,'" Tsoukalis said in an email.

CAISO and FSP

The Powerex brief also calls out CAISO for being the only FERC-jurisdictional organized electricity market without fast-start pricing.

The company explains that in markets with FSP, "special pricing logic" is applied to ensure that the cost of starting and operating fast-start units is allowed to set the market's LMPs when those units are determined to be providing supply at the market's margin. In markets without FSP, the LMP can remain "well below" the cost of running peakers and "artificially" depress wholesale prices, reducing the amount paid to local generators and imported electricity from neighboring balancing authority areas.

"Avoiding the adoption of fast-start pricing therefore largely benefits utilities (and their ratepayers) in jurisdictions like California that typically import electricity during the hours of the day that gas peaking units are frequently used, while harming suppliers (and their ratepayers) in jurisdictions that typically export electricity during those same hours," Powerex wrote.

Powerex pointed out that CAISO opposed a 2016 FERC proposal that would have required all organized markets to adopt FSP and that the ISO's Department of Market Monitoring intervened to oppose adoption of FSP in any market.

"Such opposition aligns with California's own interests, since the state has historically been a large importer of electricity from both Northwest and Southwest utilities in those hours that gas peakers are running," Powerex wrote.

Reached for comment on Powerex's contentions, CAISO pointed out that its Price Formation Enhancements (PFE) Working Group is currently exploring the potential for implementing FSP in the ISO's markets.

"We recognize this feature has been adopted in other markets, with each carefully considering integration into its existing design. Different design features of fast-start pricing have tradeoffs that need to be considered by the stakeholders, and in particular, compatibility with existing features of the ISO market design that were specifically developed to compensate flexible and responsive resources with much the same goal as fast-start pricing," the ISO said in an email.

Still, CAISO said its own analysis, presented to the PFE in April, showed a "minimal $0/MWh impact of fast-start pricing in the Northwest with similar minimal impacts in the Southwest, the exception being very narrow stressed system conditions under which the price impact was small in the CAISO and some specific areas of the Southwest ranging from $2 to $8/MWh depending on the sensitivity."

Other Features

While the brunt of Powerex's response dealt with FSP, the company also briefly contested the Brattle paper's assessment of other market features, including GHG pricing mechanisms, congestion revenue allocation and transmission optimization.

Regarding the last feature, Powerex says the Brattle paper incorrectly asserts that "some stakeholders" — that is, Markets+ supporters — have suggested that the market would rely "solely" on flow-based optimization of transmission within its territory, while EDAM would rely on both flow-based and contract path-based optimization.

Powerex said it recognizes that both markets will need to apply contract path limits for rights on transmission located within the boundaries of one market but used in another market.

"But the actual distinction that has been pointed out is that in EDAM, the California ISO will also apply contract-path limits to EDAM transfers between balancing areas participating in the EDAM, just as it applies contract-path limits for [Western Energy Imbalance Market] transfers between entities in the EIM," it said. "In contrast, Markets+ will limit transfers between balancing areas participating in Markets+ based on physical flow-based limits, enabling more efficient use of the transmission system." ■

PG&E Gets Mixed FERC Decision on Tx Rates

Commission Rejects Tree Removal Request, Doesn't Pause Wildfire Cost Recovery

By Henrik Nilsson

FERC on Oct. 8 granted and denied in part challenges to Pacific Gas and Electric's 2022 transmission rates, finding that PG&E must remove certain costs from its rate base while also denying a request to pause the utility's ability to recover costs stemming from two massive fires in California.

The order concerns PG&E's rate year 2022 information filing, which reflected increased costs in both retail and wholesale base transmission revenue requirements (TRRs) (*ER19-13*).

The utility reported that its retail base TRR would increase from approximately $2.214 billion to $2.812 billion, while its wholesale base TRR would rise from about $2.202 billion to $2.799 billion.

The California Public Utilities Commission and the California cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside challenged the update. FERC handed wins to both sides in its decision while also scheduling some issues for hearing and settlement judge procedures, according to the order.

In siding with the challengers, FERC found that PG&E cannot claim that its vegetation management, such as tree removal, is similar to initial construction activities, which would have allowed PG&E to tack those costs onto its rate base. Instead, FERC ordered PG&E to reclassify such costs as operating and maintenance expenses and remove the costs from its rate base.

"PG&E has not demonstrated that tree removal associated with its [right of way] expansion qualifies as a substantial addition to plant nor a construction of a new asset, and accordingly, PG&E must record such costs in the appropriate O&M expense account," the order stated.

However, FERC denied CPUC's request for an order requiring PG&E to remove costs related to the 2019 Kincade Fire and the 2020 Zogg Fire. The devastating fires burned thousands of acres and destroyed hundreds of buildings in Northern California, and CPUC has hit PG&E with severe penalties over the utility's alleged role in those fires and others. (See *CPUC Fines PG&E $45M for 2021 Dixie Fire*.)

In its 2022 challenge, CPUC asked FERC to avoid holding ratepayers responsible for the wildfire recovery costs until liability had been determined in various pending investigations and regulatory proceedings, according to the order.

FERC denied the challenge in the Oct. 8 order, finding that it rejected a similar challenge in San Diego Gas & Electric's formula rate annual update in 2016.

"Consistent with this precedent, we are not persuaded to hold the allowance of costs at issue in this proceeding in abeyance pending resolution of the state criminal, investigatory and regulatory proceedings," the order stated. "As in the SDG&E proceeding, the ongoing and potential state proceedings CPUC describes could take significant time to resolve, meaning that this proceeding would 'be held in abeyance for an indefinite period of time.'"

FERC noted that its order "does not limit any party's right to challenge the justness and reasonableness of the allowance of costs associated with the Kincade and Zogg fires in subsequent PG&E annual informational filings, including by pointing the commission to any relevant information that may emerge from state proceedings regarding the Kincade and Zogg fires."

Additionally, FERC rejected challenges to PG&E's accounting of costs related to upgrades to transmission towers, monitoring systems and a boardwalk replacement program.

CPUC also targeted insurance proceeds, wildfire-related costs and costs associated with removing the PG&E-operated Caribou-Palermo transmission line, which failed in 2018, resulting in the Camp Fire, one of the deadliest in California's history. (See *Ancient C Hook, Financial Manipulation Caused Camp Fire*.)

Similarly, CPUC argued that ratepayers should not bear the burden of reconnecting the Grizzly Powerhouse, a hydropower project, to the transmission grid, saying that "would not be necessary but for the Camp Fire," according to the order.

However, FERC declined to take a position on those challenges, finding that the matters "raise issues of material fact that cannot be resolved based on the record before us." Instead, the commission sent the matters for a trial-type evidentiary hearing but encouraged the parties to reach a settlement before hearing procedures commence.

Representatives for the parties did not return requests for comment. ■

FERC denied the CPUC's request that PG&E remove from its rates costs related to 2019 Kincade Fire and 2020 Zogg Fire (pictured above). | *California Conservation Corps*

CAISO/West News

Batteries, Energy Transfers Support ‘Uneventful’ Summer in West

Grid Conditions Smooth Despite Record Peak Load, Extreme Heat

By Ayla Burnett

The addition of new resources and broader support from the Western Energy Imbalance Market (WEIM) led to an “uneventful” summer for the Western grid, industry experts said — despite record peak loads and *July being the hottest month ever recorded* across the region.

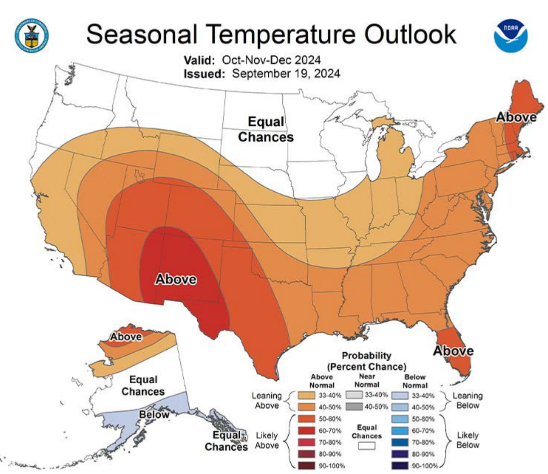
A key factor in that success: more batteries.

“A big benefit that we found from this summer was the growth of battery energy storage within the California ISO,” Scott Olson, director of policy, regulatory and markets at Avangrid Renewables, said during a Sept. 25 Western Energy Markets (WEM) Governing Body panel discussion. “Having 10 gigawatts of batteries … helped us to the uneventful outcome that we actually appreciated.”

Battery storage is playing an increasingly important role as the industry continues to replace conventional resources with intermittent renewables. California will need around 50 GW of batteries to meet its 2045 greenhouse gas reduction goals, according to a CAISO *special report*, and it’s well on its way. Battery storage capacity in the ISO has grown from 500 MW in 2020 to 11,200 MW as of June 2024, and the WEIM includes an additional 3,500 MW.

“Our growing battery fleet was instrumental in balancing supply and demand throughout the heat wave,” CAISO spokesperson Anne Gonzales told *RTO Insider* in an email.

Pam Syrjala, senior director of supply and trading at Salt River Project, agreed that while summer was challenging due to extreme heat, conditions were better than the prior summer, largely thanks to battery storage.



Seasonal temperature outlook from the National Weather Service's Climate Prediction Center. | *NOAA*

“Last summer, we were trying to implement a large number of battery resources into our system, so we were bringing on almost 450 MW of batteries” Syrjala said during the panel discussion. “This summer, we brought on probably over 650 MW of batteries, and it was a night-and-day difference.”

Temperature variation also contributed to more manageable grid conditions, with certain parts of the West, like Southern California, experiencing above-normal but not historically high heat, compared with the central part of the state, which broke temperature records.

“That variation, while small, was enough to tamp down demand and maintain grid reliability,” Gonzales said.

Assistance Energy Transfers

Relying on the transfer capability of the WEIM and on the market as a whole also contributed to smooth summer operations. In a Sept. 25 market update discussing second-quarter performance, Guillermo Bautista Alderete, CAISO director of market performance and advanced analytics, highlighted that WEIM transfers were substantial, and that expansion of the market “unlocked increasing volumes of economic transfers.”

The assistance energy transfer (AET) program, which allows WEIM areas to receive energy transfers when they don’t meet the market’s resource sufficiency requirements ahead of a delivery interval, played an important role this summer. Six WEIM balancing areas opted into the AET program in June, followed by 10 more in July and August, and nine in September. The total surcharges assessed were about $72,000 for all the balancing authorities involved.

WEM Governing Body Chair Rob Kondziolka said that while the ISO discourages BAs from leaning on the AET program too heavily, it helped a lot.

Why This Matters

The lack of grid emergencies in the West this summer, despite record heat and loads, suggests how significantly batteries will affect grid operations with wider adoption.

“Assistance energy transfers has been a great benefit, we think, to the market design,” Olson said. “We only use it in small amounts, but, boy, when it’s there relative to the alternative in the real-time market … it’s absolutely a huge benefit to us.”

Kelsey Martinez, manager of system operations at PNM Resources, backed up Olson’s view.

“It just allows you that peace of mind that you’re not going to have to change your operating process in the midst of an energy crisis,” Martinez said.

The AET program was pushed by NV Energy and heavily debated in its beginning stages, said Kondziolka, who expressed satisfaction with its benefits, despite the associated costs.

‘We Can’t Let Our Guard Down’

Even with record peaks and high temperatures, CAISO issued no energy emergency or flex alerts. And while wildfire danger was high, there were no disruptions to the bulk electric system, Gonzales said.

California energy officials — including those at CAISO — entered summer ‘cautiously optimistic’ about grid conditions, and the ISO is approaching fall with a similar mindset, she said. (See *Calif. Officials ‘Cautiously Optimistic’ on Summer Reliability*.)

“We need to be cautious about the successes of the grid this summer. We can’t let our guard down,” Gonzales said. “We were closely monitoring equipment fatigue and ambient de-rate (reduced output) from the prolonged heat waves. When generators are running at high rates of output for multiple consecutive days, we start to get concerned about equipment failure and outages. And we continue to closely track wildfire activity extending into October.” ■

CAISO/West News

Wash. Kicks off Cap-and-Invest Electricity Forum

Program Established to Discuss Grid Issues Related to Carbon Market

By Henrik Nilsson

Washington's Department of Ecology kicked off its first virtual electricity forum Oct. 3 to provide updates on recent electricity-related rulemaking efforts related to the state's carbon market and to give stakeholders a chance to discuss those initiatives.

The state's Cap-and-Invest Electricity Forum aims to allow parties to discuss policy issues related to Washington's cap-and-invest program and greenhouse gas emissions reporting programs.

The Ecology Department has moved forward with amending several electricity provisions in its rules. The rulemaking closest to completion concerns centralized electricity markets, such as CAISO's Western Energy Imbalance Market/Extended Day-Ahead Market and SPP's Markets+.

The rule establishes a framework for accounting for "specified" electricity imported through centralized markets and defines the electricity importer for specified electricity imported through a centralized market. The update is anticipated to go into effect in January.

The agency is also working on "linkage" rulemaking to align cap-and-invest program regulations with California and Québec as Washington looks to join the larger shared carbon market. (See *Calif., Quebec, Wash. to Explore Linking Carbon Markets*.) The recently enacted *Senate Bill 6058* allows Ecology to adjust the cap-and-invest program by, for example, aligning allowance purchase limits for auctions across jurisdictions and having the same compliance period dates.

"This rulemaking may also be used as an opportunity to address other electricity sector topics, including centralized electricity markets," Camille Sultana, senior environmental planner at the Ecology Department, noted during the meeting.

Sultana added that Ecology will provide more information on the bill's implementation later this fall. The goal is to publish a proposed linkage rule in spring 2025 and put it up for adoption later that year. However, the timeline is subject to change as the agency must consider anticipated updates to California and Québec's respective cap-and-trade programs.

The department also opened the floor for participants to chime in on GHG issues related to centralized electricity markets, such as accounting for emissions from electricity from "unspecified" resources, emissions leakage and accounting for energy flowing from centralized markets with different operators.

| © RTO Insider LLC

Why This Matters

The new forum could help electricity sector stakeholders work through the complex issues developing at the intersection of Washington's cap-and-invest program and the West's increasingly centralized power markets.

Clare Breidenich, assistant executive director of the Western Power Trading Forum, said the agency should define surplus energy in the context of GHG accounting in centralized markets.

"I think by establishing clear requirements and conditions for what Ecology thinks is appropriate for those markets, that will give the guidance to the market operators and help them to align their approaches," Breidenich said.

Participants also discussed emissions reporting requirements and the transition from netting to a wheel-through framework under SB 6058.

As defined in the bill, "'electricity wheeled through the state' means electricity that is generated outside the state of Washington and delivered into Washington with the final point of delivery outside Washington including, but not limited to, electricity wheeled through the state on a single NERC e-tag, or wheeled into and out of Washington at a common point or trading hub on the power system on separate e-tags within the same hour."

Alisa Kaseweter, climate change strategist at Bonneville Power Administration, said the definition "seems to conflate what the industry would think of as a standard wheel-through which happens on a single e-tag with perhaps some netting."

Sultana noted that SB 6058's definition of a wheel-through "might not directly align with industry standard." She added that Ecology's "ability to modify this definition in ways that are not aligned with what's already there in statute is beyond our authority." ■

ERCOT News

Texas Lawmakers Pile on $5B Fund's Controversy

Deloitte, PUC Criticized for Role in Vetting TEF's 'Fraudulent' Application

By Tom Kleckner

Deloitte's Rod Kleinhammer (left) reads his prepared statement to the TEF's advisory committee. | *Texas Senate*

Texas lawmakers charged with overseeing the state's $5 billion fund for new gas-fired generation took aim this week at the consulting firm managing the program.

During a public hearing Oct. 8, the Texas Energy Fund (TEF) Advisory Committee roasted Deloitte representatives for missing an apparently fraudulent loan application that accounted for 13.2% and left a nearly 1.3-GW hole in the fund's portfolio.

Deloitte principal Rod Kleinhammer, a senior partner overseeing the firm's Texas business, defended his staff's work. He said they could have been more intensive in performing due diligence of the 72 applicants for TEF funds. Deloitte conducted what amounted to cursory background checks of the applicants and found no negative results, Kleinhammer said, and added it intended a deeper dive after arriving at its shortlist of 17 projects deserving of loans.

"We should have accelerated some of the additional risk and reputational checks we had planned for due diligence to occur prior to the release of the 17 Texas energy fund loan applications being made public," he told the committee, reading his short, prepared statement. "We've modified our processes and are confident the safeguards we have in place will continue to assure that no entities will be approved for funding before a rigorous and thorough review of the applicants and sponsors has been completed."

That may not be enough.

Lt. Gov. Dan Patrick (R), one of the state's most powerful political leaders, posted a *statement* after the hearing calling Deloitte's failure to catch the sketchy application a "blunder." He said the Public Utility Commission should follow through on its demand to claw back at least 10% of Deloitte's contract and for the legislature to review the state's other contracts with Deloitte, which average about $250 million annually, according to Kleinhammer.

Why This Matters

The apparently fraudulent application that slipped through the cracks in Texas leaves a nearly 1.3 GW hole in the state's bid to build 10 GW of gas-fired generation.

"Our grid needs more dispatchable power as quickly as possible, and the Texas Energy Fund loan program is the most expeditious way to get more dispatchable megawatts online" he said. "Deloitte has only slowed down this important program. They need to correct their errors now or be gone."

