ISSN 2377-8016 : Volume 2023/Issue 16 ▪ April 18, 2023

# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

Spring 2023 Joint CREPC-WIRAB Meeting

## Western Day-ahead Markets Debated at CREPC-WIRAB (p.7)

FERC Commissioners Discuss Western Markets 'Dating Process' (p.9)

PJM

## PJM Seeks Settlement over Elliott Nonperformance Penalties (p.21)

PJM: Elliott Nonperformance Penalties Total over $1.8B (p.21)

PJM Seeks to Delay Capacity Auctions Through 2028 Delivery Year (p.23)

ERCOT

## ERCOT Stakeholders Endorse Staff's Bridge to PCM (p.13)

ERCOT, Austin Energy Settle Uri Dispute (p.14)

CAISO/West

## TransWest Express to Break Ground After BLM Approval (p.12)

MISO

## Iowa Regulators Ponder MISO Tx Projects After ROFR Ruling (p.16)

**COVER:** Western regulators and stakeholders filled a conference room at the Hyatt Regency Lake Tahoe Resort in Incline Village, Nev., for the spring CREPC-WIRAB meeting. | © *RTO Insider LLC*

**RTO Insider LLC**
10837 Deborah Drive
Potomac, MD 20854
(301) 658-6885



# In this week's issue

## Stakeholder Soapbox

# Biden's Cyber Strategy Risks Demonizing Biggest Ally: The Private Sector

## *Attempting to Shape Market Forces and Regulate the Private Sector May Backfire*

*By Shahid Mahdi*

Shahid Mahdi

April 16 marked 30 years since one of the seminal moments of our digital being. In 1993, amidst a need to keep up with the dizzying pace of technological innovation, the Clinton administration announced a cryptographic device that would enshrine itself in cybersecurity history.

The MYK-78 was developed by the National Security Administration to give the government a "*back door*" into all communications in the interest of national security. Nicknamed the "Clipper Chip," it would permit federal, state and local law enforcement to access and decipher voice and data transmissions at their discretion.

Unsurprisingly, the notion of the government having a permanent opt-in method to eavesdrop on all cell phones, computers and pagers was met with a vociferous uproar. Sure enough, a meager three years and much backlash later, the Clipper Chip was scrapped.

The rise and very quick fall of the Clipper Chip is a cautionary tale of how a failure to understand the operational environment of privacy and tech can lead to failures in policy.

President Biden's *National Cybersecurity Strategy*, published March 2, is not a failure in policy. It espouses objectives that are long overdue amidst a world of pervasive cyber threats. It includes the desire to eliminate malicious cyber actors from Russia and China and defend critical infrastructure like hospitals and power generation. "Its implementation will protect our investments in rebuilding America's infrastructure, developing our clean energy sector, and re-shoring America's technology and manufacturing base," the Strategy says. It would expand "the use of minimum cybersecurity requirements in critical sectors," building on those governing the electric industry.

However, one particular element of the Strategy must tread very carefully: "Shape Market Forces to Drive Security & Resilience." It aspires to promote privacy and security of personal data, and, interestingly, aims to shift liability for software products from users to tech companies to promote security practices.


MYK-78 Clipper Chip | *Travis Goodspeed, CC BY-SA 2.0, via Wikimedia Commons*

This comes at a time when relations between government and tech are at something of a nadir. Apple, Google and Meta have been vocal about their privacy practices: Tim Cook *was obstinate* in refusing to give the government a back door into iPhones; Meta *promulgated end-to-end encryption* loud and clear on its Messenger and WhatsApp platforms. The message here? Trust us as we'll keep the government out of your pocket. And from Apple: *Our privacy measures are way better* than our competitor's.

Federal Trade Commission Chair Lina Khan has *dialed up government bellicosity* toward the tech companies, and the Strategy will further empower this. The FTC may be one of the first agencies to take advantage of the ability to "shape market forces" if given the power by Congress to do so. Should the liability initiatives in the Strategy give birth to more lawsuits, tech companies will be hit with a deluge of regulations and policies — a tightening of the government leash on the so-called market forces.

And then battle will be done in the courts, as it's being done already. The language "shifting liability" may be innately at war with the biggest, most substantial legal defense in a tech company's arsenal: Section 230 of the Communications Decency Act, which Biden and company have been vocal about revamping. Section 230 exculpates a publisher from the content on its platform (i.e., you can't prosecute Meta for a graphic video posted to Facebook). The Supreme Court is *deliberating over a case* predicated on Section 230 at the time of this writing.

Further friction between tech and government would also, ironically, weaken the Strategy itself. Why? The "Defending Critical Infrastructure" and "Dismantle Threat Actors" sections of the Strategy involve the promotion of public-private collaboration. Widening the existing wedge between tech and the government doesn't sound like the way to do this.

Alphabet, Meta, Apple, Amazon, and Microsoft and company arguably have the most sophisticated, talented minds and data repositories that can safeguard the U.S. in a world of nefarious cyber threats. Why run the risk of antagonizing them? ■

*Shahid Mahdi is product lead for EnerKnol, a provider of energy regulatory intelligence software.*

## FERC/Federal News

# Grid Strategies Reports Spiking Congestion Costs

By James Downing

The cost of transmission congestion doubled in the organized electricity markets between 2020 and 2021, rising by billions of dollars, according to a report released Thursday by Grid Strategies.

All of the ISOs and RTOs except for CAISO publish their congestion costs; they were up $7.7 billion on the year, which, extrapolated to the rest of the country, leads to a national cost of $13.4 billion, according to "*Transmission Congestion Costs in the U.S. RTOs*."

Congestion costs rebounded in 2021 after reduced demand from the height of the COVID-19 pandemic in 2020 led to lower costs that year, but other factors helped fuel that increase.

"The price transparency and generally more favorable transmission expansion policies in the RTO regions tend to reduce congestion in those areas relative to non-RTO regions," the paper said. "However, RTO regions have experienced more renewable deployment in recent years than non-RTO areas, which may somewhat offset those factors as renewable expansion tends to increase transmission congestion when it outpaces transmission expansion."

The best way to cut congestion is to build new transmission, the report said, citing a PJM analysis that found that transmission enhancements approved in the past decade have cut costs to serve consumers by $280 million annually.

No similar numbers exist for how interregional lines would benefit consumers by cutting congestion, but Lawrence Berkeley National Laboratory found that interregional transmission links can have just as much, if not more, value than intraregional links.

While the bounce back from the pandemic was a national trend, different regions had different factors impacting the rise of congestion.

ISO-NE continues to deal with increased congestion as transmission development has lagged the development of renewable energy.

"A new wind generator in coastal Maine went online in late 2020, and along with other abundant wind generation, and in the absence of proactive transmission additions, congestion increased," the report said.

Higher natural gas prices, especially on the coldest days of winter, helped to push up congestion in NYISO. MISO saw congestion costs nearly triple in 2021 to $2.8 billion, with roughly $730 million of that total alone from the February storm, also known as Winter Storm Uri, that knocked out power in Texas and surrounding states.

"This is consistent with the general pattern nationally that much of the congestion (and value of transmission) occurs in a relatively small percentage of the hours," the report said.

SPP saw congestion prices more than double to $1.2 billion, with its market monitor attributing the increase to the distance between generation and load centers, outages of key transmission lines, volatile fuel prices and Uri.

Texas was also obviously heavily impacted by Uri, with congestion costs representing 33% of total costs in February 2021, compared to 15% in February 2020. The growth of renewables also helped push up congestion.