The application in question was proffered by Aegle Power, which said NextEra Energy was a party to the application, which the Florida company has denied. It also turned out that Aegle's CEO, Kathleen Smith, had *pleaded guilty* in 2017 to embezzling a "significant" amount of money from a company that was trying to build a power plant in Corpus Christi, Texas. (See *Texas PUC Rejects Possible 'Fraudulent' Loan Application*.)

"The lack of just basic due diligence is astounding to me," state Sen. Charles Schwertner (R), who co-chairs the advisory committee, told Kleinhammer. He noted Smith's name was "all over the application" and received affirmation from the Deloitte rep.

"And no one bothered to interview or Google her name?" he asked incredulously. "This is the second-largest, 1.2-GW, second-largest project in the Texas Energy Fund. Is it astounding that it wasn't a baseline like, 'Who am I dealing with?'"

Schwertner recalled an earlier conversation with Kleinhammer, in which they discussed Deloitte's mantra of KYC (Know Your Client).

"You were like, all giddy about it, almost," Schwertner said. "Do you know Aegle Power?"

"I do now," Kleinhammer responded. "Now that I know what I'm looking for, it is very easy to find out, sir."

"What do you mean, what you're looking for?" Schwertner replied, not hiding his frustration. "'If they're a convicted felon, I should probably not advance them.' Is that what you're looking for? Do we need to spell it out for you?"

Smith had agreed to attend the hearing, but Schwertner said she pulled out Oct. 7 because she said she couldn't leave Florida because of Hurricane Milton's approach.

Sitting next to her empty chair, Mitchell Ross,

ERCOT News

general counsel for NextEra Energy Resources, the competitive business for the giant Florida company with about a $160 billion market cap, said the subsidiary never committed to or applied for any project seeking Texas Energy Fund support.

He said discussions were held with Aegle, but that no equity commitment was ever made. Initial conversations began with Aegle's investment banker in May, but by July, Ross said, NextEra's deal team had decided to end the negotiations, partly because of Smith's criminal history. He said a May letter submitted to the PUC and claiming a $252 million equity commitment from NextEra was fraudulent and has been reported to the U.S. Attorney's Office.

"We do not support the application, and I agree that false statements and fraud have been committed against the state of Texas," Ross said.

As if that weren't enough, Coronado Power Ventures *notified* the PUC that the *air permits Aegle said it had secured* from the Texas Commission on Environmental Quality and the U.S. EPA actually were issued to its La Paloma Energy Center in South Texas. The project since has been *canceled*.

Coronado Power CEO John Upchurch said the application was made without his company's "knowledge or consent."

In a strange twist, Upchurch was CEO and Smith president at Chase Power from 2008 to 2012, when the embezzlement occurred. Federal authorities charged both with filing false invoices and using their company credit cards for personal travel, country club memberships and other expenses. Like Smith, Upchurch pleaded guilty to the charges.

"Deloitte's failure to uncover the falsified application presented by Aegle Power, whose CEO was previously convicted of embezzlement, is outrageous, and the [PUC's] advancement of this unvetted project is extremely troubling," Patrick said in his statement.

PUC Chair Thomas Gleeson offered his apologies, saying the commission had "too much of an arm's length relationship with our contractor."

"I should have ensured we were more heavily involved in the review," he told lawmakers. "Ultimately, it is my responsibility to make sure that Deloitte is doing what they need to do."

The commission said it will strengthen the oversight process to address the issues that led to the Aegle Power application's acceptance and denial. Executive Director Connie Corona said staff will meet with the 16 remaining applicants and conduct site visits to verify their legitimacy.

The PUC and Deloitte are negotiating over the 10% clawback of the latter's contract, which is valued at $73 million over four years. An addendum could up the spending to $107 million.

Texas Sen. Charles Schwertner | *Texas Senate*

Kleinhammer said the two sides are close, but Gleeson offered a different perspective. He said there will be no negotiation over the 10% number, which amounts to $7.3 million.

"That is $7.3 million, which is 10% of their base contract. That number is non-negotiable. It is not moving down," Gleeson told the committee. "So, from my view, there is no ongoing negotiation. There is a number that needs to be met, and when it is, we will present you with an agreement of that number."

Gleeson said the commission also has referred the matter to the Texas attorney general's office, citing the "lies and false statements" in the application.

"It is fraud," he said. ■

ERCOT News

ERCOT, CPS Energy Negotiating RMR, MRA Options for Retiring Units

By Tom Kleckner

ERCOT's Chad Seely explains the options for extending the life of three CPS Energy coal-fired units. | *ERCOT*

ERCOT staff and CPS Energy continue to work "very closely" in negotiating reliability must-run contracts (RMR) for three aging coal-fired units that the grid operator says are necessary for reliability in the San Antonio area.

General Counsel Chad Seely told ERCOT's Board of Directors on Oct. 10 that the ISO is positioning itself to come before the board during its December meeting for a "full evaluation" of whether the directors want to select one or more of the RMR units.

"This is a big decision for the board to evaluate the local reliability impacts that we have identified as a result of these resources going away and making sure that you have a complete set of information to evaluate the cost/benefits of what your decision may be," Seely said.

San Antonio's municipal utility told ERCOT this year that it planned to retire the three coal units, which date back to the 1960s, in March 2025. However, ERCOT said the Braunig Power Station units, with a combined summer seasonal net maximum sustainable rating of 859 MW, were needed for reliability reasons and *issued a request* for reliability must-run proposals in July. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

Complicating matters is that CPS Energy has said each unit must be inspected and repaired — consecutively, not concurrently — if it is to operate beyond its retirement date.

Rick Urrutia, the utility's vice president of generation operations, said the inspection outage for Braunig Unit 3, the largest (412-MW maximum summer rating) and most desirable RMR resource, will take at least 60 days. That could be delayed by long lead times for needed parts for repairs, he said.

Why This Matters

Under certain conditions, such as when high system demand coincides with an outage of a major transmission line or one or more generation units, lines that deliver power from South Texas into San Antonio could be overloaded and possibly lead to cascading outages.

"That schedule can change if we find any major 'discovery work,' in which some of that equipment or systems has to have extensive repairs," Urrutia said.

Negotiations between the two parties have focused on the lost opportunity cost if Unit 3's outage begins before any RMR service; the outage, inspection and repair processes for all three units; and the costs of any potential RMR service.

CPS Energy agreed to move Unit 3's suspension date up to March 2 under what ERCOT is characterizing as a pre-RMR agreement. That would improve the odds for its availability and potentially one of the other units for next summer, should the board choose that path, Seely said.

ERCOT says the RMR units will be important in addressing the South Texas export interconnection reliability operating limits (IROLs) staff established this year. Their analysis revealed that under certain conditions, such as when high system demand coincides with an outage of a major transmission line or one or more generation units, lines that deliver power from South Texas into San Antonio could be overloaded and possibly lead to cascading outages.

Potential RMR or must-run alternative service would reduce the loading on the 345-kV lines subject to the IROLs.

An ERCOT solicitation for must-run alternatives (MRA) to the Braunig units resulted in one response. A 200-MW multi-hour energy storage resource responded within minutes of an Oct. 7 deadline, proposing to start in the summer of 2026 and end March 1, 2027.

"That's a little disappointing that we weren't able to get more interest from the industry because ultimately, the consumers of Texas will have to pay for any type of solution the board deems appropriate," Seely said.

The grid operator says the ESR would provide a positive shift factor for the IROL in that it's north of the South Texas constraint and would reduce loading. Staff will conduct eligibility and qualification analysis of the proposed MRA. ■

ERCOT News

ERCOT Board of Directors Briefs

No Demand Mark During 'Mild' Summer

Although Texas recorded its sixth-hottest summer on record, ERCOT failed to set a new mark for peak demand despite loads similar to last year's record. The grid operator came close when it registered a preliminary peak of 85.56 GW on Aug. 20, but it was later reduced to 85.12 GW.

Dan Woodfin, vice president of system operations, told the ERCOT board that wholesale energy storage charging was included in the initial figure. ERCOT treats the charging as negative generation from a settlements perspective, he said.

The ISO's all-time demand mark remains 85.51 GW, set during August 2023. The ERCOT grid recorded 22 days of demand exceeding 80 GW through August, compared to 43 days of 80 GW last year.

Natural gas prices and renewable energy helped keep prices low during the summer. Wind (27.85 GW), solar (20.83GW) and energy storage (3.93 GW) resources all set highs through August, according to *Grid Status*.

More renewables are on the way. Solar and storage (155 GW each) and wind (34 GW) account for the bulk of capacity in ERCOT's interconnection queue. The queue contains 25 GW of gas-fired capacity.

Dan Woodfin, ERCOT | *© RTO Insider LLC*

2025 AS Methodology OK'd

The board approved several measures previously endorsed by its Reliability & Markets (R&M) Committee and the Technical Advisory Committee (TAC).

- The minimum amount of *ancillary service products* to be procured in 2025, which will include three minor modifications to ERCOT contingency reserve service (ECRS). (See *ERCOT Technical Advisory Committee Briefs: Sept. 19, 2024*.)
- A *real-time market price correction* resulting from an incorrect recall of ERCOT contingency reserve service. Affected counterparties will receive more than $3.5 million in settlements.
- A *real-time price correction* after a resource was identified incorrectly as not being qualified for security-constrained economic dispatch. It will result in more than $323,000 in settlements to counterparties.

The Public Utility Commission must approve all three actions.

The directors agreed with R&M and remanded back to TAC a protocol change (*NPRR1190*) that would recover demonstrable financial loss arising from a manual high dispatch limit override to reduce real power output, should the output be used to meet qualified scheduling entity load obligations.

The board asked TAC to gather more information on the initial market policy framework and reassess the need for the compensation mechanism introduced by *NPRR649* in 2017 and whether it's still needed in today's market.

TAC's consumer segment opposes the change in its current form, saying it would reward overscheduling power that cannot be delivered. That will force consumers to subsidize insufficient hedging by other market participants in the face of changing grid conditions.

New CFO; Board Vacancies

The directors ratified Richard Scheel as an officer following his promotion as ERCOT's new CFO and chief risk officer. Formerly the ISO's controller, Scheel has more than 20 years of finance experience. He replaces Sean Taylor, who announced his retirement in August.

The board also designated Scheel to join Chad Seely and Leslie Wiley as managers and officers of the two *debt-financing mechanisms* paying back $2.9 billion in market costs from the disastrous 2021 winter storm.

The meeting may have been the last for independent director Bob Flexon, who says he will step down from the board when his term expires Dec. 1. That will leave the board with three vacancies. A selection committee has yet to name a replacement for former Chair Paul Foster, who left the board this year, and the Office of Public Utility Counsel (OPUC) does

In Other Action

The ERCOT board:

- Approved an ancillary service methodology for 2025.
- Ratified a new CFO and learned of a board vacancy.
- Announced ERCOT's presence on Instagram.
- Approved 11 revisions.

ERCOT News

not have a CEO to fill its seat.

The grid operator's board consists of eight independent directors, two members from the Public Utility Commission, and single seats for the OPUC and ISO CEOs. Members are required by law to not have fiduciary duty or assets in the ERCOT market and to be Texas residents.

ERCOT Now on Instagram

ERCOT continues to expand its social media presence by joining *Instagram*, adding to its existence on X (formerly Twitter), Facebook and LinkedIn.

"Please come and follow us," CEO Pablo Vegas said. "That's how you know you're cool, if you've got a lot of followers."

Board Approves 11 Revisions

The board unanimously approved a consent agenda with seven NPRRs, two changes to the Nodal Operating Guide (NOGRR), an Other Binding Document Request (OBDRR) and a single revision to the Retail Market Guide (RMGRR) that will:

- *NPRR1188*, *OBDRR046*: Modify the dispatch and pricing of controllable load resources (CLRs) in response to the PUC's directive to increase the use of "load resources for grid reliability." The NPRR revises the market-participation model of CLRs that are not aggregate load resources so they are dispatched at a nodal shift factor and settled for their energy consumption at a nodal price.
- *NPRR1215*: Clarify that the day-ahead market's energy-only offer credit exposure calculation zeroes out negative values, with any zeroed-out values being included in the calculation of the depth percentile difference.
- *NPRR1221*, *NOGRR262*: Align manual and automatic firm load shed provisions; clarify the proper use and interplay of under-voltage load shed, under-frequency load shed and manual load shed; and address reliability concerns over the extent of transmission operators' manual load-shed capabilities.
- *NPRR1227*, *RMGRR181*: Align defined protocol terms and add five definitions ("acquisition transfer," "decision," "effective date," "gaining competitive retailer" and "losing competitive retailer") that previously were in the Retail Market Guide (Acquisition and Transfer of Customers from one Retail Electric Provider to Another). The NPRR replaces the broadly titled terms "decision" and "effective date" with the specific terms "mass transition decision," "acquisition transfer decision," "mass transition effective date" and "acquisition transfer effective date" to provide clarity. The change also expands the "gaining competitive retailer" and "losing competitive retailer" definitions to apply beyond the mass transition and acquisition transfer processes.
- *NPRR1236*: Reflect Real-Time Co-optimization Plus Batteries (RTC+B) Task Force's modifications to the reliability unit commitment capacity-short calculations and address limits in the current calculations by considering ancillary service sub-types. It changes the calculation process involving regulation down service and addresses changes required to align protocol language with recently approved *NPRR1204* (Considerations of State of Charge with Real-Time Co-Optimization Implementation).

ERCOT CEO Pablo Vegas | *ERCOT*

- *NPRR1237*: Document the scenarios in which market participants are required to successfully complete retail qualification testing, regardless of whether the market participant previously received a qualification letter from ERCOT from prior retail flight testing.
- *NPRR1244*: Align eligibility provisions for CLRs not providing primary frequency response (PFR) to provide ECRS. It also would include in physical responsive capability's calculation only the capacity of CLRs when they are qualified to provide regulation service and/or regulation reserve service that requires the CLR to be capable of providing PFR.
- *NOGRR263*: Clarify that a CLR is required only to provide PFR when it is providing an AS that requires that resource to be able to provide PFR. ■

— Tom Kleckner

ISO-NE News

Panel Calls for Greater Interregional Planning Across the Northeast

By Jon Lamson

Unlocking the full potential of Quebec hydropower to balance renewables through the Northeast will require major efforts to overcome barriers to transmission planning and development, speakers at a *webinar* led by the Acadia Center emphasized Oct. 9.

While *studies* have shown increased bidirectional transmission capacity between the Eastern Canadian provinces and the Eastern U.S. could significantly reduce the costs of decarbonizing the grid, such transmission projects so far have struggled. (See *Québec, New England See Shifting Role for Canadian Hydropower* and *National Grid Backs out of Twin States Clean Energy Link Project*.)

The webinar kicked off with pre-recorded remarks from U.S. Sen. Ed Markey (D-Mass.), who said "the clean energy revolution is here at our doorstep," but "our grid is an inaccessible, one-lane road from the Model T era."

Markey highlighted his proposed legislation that would direct FERC to require RTOs to regularly engage in interregional planning and establish independent transmission monitors. (See *Dems Introduce Bill on Transmission Planning, RTO Transparency*.)

Despite the significant up-front costs of major new transmission lines, grid modeling indicates that "in a low-carbon system in New England and Québec, building more bi-directional transmission lowers the cost of electricity," said Emil Dimanchev, a research affiliate at the MIT Center for Energy and Environmental Policy Research.

Increased bi-directional transmission would reduce the need to curtail renewables during periods of excess generation, Dimanchev said. It also would reduce reliance on gas resources by enabling hydro to take a greater balancing role paired with intermittent renewables.

Along with cost savings, increased interregional transmission also could provide significant reliability benefits.

"Transmission gives us this ability to combine wind resources from both sides of the border, which together are much more reliable," Dimanchev said.

Adrienne Downey, principal engineer at the floating offshore wind developer Hexicon, said offshore wind pairs particularly well with hydropower when there is enough transmission capacity to enable hydro to firm up the intermittencies of wind.

"Offshore wind is pretty much a match made in heaven with this load growth, these winter peaks … and looking at hydro and the opportunity to replenish reserves," Downey said.

Hexicon is part of a coalition that has *proposed* a "shared offshore backbone transmission corridor" to connect offshore wind resources along the northern Atlantic coast, reaching shore in both New England and Nova Scotia.

The proposal likely would pay for itself through reduced power costs but remains "really a question of proactive planning," Downey said.

Additional interregional transmission capacity also would help to even out localized weather patterns as weather-dependent renewables make up a larger portion of the generation mix, said Hannes Pfeifenberger of the Brattle Group.

About 4 GW to 7 GW of transmission capacity likely will be needed and would be "cost effective" between Canada and both New England and New York, but "the reality is there are significant barriers," Pfeifenberger said. A lack of trust between regions, inadequate planning tools and regulatory constraints all pose challenges.

Why This Matters

Despite the significant up-front costs of major new transmission lines, grid modeling indicates that building more bi-directional transmission would lower the cost of electricity in New England and Québec.

"You need everybody at the table, which is why it's so challenging," Pfeifenberger said. He emphasized the need to build understanding around the importance of interregional planning to lay the groundwork for agreements regarding specific transmission needs and cost allocation frameworks.

Downey said grid operators, lawmakers and officials must work to expand beyond often-ingrained habits of hyper-focusing on the local grid, while also respecting the cultural differences in how regions approach their power system.

"To bridge that, and to have these broader regional discussions, there's some cultural sensitivities," Downey said. "It's important that we think about this as a social and cultural exchange with related co-benefits."

Beyond just adding new lines, transmission planning could help identify opportunities to increase line capacity when conducting asset condition upgrades, Pfeifenberger said.

Costs associated with maintaining the aging New England grid have accelerated in recent years, putting pressure on ratepayers and causing friction between the states and transmission owners, who have proposed several infrastructure projects costing hundreds of millions of dollars. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

Increasing line capacity could cost more in the short term but could provide significant long-term savings, Pfeifenberger said.

"We have an existing grid that was built in the '60s and '70s," Pfeifenberger said. "We can save money and reduce community impacts by better planning." ■

| Shutterstock

ISO-NE News

ISO-NE Outlines 2025 Annual Work Plan

By Jon Lamson


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

ISO-NE's work in 2025 will focus on capacity auction revisions, establishing a regional energy shortfall threshold (REST), complying with FERC orders 1920 and 2023, and implementing market and technology improvements, COO Vamsi Chadalavada *told* the NEPOOL Participants Committee (PC) Oct. 10.

The capacity auction changes are focused on improving how the capacity market assigns value to different resources and altering the timing of capacity auctions and capacity commitment periods (CCPs). The scope of work for the project is extensive, and ISO-NE expects the project to extend into 2027, in preparation for the 2028/2029 CCP. (See *ISO-NE Responds to Feedback on Capacity Auction Reforms Scope*.)

Regional Energy Shortfall Threshold

The REST is an effort to quantify how much shortfall risk from extreme weather events the region is willing to accept during a given season.

Chadalavada said the RTO will start working on the REST project in the fourth quarter of this year, continuing into the first or second quarter of 2025. ISO-NE is planning to conduct the first REST assessment for the winter of 2025/26.

"Results of the first assessment will provide more data on the risk trends to guide the timing and nature of the next phase, which is to evaluate whether the possibility of exceeding the REST requires development of specific regional solutions to mitigate risks," Chadalavada said.

He emphasized the need for stakeholder input — especially from the states — to determine an acceptable threshold.

Transmission Planning

Chadalavada said ISO-NE is planning to initiate a request for proposals process in 2025 for its newly approved longer-term transmission planning framework, "in anticipation of a request from the states for a competitively selected transmission solution to address the future, clean energy needs in connection with the *Transmission 2050 Study*." (See *FERC Approves New Pathway for New England Transmission Projects*.)

The RFP process will likely take about 18 months "from initiation through final recommendation," Chadalavada said.

He noted that ISO-NE will continue to work with stakeholders on "the assimilation" of the LTTP process with FERC Order 1920, with compliance on the order due in summer 2025. (See *With FERC Inaction, ISO-NE Delays Order 2023 Implementation*.)

ISO-NE is also planning to work with the states in the coming year on an approach to "right-sizing" transmission upgrades "to support integration of renewables and higher load levels over the life of the transmission asset."

The discussions will include a focus on "methods for distinguishing right-sizing costs from asset condition project costs so that they can be evaluated accordingly," Chadalavada said, adding that the discussions will likely begin when the states and transmission owners have completed their work on improving the asset condition project review process.

In response to a request from the New England States Committee on Electricity (NESCOE), Chadalavada said ISO-NE will begin discussions at the Planning Advisory Committee about how advanced transmission technologies should be incorporated into transmission planning processes.

"To the extent that ISO-NE considers such technologies currently, bringing greater visibility to that would be informative," NESCOE wrote in August. "An effective planning process should result in the deployment of these technologies when they provide a net benefit to consumers."

Budget Increase

The PC also approved a 13.6% increase in its *annual budget*, driven by new investments in personnel and technology focused on clean energy, the impact of inflation on current operations, and a $7.8 million true up. The increases bring the projected 2025 ISO-NE budget up to about $314 million.

ISO-NE has emphasized that the budget increase is needed to meet the growing complexity of managing the grid during the clean energy transition. The increase follows a 21.5% budget increase in 2024. (See *ISO-NE Proposes 21.5% Budget Increase for 2024*.)

The budget is intended to support the addition of about 50 new full-time equivalent positions in 2025, along with improved cyber security and software capabilities.

One stakeholder stressed that increased resources should come with increased expectations regarding the workload ISO-NE is able to take on in the future and expressed hope that the RTO will be able to accommodate more stakeholder requests.

Operations Report

Overall energy market value was down nearly 8% in September compared to September 2023, Chadalavada told the PC, presenting his monthly *operations report*. Average locational marginal prices were down by about 18% from August of this year.

While ISO-NE hit its annual peak load of more than 24,000 MW in September 2023, the September peak for this year topped out at just 16,853 MW.

Annual power system carbon emissions continue to track higher in 2024 relative to 2023, driven by an increase in natural gas emissions. ■

MISO News

MISO Demand Response Under Increasing Scrutiny; IMM Warns of More Potential Schemes

By Amanda Durish Cook

CARMEL, Ind. — Demand response in MISO is poised to be subject to more rigorous standards as the Independent Market Monitor warns of more potential bad actors.

Carrie Milton, Potomac Economics | © *RTO Insider LLC*

Carrie Milton, of the IMM staff, appeared before an Oct. 11 Market Subcommittee to put MISO and stakeholders on alert that MISO's market likely contains more deceptive demand response players. It's a warning IMM David Patton has delivered before. (See "IMM Demands Tougher Demand Response Requirements," *MISO: Hurricanes, Heat Wave Noteworthy Against Relatively Peaceful Summer*.)

Milton said the IMM has "dug into" researching performance of MISO's demand response since fraud in MISO's DR markets emerged three times within the past two years. (See *FERC Catches Ketchup Caddy Co. in Another Fake DR Scheme in MISO*.)

Milton said a review of Demand Response Resource Type I performance from 2023 to 2024 showed that those resources fall short of the amounts they promise. She said of 213 spinning reserve deployments across 22 event days in 2023-2024, more than 40% of the DRR Type I resources did not perform adequately. About 200 MW of DRR Type I participates regularly in energy and ancillary services.

FERC recently uncovered three companies manipulating MISO's demand response market and collecting unwarranted payments. The commission found that an air separation facility in Indiana accepted payments for fabricated load reductions, an Arkansas steel mill for years made faux use reductions, and an obscure, Texas-based LLC formed to sell in-car ketchup holders fraudulently enrolled customers and made sham DR offers in three capacity auctions.

Milton said demand response that fails to respond to MISO's calls for spinning reserve deployments faces only small penalties and, in some cases, still receives make-whole payments, "eliminating any incentive to curtail."

"We have a lot of concerns about this. MISO's rules, penalties and participant conduct all raise concerns for us," Milton said.

She also said the Batch-Load Demand Response category, introduced by MISO in 2020, contains the worst performers.

"This class of DR is cycling load that agrees not to increase rather than to curtail," Milton said.

Milton also said MISO's practice of accepting mock tests instead of actual performance testing "presents serious opportunities" for misrepresenting a resource's abilities. She said up to 25% of DR resources submit mock tests for accreditation.

"Since 2019, our demand response has received over $800 million in capacity payments. That's a lot of money," Milton said.

Milton repeated Patton's asks that MISO eliminate mock testing and the batch-load demand response category, intensify penalties and automate validation of end-use registrations so end-use customers can't contract with multiple market participants. She also asked MISO to require utility-grade meters and five-minute data for DR providing reserves.

Stakeholders warned that the IMM's recommendations might make DR participation in the MISO markets unattractive.

Louisiana Public Service Commission staffer Robert Vosberg said he wanted the IMM to quantify the impacts of its recommendations on ratepayers' bills.

Jim Dauphinais, an attorney representing multiple industrial customers in MISO, asked for a "less intrusive" list of recommendations.

"If we make this too difficult for customers, they will exit the program," WEC Energy Group's Chris Plante warned. He added that if "even half" of the 7 GW seasonal average of demand response that cleared the MISO capacity auction this year fails to participate, MISO will be in hot water.

"We just want it to be reliable," Milton said of demand response. "It needs to be reliable, and MISO needs to be able to count on it. That's the crux of this. … We need to make sure that these are legitimate resources that exist and are capable of curtailing load when called upon."

MISO plans to beef up its demand response participation rules and hopes to have the stepped-up requirements in place by next year. (See *MISO Subcommittee to Act on Bad Actor Demand Response*.)

Why This Matters

MISO's markets have been rocked by three demand response frauds in two years. With the Monitor warning of more, MISO is enacting tougher participation rules while proposing a stricter capacity accreditation for load-modifying resources.

MISO adviser Michael Robinson remarked that demand response has been getting more attention lately.

"It's almost like we should have a joint Resource Adequacy Subcommittee and Market Subcommittee meeting on demand response," he joked.

Robinson said while MISO already has rules to discourage demand response frauds, the recent instances mean it wouldn't hurt to do more to discourage artificially inflated baselines, fraudulent registrations and artificial curtailments.

Robinson prefaced his comments by invoking a recent trip to a western Michigan orchard. He said when storing apples for the winter, one periodically should go through the bushels to look for bad apples.

"We are responding to essentially three bad apples that FERC has identified. And if you listened to the Market Monitor this morning, there are probably a few more," Robinson said.

In August, Robinson jokingly invoked Dire Straits 1985 rock song "Money for Nothing" to describe the three recent schemes.

The rules will impel market participants to prove their legitimacy annually by sharing their contractual agreements with MISO. They also will require regularly updated meter data alongside attestation of baseline use. MISO will screen offer parameters and stop allowing whole event days to be precluded from the baseline calculation and instead use just the hours where LMRs responded.

MISO's IMM also would assess demand response for withholding and create reference level calculations for demand response resources.

MISO News

New LMR Accreditation Looks Certain

A more exacting accreditation remains on the way for MISO's load-modifying resources over members' objections.

MISO said staff will make a final presentation in November before filing the new LMR accreditation with FERC.

The RTO plans to accredit its load-modifying resources based on their past performance levels by the 2028/29 planning year. It said it will split LMRs into two categories — those that can respond in 30 minutes or less and those that can't — and accredit them accordingly. (See *MISO Tries to Win over Stakeholders on New LMR Capacity Accreditation*; *MISO Proposes to Split LMR Participation, Accreditation into Fast/Slow Groups*.)

MISO's LMR Type II category would have a maximum response time of 30 minutes and presumed availability for all of MISO's maximum generation emergency step two events.

Conversely, an LMR Type I class would carry a maximum response time of six hours and be called up earlier, when MISO declares a maximum generation alert. MISO has long said it needs to be able to access LMRs outside of actual emergency declarations.

MISO plans to use a similar accreditation with its availability-based method for its more traditional generation resources. However, to measure demand response, MISO said it will use backward-looking meter data from hours when capacity advisory declarations are in place to accredit resources. The RTO plans to draw on data from a minimum of 65 historical hours per season over the past year and will give more weight in accreditation to performance during hours where capacity advisories escalated into maximum generation events, alerts or warnings.

MISO said it will cap accreditation at an LMR's maximum stated capability during registration. The RTO also said it will reduce accreditation when LMR owners submit inaccurate availability information. Currently, MISO doesn't tie the accuracy of LMR availability data to accreditation values.

The new accreditation model will put an end to demand resources being free to dual register as both LMRs that collect capacity payments and demand response resource types, which receive energy payments.

Joshua Schabla, a MISO market design economist, said MISO's proposed accreditation design appropriately allows for "diversity of performance and diversity of characteristics."

At an Oct. 9 Resource Adequacy Subcommittee meeting, Schabla said in addition to the usual large factories and mills, MISO's LMRs also include about 250 resources that are 1 MW or smaller. He said the availability-based accreditation will keep smaller LMRs participating alongside the sites capable of significant load reductions.

"We do think that our overall design captures as much of this as reasonable," Schabla said. He added that it's difficult to keep the design simple because of the array of MISO's LMR types.

Schabla said MISO remains convinced it needs to call on its longest-lead LMRs during maximum generation alerts rather than when actual emergencies arrive.

MISO's Joshua Schabla addresses the Resource Adequacy Subcommittee Oct. 9 | *© RTO Insider LLC*

"We're trying to incentivize more rapid response time. For longer lead resources to be effectively utilized, MISO needs the capability to deploy them earlier. … If you have a six-hour lead time, we need to deploy you earlier to effectively use you," he said.

Plante said most of WEC Energy Group's large industrial customers aren't comfortable with a 30-minute lead time, citing safety concerns with powering down so quickly. On the other hand, Plante said WEC's slower-moving LMRs are uneasy with the risk exposure of being called up six hours ahead of when they're needed. Plante said a two- or even five-hour notification might be more suitable.

"What I'm hearing is neither option is really viable," Plante said.

MISO and stakeholders sparred over the RTO's goal to discontinue use of LMRs being able to use a firm service level option to participate. MISO's firm service level option currently allows LMRs to select a prespecified baseline when registering, agreeing not to use more than that during emergencies. Unlike other LMRs, those using firm service level must curtail all nonfirm load from the system, rather than deducting a megawatt amount from a baseline demand.

Several stakeholders said MISO should preserve the firm service level option, calling it a cornerstone of LMR use in MISO. Dauphinais, the attorney representing multiple industrial customers in MISO, said it would be a "fatal flaw" to cut the participation option.

"We don't see stated availability moving as fast as we see these loads moving," Schabla explained. He said MISO needs a more accurate measurement of LMR capability.

Schabla said MISO expects there to be a "tolerance band" around the actual reductions LMRs can make, using the fluctuating draw of air conditioning programs as an example.

"By no means are we expecting you to know exactly what you can provide. We expect you to tell us, within a margin, of what you can give us," Schabla said.

Multiple MISO stakeholders derided MISO's reliance on its Demand Side Resource Interface tool for availability data. They complained that the DSRI, which recently replaced the MISO Communication System for communicating LMR availability, is not well understood and that members could use training sessions.

Schabla said he agreed MISO should provide member training on the system sooner rather than later. ■

MISO News

Clean Grid Alliance Wants MISO Market Participation Rules for HVDC

By Amanda Durish Cook


David Sapper, Clean Grid Alliance | *© RTO Insider LLC*

CARMEL, Ind. — Clean Grid Alliance is asking MISO to incorporate rules for HVDC into MISO's energy and ancillary services markets.

"We think working out market participation rules for HVDC is timely and warranted," Clean Grid Alliance Vice President of Transmission and Markets David Sapper told stakeholders at an Oct. 10 Market Subcommittee meeting.

Sapper said many expect that the companion portfolio to MISO's second long-range transmission plan will include HVDC lines, necessitating MISO to think about market-dispatchable HVDC.

"The lack of rules is a hindrance to HVDC development, in particular MISO long-range transmission planning," he said.

The Market Subcommittee adopted the issue through general consent at the meeting.

Sapper said HVDC lines can help quell system volatility, help deliver new resource types and improve efficiency across seams. He said HVDC-enabled resources shared between MISO zones versus from different grid operators could warrant unique rules.

"This could get complicated, but at least the HVDC technologies are well understood," Sapper said, adding that MISO could create a task team or force to recommend participation plans in markets. He said the work might borrow from MISO's existing participation plan on asynchronous resources.

Clean Grid Alliance's ask continues a trend of MISO stakeholders asking the RTO to anticipate the contributions HVDC can make and how they could alter markets.

The Southern Renewable Energy Association approached MISO and stakeholders at the July Resource Adequacy Subcommittee, asking them to consider that HVDC lines can be a source of external capacity. The nonprofit said lines are capable of infusing faraway generation into MISO's local resource zones and could alter auction clearing. (See *Renewable Group Asks MISO Community to Consider HVDC Capacity*.)

The subcommittee also ultimately took up the issue. ■

MISO News

Transition Spurs Power Producers to Ask for Fresh Look at MISO Cost of New Entry

By Amanda Durish Cook

CARMEL, Ind. — Midwestern power producers are asking for re-evaluation of MISO's cost of new entry in light of recent clean energy goals.

The Coalition of Midwest Power Producers (COMPP) recently approached MISO's Market Subcommittee to ask that MISO reconsider cost of new entry (CONE) being rooted in 20-year gas plants.

Currently, MISO's CONE represents the cost of building an advanced combustion turbine and differs by zone to reflect regional differences in construction costs. The CONE calculation assumes a 20-year lifespan and loan term; considers debt-to-equity ratio and interest rates; and includes capital costs, property taxes, insurance costs, and operations and maintenance expenses. Values are used to set the limit for clearing prices in MISO's capacity auctions.

COMPP pointed out that Illinois in 2021 passed the Climate and Equitable Jobs Act (CEJA), which stipulates that most combustion turbines be retired by 2040. The group said it's no longer appropriate to presume a 20-year project life and loan term for gas plants in Zone 4's CONE calculation and asked MISO to "develop a process to adjust" Southern Illinois' Zone 4 CONE "by reducing the assumed project life and loan term to capture CEJA's retirement mandates."

COMPP said MISO might expand its CONE investigation into other local clearing zones as they rev up and implement clean energy goals and 20-year gas plant waypoints go out of fashion.

MISO's CONE averages nearly $330/MW-day; the dollar value has been climbing in the past few years. (See *MISO 2024 CONE Values Jump on Inflation*.)

COMPP asked that MISO readjust its Zone 4 CONE assumptions by the 2025/26 planning year.