"In 2021, 3 GW of wind output and 3.6 GW of solar came online [in ERCOT] without concomitant transmission development, which contributed to a real-time congestion cost increase of 46%," the report said. ■

| RTO | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| ERCOT | 497 | 976 | 1,260 | 1,260 | 1,400 | 2,100 |
| ISO-NE | 39 | 41 | 65 | 33 | 29 | 50 |
| MISO | 1,402 | 1,518 | 1,409 | 934 | 1,181 | 2,849 |
| NYISO[2] | 529 | 481 | 596 | 433 | 297 | 551 |
| PJM | 1,024 | 698 | 1,310 | 583 | 529 | 995 |
| SPP | 280 | 500 | 450 | 457 | 442 | 1,200 |
| TOTAL | 3,771 | 4,214 | 5,090 | 3,700 | 3,878 | 7,745 |

Congestion costs in the organized markets in recent years (millions $) | *Grid Strategies*

FERC/Federal News

# EIA: US Natural Gas Use Hits 5-Year Low in Mild Winter

## *Inventories Higher than Average as Heating Season Ends*

*By John Cropley*

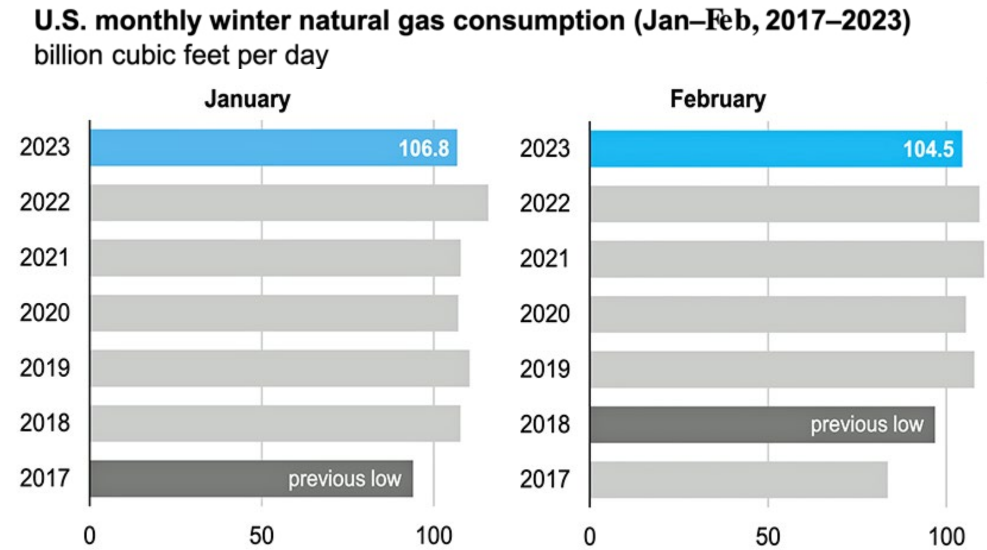
The U.S. Energy Information Administration on Wednesday *reported* that domestic use of natural gas reached a six-year January low this year.

Domestic consumption in February 2023 was the lowest in five years for that month. As a result, EIA said in its *Short-Term Energy Outlook*, natural gas inventories at the end of March were 19% higher than the average over the preceding five years.

Use of natural gas is widely targeted for gradual reduction in a planned transition to renewable energy sources, but the reduced use this past winter was attributed to mild weather and the resulting decrease in demand for it as a heating fuel in the residential and commercial sectors.

This varied by region. Natural gas accounts for 70% of space-heating fuel in the Midwest Census Region and 52% in the Northeast Census Region, for example. Residential and commercial gas consumption was down 16% and 22% in those two regions, respectively, from the January-February average in the preceding five years.

But in the West Census Region, one of the coldest winters in years caused gas consumption to surge in the electric power sector more than in the residential and commercial sectors: 33% more gas was burned in January and February than the average over the preceding five years, EIA said.




U.S. natural gas consumption was at a six-year low in January and five-year low in February. | *EIA*

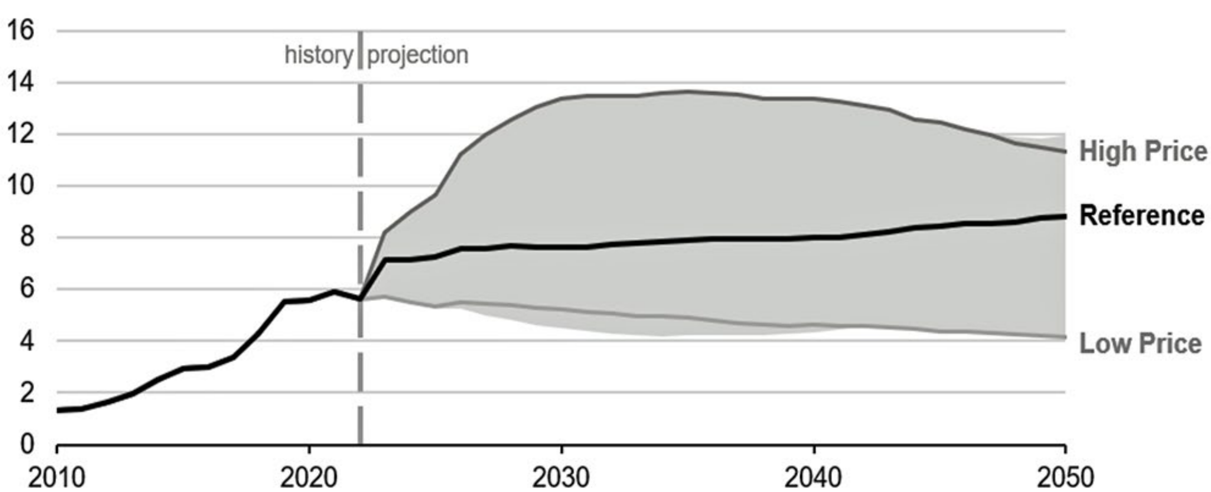
The U.S. is the world's largest producer of natural gas and more recently became the largest exporter of its liquid form. EIA projects continued year-over-year growth of LNG exports in 2023 and 2024.

Meanwhile, EIA on April 11 *said* that it expects continued and long-term growth in U.S. production of "associated natural gas" — gas that is extracted from oil formations.

Associated natural gas historically was a footnote, accounting for only about 6% of domestic supply as recently as 2010. But in its *Annual Energy Outlook*, EIA is projecting it will account for approximately 20% of total U.S. natural gas production through 2050.