MISO is set to discuss a possible CONE recalibration with stakeholders at upcoming meetings of its Resource Adequacy Subcommittee. ■

Turbine work at the Ameren Venice Power Station in Illinois | *Google Earth*

MISO News

IRP Settlement Accelerates Xcel's Clean Energy Transition

By Amanda Durish Cook

Xcel Energy has reached a settlement with clean energy nonprofits that further swings the utility's integrated resource planning toward zero-carbon resources.

The utility and Clean Grid Alliance, Fresh Energy and Minnesota Center for Environmental Advocacy announced a settlement agreement in early October that will nudge Xcel Energy's *Upper Midwest Energy Plan* to zero carbon emissions sooner. Other parties to the settlement include the Minnesota Department of Commerce, labor unions and generation developers.

The agreement affects both Xcel's integrated resource plan (24-67) and its Firm Dispatchable Resource Acquisition (23-212) dockets before the Minnesota Public Utilities Commission. Now Xcel's Firm Dispatchable Resource Acquisition is open not just to gas, but also to renewables and storage. Xcel also has pledged to better use existing gas plants to avoid the need for multiple gas peaking plants in its IRP.

In the firm dispatchable docket, Xcel has agreed to build more than 300 MW of new storage across two standalone projects, as well as an additional 230 MW in the form of a wind-and-storage hybrid project and a 170-MW solar-and-storage project. Xcel also will extend two power purchase agreements with existing gas plants and build just one 374-MW peaker gas plant in Lyon County that also will be hydrogen-capable. The settlement negates the need for a second natural gas plant Xcel had proposed for Fargo, N.D.

In addition to the resource acquisition docket, the settlement dictates even more wind, solar and storage through 2030 via the IRP, including: 600 MW of standalone storage; 400 MW of new solar connecting to the grid at the A.S. King plant site in Oak Park Heights, Minn.; and 3.2 GW of wind additions, most of which will use the Minnesota Energy Connection transmission line.

Xcel also agreed to plan for longer lifespans of its nuclear plants. It will use a 2050 retirement date for the Monticello Nuclear Generating Plant and 2053 and 2054, respectively, for Prairie Island Generating Plant Units 1 and 2.

An earlier version of Xcel's IRP assumed a little more than 2.2 GW of new gas peaker capacity by 2030, spread across six or more new plants. The settlement terminates all but the Lyon County plans. Xcel also agreed to explore thermal battery options with Rondo Energy and file a pilot proposal with the Minnesota PUC by the end of 2025.

As part of the settlement, another filing with state regulators will come due in late 2025. Xcel agreed to devise a new model for planned and scaled distributed solar and storage capacity procurement and file it at the commission by Oct. 3, 2025.

Finally, Xcel and parties agreed the utility would try to bolster rates of participation in its energy efficiency programs for its low-income customers, track data and report on results in its next IRP.

| Xcel Energy

Xcel said the agreement will allow it to reliably ensure an up to 88% carbon emissions reduction by 2030 from a 2005 baseline. The company also said the new plan unlocks tax credit savings from the Inflation Reduction Act for renewables and energy storage.

Xcel said it expects a final decision on the settlement from the Minnesota PUC in early 2025.

Leadership at the clean energy nonprofits had good things to say about the shift in resource planning.

"This joint effort marks major progress in Xcel's and Minnesota's energy transition," Fresh Energy Executive Lead of Policy Allen Gleckner said in a press release. "All the parties involved are working [toward] the same goal: reliably decarbonizing our state's electricity."

"In addition to the 3.6 GW of new clean energy projects in the short term, we are very excited to see significant battery storage projects be selected. Storage is a real game-changer," added Peder Mewis, Clean Grid Alliance's regional policy director. "Among other things, it will help during extreme weather conditions and is critical for maintaining reliability and meeting Minnesota's clean energy standard."

Minnesota Center for Environmental Advocacy Climate Program Director Amelia Vohs called the settlement a "great outcome for the climate."

"This plan invests in innovation that maximizes value for customers, creates jobs and supports the communities we serve," said Ryan Long, president of Xcel Energy in Minnesota, South Dakota and North Dakota. "We're making great progress toward our vision for reliable, affordable, 100% carbon-free electricity, and we appreciate the support of our stakeholders on an agreement that allows us to keep building the clean energy economy of the future." ■

Why This Matters

The recent agreement means Xcel Energy's integrated resource planning and firm resource plan in early 2025 will rely less on gas and more on renewables and storage

MISO News

MISO Argues to FERC for 2nd Look at Crypto-stressed Flowgate Management

By Amanda Durish Cook

MISO wants FERC to reconsider its decision to let a jointly managed flowgate with SPP stand, with the RTO arguing the North Dakota cryptomining facility burdening the line is SPP's responsibility alone.

FERC in September denied MISO and Montana-Dakota Utilities Co.'s separate complaints over the Charlie Creek flowgate. The two wanted market-to-market (M2M) coordination lifted after the Atlas Power Data Center opened and brought a 200-MW load to SPP's transmission-constrained northwestern North Dakota load pocket. MISO and MDU maintain the congestion management the data center is instigating shouldn't extend beyond SPP. (See *FERC Refuses MISO, MDU Complaints Regarding Crypto-strained MISO-SPP Flowgate*.)

In an Oct. 10 rehearing request, MISO continued to insist SPP is misapplying the two's interregional coordination process in the joint operating agreement by insisting on interregional help for a provincial issue MISO is powerless to resolve (*EL24-61*).

"By summarily rejecting the complaints, and by refusing to properly examine the evidence submitted by MISO and MDU, the Sept. 10 order failed to engage in reasoned decision-making, thereby allowing SPP's unjust and unreasonable rate practice to continue unabated in violation of the FPA," MISO said.

MISO said its members have made more than $40 million in undue payments to SPP because of congestion on the flowgate. It pointed out the flowgate consists of two SPP transmission lines owned by the Western Area Power Administration in "a load pocket where MISO has no regional flows and is unable to relieve congestion due to the lack of available generation."

MISO said it offered "extensive evidence demonstrating the local nature of congestion" in its original complaint and said SPP's insistence on using M2M coordination to manage it is counter to good utility practice.

MISO said FERC was wrong to read M2M coordination requirements as strictly those laid out in the joint operating agreement and not consider that the interregional coordination process dictates that M2M coordination should be reserved for issues that are regional, not local.

"It is well-established that tariff and contract provisions should not be interpreted in isolation from each other," MISO argued. ■

Line in Williston, N.D. | *Western Area Power Administration*

MISO News

Dynegy Unsuccessful in Rehearing Requests of 2015 MISO Capacity Auction Manipulation Case

By Amanda Durish Cook

Nearly a decade on, the saga over Dynegy's manipulation of MISO's capacity market continues, with FERC denying the company's asks for procedural changes that might have softened repercussions in the case.

FERC dismissed all four of Dynegy's rehearing requests related to evidence, intent, a report on remand, and the bounds of FERC's jurisdiction in an Oct. 4 order (*EL15-70*).

The latest order is part of FERC's yearslong inquiry into Dynegy's apparent manipulation of clearing prices in MISO's 2015/16 capacity auction. This year, the commission directed hearing and settlement procedures. (See *FERC Sets Dynegy's MISO Market Manipulation Case for Hearing*.)

Approximately eight years after the auction, commission staff unwound FERC's original conclusion that Dynegy — now owned by Vistra — conducted itself appropriately in the auction. That's due to a D.C. Circuit Court of Appeals 2022 ruling that FERC hadn't sufficiently supported its decision to accept the $150/MW-day Southern Illinois capacity price produced in the 2015/16 auction. (See *FERC Staff Finds Dynegy Manipulated 2015 MISO Capacity Auction*.)

This time, FERC rejected Dynegy's fresh argument that it didn't know it was manipulating MISO's capacity market by refusing to sell capacity at a loss ahead of the auction. The commission said Dynegy should have been aware the actions it took to make sure one of its resources set the clearing price for Southern Illinois to raise profits amounted to manipulation.

Why This Matters

FERC's hearing into Dynegy's apparent manipulation of MISO's 2015/16 capacity auction will continue unscathed after Dynegy tried unsuccessfully for rehearings in the case. Illinois ratepayers could see millions in refunds.

At the time of the 2015/16 capacity auction, Dynegy owned the coal-fired Baldwin Generating Station in downstate Illinois | *EcoWatch*

FERC also said Dynegy's argument ignores intent.

"Dynegy's argument that its pre-auction sales strategy was 'driven by a desire to stop losing money' misses the point because it ignores the broader question of whether that sales strategy was part of an intentional or reckless effort to set the Zone 4 clearing price in the auction," FERC said.

Dynegy argued it "could not have known that [FERC's] market manipulation rules would compel Dynegy to operate a charity — mandating that Dynegy donate its capacity to the market at prices that would not cover its going-forward costs."

FERC declined to take up Dynegy's claim that its alleged manipulation scheme might involve non-jurisdictional retail transactions in South Carolina rather than the MISO portion of Kentucky. The commission said it is best to "defer any legal determination as to jurisdiction until after the hearing because certain disputed issues of material fact are likely to bear upon the jurisdictional question."

Dynegy also proved unsuccessful in persuading FERC to strike from the record its heavily redacted report from June 2022 that *concluded* that manipulation occurred.

FERC said the report is necessary to the case because the D.C. Circuit Court of Appeals ordered FERC to establish a public record in the case, which was lacking after the nonpublic investigation and a poorly explained decision in 2019 to accept the Zone 4 capacity price.

"[P]arties and participants are free to rely on the remand report in making their cases, and at that point, Dynegy is free to challenge the parties' or participants' use of the remand report. … In this way, information would be appropriately considered by the presiding judge in an evidentiary hearing encompassing allegations of market manipulation," FERC said.

Finally, FERC rejected Dynegy's claim that FERC didn't share exculpatory evidence with the company during the nonpublic investigation.

Dynegy contended that it could have used nonpublic, video footage of testimony to help prove its innocence.

FERC countered that the investigation was closed without a show-cause order or sanctions and pointed out that it's under no obligation to share exculpatory evidence in a Section 206 proceeding. Further, the commission said its staff combed through materials and didn't find anything that could be deemed exculpatory.

At any rate, FERC said the footage Dynegy singled out is now part of the nonpublic record in the case and can be addressed during hearing proceedings. ■

NYISO Extends Reliability Needs Assessment Comment Period

Stakeholders Continue to Question Large Load Flexibility Assumptions

By Vincent Gabrielle

In response to stakeholder criticism, NYISO has updated its draft *Reliability Needs Assessment* to include an executive summary and appendices, and extended the comment period on the report to Oct. 14.

“We definitely heard stakeholders’ concerns about not having enough time to review the complete report with the executive summary,” Ross Altman, senior manager of reliability planning for NYISO, told the Transmission Planning Advisory Subcommittee on Oct. 9. “So, we tried to shift the schedule up a little bit on that.”

Altman said NYISO would try to address the comments for the next version of the RNA, to be presented Oct. 21 to the Electric System Planning Working Group meeting and Oct. 24 to the Operating Committee.

“As one of the people who asked for more time, I want to say thank you for giving us a little bit more time; it’s appreciated,” said Kevin Lang of Couch White.

Stakeholders spent most of the meeting discussing the results of the RNA, which predicted that on a peak summer day with expected weather conditions (95 degrees Fahrenheit), New York City would be deficient by 17 MW for one hour in 2033, rising to 97 MW for three hours in 2034. The analysis suggests that the ISO needs to declare an official reliability need for the city’s capacity zone. (See *NYISO Draft RNA Finds Reliability Need for New York City*.)

The discussion focused on whether that was actually significant, or if it was a result of uncertainties in NYISO’s data and assumptions.

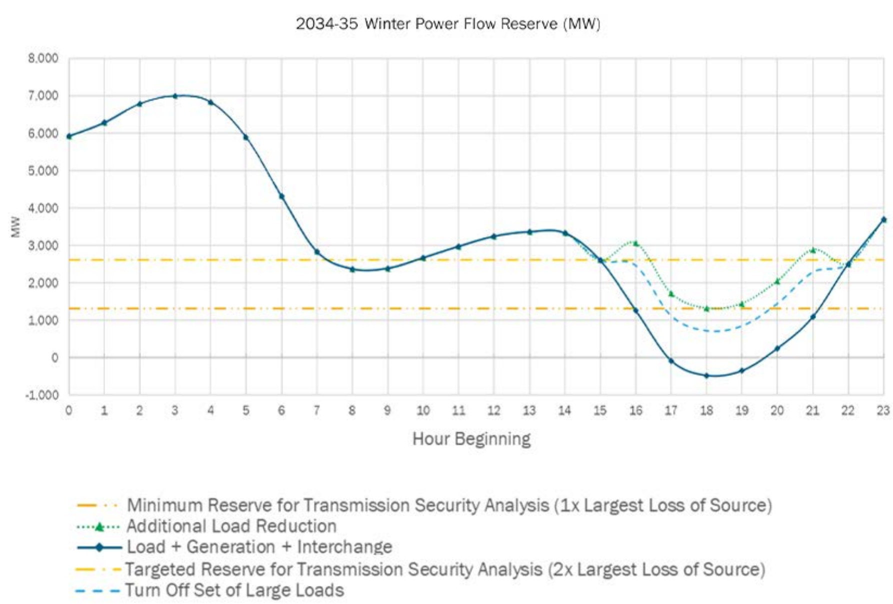
“So the results point to a 17-MW, one-hour deficiency 10 years from now?” asked Marc Montalvo, CEO of Daymark Energy Advisors. “Is that statistically different from zero?”

Montalvo pointed out that the given the magnitude of the system and the uncertainties, 17 MW might just be statistical “noise.” He asked Altman how to interpret that “in an actionable way.”

“Do we run out and do something, or do we say, ‘Look, this needs five more years of information before we even start to worry about it’?” he asked.

Altman said that before any solution was solicited, NYISO would re-evaluate if the need still existed based on updated information. He pointed out that there were resources in development that could come online in the next 10 years but were not far enough along to meet NYISO’s base case assumptions.

“We have an opportunity to re-evaluate next year to see if the updates would make the problem go away,” Altman said. “And then in the evaluation of solutions, we do consider which solutions are best suited for meeting this need, but we have to have a solution. … We can’t just show there’s a reliability violation and do nothing about it.”



| NYISO

Why This Matters

Whether New York City has a looming reliability shortfall depends, in large part, on NYISO's data and modeling assumptions.

Crypto Companies Pivoting to AI

Stakeholders also revisited NYISO’s assumption about the flexibility of cryptocurrency mining and hydrogen-producing loads.

The ISO had issued a preliminary finding of a statewide shortfall of as much as 1 GW by 2034, but it revised its assumptions about the flexibility of such large loads during peak hours, which reduced the loss-of-load expectation to below 0.1. (See *NYISO: Large Load Flexibility Eliminates 2034 Shortfall Concern*.)

But there is a very real possibility that these loads will not be as flexible as NYISO assumes. *Cryptominers* are increasingly *shifting their facilities*’ operations to *training artificial intelligence*.

“There is an increasing interest among cryptocurrency mining facilities to actually switch over to doing AI, which, because of their service level agreements, is much less flexible,” one stakeholder noted. “Their willingness to do one and not the other depends on, to a large extent, the price of Bitcoin or whatever other cryptocurrency they’re mining.” A data center’s stated purpose as a cryptomining operation had very little bearing on whether it would remain as one in the future, they said.

Reuters reported in August that technology companies are seeking the energy assets held by crypto miners as they race to secure electricity supply for AI and cloud data centers, estimating that about 20% of cryptocurrency could pivot to AI by the end of 2027.

“We do monitor [that], but we do recognize that we don’t know exactly how they continue to evolve,” Altman said. “Any specifics you have on that, or research you’d like to share, please email” the ISO. ■

NYISO News

NYISO: No Worries Ahead of This Winter

NYISO expects that it will be able to operate reliably, according to the *Winter 2024 Operating Study* presented to the Systems Operations Advisory Subcommittee on Oct. 9.

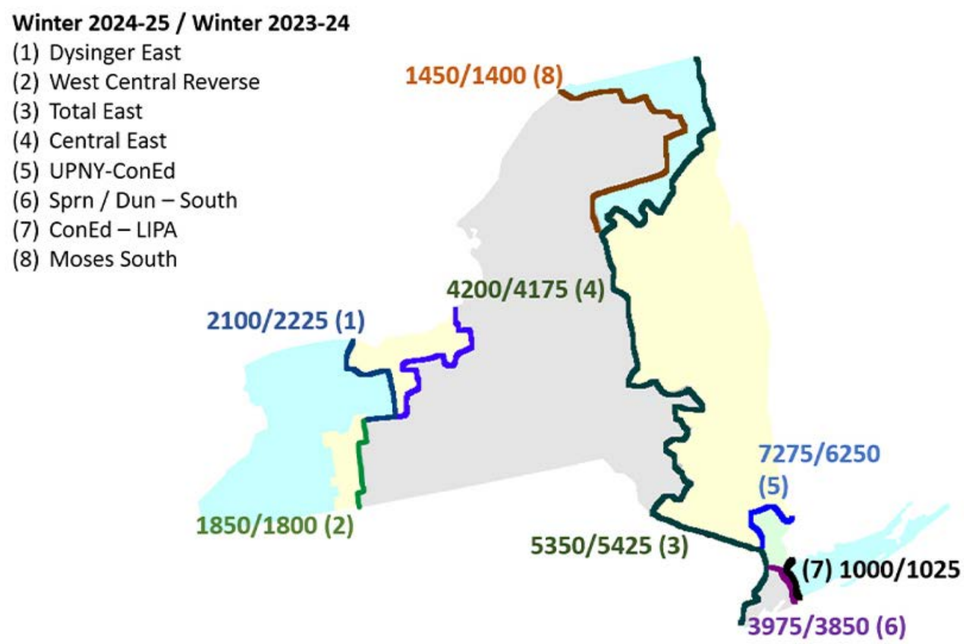
The ISO forecasts a 23,800-MW peak demand against 41,321 MW of total available capacity this winter, a 73.6% margin. This season's load forecast is about 1.73% less than last winter's expected 24,220 MW and about 7.53% lower than the all-time peak of 25,738 MW, set in January 2014.

Peak load was only 22,754 MW last winter, which was very mild. It was only one of three times during that January when load went above 22,000 MW. (See *NYISO Recounts Mild Winter*.)

The study notes that 935 MW of new *generation* have come online since last winter, spread across 13 projects. Most of these are solar farms, but they also include two wind farms over 100 MW in upstate New York and one battery facility outside of Buffalo.

Four gas turbine plants, totaling 60 MW, were modeled as deactivated since winter 2023. ■

— Vincent Gabrielle



Changes in internal thermal transfer limits | *NYISO*

PJM News

Maryland: The State Where 'Transmission Has Come to Die'

Clean Energy Roundtable Tackles How State Can Get More Generation, Tx Online

By K Kaufmann

COLLEGE PARK, Md. — Maryland consumes five times more electricity than it generates, has limited access to transmission in the central and eastern parts of the state and at present has only six projects totaling 1,245 MW in PJM's interconnection queue.

"Maryland, as many of you know, has been a state where transmission has come to die," said Jason Stanek, executive director of governmental services at PJM, in his opening remarks as moderator for a grid reliability roundtable at the Maryland Clean Energy Summit on Oct. 7.

A former chair of the Maryland Public Service Commission, Stanek provided an overview of the state's dilemma as it seeks to cut its greenhouse gas emissions 60% below 2006 levels by 2031 and decarbonize its power grid by 2035, all while attracting new business, including megawatt-guzzling data centers.

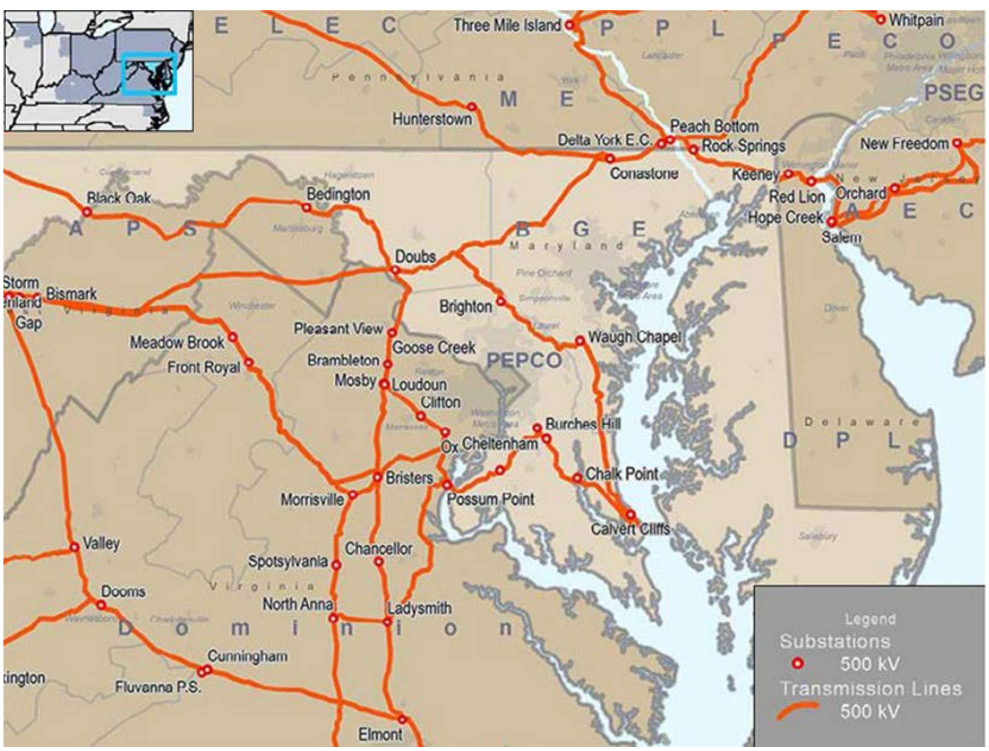
PJM estimates data centers will grow from 4% of Maryland's power demand in 2024 to 12% in 2029 and 16% in 2039, but Stanek cautioned those numbers could be conservative, and the RTO revises the projections every year. At present, new generation coming online in Maryland is being outpaced by retirements by about 10 to one, he said.

"Last year, Maryland held an unenviable position of needing to import [power] every single hour of every single day," he said.

Facing each other across tables running along three sides of the meeting room, participants ranged from state lawmakers to offshore wind developers and other industry experts, each with different perspectives on the state's challenges and possible solutions, both short and long term.

Del. Lorig Charkoudian (D) talked up a bill she hopes to introduce in Maryland's General Assembly in January, aimed at accelerating the permitting process for energy storage and other distributed energy resources coming onto Maryland's distribution system, outside of PJM's jurisdiction.

"I think that PJM doesn't do the job it needs to be doing on transmission planning, and I think that our hands are tied, and so … I have finally just given up and put [planning provisions] into this bill," Charkoudian said.



Maryland's high-voltage transmission system: Access to high-voltage lines is limited in the central and eastern parts of the state, which has to import about five times more power than it generates. | PJM

> **Why This Matters**
>
> Maryland desperately needs new generation and new transmission but has no plan for how to get both online. The search for solutions could provide new models for other states dealing with similar challenges.

An outline of the bill is being circulated for input from stakeholders but has been informally dubbed "Build Stuff in Maryland," she said. "The idea is, what can we do fastest? And the thing we can do fastest is distribution utilities can put storage on the distribution grid; so, medium size … 1,2,3 MW at substations, and that can be done at a pretty quick scale to respond to some of the immediate [reliability] problems, assuming storage is treated fairly in capacity markets."

While not on the bulk transmission system, these projects could "address our resource adequacy problems fairly quickly," she said.

Stanek and others pointed to FERC's recently passed *Order 1920*, which aims to provide a new, more comprehensive framework for RTO and ISO transmission planning, for example, calling on the grid operators to consider grid-enhancing technologies, such as advanced conductors, that can increase capacity on existing lines.

David Townley, public policy director at CTC Global, an advanced conductor manufacturer, argued that waiting for much-needed transmission to be built can take years, triggering additional risks as new generation comes online. "By the time you get the line built, you may be in a congestion point; it may not be the solution anymore," Townley said. "Take steps you can take now to open up those capacities … because the lines are loading up and changing."

Abe Silverman, assistant research scholar at the Ralph O'Connor Sustainable Energy Institute at Johns Hopkins University, cautioned that full implementation of 1920 is still five years away but that states now should be codifying their goals and policies for clean energy and grid planning.

"That will help a lot," said Silverman, who

PJM News

previously was general counsel and executive policy counsel for the New Jersey Board of Public Utilities (BPU). "So, the more you can put on paper and hand to PJM [and] say, 'These are our goals,' the stronger that 1920 planning process will be."

States like Maryland should encourage their neighbors in the PJM service territory to "codify their rules in a comparable manner." Then they present PJM with a "comprehensive action plan" as part of the 1920 process, he said.

State of the Grid

Stanek was quizzed on PJM's request to FERC for a rehearing of 1920, one of many the commission has received and is considering.

PJM found the 1,363-page ruling "overly restrictive for a footprint as diverse and wide, serving 65 million customers," he said. "So, the purpose of the request for rehearing was to preserve our right to inform FERC that we think there should be more flexibility in how PJM complies" with the rule.

"Otherwise, this final rule is effectively one-size-fits-all," Stanek said. At the same time, PJM is moving ahead to comply with the timelines set out in the rule, he said.

Stanek's opening presentation zeroed in on the key challenges for transmission planning in Maryland.

The state's generation mix is 42.8% natural gas and 42.9% nuclear, with coal and hydro providing about 5% each, and wind and "other" accounting for a final 4.3%.

But what's in PJM's interconnection queue for the state is 54% energy storage, 44% solar, 1% wind and less than 1% natural gas and hydro. In addition to the six projects awaiting interconnection agreements, Maryland has 35 projects totaling 1,338 MW that have agreements but have yet to be built.

The state is one of a handful that does not have an overarching, holistic plan for infrastructure development to help guide the transition to clean energy — as opposed to the *GHG emission reduction plan* the Maryland Department of the Environment issued at the end of 2023 — Stanek said.

Further, Maryland's offshore wind projects are not included in the state's interconnection queue because they will be coming onshore in Delaware before connecting to the PJM grid, Stanek said.

The U.S. Bureau of Ocean Energy Management recently *approved* the Maryland Offshore

The Grid Reliability Roundtable at the Maryland Clean Energy Summit. | *© RTO Insider LLC*

Wind Project, which includes two separate sites totaling up to 2 GW of power. Maryland's other major offshore wind project, Ørsted's Skipjack 1 and 2, has been on hold since the company *backed out* of its offtake agreement with the state in January. The company has said it would "reposition" the project for future offtake agreements.

For PJM, Stanek said, the short-term solution for Maryland is, first, to ensure no shutdowns of existing baseload generation — coal, natural gas or nuclear — until the necessary transmission is in place to handle the new carbon-free generation in the queue.

The RTO intervened in the planned closure of the Brandon Shores coal-fired power plant in 2025, citing a potential for up to 600 reliability violations in Maryland, Delaware, Pennsylvania and Virginia to keep the 1,283-MW plant online via a reliability-must-run agreement with its owner, Talen Energy.

Stanek said Maryland also should accelerate permitting and siting of new generation, but cautioned getting new projects online could be complicated by Maryland's profile as a high-risk state for utility investors in rankings from S&P Commodity Insights. In S&P's most recent evaluation, the state was placed in the bottom of nine possible rankings, meaning it has the highest regulatory risk for investors, said Lillian Frederico, the company's energy research director.

Frederico stressed that the rankings are not intended to evaluate whether state utility regulators are doing a good job, how they are implementing state policies or if those policies are "good, bad or indifferent." Rather, S&P looks at regulatory decisions in rate cases and other actions, based on "the comparative level of risk for investors" and for the returns on the money they invest in utilities, she said.

Maryland's ranking has been affected by the new commissioners on the PSC, in particular, Gov. Wes Moore's appointment of former consumer advocate Frederick H. Hoover as commission chair. Moore (D) also named Bonnie Suchman and former state Del. Kumar P. Barve (D) to the commission.

"Just the fact that these are different people appointed by a different governor with a different political agenda, there's some concern that there could be shifts in policy that may or may not be favorable," she said. "When you have uncertainty, uncertainty equals risk."

Transmission as Common Ground

While it may not be a direct result of rankings like S&P's, Maryland has significantly fewer projects in PJM's interconnection queue than its neighbors, including Pennsylvania (91), Virginia (107) and even West Virginia (14).

Beyond the six projects awaiting interconnection agreements, Maryland also has 35 projects totaling 1,338 MW that have agreements but have yet to be built.

Adding to investor perceptions of uncertainty, Stanek said the state has a spotty track record on permitting new transmission projects. The latest, the proposed Piedmont Reliability

PJM News

Project, a new 500-kV line stretching 70 miles over three counties, already is stirring the kind of local reaction — "quick and largely fierce" — that has stalled past projects, he said.

While not confined to Maryland, "NIMBYism is clear," Stanek said. "Nobody wants a transmission project in their backyard."

PJM awarded the Public Service Enterprise Group the contract for the line as part of its Regional Transmission Expansion Plan (RTEP) portfolio of projects costing about $5 billion, in a process the Maryland Office of People's Counsel has *criticized* as not providing enough time for local review and input.

Charkoudian also argued that PJM's planning process for the RTEP has not considered offshore wind development on the Atlantic Coast.

"We're bringing massive amounts of generation onto the Eastern Shore, high-capacity offshore wind, which has the same capacity as some of the gas plants that are being defended and supported and we're being begged to keep online," she said. "And there's not a planning mechanism. It is essentially … a problem for the developers or the states who want to subsidize that offshore wind to figure out how to get [it] onshore."

Both Charkoudian and state Sen. Brian Feldman (D), chair of the Senate Education, Energy and Environment Committee, promised new initiatives on siting and permitting in the upcoming legislative session. For solar projects that have stalled out while in the PJM queue, Charkoudian's bill could include new incentives and could push for better planning of offshore transmission so that it will "solve Maryland load issues," she said.

Another possibility could be for Maryland to consider a state agreement approach (SAA) with PJM, similar to New Jersey's, to provide the kind of long-term, integrated transmission planning the state needs for offshore wind, Charkoudian said.

Silverman, who was at the New Jersey BPU during the SAA negotiations, said it took four years and extensive coordination between regulators and the legislature to come up with the mix of laws and regulatory actions needed to move the initiative forward.

He again stressed the importance of regional collaboration and how the need for expanded transmission could provide common ground for states with differing policies on clean energy and grid decarbonization.

"One of the things I spend a lot of time doing is talking to states across the political spectrum," Silverman said. "We may not agree on the benefits of offshore wind, but I think what we can agree on is, if there's a transmission facility that reduces consumer costs in your state, you should be for it. If it's going to improve reliability, you should be for it, and most transmission lines meet those criteria." ■

PJM Proposes Expedited Interconnection Studies for High-capacity Factor Generation

By Devin Leith-Yessian

PJM Vice President of Planning Paul McGlynn | © *RTO Insider LLC*

VALLEY FORGE, Pa. — PJM *presented* to the Planning Committee on Oct. 8 an overview of a concept it is developing to allow high-capacity factor resources to be accelerated into the Phase 1 study period of Transmission Cycle 2 (TC2). If approved by the PJM Board of Managers and FERC, a new application window would be opened for generation developers to propose new projects.

The Dec. 17 application window for TC2 would not be changed with the goal of having little to no impact on the milestones for projects that already have been sorted into that cycle. A special session of the PC has been scheduled for Oct. 18 to discuss the proposal in more detail.

"We've been having a lot of internal discussions on what we can do and address the potential resource adequacy concern that we have," PJM Vice President of Planning Paul McGlynn said, adding that the RTO sees the concept as a one-time opportunity to use TC2 to allow more resources to enter the study process to get interconnected more quickly.

Director of Interconnection Planning Donnie Bielak said staff have looked at every technical approach to getting significant quantities of capacity online soon enough, and this was the only one that met the reliability needs projected toward the end of the decade. (See "PJM Models Suggest Capacity Shortfall Possible in 2029/30 Delivery Year," *PJM PC/TEAC Briefs: Aug. 6, 2024*.)

Bielak said there would be strict reliability criteria to determine which projects are eligible, with it likely that only a "very, very select few" would qualify. More specific details about eligibility will be presented Oct. 18.

Vitol's Jason Barker said he's concerned about the precedent this would set and the possibility PJM may seek similar modifications to the queue structure in the future.

Barker asked if developers who are offered accelerated queue positions will be required to post security to assure timely commercial operation or if an accelerated project fails to meet the promised commercial operation dates, it will be liable for damages to prior queue participants for cost shifts caused by the discriminatory acceleration of the so-called reliability projects.

Even with expediting, he said there are supply chain issues affecting the entire industry that could affect the preferred projects. ■

W.Va. PSC Adviser Jackie Roberts Announces Retirement

By Devin Leith-Yessian

Jackie Roberts, federal policy adviser for the West Virginia Public Service Commission and a pillar of PJM's relationship with state consumer advocates and regulators, announced her retirement Oct. 8, capping a 14-year career with the state.

Roberts has worked for the PSC since January 2021, when she joined after serving as the West Virginia consumer advocate for more than a decade. Her final day with the PSC is Nov. 12.

The hallmarks of her career, Roberts told *RTO Insider*, include her work establishing the Consumer Advocates of the PJM States (CAPS) and breaking PJM's internal market monitoring unit off as an independent company, Monitoring Analytics.

The creation of CAPS, and the funding that came with it, has improved consumer advocates' participation at PJM and allowed them to take a more proactive role in the stakeholder process, she said.

Greg Poulos, executive director of CAPS, said Roberts has a gift for bringing people together and has made a positive impact on consumers through her advocacy.

"Throughout the time I've known Jackie, she has been a strong advocate, with an incredible wealth of knowledge, passion and strong communication skills," Poulos said. "For me, her efforts to connect and collaborate with all parties that are interested has helped create many successful outcomes. Her efforts to encourage collaboration have made her involvement in stakeholder processes at state, regional and federal levels incredibly valuable."

The Independent Market Monitor has also been a success, Roberts said, preventing undue RTO influence on the monitoring role.

She expressed concern, however, that the Monitor's work could be jeopardized by contract deliberations that have been ongoing for more than a year regarding the future of the position. "It causes disruption for the Market Monitor and his staff and considerable angst on behalf of the commission," she said.

Surveying the challenges facing the PJM region, Roberts said resource adequacy is a growing concern, as well as the cost of electricity, noting a significant increase in Base Residual Auction prices with the potential for another fourfold increase in the auction scheduled for December. (See "Price Cap Increases in 2026/2027 BRA Planning Parameters," *PJM MIC Briefs: Sept. 11, 2024*.)