EIA bases its prediction on three trends:

- rising oil prices that will support increased production from nontraditional or unconventional oil formations that contain significant amounts of natural gas;
- the tendency of these unconventional oil wells to produce a higher ratio of natural gas to oil as they age; and
- increasingly favorable economics for associated natural gas resources, in part because of official policies such as the Inflation Reduction Act's penalties for venting and flaring methane. ■



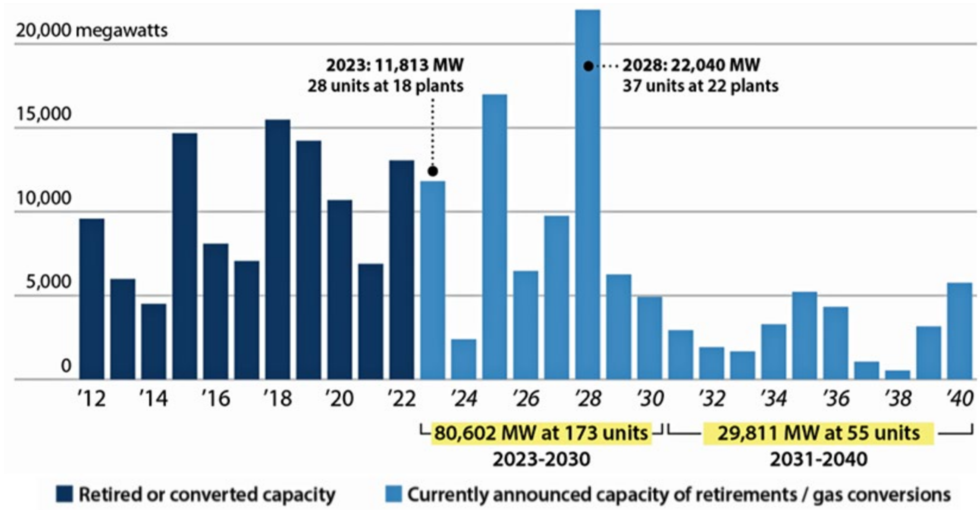

U.S. natural gas production (Tcf) is expected to increase through 2050. | *EIA*

# FERC/Federal News

## IEEFA Report Forecasts Wave of Coal Power Retirements Through 2030

### *Fewer Plants Burning Less Coal, Generating Less Electricity*

*By John Cropley*




Announced closures of coal-burning power plant units varies widely from year to year. | *Institute for Energy Economics and Financial Analysis*

An energy market research group estimates that 159 GW of coal-fired power production will be online in the U.S. in 2026, down half from a peak of 318 GW in 2011.

By 2030, the Institute for Energy Economics and Financial Analysis report projects, the U.S. coal-fired fleet will be down to 116 GW, as gas, wind and solar power supplant it.

Fewer than 200 large units — those rated at 50 MW or more — now operating have not announced retirement dates, IEEFA said. The organization also noted an even steeper decline: Coal-fired plants now burn less than half as much coal and produce less than half as much electricity as they did in 2011.

Data were derived from internal IEEFA research, the U.S. Energy Information Administration, S&P Global and company reports.

IEEFA data analyst Seth Feaster, author of "U.S. on Track to Close Half of Coal Capacity by 2026," said in a news release April 3 that the continuing trend does not bode well for the industry.

"This milestone is another clear sign of the ongoing and deep restructuring of the U.S. coal industry, as demand for the fuel continues to drop quickly," he said. "It is likely to result in significant mine closures, layoffs, and falling tax and royalty payments in coal-producing states."

IEEFA states that it takes a nonpartisan, evidence-based approach to its mission, which is to accelerate the transition to a diverse, sustainable and profitable energy economy. The 501(c)(3) nonprofit corporation lists multiple climate advocacy organizations among its financial supporters.

Its report speculates that coal power generation may decrease even more quickly than projected because of higher operation and maintenance costs for the remaining units, most of which went into service in the 1970s.

EPA in the last two months has taken multiple steps to tighten emissions regulators from coal-burning power plants; these are expected to prompt additional retirements. (See *EPA Proposes Tougher MATS Regs on Coal Power Plants*.)

The long-running effort to restrict and or reduce coal as a fuel in the U.S. has drawn criticism from the coal industry and its allies as a threat to energy security. But as federal and many state governments press to speed the transition from fossil fuels to emissions-free alternatives, some grid operators are voicing similar concerns. (See *PJM Chief: Retirements Need to Slow down*.)

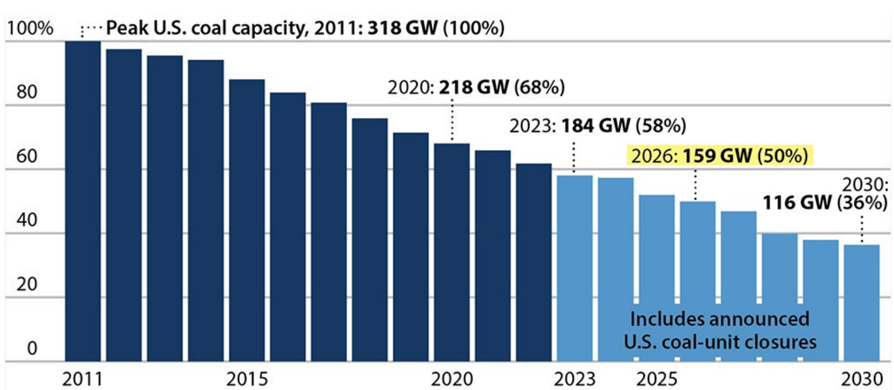
The IEEFA report projects more than 80 GW of coal retirements from 2023 through 2030 and indicates 10.5 GW of the retired plants are expected to be converted to burn natural gas.

The pace of retirements will be steady over time, the report said, but not from year to year, as construction delays have ensued on renewable energy projects. For example, 11.8 GW of coal-fired capacity is currently announced for closure in 2023, less than 3 GW in 2024, 17 GW in 2025, roughly 10 GW in 2026 and 22 GW in 2027.

With the 2022 passage of the landmark Inflation Reduction Act, and its heavy emphasis on accelerating the energy transition and building a supply chain for it, the numbers could be in flux for a while.

The report noted that multiple factors in favor of coal in 2022 — soaring natural gas prices, high demand for power and the post-pandemic economic rebound — were counterbalanced by railroad delivery problems, a labor shortage and utility reluctance to increase coal use.

When coal's use as a fuel for generating electricity in the U.S. peaked in 2011, it was responsible for 44% of power generation, EIA data cited in the report indicate. Based on current announcements and trends, coal's power market share could decrease to 10% or less by 2030, IEEFA said. ■




The Institute for Energy Economics and Financial Analysis projects a steady decline in U.S. coal-fired power generation. | *Institute for Energy Economics and Financial Analysis*

# Western Day-ahead Markets Debated at CREPC-WIRAB

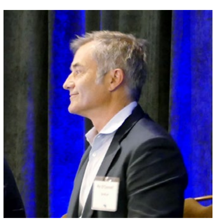
*By Hudson Sangree*

Western regulators and stakeholders filled a conference room at the Hyatt Regency Lake Tahoe Resort in Incline Village, Nev., for the spring CREPC-WIRAB meeting. | *© RTO Insider LLC*

INCLINE VILLAGE, Nev. — Speakers debated whether the West would benefit more from the one day-ahead market run by CAISO or with another run by SPP at last week's meeting of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Body.

The spring CREPC-WIRAB meeting took place as CAISO is drafting tariff language to add an extended day-ahead market (EDAM) to its real-time Western Energy Imbalance Market (WEIM) and SPP is developing its Markets+ program with a day-ahead market as its centerpiece. (See *SPP: 31 Entities Join in Markets+ Development*.)

Advocates for a CAISO-led day-ahead market and others backing SPP spoke on two panels Wednesday at the Hyatt Regency Lake Tahoe Resort, where Western regulators and stakeholders filled a large meeting room to capacity.



Ric O'Connell, GridLab | *© RTO Insider LLC*

"Markets give us affordable and reliable energy through breadth, depth and transparency," said Ric O'Connell, executive director of GridLab, a nonprofit technical advisory firm in Berkeley, California. "We need a market that's broad enough to capture resource and load diversity, and we need a market that's deep and liquid so that there's a lot of energy traded in that market, either in real-time or in the day-ahead."

A Western day-ahead market without California would lack those attributes, O'Connell said.