"Many people will simply not be able to afford electricity. I know PJM will say, 'That's not what we do; that's what the states do,'" she said. But she argued that PJM plays a role in the costs for retail ratepayers.

State utility commissions are on the front lines of managing rising rates, but PJM has not given their recommendations the proper weight when making decisions about capacity market design and the generation interconnection queue, Roberts argued. She pointed to a protest the PSC filed with FERC seeking participation in PJM's Liaison Committee. (See *FERC Rejects Complaints from IMM, W.Va. PSC Arguing for Access to PJM Liaison Committee*.)

"I think it takes good leadership at PJM to balance and implement the appropriate stakeholder input," she said. "I'm concerned that PJM is just managing those stakeholders and not taking leadership to incorporate really good suggestions into their operations."

Roberts has held positions on the National Association of State Utility Consumer Advocates, NERC's Member Representatives Committee, the Keystone Policy Center's Energy Board and the executive committee of Edison Electric Institute's Critical Consumer Issues Forum. She continues to serve on the U.S. Commodity Futures Trading Commission's Energy and Environmental Markets Advisory Committee.

Prior to her time in West Virginia, Roberts worked as an attorney at the Ohio Consumers' Counsel and as corporate counsel for electric and natural gas utilities in New England.

PJM Senior Vice President of Governmental and Member Services Asim Haque, also former chair of the Public Utilities Commission of Ohio, said Roberts will be missed.

"Jackie has been not only an important voice in this industry, but she's also been a friend to me going back to my Ohio days," he said. "She will definitely be missed professionally, and I'll miss her personally."

West Virginia PSC Chair Charlotte Lane said Roberts "brought a lot of knowledge and insight into her position as our federal liaison. She will be missed."

The complex, challenging work found in the electric sector, as well as the opportunity to work with a diverse range of stakeholders, has kept her interested for nearly 20 years. Roberts said she hasn't decided what her future in the electric sector may look like, but she plans to spend much more time riding her horse.

"It has been a great privilege to work on PJM issues for the last almost 20 years. I've learned a lot. I appreciate the professional relationships I have developed through that process, and I appreciate what could be robust differences of opinion. What's important is we move forward with what's in the best interest of retail and wholesale customers." ■

Jackie Roberts, W.Va. PSC | *© RTO Insider LLC*

PJM News

Stakeholders Reject Granting PJM Authority to Revise Capacity Auction Rules

By Devin Leith-Yessian

Independent Market Monitor Joe Bowring said allowing such changes to the conduct of capacity auctions would be a drastic change that would undermine market certainty. | *© RTO Insider LLC*

VALLEY FORGE, Pa. — The Market Implementation Committee rejected a PJM *issue charge* that envisioned adding notice that Base Residual Auction (BRA) rules are subject to change, with two-thirds of stakeholders opposed.

PJM Associate General Counsel Chen Lu said the issue charge was borne of a 3rd U.S. Circuit Court of Appeals March opinion. Allowing PJM to revise the reliability requirement for the DPL South locational deliverability area (LDA) after the parameter had been posted would violate the filed rate doctrine, the court ruled. (See *3rd Circuit Rejects PJM's Post-auction Change as Retroactive Ratemaking*.)

The issue charge deliverables include notice that PJM may "correct capacity auction rules, provided FERC has approved such rules," and that such rules are known in advance of the auction "to allow those submitting offers to do so in reliance on conclusive rules and the orderly administration of the capacity market. Market sellers would be permitted to revise any pre-auction elections that occurred prior to FERC approval of any auction rule changes."

The scope includes adding language that there are no legal consequences associated with the posting of the planning parameters, which Lu said was intended to address the court opinion that once a posting is made, it is binding unless there was prior notice of the potential for changes. The issue charge states that member recommendation would be required for changes to the installed reserve margin (IRM) or forecast pool requirement (FPR).

Prior to the vote, Lu said the issue charge would seek proposals allowing PJM to ask FERC to change any relevant deadlines for pre-auction activities or the commencement of the auction. If the commission granted changes to auction rules or parameters that already had been set, the issue charge called for proposals to allow market participants to revise their elections.

Several stakeholders argued that granting PJM the change would undermine market certainty by allowing PJM to set dates certain for auction parameters and the rules defining them, only to change them after the fact. There also were questions of how much review stakeholders would have before PJM files possible changes with FERC.

Independent Market Monitor Joe Bowring said allowing such changes to the conduct of capacity auctions would be a drastic change that would undermine market certainty and might limit the time available for the PJM and Monitor to review offers into the auction. He argued the issue charge would be an "overreaction" to the court decision.

> **"This proceeding should lead all stakeholders, including both PJM and the generators that will reap the more than $100 million windfall due to the court's decision, to take all necessary steps to ensure that we never find ourselves in this position again."**
>
> —FERC Chair Willie Phillips

"PJM explicitly created a period of 60 days at the end of the offer submission process to permit anyone to take issues with market offers to FERC prior to an auction. PJM's proposed approach could eliminate that period that was designed to reduce the probability of any party challenging auction results," he said.

Calpine's David "Scarp" Scarpignato said PJM already makes changes to auction postings and parameters and questioned what additional changes would be in scope.

Lu responded that PJM's reading of the court opinion is that changes can be made only within the existing rules governing the auction, while the proposal would allow petitioning FERC to change those rules.

Scarp also said the language allowing relevant deadlines and auction elections to be changed was vague, stating that modifying a parameter could change the viability of bilateral transactions or make it worthwhile for a generation owner to seek an exemption from the requirement that resources offer into the capacity market.

Vistra's Erik Heinle said the revisions made to the issue charge would improve market certainty and parameters occasionally may need revising when new data comes in or if it's determined that posted data is incorrect. He added that it's important that stakeholders are involved in the process.

Lu pointed to FERC Chair Willie Phillips' concurrence in the commission's order reversing its authorization of the reliability requirement change, in which Phillips called for changes to allow for corrections of errors in auction design. (See *Following Court Ruling, FERC Reluctantly Reverses PJM Post-BRA Change*.)

"This proceeding should lead all stakeholders, including both PJM and the generators that will reap the more than $100 million windfall due to the court's decision, to take all necessary steps to ensure that we never find ourselves in this position again," Phillips wrote. "That includes putting in place controls to ensure that a similar error does not reoccur and, should it somehow happen again, that PJM or the commission has the authority to correct that error and protect customers from such a manifestly inequitable result. Basic equity, and the public interest, demand nothing less." ■

Stakeholders Endorse Coalition Proposal on CIR Transfers

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The Planning Committee narrowly endorsed a coalition proposal to rework how generation owners can transfer capacity interconnection rights (CIRs) from a deactivating unit to a new resource. (See "Voting on CIR Transfer Proposals Deferred to October," *PJM PC/TEAC Briefs: Sept. 12-13, 2024*.)

The coalition *proposal* received 51.8% support during the Oct. 8 vote, beating out a PJM proposal that received 40.6% support and a package from the Independent Market Monitor that received 11.1%.

The coalition proposal would create a technology agnostic process for new resources to replace gas generation being forced to deactivate in states with strong clean energy requirements. It has a nine-month timeline for applications to be reviewed, a replacement impact study identifying any potential network effects and the drafting of an interconnection agreement. The proposal was modified based on feedback at the Sept. 12 PC meeting to include thermal alongside the voltage and short circuit analyses in the replacement impact study.

Unlike PJM's proposal, replacement resources would be permitted to proceed with the expedited process if minor network upgrades are identified and all resource types would be eligible. PJM's proposal would bar storage from participating on the basis that the original generator's deliverability analysis did not envision charging.

The coalition proposal also was revised since September to add a three-year requirement on the commercial operation date, although development milestones may be extended for delays outside the developer's control or resources that have "industry-recognized elongated construction timelines."

The PJM *proposal* would have had a longer study timeline of about 13 months and tighter requirements, not allowing any projects with "material adverse impacts," such as requiring network upgrades or consuming transmission headroom above the deactivating generator. Any proposals with such impacts would be required to go through the full interconnection process.

Several stakeholders argued shifting projects to the queue if there are adverse impacts would be overly onerous and they instead should be given an opportunity to revise the scope of the project to fit PJM's requirements. The coalition proposal would allow such changes to projects.

The Monitor's *proposal* would have created a CIR transfer process administered by PJM where any generation project in the queue that could resolve transmission violations prompted by a deactivation would be studied in an expedited process. Generation developers also would be permitted to propose new resources or alterations of existing queue projects to resolve the violations.

When selecting projects, PJM would consider their cost, reliability contribution and construction risks such as permitting.

The Monitor's proposal was modified since September to abide by the scope of the issue charge, which allows only proposals that focus on replacement resources interconnecting at the same substation as the deactivating resource. The Monitor's package previously would have allowed replacement resources to be considered regardless of point of interconnection, so long as they addressed reliability issues associated with a deactivation. ■

Why This Matters

CIR transfers are one of several areas where stakeholders are seeking to improve how generators retire from PJM as concerns mount that new resources will not keep pace, leading to a capacity shortage in 2029/30.

Tonja Wicks, of Elevate Renewables, presents a stakeholder coalition package regarding CIR transfers. | *© RTO Insider LLC*

PJM PC/TEAC Briefs

Planning Committee

LS Power Seeks Issue Charge to Align CETL Calculation with Winter Risk

VALLEY FORGE, Pa. — Tom Hoatson, of LS Power, presented to the Planning Committee the third in a "trilogy" of issue charges seeking changes to PJM's effective load carrying capability (ELCC) accreditation paradigm, focusing on aligning the capacity emergency transfer limit (CETL) with PJM's winter-skewed risk modeling.

LS Power presented two issue charges at the September Markets and Reliability Committee meeting addressing the transparency of ELCC and how it is applied to individual units. (See "LS Power Issue Charges on Accreditation Transparency, Unit-specific Performance," *PJM MRC Briefs: Sept. 25, 2024*.)

The *issue charge* states that PJM models transfer limits for locational deliverability areas (LDAs) looking at their summer peaks, which is incongruent with a risk modeling approach that has shifted the bulk of risk into the winter. The issue charge is set to be voted on at the PC's Nov. 6 meeting. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

"Having switched now to a model that assesses risk throughout the year, using a summer peak-based CETL calculation without reference to the EUE [expected unserved energy] distribution creates a misalignment between the periods when capacity is most valuable and the transfer limits for LDAs during those periods," the issue charge reads.

Hoatson said that during the December 2022 Winter Storm Elliott, it appeared there was insufficient west-to-east transfer capability despite no such transmission constraints being modeled in the CETL analysis. The winter power flow issues were not modeled in CETL for that LDA.

Stakeholders Endorse Dual Fuel Manual Definitions

The PC endorsed by acclamation a proposal to revise the definition of dual-fuel combustion turbines and combined cycle resources to reflect the Reliability Assurance Agreement (RAA) definitions accepted by FERC in July (*ER24-1988*). (See "First Read on Manual 21B Revisions," *PJM PC/TEAC Briefs: Sept. 12-13, 2024*.)

The change would allow dual-fuel resources that are capable of starting on their primary fuel before shifting to their secondary to qualify as dual-fuel. During the earlier stakeholder process, Calpine's David "Scarp" Scarpignato said some gas units can start on a small amount of fuel already purchased and packed into the portion of the gas pipeline on generator property, even if the regional pipeline is offline. (See "Quick Fix for Dual-fuel Classification Endorsed," *PJM MRC Briefs: April 25, 2024*.)

Transmission Expansion Advisory Committee

2024 RTEP Window 1 Projects Include Expansion of 765-kV Network

PJM has closed the solicitation period for transmission developers to propose projects in its 2024 Regional Transmission Expansion Plan (RTEP) Window 1, which focuses on addressing heavy power flows from west to east driven by load growth in Dominion being served by power in the western half of the footprint.

Senior Manager of Transmission Planning Sami Abdulsalam *said* past RTEP windows have resolved much of the need to import power from the east and are performing well in the analysis. But load growth is continuing to accelerate and driving more transfer needs.

"Data centers are a strong influencer toward the increasing load forecast," he said, as well as electrification and electric vehicles.

PJM received 88 project components, with an additional six packages of components, all of which include expanding the RTO's 765-kV network either toward the area of the Joshua Falls and Acton-Morrisville substations or into northern Virginia near the John Amos substation. The proposals include 48 upgrades of existing facilities, 40 of which are mostly new greenfield infrastructure.

Staff will begin shifting toward building the components into a package they believe meets the regional needs most effectively, with an eye toward future expandability. Once that has been completed, Abdulsalam said Board of Managers approval of a recommended package is being targeted for the first quarter of 2025, with first reads at the TEAC expected in December and January.

Several residents in the northern Virginia region spoke out against the proposed expansions, saying that constructability will be inhibited by the impacts to residents already being affected by several projects and asking whether new generation could be an alternative.

Status of Supplemental Projects

FirstEnergy has reduced the scope of a *project* to upgrade equipment at its Beaver substation in the ATSI zone to replace a 345/138/13.2-kV transformer with a higher-rated unit. The original scope included replacing two existing transformers and installing two more 138/13.2-kV units. The change reduces the project cost estimate from $12.7 million to $10 million with an in-service date of March 23, 2029.

American Electric Power (AEP) *presented* a $185 million project to build two new 345-kV substations to accommodate 1,100 MW of new load in the New Carlisle, Ind., region expected to come online by Dec. 15, 2026. Both of the new substations would cut into the Elderberry-Dumont and Dumont-Olive Bypass 345-kV lines.

Toward Elderberry, the new Larrison Drive facility would be configured as a breaker and a half, with 16 345-kV breakers and six bus ties to the new customer for $70.4 million. The New Prairie substation would be similarly configured and cost $79.5 million.

Five overtaxed 345-kV breakers would be replaced at the Olive substation and three new breakers would be added for $29.3 million. End work also would be required at the Sorenson, Elderberry and Dumont substations for $1.72 million for each facility. A sag study and mitigation for the Kenzie Creek-Thomson 345-kV line would cost $620,000 more.

AEP also presented a need to serve a 1,000-MW data center near Granger, Ind., which aims to come online initially with 300 MW of load in December 2027 and ramp up to its full consumption in January 2029.

PPL *presented* an $81 million project to build a new 230-kV switchyard to serve a 1,000-MW customer near Hazleton, Pa. The load is expected to come online in 2027 with 250 MW, growing to 1,000 MW in 2030.

The new Tresckow switchyard would be cut into the Harwood-Siegfried and Harwood-East Palmerton 230-kV lines for $8 million. The facility itself would cost $45 million and be configured as a breaker and a half with four bays and a 125-MVAr capacitor bank. Three 230-kV lead lines would stretch four miles to the customer for $28 million. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

PJM Proposes Changes to Demand Response Availability Window

VALLEY FORGE, Pa. — PJM's Pat Bruno *presented* three initial design components to rework the availability window for demand response (DR) resources. The window determines when the curtailment capability is evaluated as accredited capacity and expected to be online for dispatch. (See *PJM Stakeholders Discuss DR Winter Availability*.)

Demand response providers have argued the winter availability window, which spans 6 a.m. to 9 p.m., misses a significant amount of capability and artificially constrains the value DR can provide.

"As long as they commit to curtail in those hours, we believe there's additional reliability value," Bruno said.

PJM proposed expanding its analysis to a 24-hour availability window and creating estimated load and curtailment capability values for each hour. Separate summer and winter availability values still would be determined.

Bruno said the change would better improve incentives for curtailment service providers to enroll customers with flatter load profiles and the ability to reduce their consumption any time of day.

David 'Scarp' Scarpignato, Calpine | © *RTO Insider LLC*

Calpine's David "Scarp" Scarpignato said DR participants' firm service level (FSL) is based on load during peak hours, and the further an increment is from that time the less accurate their FSL values will be. For DR that is offline or has significantly lower load at night, he said this could result in participants being paid to be available for curtailment when they would be offline. In the event of a performance assessment interval during the night, he said it also could result in capacity performance (CP) bonus payments to consumers that would have been offline regardless of their commitment.

"If they don't take any action, they shouldn't get a bonus ... but if they take an action, they should get paid," Scarp said.

PJM also proposed modifying the winter peak load (WPL) calculation to be based on load during five winter coincident peak days when modeling DR winter capability. Bruno said this would address an overstated WPL.

The third proposal would create an hourly winter DR load shape using aggregate hourly load profiles to account for the different patterns between system and DR load. No change would be made to the summer process.

Bruno said PJM plans to run effective load carrying capability (ELCC) analysis on the impact the proposals may have on resource accreditation and present the results at future stakeholder meetings.

Independent Market Monitor Joe Bowring said PJM's proposals could create inconsistencies with generator ELCC values that are based on actual performance data for a small number of very high-demand winter hours, while DR would be accredited based on expected capability.

"Actual performance data should be used consistently for all resource types under the current PJM approach to ELCC in order to avoid creating preferential treatment for any resource class," he said.

Issue Charge Rethinking External Resource Capacity Rules Endorsed

Stakeholders endorsed by acclamation an *issue charge* brought by the North Carolina Electric Membership Corp. to revise several aspects of how external, pseudo-tied generators interact with PJM's capacity market. (See "External Resource Capacity Clearing," *PJM MIC Briefs: Sept. 11, 2024*.)

Presenting the issue charge on behalf of ACES Power, Executive Director of Regulatory Strategy John Rohrbach said it seeks to harmonize the regional clearing price external resources receive with how CP penalties are calculated. Under the status quo, he said external resources are assigned to the rest-of-RTO zone when determining the clearing price they receive. But the penalty rate they are held to can be based on the specific locational deliverability area where their energy is delivered.