"California has close to half the load of the West," he said. "California has massive transmission connections both to the Pacific Northwest and to the Desert Southwest, and it's been trading with [entities in those regions] for decades … so I would posit that a Western market that does not include California is going to lack the breadth and depth that we need to unlock the benefits of affordable and reliable energy in the West."

The Western Energy Imbalance Market encompasses 80% of load in the Western Interconnection and has achieved $3.4 billion in benefits for its participants, including $1.5 billion last year alone, he said.

"We have huge potential to increase those benefits if we move to a day-ahead market that covers that same 80%," and even more if CAISO were to lead a Western RTO, he said.

Having two markets in the West and bifurcating those benefits would be a step backward, O'Connell said.

## 'A Swiss Cheese Universe'

In a subsequent panel, Stefan Bird, CEO of PacifiCorp division Pacific Power said the benefits of CAISO's WEIM are proven and substantial.

PacifiCorp co-founded the interstate trading market with CAISO in 2014 and was the first utility to commit to joining EDAM in December. The utility serves 2 million customers in California, Idaho, Oregon, Utah, Washington and Wyoming. (See *PacifiCorp to Join EDAM, Final Plan Released*.) The company is so far not among the 31 utilities and industry groups that have officially signed on to SPP's effort to develop a Western market.

"It doesn't matter if we're in our red states or blue states. We save money, improve reliability and reduce emissions [through the WEIM]," Bird said. "It's not theory. This is the real deal."

PacifiCorp has derived nearly $600 million in benefits as a WEIM participant, much of it by buying cheap solar power from California and other Western states, he said.

"Prior to the EIM existing, we wouldn't have been able to take advantage of all that low-cost solar that was being deployed very rapidly in California [without] enough load in California to use it all," Bird said. "The alternative in California was to curtail it. But for the EIM being able to trade very rapidly intra-hour — as opposed to the old days [when grid operators would] pick up the phone and try to make trades on an hourly basis — that simply wasn't possible."

PacifiCorp has reduced its greenhouse gas emissions by 42.6 million metric tons since 2014 because it does not need to run its fossil fuel-burning plants as much when renewable power is available through the WEIM, he said.

"The morning sun comes up with all that solar energy in Utah and southern Oregon and California, Bird said. "We're taking every bit of it we can, and we back off our coal fleet, our gas fleet. We're not incurring those fuel costs. We're not burning the emissions, and we save our customers money."

# Spring 2023 Joint CREPC-WIRAB Meeting

"We don't want to see those benefits disappear or get broken, and that's precisely what's being contemplated in a separate [SPP day-ahead] market that would be created on top of [the WEIM's] footprint," Bird said.

Having two day-ahead markets in the West would produce seams problems between balancing areas and provoke "situations of conflict where a peace treaty has got to be negotiated, and that's going to take years," he said.

It would be "a Swiss cheese universe that I think would really put a dent in those [WEIM market] benefits that are most important to us," Bird said.

## Independent Governance

Tom Bechard, CEO of Canadian energy marketer Powerex, said the seams issue was being overblown by those in favor of a CAISO-led day-ahead market. Powerex has been a WEIM member since 2018, but Bechard's comments reflected a preference for SPP's Markets+.

"There are some people in the room who are putting seams coordination first," Bechard said. "I think that's really kind of a misplaced priority. The [dialogue] I'm hearing about seams seems to be more fear-based than fact-based. And I know for a fact that seams can be managed efficiently through joint operating agreements."

A higher priority for those weighing day-ahead markets should be governance, Bechard said. He recommended a model resembling SPP's governance structure.

"It is not just an independent board that's required," Bechard said. "You need to have stakeholders with voting rights, and you need to have an impartial operator. Having stakeholders with voting rights ensures that it's the stakeholders that determine what goes to the board rather than the market-operator staff. And having an impartial operator ensures that the operator is not subject to undue influence from any particular state or set of states."

SPP has an independent board, a committee of state regulators and stakeholder groups that develop and vet policy proposals. It plans to apply the same governance structure to Markets+.

CAISO staff and management develop policy proposals with stakeholder input. The ISO is led by a Board of Governors appointed by the California governor and confirmed by the state Senate, resulting in all of its members being Californians. A legislative effort is underway to open the board to out-of-state members so CAISO can become an RTO. (See *Lawmaker Introduces Bill to Turn CAISO into RTO*.)

Pacific Power CEO Stefan Bird (left) and Powerex CEO Tom Blechard debated the merits of day-ahead markets being developed by CAISO and SPP. | *© RTO Insider LLC*

The WEIM Governing Body includes members from outside California and shares joint authority with the ISO Board of Governors over matters affecting the interstate market. EDAM also would be governed under a joint-authority model.

## 'Grid of the Future'

Bechard contended that an SPP day-ahead market could offer greater benefits in the future through resource diversity, assuming new interregional transmission lines connecting it to the Pacific Northwest get built.

When envisioning a day-ahead market, "we shouldn't be thinking about the grid that we have today," he said. "We should be thinking of the grid of the future."

As more solar comes online in the Desert Southwest and California and thermal generators retire, resource diversity and trading benefits between the regions will diminish, he said.

"They're going to have the same resources, the same load, the same issues with solar oversupply and evening ramp and net peak load," Bechard said. "We see that opportunity to trade between those markets declining."

Resource diversity and economic value between the Pacific Northwest and SPP will be greater, he said. The Northwest has large amounts of hydropower, and SPP has 30 GW of wind power in an area with weather patterns and peak demand times different from the West's, he said.

Bechard cited a Lawrence Berkeley National Laboratory report that showed some of the nation's highest-value transmission lines could be built linking SPP to the West, alleviating congestion and allowing resource transfers. (See *Lawrence Berkeley Lab Sees New Transmission Value Spike in 2022*.)

If the 31 entities that have signed on for the development phase of SPP's Markets+ program continue to its operational phase, the market would have a 50 GW peak load, he said.

California has a 54 GW peak load, so if CAISO were a separate market, there would be "two big markets … optimizing within their footprints" and potentially engaging in "robust and automated trade" in the day-ahead time frame, he said.

"It's much better than the status quo," Bechard said. "And it's definitely not a step back from what we have today." ■

Spring 2023 Joint CREPC-WIRAB Meeting

# FERC Commissioners Discuss Western Markets 'Dating Process'

## *Christie, Clements Urge Careful Consideration of Market Options in the West*

*By Hudson Sangree and Elaine Goodman*

INCLINE VILLAGE, Nev. — FERC Commissioners Allison Clements and Mark Christie offered their thoughts on Western market formation to a large gathering of state regulators and stakeholders at last week's meeting of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Body (CREPC-WIRAB).

Christie urged caution on joining an RTO, and Clements said "bigger is better" when it comes to organized markets. But both said the West will have to make its own decisions on market options.

Those options now include the Western Power Pool's Western Resource Adequacy Program (WRAP), SPP's planned RTO West and its Markets+ day-ahead offering, and CAISO's extended day-ahead market for its real-time Western Energy Imbalance Market (WEIM). A legislative effort is underway that could eventually allow CAISO to become a multistate RTO. (See related story, *Western Day-ahead Markets Debated at CREPC-WIRAB*.)

Clements compared the situation to a "dating process," a metaphor she said she had borrowed from others at the meeting. And like other speakers, she noted the difference between pre-pandemic circumstances in the West and the current push toward Western regionalization.

"You really have made great progress in the last two and a half years," she said. "Before COVID, everyone was just kind of looking around and checking each other out, and, wow, we come back from COVID and things have gotten serious."

"I want to be clear that FERC's job is not to be the parents to choose for you," she said. "We're not going to choose between the banker and the lawyer. We're not going to choose between the banjo player and the marketer. Right? You are going to make a decision on your own."

Clements pointed to the $3.4 billion in cumulative benefits obtained by participants in CAISO's WEIM as evidence of the value of market development. The market allows participants to trade inexpensive renewable resources and to optimize dispatch across portions of 11 Western states and one Canadian province.

"The benefits of the EIM have really kind of shut the door on the question of whether or not increased market optimization works," Clements said. "It feels like that conversation is done. Markets designed well save customers money. That's the bottom line."


FERC Commissioner Allison Clements | *© RTO Insider LLC*

She also praised the progress on WRAP, a first-of-its kind effort to coordinate resource adequacy across much of the Western Interconnection. FERC approved the program's tariff in February. (See *FERC Approves Western Resource Adequacy Program*.)

Decisions about whether to join WRAP, the proposed day-ahead markets or to engage in interregional transmission planning could have long-term consequences and must be considered carefully, Clements said.

"The idea that you would choose one partner for resource adequacy and one partner for the day-ahead market and another partner maybe down the line for transmission system planning creates a lot of inefficiency and leaves a lot of savings on the table," she said.

"You know, to my mind, it's always the case that bigger is better," she said. "The broader the interconnected nature of the system, the more ability you have to ensure reliability in extreme weather because the extreme weather won't cover the whole system."

A state-led market study in 2021 estimated that a West-wide RTO would save $833 million per year in production costs by 2030, Clements noted.

RTOs have seams agreements with each other and the ability to dispatch across those seams, and they can develop transmission while avoiding unnecessary costs and redundancies, she said.

"There are a lot of benefits that come with the full-scale development of an RTO, and there are issues to deal with as well," she said. "I won't pretend it's just a rosy walk in the park."

Seams agreements between RTOs can be especially difficult, requiring "intensive coordination," she said.

"So, as regulators, you want to be at the table very early to think about how that coordination is going to get set up," Clements said. "It's not the kind of thing you want to leave and punt down the road and just see how it goes for a while."

"Those are the questions I'm asking myself, as I see you all asking yourselves and engaging in these conversations around 'what and where do we go from here?'" Clements said. "I will say I'm really impressed by where you are. And I look forward to continuing to watch you all and support you all trying to figure out your next steps."

### 'Lowest Rates in America'

In a separate session, FERC Commissioner Mark Christie weighed in on the question of whether Western states should join an RTO.

"You in the West will decide for yourselves what you want to do," said Christie, who noted the range of options between doing nothing and joining "a full-scale RTO with all the bells and whistles."

The West could come up with a unique construct that's not being used elsewhere in the U.S., Christie said. Market choices, including real-time and potentially day-ahead market choices, could be meshed with a resource adequacy program such as WRAP, which Christie lauded as being creative, simple and voluntary.

"What could be more simple than having load-serving entities mutually pledge to reach certain resource requirements and to make available their excess resources when another participant needs it?" he said. "And to help each other in a reasonable way and on a voluntary basis."

Another aspect of the RTO decision is what a state utility commission would relinquish in

## Spring 2023 Joint CREPC-WIRAB Meeting

FERC Commissioner Mark Christie | © RTO Insider LLC

choosing to go with an RTO.

"If you want to give up your transmission planning, you've got to ask yourself, what am I giving up?" said Christie, who served 17 years on the Virginia State Corporation Commission before joining FERC in 2021. "Well, you're giving up the ability … to control how assets are going to be deployed and how much money is going to be spent and how the costs are going to be allocated."

"Maybe you want to do that," he added. "Maybe that works for you. My point is, don't accept unskeptically the benefits of any construct."

Putting customers first should be the driving interest for state and federal regulators, Christie said. He pointed to three Western states — Utah, Idaho and Wyoming — that had the lowest electric rates in the nation as of the morning of his presentation.

"If the promise of an RTO is [that] it's going to save us all this money, and we're sitting here in these three states and we have the lowest rates in America, the question would be, 'Seriously? … It's going to save us money? How?'" ■

# Calif. Agency Seeks to Transform Wildfire Safety Culture

*By Elaine Goodman*

INCLINE VILLAGE, Nev. – A relatively new California agency is working to transform utilities' wildfire safety culture by shifting away from penalties and enforcement to a proactive, learning-based approach.

The California Office of Energy Infrastructure Safety was established through state legislation following devastating wildfires in 2017 and 2018, according to Caroline Thomas Jacobs, the office's director. The agency got its start as the Wildfire Safety Division within the California Public Utilities Commission but became a standalone department in July 2021.

The office, known as Energy Safety for short, is now about three years old.

Thomas Jacobs talked about the new initiative during a panel discussion at last week's joint meeting of the Committee on Regional Electric Power Cooperation (CREPC) and the Western Interconnection Regional Advisory Body (WIRAB).

Energy Safety's activities are based on a shift from "a compliance-based, reactive, penalty-enforcement approach to issues of safety to implementing a new, proactive planning-learning-improvement regulatory cycle," Thomas Jacobs said.

Among its duties, the agency reviews utilities' wildfire mitigation plans and assesses their safety culture each year. Wildfire mitigation plans are based on a "maturity model" in which utilities explain where they are in terms of wildfire prevention activities and where they expect to be as a result of safety investments.

In the safety culture assessment, utilities survey their employees and contractors — from frontline inspectors to senior managers — on their understanding of and approach to wildfire safety. Energy Safety then makes recommendations on how safety culture could be improved and follows up to see if the recommendations are being implemented.

But enforcement isn't disregarded: Energy Safety also conducts inspections, audits and investigations to see whether utilities are complying with their approved wildfire mitigation plans.

Panelist Brian D'Agostino, vice president of wildfire and climate science at San Diego Gas & Electric, said the new framework is "having a real impact" on the utility's culture and helping it maintain focus on priority safety areas.

"These safety culture assessments don't come back and say everything's great top-to-bottom," D'Agostino said. "It gives us areas where we can really focus on and areas where we can improve."

Panelist Sumeet Singh talked about how safety culture has changed at Pacific Gas and Electric, where he is executive vice president of operations and chief operating officer.

"Frankly, the wildfire risk is something that surprised PG&E," Singh said. "One of the big reasons for the surprise was the significant drought that happened in 2014 to 2016 that completely changed the environment in which the overhead electric assets operated."

The change was initially missed because of the utility's focus on reliability and running assets to failure, Singh said. Now, he said, PG&E has adopted a mindset seen in high-hazard industries.

The Camp Fire, which destroyed much of the town of Paradise in November 2018 and killed more than 80 people, along with a series of Northern California wine country fires in October 2017, forced PG&E into bankruptcy and led to a multibillion-dollar settlement with fire victims.

In June 2020, the utility pleaded guilty to 84 counts of involuntary manslaughter and one count of arson in connection with the Camp Fire. In February, PG&E pleaded not guilty to 11 charges stemming from the September 2020 Zogg Fire. (See *PG&E Pleads Not Guilty to Manslaughter Charges*.)

Singh said that mitigations in the utility's wildfire safety plan include plans for undergrounding 10,000 miles of distribution lines and replacing bare lines with covered conductor or insulated wire in high fire-threat areas. (See *PG&E Scales Back Plan to Underground Lines*.) PG&E is also turning to remote grids and microgrids in situations where a handful of customers in remote areas are served by distribution lines that run across risky terrain.