Responding to stakeholders questioning whether the CP penalty rate and annual stop-loss limit calculations would be in scope, Rohrbach said the issue charge does not seek to modify the calculations, but rather ensure they are applied consistently between internal and external generators.

Rohrbach said the issue charge also seeks to recognize the expected output of external resources when determining load serving entities' self-supply obligations — in other words, counting those units toward meeting their reliability requirement.

Third Phase of Market Rules for Hybrid Resources Endorsed

Stakeholders endorsed a PJM *proposal* to establish rules for non-inverter generators paired with storage — the third phase of its hybrid resource paradigm. The changes are set to go for a first read at the Markets and Reliability Committee Oct. 30 and a vote Nov. 20. (See "PJM Proposes Rules for Non-inverter Hybrid Resources," *PJM MIC Briefs: Sept. 11, 2024*.)

Non-inverter hybrids participating in the energy and ancillary service markets would be modeled as storage akin to PJM's Energy Storage Resource Participation Model detailed in Manual 11. PJM's Maria Belenky said staff examined how this would interact with gas fuel availability.

Accreditation would be based on the battery as the primary resource, while also considering the availability of the non-inverter resource. That combination may lead to a final result differing from the ELCC values for standalone storage.

Hybrids with a component that would be subject to the requirement that resources offer into the capacity market also would be required to offer.

The changes also seek to generally fine tune hybrid rules, such as allowing the generation owner to determine whether the storage component would be offered as a closed or open loop. Belenky said current rules categorize storage based on physical capability, but there may be instances where a battery capable of charging from the grid instead may be contractually limited to drawing from the generator it is paired with.

PJM Presents Conforming Revisions to Manual 28

PJM's Suzanne Coyne *presented* a first read on revisions to Manual 28: Operating Agreement Accounting to codify the lost opportunity cost (LOC) payments for hybrid resources.

The changes include the formula for LOC credits and the deviation calculation. Both were added to the Tariff and Operating Agreement as part of PJM's Phase 1 of hybrid resource rules, which was accepted by FERC in September 2023 (*ER23-2484*). ■

— Devin Leith-Yessian

PJM News

PJM OC Briefs

Winter 2024/25 Study Finds No Reliability Issues

VALLEY FORGE, Pa. — The annual winter *study* conducted by the Operations Assessment Task Force (OATF) found no identified reliability risks for the 2024/25 season, PJM's Mark Dettrey told the Operating Committee.

The study will be presented in full during the OC's Nov. 8 meeting and includes a detailed power flow analysis to determine whether conditions such as the largest gas contingency or low/no renewable output could prompt a reliability emergency. While no such issues were found, a preliminary case replicating some of the factors at play in the December 2022 Winter Storm Elliott found the RTO could fall under the reliability requirement if the high forced outage rate were to repeat.

PJM's Chris Pilong said the case was a "numbers game" looking at available capacity and forced outage rate without getting into the same detail as the power flow analysis.

The power flow analysis was built on the 50/50 non-diversified peak load base case of 141,233 MW and exports of 4,462 MW. It includes a preliminary installed capacity (ICAP) of 179,821 MW and forced outages of 17,955 MW. Pilong said the capacity figures used in the analysis include resources that do not hold a capacity obligation but historically have been available, including generation not obligated to offer into the capacity market.

The gas contingency case held a 7.1-GW reserve margin over the 90/10 diversified load forecast and a 6.4-GW day-ahead scheduling reserve requirement — the low/no renewables scenario had an 8.7-GW margin. The analysis assumed an 18-GW forced outage rate and 5.5 GW of exports.

The extreme winter storm scenario increased the forced outage rate to 46 GW to simulate the impact of a storm similar to Elliott. Exports were cut to the 3-GW firm interchange and 7.1 GW of load management added to the modeling, resulting in the reserve margin falling 13.8 GW below target.

PJM Seeking More Prompt Data Request Responses from Generators

PJM's Eli Ramsay *encouraged* generation owners to self-schedule units for cold weather preparation exercises ahead of the winter and presented an overview of the data request process, which could result in members being found in breach of the Operating Agreement if they do not respond.

Tom Hoatson, LS Power | © *RTO Insider LLC*

PJM will open a data request for generation owners Nov. 1 with a checklist of cold weather preparation steps and asking for any improvements that have been made to resources since Winter Storm Elliott. The request will be open through Dec. 15, with a reminder one week before the deadline.

Generation owners who do not respond to data requests will be notified they may be in breach of the OA, with 48 hours to supply the information through a remediation data request.

Pilong said the response rates for the Cold Weather Preparation Checklist and Fuel and Emissions annual survey historically have been around 80%, which has trended in the mid- to high-90% range in recent years. Pilong said the increase followed outreach to generation owners, which PJM is trying to step back from, instead relying on members to report that information when requested.

PJM's Kevin Hatch said operators rely on generators to update their parameters in eDART when cold weather advisories are issued, which provides dispatchers with visibility into unit availability. Self-scheduled drills ensure those parameters can be relied on if a generator is needed.

Monitor Presents Results of Synchronized Reserve Performance Inquiry

Joel Romero Luna, senior analyst with PJM's Independent Market Monitor, *presented* the findings of outreach to synchronized reserve resources that failed to perform during a July 8 event, finding that a majority of the shortfall was due to communication failures or delays.

Synchronized reserve performance has lagged in recent years, leading PJM to increase the reserve requirement by 30% last year after backtracking on an earlier doubling of the target. (See "Stakeholders Reject PJM Synch Reserve Manual Change; RTO Overrides," *PJM MRC/MC Briefs: May 31, 2023*.)

The Monitor spoke with 146 resources, representing about 93% of the total 1,755-MW shortfall during the July 8 synchronized reserve event, in an effort to better understand what led to the underperformance. More than 800 MW of shortfall could be attributed to communication issues, with most of those units

PJM News

following signals in PJM's Automatic Generator Control (AGC) system. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

Luna noted that stakeholders have approved a PJM proposal to send synchronized reserve deployment signals through AGC, which he said could address some of the underperformance seen in July. If all units following their basepoints through AGC had responded to the synchronized reserve deployment, Luna said the performance rate would have been 76%, rather than the 46% seen July 8. While that would be an improvement, he said that would remain inadequate.

Inaccurate parameters, delayed action by plant workers, lacking knowledge of business rules and modeling issues all contributed to underperformance as well. In some cases, changes in ownership caused knowledge gaps about how to respond or resources were assigned reserve commitments for the first time and did not know how to respond.

"We saw a lot of that: units that were not aware that they were being assigned reserves and were required to respond," he said.

The use of phone calls within companies to relay reserve deployment information contributed to the delays, Luna said. PJM Director of Operations Planning Dave Souder responded that the RTO's All-Call signal results in a call to committed reserves within seconds of a deployment and the issue lies in how companies receive and process that information.

Quick Fix Proposal on Day Ahead Schedule Reserve Calculation

Hatch *presented* revisions to Manual 13: Emergency Operations seeking to clarify how PJM calculates the annual Day Ahead Scheduling Reserve (DASR) and uses the figure to determine when the 30-minute reserve target is insufficient. PJM proposed the change through the quick fix process, which allows a solution to be brought concurrent with an *issue charge*. Approval may be sought at the Nov. 8 OC meeting.

Hatch said the reserve target does not account for the varying risks and needs PJM can experience day to day, which can result in additional reserves being needed in some circumstances. The 30-minute target is set at the greater of the primary reserve requirement, the largest active gas contingency or 3,000 MW, whereas the DASR is based on underforecast load error and generation forced outage rates.

"We need to look for a percentage-based approach," he said.

Souder said the revisions would codify existing practice around the reserve adequacy run and no changes would be made to market-based reserve procurement.

Stakeholders rejected an earlier PJM proposal to allow it to replace the 30-minute target with a formula that would select the greater of the load forecast error and forced outage rate together multiplied by the forecast peak load, the primary reserve requirement or the largest active gas contingency. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

First Read on Several Changes to Generator Operational Requirements

PJM's Madalin How *presented* a package of revisions to Manual 14D: Generator Operational Requirements drafted through the documents' periodic review.

New language was added requiring generation owners to provide PJM with information about changes to wind resources that may impact their characteristics without modifying the resource's output to the extent to require going through the interconnection queue. PJM's Joe Mulhern said information about changes in turbine technology could affect forecasting.

The revisions also include reformatting the Cold Weather Preparation Guideline and Checklist for readability, clarifying how generation owners should proceed if they lose remote control of MW or MVAR output and clarifying the requirement that all generators must provide PJM with reactive capability curves before entering operation and complete reactive testing within 90 days after coming online.

Several stakeholders questioned whether the changes were too substantive to be appropriate for the periodic review process and requested more time to review the language before moving to a vote next month.

September Operating Statistics

PJM experienced a 1.23% hourly forecast error in September, with a peak error of 1.74%, according to the RTO's monthly operating *report*. PJM's Marcus Smith, lead engineer for load forecasting, said Sept. 19 saw an approximately 6% underforecast due to weather forecast error, while Hurricane Helene contributed to overforecasting Sept. 27 and 28.

Two shortage cases were approved Sept. 4 due to high load and a reduction in dispatchable generation. ■

— Devin Leith-Yessian

Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW

Report Commissioned by EDAM's NW Backers Shows $430M in Yearly Benefits from CAISO Market

By Robert Mullin

The Bonneville Power Administration would earn $65 million in annual benefits from joining CAISO's Extended Day-Ahead Market but face $83 million in increased yearly costs from participating in SPP's Markets+, according to a new Brattle Group study that is sure to further inflame the ongoing debate over day-ahead markets in the West.

The *BPA Day-Ahead Market Participation Benefits Study*, which examines scenarios for 2032, extends similar findings to the rest of the Pacific Northwest (PNW) system.

"We find that if most of the Pacific Northwest, including BPA, joined EDAM, customers in the region would see a cost reduction of $430 million per year," Brattle Principal John Tsoukalis, lead author of the study, said in an Oct. 9 press release accompanying the study.

By contrast, PNW net system costs would collectively increase by $18 million under a situation in which most of the region's entities participate in Markets+, Brattle found.

In the study, the PNW system includes BPA, Avista, PacifiCorp's West balancing authority area, Portland General Electric (PGE), Puget Sound Energy, Seattle City Light and the numerous public utility districts that largely rely on BPA for low-cost power to serve electricity customers in mostly rural areas of Oregon and Washington.

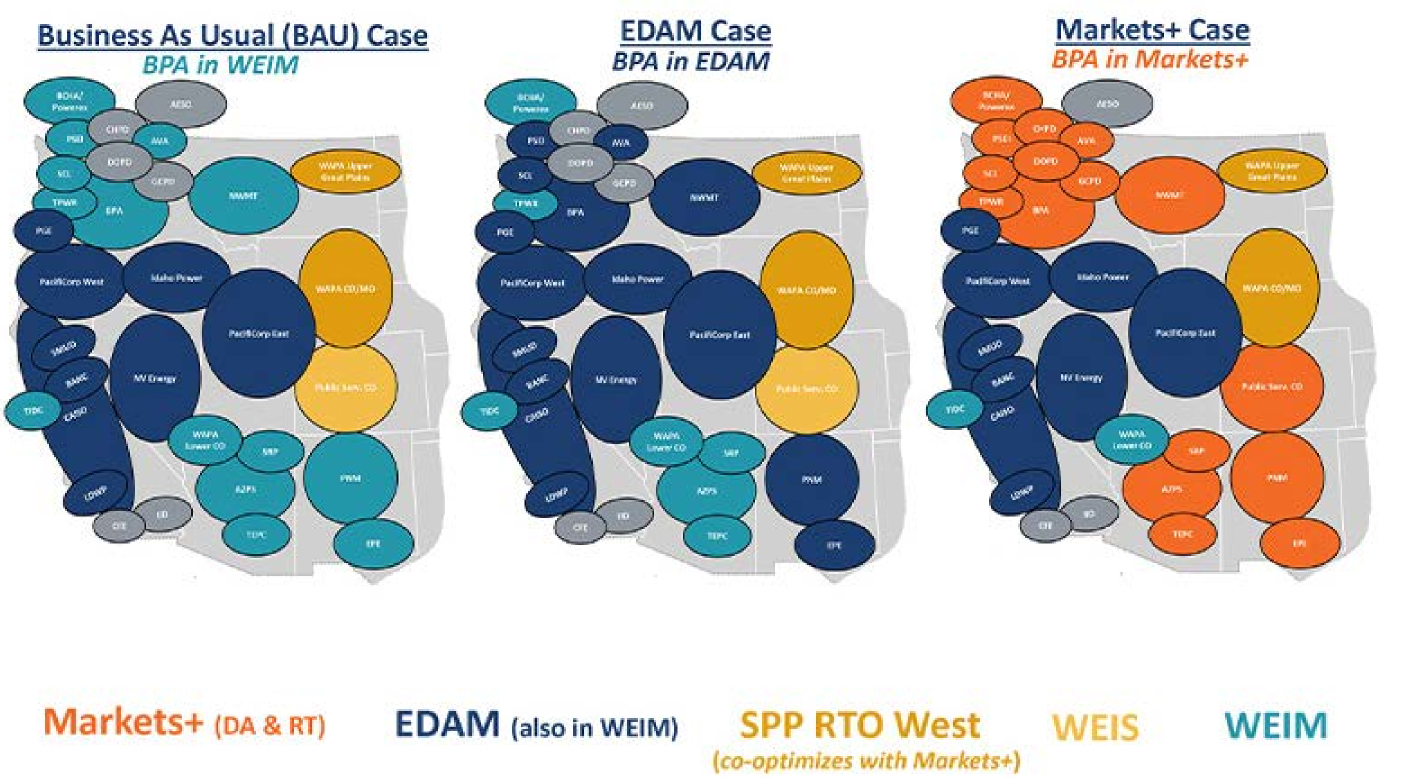
The report is the latest in the series of Western day-ahead market studies performed by Brattle, the most recent being a white paper comparing key features of the EDAM and Markets+. (See *Brattle Study Likely to Fuel Debate over EDAM, Markets+*.) It was not commissioned by BPA, but rather by a group of Northwest-based EDAM proponents, including the Northwest & Intermountain Power Producers Coalition (NIPPC), NW Energy Coalition (NWEC), PNGC Power and Renewable Northwest, as well as GridLab.

Those organizations have been firmly in the camp of electricity sector stakeholders who have argued that the West must create a market with the largest possible footprint — and that pointedly includes CAISO — to allow participants to fully tap the "diversity benefit" of resources and loads that would become available from such an arrangement. The Brattle BPA study throws its weight behind that argument.

Why This Matters

The study, sure to be contested by Markets+ supporters, shows BPA and the Northwest gaining much more from joining EDAM. The agency's choice of a day-ahead market will be key to determining the future market landscape in the West.

"The key benefit differentiator in customer cost savings between the two markets is the diversity of the generation resource mix available in an EDAM footprint, which includes the Pacific Northwest as well as parts of the



The Brattle Group's BPA day-ahead market benefits study examines three cases of market participation. | *The Brattle Group*

SPP News

Southwest," Brattle said in its press release.

Study Structure

The BPA study participants included the Balancing Authority of Northern California, El Paso Electric, Idaho Power, Los Angeles Department of Water and Power, NV Energy, PGE, PacifiCorp, Public Service Company of New Mexico, Sacramento Municipal Utility District and other utilities, transmission owners and independent power producers.

Those participants "helped refine our model by performing full reviews of relevant modeling assumptions including transmission rights, transmission costs, load forecasts, fuel prices, generation mix and costs, etc.," Brattle said, calling out PacifiCorp and PGE among the "several" reviewers that "were able to provide details relevant to BPA's system."

Brattle worked with the Northwest Power and Conservation Council to fine-tune its flexibility modeling of BPA's hydroelectric system, assuming the federal power agency's ability to dispatch its fleet would be the same across all market scenarios.

The BPA study was conducted "using a nodal production cost model of the [Western Interconnection] with added markets, transmission rights and contract-path trading functionality." It chose 2032 as the study year "to reflect the first decade of markets operations, representing an intermediate year that captures known changes in resource mix and transmission infrastructure."

The study models a "business as usual" (BAU) case that reflects current utility participation in markets and the known decisions on day-ahead markets (all for EDAM at this point), as well as two "market participation" cases. In the Markets+ case, BPA and almost all utilities presently uncommitted to a day-ahead market join the SPP market, while an EDAM case shows all existing Western Energy Imbalance Market (WEIM) participants either remaining in that market or joining EDAM.

The study also models two extreme weather events, each based on a historic cold snap and heat wave.

"These events are modeled as single weeks in which we increase modeled loads (peak and energy) and gas prices, including gas price volatility beyond typical weather-normalized values to reflect the increased strain on the system and the ability of markets for addressing such strain," the study said.

The study's transmission assumptions include a "detailed view of the physical transmission system and long-term (contractual) transmission rights"; multiple trade type options between BAAs; and "GHG unit-type-specific trading structure which closely mimics the unit-specific GHG import tracking and charge structures in the EDAM and Markets+ designs." It also assumes participants will make all their transmission available to the market, except where study participants have called out specific carveouts.

'Key Differentiators'

BPA's $65 million estimated benefit from participating in EDAM came down to two key factors, Brattle said.

The first factor is the expectation that BPA will reduce its adjusted production costs (APC) by $43 million in the CAISO market because of increased sales revenues stemming from higher prices in EDAM during the hours when the agency usually sells power.