But Singh said PG&E is also working to change its safety culture. One goal is to make sure that employees who know the assets feel empowered to speak up if they spot a problem, he said.

Another issue has been the different perception of risk among employees ranging from inspectors to supervisors and executive leadership. The focus now is to "align on the perception of risk," Singh said.

He gave as an example an employee who has been working on electric systems for a long time.

"They may have been OK at one point in time to look at [an] adverse condition in the health of a tree and say, you know what, we can actually remove or address that in six months," Singh said. "That's not the case anymore. That's an immediate safety issue that actually needs to be addressed right away." ■


From left: Caroline Thomas Jacobs, California Office of Energy Infrastructure Safety; Brian D'Agostino, San Diego Gas & Electric; Sumeet Singh, Pacific Gas and Electric; and Oregon PUC Commissioner Letha Tawney. | *© RTO Insider LLC*

## CAISO/West News

# TransWest Express to Break Ground After BLM Approval

By Robert Mullin

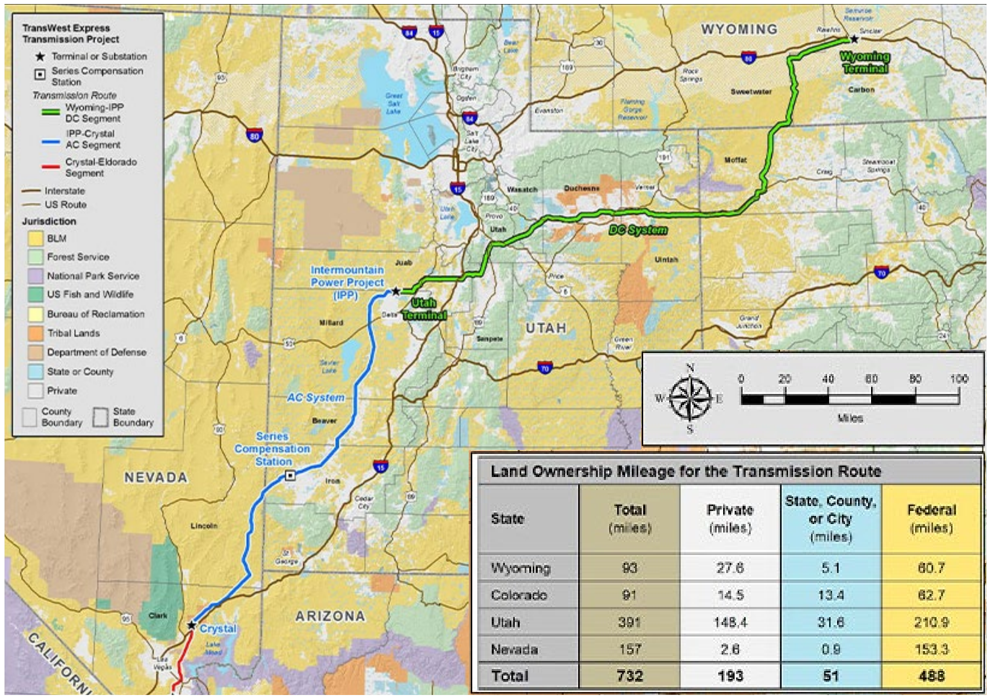
Developers of the Western Interconnection's largest transmission project in decades can begin construction after getting the go-ahead from the U.S. Bureau of Land Management on April 10.

BLM *issued* a notice to proceed (NTP) to the TransWest Express (TWE) project, a 732-mile high-voltage line that will be capable of transmitting 3,000 MW of energy from wind farms in Wyoming to consuming markets to the west — specifically California. The NTP is the final step of a BLM approval process begun in 2008.

"Achieving the BLM NTP milestone provides important certainty that is needed as we work to complete other pre-construction steps such as finalizing our [engineering, procurement and construction] contractor team. We plan on commencing construction activities on the TWE project before the end of the year," TransWest CEO Bill Miller said in a statement.

TWE would cross federal land for about two-thirds of its path, traversing three Western transmission planning regions. The project would consist of three linked segments: a 405-mile, 3,000-MW HVDC line between Wyoming and Utah; a 278-mile, 1,500-MW HVAC line between Utah and Nevada; and a 49-mile, 1,500-MW HVAC transmission line in Nevada. It would connect in Utah to lines serving the Los Angeles Department of Water and Power and in Nevada to CAISO's balancing authority area.

"Public lands continue to play a vital role in advancing President Biden's goal of achieving a net-zero economy by 2050," BLM Director Tracy Stone-Manning said in a press release. "This large-scale transmission line will put people to work across our public lands and will help deliver clean, renewable energy. Our responsible use of public lands today can help ensure a clean energy future for us all."




| Land Ownership Mileage for the Transmission Route | | | | |
|---|---|---|---|---|
| State | Total (miles) | Private (miles) | State, County, or City (miles) | Federal (miles) |
| Wyoming | 93 | 27.6 | 5.1 | 60.7 |
| Colorado | 91 | 14.5 | 13.4 | 62.7 |
| Utah | 391 | 148.4 | 31.6 | 210.9 |
| Nevada | 157 | 2.6 | 0.9 | 153.3 |
| Total | 732 | 193 | 51 | 488 |

The 732-mile TransWest Express transmission line is designed to deliver Wyoming wind power to markets farther west — particularly California. | *TransWest Express*

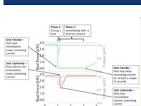
TWE is expected to create about 1,000 jobs during its construction phase, according to BLM. The line would tap power generated by the 3-GW Chokecherry and Sierra Madre Wind Energy Project in Wyoming, which will also partially sit on public lands administered by the BLM once construction is complete.

Both TransWest and the wind project are owned by The Anschutz Corp.

Last week's federal approval marked the second milestone for TWE in less than a month. In March, FERC approved an agreement allowing the company to continue its effort to become a participating transmission owner (PTO) in CAISO under a new "subscriber PTO" model the ISO is developing to accommodate lines not funded by its transmission access charge, a cost allocation mechanism. Instead, TransWest would be completely funded by its own customers. (See *FERC OKs CAISO-TransWest Move Toward PTO Status*.)

TransWest said it expects to complete construction of the first stage of the transmission project in 2027. ■

## West news from our other channels



*NERC, WECC Outline EV Charging Reliability Impacts*

NetZero Insider

*Analyst Foresees $35-$45 Range for Wash. LCFS Credits*

NetZero Insider

*Clean Energy Startups Earn Millions in CEC Grants*

NetZero Insider

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

ERCOT News

# ERCOT Stakeholders Endorse Staff's Bridge to PCM

*By Tom Kleckner*

ERCOT stakeholders agreed last week to endorse staff's recommended changes to the operating reserve demand curve that will serve as a bridge to Texas regulators' proposed performance credit mechanism (PCM).

Staff are proposing to add multistep floors within the same range of operating reserves. Their analysis has shown floors of 6,500 MW at $20/MWh and 7,000 MW at $10/MWh would have increased revenues to generators by about $500 million during the 2020 and 2022 pricing years.

ERCOT says that the ORDC increasing during substantial operating reserve surplus periods will improve pricing signals, help retain existing assets, add new dispatchable generation and reduce the frequency of reliability unit commitments — all objectives of the Public Utility Commission when it directed the grid operator to evaluate bridging options.

After exploring several other alternatives in recent weeks, the Technical Advisory Committee sided with the staff proposal during a special meeting April 10 by a 21-6 margin, with two abstentions. All six representatives of the Consumers segment voted against the endorsement, citing a preference for a dispatchable reliability reserve service that they said would create more reserves and lead to a bigger reserve margin.

TAC members were supportive of an initial staff recommendation to publish an indicative PCM but determined it didn't meet the bridging option's requirements. The PUC required alternatives that make only minimal system changes and be implemented within a year, align with the existing market framework and can be hedged by market participants through their energy positions.

Mark Dreyfus, who represents the city of Eastland and other commercial consumers, said the proposed floors will create a "significant" wealth transfer from consumers to generators. He called for more transparency and reporting from the generators on the increased revenues intended to stimulate generation construction.

"I think it is important that we get … some commitment that these funds won't be used for the purposes that are laid out in the investment in existing generation and in new generation," he said. "There's no obligation on the part of the generators at the end, nor are they competing for these funds."


ERCOT headquarters in Austin, Texas | © *RTO Insider LLC*

Dreyfus found support from Randy Jones, a 17-year Calpine executive who spent two years on the previous ERCOT Board of Directors representing the Independent Generators segment. TAC Chair Clif Lange jokingly introduced Jones as "member emeritus."

"I get nervous when we talk about mechanisms to absolutely push money from the demand side to the supply side, without real justification and without delving into what the potential unintended consequences are," Jones said. "It seems to me that the policy shift that is occurring in Austin and at the commission is one that says, 'Look, we're tired of feeding money to renewable resources and allowing them to enjoy the benefits of the ORDC that dispatchable units actually earned.'

"Whatever change for a bridge mechanism we put in place should contain a proposal of not paying additional revenues to wind and solar and focusing on moving those revenues strictly to what it is you're trying to encourage, which is dispatchable generation.

"I couldn't agree more with Mark in the sense that we need to know … if this is actually going to serve the policy decisions that the commission has made. Maybe it's time that we shift from being revenue neutral to being more targeted with these changes," he added.

The full board will take up the recommendation today. It is expected to eventually make a recommendation to the PUC.

## Credit Group Adds Members

TAC members also confirmed two additional members to the committee's newest stakeholder group, the *Credit Finance Sub Group* (CFSG).

National Grid Renewables Energy Marketing's Jacqui Runholt and CPS Energy's Jimmy Kuo will represent the Independent Power Marketer and Municipal segments, respectively.

The CFSG now has 13 members, and they will eventually vote on the group's leadership. Austin Energy's Brenden Sager and Reliant Energy's Loretto Martin are running unopposed for the group's chair and vice chair positions, respectively. ■

## ERCOT News

# ERCOT, Austin Energy Settle Uri Dispute

### *Calpine Relaunching Plant Construction; BHER Gas Unit to Remain Offline*

*By Tom Kleckner*

ERCOT *said* Wednesday that it will pay Austin Energy a $2.86 million to settle an alternative dispute resolution (ADR) stemming from the February 2021 winter storm.

The *settlement* covers 15 pricing intervals over Feb. 14-15, when ERCOT issued high-dispatch limit override (HDLO) instructions for Austin Energy's Fayette Power Plant, reducing its power output during the storm's first two days. At the time, the grid operator was desperately cutting load to help keep the system afloat after more than 50 GW of generation was knocked offline by the frigid weather from Winter Storm Uri.

The utility said in its ADR claim that Fayette's power reduction kept it from fully serving Austin Energy's native load and it incurred financial losses by purchasing power in the real-time market to cover contractual obligations.

Under ERCOT protocols, Austin Energy and other qualified scheduling entities (QSEs) are eligible for real-time HDLO payments if a resource's power output is reduced by a manual dispatch override and it can show a "demonstrable" financial loss.

To be eligible, QSEs must have complied with the grid operator's dispatch instructions to reduce power, received an economic dispatch base point equal to the resource's HDLO during the 15-minute interval, and filed a timely dispute.

ERCOT found Austin Energy met its obligations. However, it denied compensation for eight other intervals on Feb. 14, saying the utility's total generation and trade energy purchases were higher than its total load obligations during that period.

Austin Energy is an ERCOT non-opt-in entity (meaning it has not opted into the competitive retail market) that meets its load obligations through its own generation fleet, day-ahead market purchases and bilateral trades. The utility uses 600 MW of Fayette, which it jointly owns with the Lower Colorado River Authority.

ERCOT declined comment beyond its market notice.

The grid operator last year *denied* a settlement and billing dispute by Engie Energy Marketing after the company failed to meet a responsive reserve service obligation during the height of the winter storm. ERCOT said Engie was unable to demonstrate that ERCOT staff violated any obligations under the protocols.

Engie was seeking $48.7 million in damages.

Austin Energy's Fayette Power Plant, co-owned with the Lower Colorado River Authority. | *LCRA*

### Calpine: Time to Build Plants

Calpine last week said that it is *relaunching its Texas development program* following the Public Utility Commission's embrace of market-based incentives under its performance credit mechanism (PCM) design.

"We are encouraged that the PUC has laid the foundation to ensure Texas maintains a reliable power supply through market-based mechanisms, and we are excited to move forward with projects that will deliver on that mission," Caleb Stephenson, Calpine's executive vice president of commercial operations, said in a statement April 11. "Our hope is that the legislature will respect the regulatory certainty offered by the PUC and avoid discriminatory programs or direct government procurement that would undermine competition in Texas."

Stephenson said the PUC has "sent a clear signal that Texas is ready to support ambitious investments in a more reliable grid based on the principles of competition, not government mandates."

Texas lawmakers have responded to the PCM proposal by coalescing around a bill that would build 10 GW of gas generation to sit on the sidelines, for use only to prevent load shed. That plan was originally estimated to cost $10 billion, but recently uncovered documents indicate it may cost as much as $18 billion. (See *Texas Legislature Moves Bills Remaking the ERCOT Market*.)

Calpine said it plans to complete a new 425-MW gas-fired plant before the summer of 2026 at its existing Freestone Energy Center north of its headquarters. It also said it will develop another 425-MW gas unit near Austin and a large-scale combined cycle gas plant to support co-located industrial load.

### 70-MW Unit to Stay Offline

BHER Power Resources on April 11 notified ERCOT that it will *indefinitely suspend operations* at one of three gas-fired units near Abilene in West Texas.

The company said the unit suffered a forced outage last summer. Unit 3 went commercial in 1988 and has a summer seasonal rating of 70 MW. ■

# ISO-NE News

# ISO-NE Sees Record-low Power Demand on Holiday Afternoon

## *Growth of Solar Panel Deployment in New England Partly Credited*

*By John Cropley*

Demand on the New England regional power system fell to its lowest level in over a quarter century on April 9, Easter Sunday, thanks to the holiday, mild weather and sunshine beating down on an ever-growing number of solar panels.

ISO-NE on April 11 said that demand on the grid was the lowest it had ever recorded since the RTO began operations in 1997.

The 6,814-MW demand between 2 and 3 p.m. shattered the previous record, 7,580 MW, set May 1, 2022.