The second factor is a projected increase in BPA's congestion revenue from zero in the BAU case to $166 million in EDAM, a product of "the amount of transmission BPA brings to the market, its advantageous position in the EDAM footprint, and price deltas between" California and the Pacific Northwest.

While the study found that BPA's congestion would average about $4/MWh in both markets, the agency's congestion revenues in EDAM would be double those of Markets+ because of its higher trading volumes in the CAISO-run market.

On the downside, Brattle found BPA's EDAM benefits would be partially offset by a $114 million loss in bilateral trading revenues and $37 million loss (to $2 million) in short-term wheeling revenues — the outcome of declining bilateral activity.

"Bilateral trading revenue falls more in [the] EDAM [case] as almost all of BPA's trading partners are in the EDAM," the study found.

In the Markets+ case, BPA's increased costs stem in part from a projected $87 million drop in bilateral trading revenues, the result of many — although not all — BPA trading partners joining the agency in the market.

But the key difference between the two cases relates to production costs. In Markets+, BPA's APC is projected to increase by $72 million because of slightly lower prices in that market during some intervals when the agency sells its power.

"The impact on prices is mostly in overnight hours, driven by the higher opportunity for increased thermal resource dispatch efficiency during these hours in the Markets+ footprint relative to the EDAM or BAU cases, which is driven by higher gas prices in the Pacific Northwest compared to the Southwest and Rocky Mountain regions," the study said, adding that the opportunity for that kind of dispatch efficiency isn't available under BAU because of "trading hurdles" between the Northwest, Southwest and Rockies region.

"The increased thermal dispatch efficiency and lower prices in the Markets+ footprint benefit net buyers in the PNW through reduced purchase costs but reduces sale revenues to the detriment of net sellers in the PNW such as BPA."

On the plus side, Markets+ would increase BPA's congestion revenues by $88 million, while short-term wheeling revenues would remain nearly flat, at an estimated $38.9 million.

"Market congestion, bilateral trading revenues, short-term wheeling revenues, and APC savings are the key differentiators of BPA's net benefits between EDAM and Markets+," the study said.

PNW Findings

The Brattle finding that EDAM's benefits for the full PNW system would far outpace those of Markets+ could be the most significant point of the study for many in the region. It could also stir the most controversy in the debate over the two markets.

The study found that the $430 million in savings in EDAM derive from a $171 million reduction in APC, "driven mainly by higher sales revenues in EDAM for the region" and $651 million in EDAM congestion revenues. Those benefits would be offset by a $283 million decline in bilateral trading revenues and a $66 million loss in short-term wheeling revenues.

The cost increase for the Northwest under the Markets+ case was largely attributed to lower sales revenues, which left the region's APC net of revenues $18 million higher than in the BAU case.

Reached for comment, BPA spokesperson Doug Johnson said, "BPA did not participate in and has not yet reviewed the study. We will attend the Oct. 17 webinar hosted by the study's authors and will comment on the results after we better understand the study's methodology, inputs and findings."

SPP spokesperson Meghan Sever said the RTO was preparing a statement on the Brattle study. ■

SPP News

FERC's Rosner Talks Priorities at American Clean Power Association

By James Downing

WASHINGTON, D.C. — FERC Commissioner David Rosner told members of the American Clean Power Association that one of his main goals as a regulator is to successfully manage the energy industry's transition.

"If you look back 20 years, the system is just completely different from what it was," Rosner said. "And if you look 20 years out forward, it's going to look different. And, so, one of the things I'm focused on is making sure in regions where there are markets … those markets are equipped to deal with that change."

Another part of reliably managing the transition FERC oversees is deciding where and when infrastructure investments are needed, he added.

Rosner is not coming new to FERC like most commissioners; he's moving up to the top floor after working as a staffer since 2017.

"Frankly, I have an unfair advantage, because there's — you'll be shocked to hear this — but there's a lot of process at a regulatory agency," Rosner said. "And that's a really good thing, because we want a lot of eyes on these orders because they affect real people, real companies, real dollars. And, so, I already know to some extent that process, and that's been a huge advantage."

He already has seen the regulator go through changes since joining as a staffer. One of the reasons the commission has seemed more partisan in recent years, he said, is a court decision (NRG Power Marketing LLC v. FERC) that ended its flexibility in dealing with Federal Power Act Section 205 filings. (See *PJM MOPR Order Reversed; FERC Overstepped, Court Says*.)

While focused on long-running debates about PJM's capacity market, the decision effectively tied FERC's hands and limited its response to Section 205 filings to an up or down vote.

"Before you would see six, seven, eight — you know — rounds of conditional compliance," Rosner said. "We can't do that anymore. It's yes or no, up or down. It's always an emergency."

Rosner also said he's committed to getting orders out as soon as they are ready, which this summer involved approving new infrastructure. He also noted the commission is working on issuing a rehearing order for Order 1920, the transmission reforms passed this spring before Rosner took office.

PJM's recent capacity auction and the price spikes caused by a narrowing supply and demand balance also are at the top of mind for the new commissioner, who said he's been meeting with state regulators from the region concerned with the shift from "abundance to scarcity." (See *PJM Capacity Prices Spike 10-fold in 2025/2026 Auction*.)

"The fundamental cure to this disease is adding capacity," Rosner said. "And so, you know, last year, I think we saw a report just come out of PJM saying they added 2,000 MW of solar. I think they have somewhere between 20,000 and 30,000 MW of signed ISAs [interconnection service agreements], some of those for batteries. And you know, I think what we're hoping to see is that we get more than 2,000 MW connected next year."

FERC Order 2023 set a new baseline for interconnection queues around the country, and the commission recently held a two-day workshop looking into other ways, some of which do not require any rule changes, to speed up that process, Rosner said.

Why This Matters

Rosner said he's committed to getting FERC orders out as soon as possible, and that the commission is working on a rehearing order for Order 1920, the transmission reforms passed this spring before he took office.

Industry Executives Discuss Maintaining Reliability as Grid Transitions

Rosner gave the keynote at an event that featured executives from around the industry describing how they responded to reliability challenges in their territories.

CAISO had to cut power briefly to some customers in 2020 as demand spiked around the West and it was unable to rely on imports, said Chief Operating Officer Mark Rothleder. The short version of what went wrong: California didn't keep up with the pace of change, represented by higher peaks due to climate change and new types of resources.

At the time, CAISO had just 250 MW of batteries online. That has ramped up to 10,000 MW, which has helped.

"You're starting to now see things stabilized," Rothleder said. "We're seeing these events happen. We're forecasting the events in the operational time frame. We're incorporating the changing conditions in the planning horizon, and we're again developing and moving and building the resources that we need for the future."

The bad times for SPP came in February 2021, when Winter Storm Uri led to blackouts, said General Counsel Paul Suskie.

Over its first two decades as an RTO, SPP approved $13 billion in transmission. That could grow by more than 50% after a vote set for the end of October, when its board will consider $7.5 billion more. Some $2 billion of that proposed transmission was planned when looking back to Uri and Winter Storm Elliott and determining what would have helped maintain reliability, Suskie said.

The new transmission lines would help connect the north to the south of SPP to better move power in emergencies. SPP also is considering proposals for eight high-voltage direct current lines to connect the Eastern and Western Interconnections as its RTO footprint expands across that seam, Suskie said.

One key policy goal of American Clean Power is getting the Energy Permitting Reform Act of 2024 to pass Congress this year, after clearing the Energy & Natural Resources Committee by a 15-4 vote.

"We are in a joyful position right now having a full consensus," said ACP President Jason Grumet. "Not a single member of our organization is opposed to the EPRA proposal."

ITC President Krista Tanner said the permitting bill is needed to avoid situations like the recently completed Cardinal-Hickory Creek Line, which took 13 years to build because it was under constant litigation. The law does not eliminate litigation under the National Environmental Policy Act, but it seeks to minimize "litigation abuse," Tanner said.

"It puts time frames on statutes, limitations on how soon you have to file; it requires courts take these cases expeditiously, and then it requires the agencies to act within certain time frames," Tanner said. "So, all of that helps a lot." ■

Company Briefs

Exxon Secures Over 271,000 Acres for Offshore CO2 Capture

Exxon Mobil last week announced it has acquired leases for over 271,000 acres in Texas state waters for an offshore carbon dioxide capture operation.

The lease with the Texas General Land Office follows Exxon's 2021 bid for federal land off the Texas coast for CO2 capture.

The company did not disclose the duration or financial terms of the lease.

More: *Reuters*

Coal-to-solar Developer BrightNight Lands $440M Investment

Renewable energy developer BrightNight last week announced it has closed a $440 million strategic investment from banking giant Goldman Sachs.

The equity investment will help BrightNight build out its pipeline of utility-scale solar and storage projects, which together represent 31 GW. The company also said it will "upsize" its corporate credit facility from $375 million to $400 million, which will give it the necessary balance sheet support to execute on its U.S. portfolio.

Among the developer's projects is the 810-MW solar installation Starfire, slated for an old mining site in Kentucky.

More: *Canary Media*

JBB Advanced Technologies to Acquire Proteus Power

JBB Advanced Technologies last week announced it has agreed to buy Proteus Power, an international developer of utility-scale renewable energy, for an undisclosed amount.

Proteus Power incorporates a total of 15.5 GW of utility-scale renewable energy projects, including utility-scale solar and battery energy storage systems.

The acquisition is expected to close by the fourth quarter of this year.

More: *Dallas Innovates*

Cryptominer MARA Taps US Shale Patch in New Power Generation Project

MARA Holdings, the world's largest publicly traded bitcoin miner, last week announced it has begun producing power in the U.S. shale patch as part of a pilot project to fuel 25 MW of its mining operations with excess natural gas.

As part of the pilot, MARA purchases natural gas at the wellhead from independent oil producers in Texas and North Dakota. It converts the feedstock, which would have otherwise been burned off in flaring, into power to run its nearby miniature data centers.

More: *Reuters*

Federal Briefs

Supreme Court to Take Up Permian Basin Nuclear Waste Dispute

The U.S. Supreme Court has agreed to review a ruling by the 5th U.S. Circuit Court of Appeals that found that the Nuclear Regulatory Commission exceeded its authority in granting a license to a private company to store spent nuclear fuel at a dump in West Texas for 40 years.

The NRC granted the license to Interim Storage Partners for a facility that could take up to 5,000 metric tons of spent nuclear fuel rods from power plants and 231 million tons of other radioactive waste. The facility would be built next to an existing dump site in Andrews County that currently contains low-level waste such as protective clothing and other material that has been exposed to radioactivity. A second license, to Holtec International for a similar temporary storage site in New Mexico, was also vacated by the 5th Circuit Court.

A decision is expected by the middle of next year.

More: *Houston Chronicle*

FERC Awards Preliminary Permit for Down East Tidal Project

FERC last month issued a preliminary permit for a proposed tidal power project in Pembroke, Maine.

The permit grants Pembroke Tidal Power Project priority to file a license application during a period of four years. A preliminary permit does not authorize the company to perform any land-disturbing activities or enter on lands or waters not owned by the company without the owners' permission.

Debbie-Anne Reese, acting secretary for FERC, noted the permit allows Pembroke Tidal to gather data and information to prepare an application to the commission for a license for the project.

More: *Bangor Daily News*

FEMA Spent Nearly Half Its Disaster Budget in 8 Days

Just eight days into the fiscal year, the Federal Emergency Management Agency has spent nearly half the disaster relief that Congress has allocated for the next 12 months.

FEMA Administrator Deanne Criswell disclosed that as of Oct. 8, the agency had spent $9 billion of the $20 billion that Congress put in its disaster fund Oct. 1 for the fiscal year that runs through Sept. 30, 2025. The rapid spending — which is likely to accelerate as aid flows to states pulverized by Hurricanes Helene and Milton — soon will force FEMA to restrict spending unless Congress approves additional funding. Under the spending restrictions, FEMA would cut off funding for disaster-related rebuilding projects nationwide and reserve its money for life-saving operations.

FEMA has frequently struggled to pay disaster costs and has imposed spending restrictions on 10 occasions since 2003, most recently in early August.

More: *POLITICO*

State Briefs

CALIFORNIA

Escondido Passes Moratorium on Battery Energy Storage Sites

The Escondido City Council last week unanimously voted to enact a temporary moratorium on battery energy storage sites.

"For the last couple years, we've heard all about how safe these projects are, and then unfortunately Escondido experienced the fire, a relatively small fire, that interrupted that entire city block for two days. I think it's important now to learn from that lesson as opposed to wait to learn that lesson until the next one," Escondido Mayor Dane White said.

The moratorium will last for 45 days, although the council is considering a 10-month moratorium.

More: *KUSI*

FLORIDA

Gov. DeSantis Reappoints La Rosa to PSC

Gov. Ron DeSantis announced he has named Michael La Rosa to the Public Service Commission, effective Jan. 2.

La Rosa was first appointed to the PSC in 2020.

La Rosa was also an elected official and served in the state House of Representatives for District 42 from 2012 to 2020.

More: *Florida Politics*

GEORGIA

Georgia Power Stops Disconnections, Waives Late Fees After Helene

Georgia Power last week announced that disconnections will remain suspended, late fees will be waived and collection activities will be paused for residential and business customers through at least Dec. 15 in the aftermath of Hurricane Helene.

As of Oct. 7, power had been restored to over 1.5 million customers, representing 99% of those impacted by the storm, according to the company.

More: *WAGA*

IDAHO

Avista Customers to See Drop in Monthly Bills

Residential Avista customers will see their monthly bills decrease by about $3 starting this month after the Public Utilities Commission approved two applications that will result in a decrease in rates.

According to Avista, power supply costs over the last year were lower than those included in retail rates because of higher wholesale electric gas prices.

More: *Idaho Capital Sun*

LOUISIANA

New Orleans Advances Proposal to Improve Grid

The New Orleans City Council's Climate Change and Sustainability Committee last week advanced a proposal to spend $100 million on a hardening of the city's utility poles, transmission and distribution lines.

The $100 million is part of the estimated $750 million to $1 billion Entergy said it will take to strengthen the city's distribution system against storms.

The $100 million investment will cost ratepayers no additional money.

More: *Nola.com*

New Orleans to Consider Solar Microgrid Proposals

The New Orleans City Council last week voted to consider proposals for a distributed power grid throughout the city.

Advocacy groups Together New Orleans and the Alliance for Affordable Energy want the city to invest up to $32 million to buy batteries for homes and community centers to create a virtual power plant. It would consist of solar panels and connected batteries at a home or business that can either power individual structures or be part of a small-scale power grid.

More: *Louisiana Illuminator*

MANITOBA

Manitoba Hydro Reports $157M Loss as Drought Affects Hydro Generation

In its 2023-24 annual report, Manitoba Hydro reported a net loss of $157 million for the fiscal year ending March 31, 2024, compared to a net income of $638 million the previous year.

Manitoba attributed the loss to lower net exports related to drought, an increase in the purchase price of power imports, and higher operating and administrative expenses due to increased wages and salaries.

About 97% of Manitoba's electricity is generated from clean hydro, with most of the remaining 3% coming from wind.

More: *Hydro Review*

MINNESOTA

Mayor Jacob Frey Vetoes Minneapolis City Council's New Carbon Fee

Minneapolis Mayor **Jacob Frey** vetoed a new fee on carbon emissions passed by the city council, saying it is illegal.

Under state law, the city can only charge regulatory fees to recoup costs. Minneapolis would not be able to establish new costs and hire a related staff person before the fee was collected on Jan. 31, 2025, the city's attorneys concluded in a legal opinion. Doing things in the wrong order could amount to charging an illegal tax, they wrote.

The fee would have charged the 36 biggest emitters in the city $452 per ton of carbon dioxide.

More: *The Minnesota Star Tribune*

RHODE ISLAND

Siting Board Reopens Permitting Process for Sakonnet River Cable

The Energy Facility Siting Board last week reopened the permitting process for transmission cables that would run up the Sakonnet River from a SouthCoast Wind farm.

The decision comes more than a year after the board paused its deliberations on the transmission lines because SouthCoast Wind had moved to pull out of a set of long-term contracts it had previously signed with Massachusetts utilities.

The project could cost as much as $5 billion and generate up to 2,400 MW.

More: *The Providence Journal*

TEXAS

CenterPoint Overhaul Will Move Lines Underground, Install Stronger Poles

CenterPoint Energy said it plans to overhaul its power grid infrastructure ahead of the 2025 hurricane season.

The company aims to add 25,000 poles made of fiberglass or other material that can withstand extreme winds to its system, in some cases replacing wood poles, before June 1, 2025. It also hopes to underground more than 400 miles of power lines and trim or remove vegetation along 4,000 miles of lines.

On top of the investments, the company also plans to ask the Public Utility Commission for permission to spend $5 billion to further strengthen its grid from 2026 to 2028.

More: *Houston Chronicle*

WISCONSIN

State Utilities Propose Nearly $2B in Renewable Projects

We Energies, Wisconsin Public Service and Madison Gas and Electric recently filed plans with the Public Service Commission to acquire and build renewable energy facilities that would cost around $1.9 billion combined.

The five projects include 500 MW of solar, around 180 MW of wind and 100 MW of battery storage. We Energies would own 80% of the projects, while WPS and MGE would each own 10%.

Pending approvals, construction of the projects would begin next year, and they are expected to come online between 2026 and 2028.

More: *Wisconsin Public Radio*