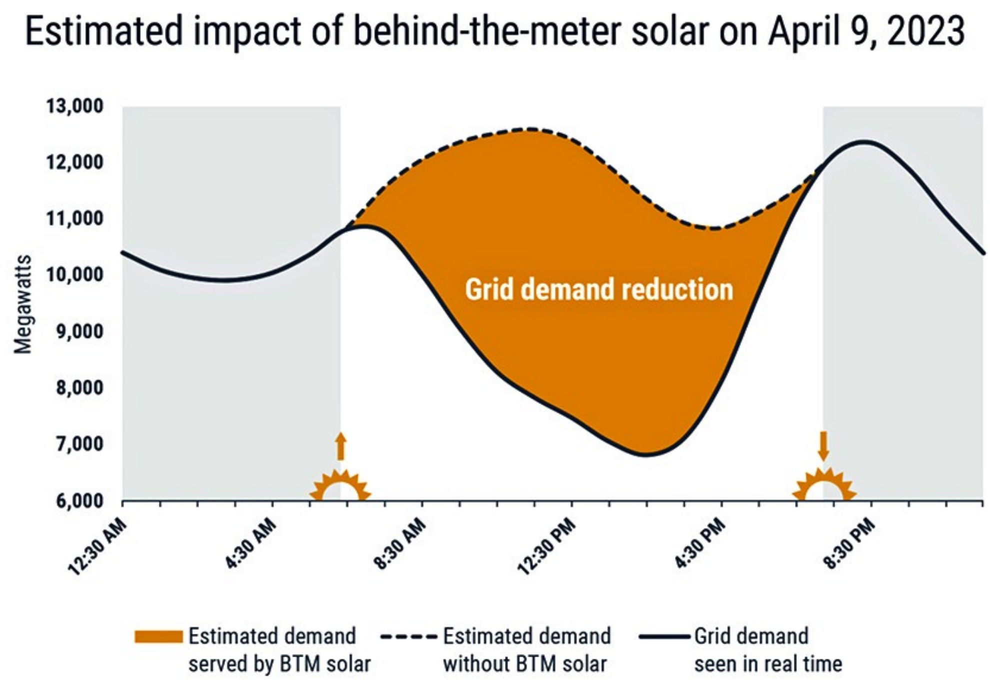
Steven Gould, ISO-NE director of operations, said the new record was not surprising.

"The evolution of New England's power system continues," he said in a *news release*. "The previous record lasted less than a year, and this one likely won't last long either. Each day, our system operators are seeing the clean energy transition play out in real time."

The lowest demand for electricity during the week is typically on Sunday, and Easter historically sees even lower demand than the average Sunday. Warmer temperatures on this Easter reduced demand even further. Abundant sunshine clinched the record, as behind-the-meter rooftop solar panels across the RTO's six-state region reached an estimated peak output of more than 4,500 MW.

ISO-NE said demand rose through the predawn hours of April 9 to peak at more than 10,000 MW just after sunrise, dropped below 7,000 MW to set the record in mid-afternoon, and rebounded quickly as the sun went lower in the sky.

Demand for the day peaked at more than




Power demand dropped to a record low across the ISO-NE system on April 9. | *ISO-NE*

12,000 MW just after sunset. This created the so-called duck curve in the flow of electricity through the grid, in which demand bottoms out in mid-afternoon rather than the overnight hours, as it usually does. The graphic representation of this phenomenon on a line chart vaguely resembles the classic rubber duck bathtub toy.

And as Gould indicated, the duck population is growing.

ISO-NE did not record its first duck curve until April 21, 2018. Through Dec. 31, 2021, it recorded 34 more duck-curve days. Then, in calendar year 2022, *it recorded* 45 duck curve days.

Solar power potential is at its strongest in the spring, ISO-NE noted, and 27 of the duck curve days in 2022 were in March, April and May.

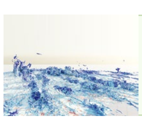
Summer 2022, with its midday air conditioning demands, saw very few ducks: two in September, one in June and none in July or August.

Late autumn and early winter also see fewer ducks, as solar power generation decreases before and after the winter solstice; ISO-NE recorded only two duck curves in January 2022 and just one in December 2022. ■


## Northeast news from our other channels

*Committee Begins Effort to Measure OSW Impact on Fisheries*

NetZero Insider



*Researchers Modeling Jet Stream Interference with OSW*

NetZero Insider

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

# Iowa Regulators Ponder MISO Tx Projects after ROFR Ruling

*By Amanda Durish Cook*

A member of the Iowa Utilities Board said last week that regulators are in the early stages of determining how the state Supreme Court's temporary reversal of right-of-first-refusal legislation will affect incumbent transmission owners' spending.

The IUB's Joshua Byrnes said the board is trying to "navigate" the injunction's effect on MISO's first long-range transmission plan (LRTP) cycle.

Byrnes said during Thursday's Organization of MISO States board meeting he is notifying other MISO state commissions that Iowa staff are still working through the implications on transmission development.

Last month's court ruling stands to affect $2.64 billion worth of transmission work in five Iowa projects that belong to ITC Midwest, MidAmerican Energy and Cedar Falls Utilities (*21-0696*).

MISO said in an emailed statement that it is reviewing the decision to determine its next steps. Staff did not address whether they might be preparing for a delay in certain LRTP projects or preparing more requests for proposals. The grid operator historically doesn't take positions on state legislation.

Iowa enacted its ROFR law in 2020 as an amendment to the legislative session's final appropriations bill. A standalone version of the law did not make it past the House subcommittee level.

LS Power challenged the law following its passage, arguing that it is unfair for it to be barred from competing for new transmission projects in Iowa unless an incumbent decides to relinquish its ROFR.

The Iowa Supreme Court ruled the legislation was unconstitutional under a state rule that an act should address just one subject conveyed in the title. The justices called the appropriations bill "a potpourri of various unrelated subjects"; legislators expressed frustration that they didn't understand the ROFR component before the late-night Senate vote was conducted.

"We are not surprised the ROFR lacked enough votes to pass without logrolling. The provision is quintessentially crony capitalism," the court said. "This rent-seeking, protectionist legislation is anticompetitive. Common sense tells us that competitive bidding will lower the cost of upgrading Iowa's electric grid and that eliminating competition will enable the incumbent to command higher prices for both construction and maintenance."

The court said that while its role is not to "second guess policy choices of the elected branches or regulators," it is the court's role to "adjudicate whether constitutional lines were crossed."

The court concluded that LS Power is "likely to succeed on its constitutional challenge." It vacated a prior appeals court decision, reversed a district court's ruling, and remanded the case to the district level to "finally" decide the merits of LS Power's arguments.

The Iowa ROFR legislation faces an uncertain future as other MISO states have introduced and sometimes discarded ROFR legislation since the beginning of the year. (See *MISO States Ramp Up ROFR Legislation*.) ■

| ITC Holdings

## MISO News

# MISO Defends New Curb on Director-Regulator Meetings

*By Amanda Durish Cook*

MISO says a recent rule change that places limits on MISO board members attending meetings hosted by state regulators is necessary, despite pushback from some commission members.

The Board of Directors voted last month to remove their option to attend meetings on MISO matters arranged by state or federal regulators. The change was made after a regular review of *board procedures* and is contained in the MISO Board of Directors Principles of Corporate Governance, which stipulates directors' conduct.

The revision leaves regulator-board member exchanges to take place largely during public board meetings, Advisory Committee meetings, and annual stakeholder meetings. MISO said the change is effective following the board's vote and was necessary to avoid the perception of partiality.

"The changes were clarifying edits to emphasize that board communications with stakeholders are most appropriate and useful in connection with open and public meetings," spokesperson Brandon Morris said in a statement to *RTO Insider*. "MISO's directors are mindful of their duties and independence as directors, as well as the independence of MISO, and are sensitive to perceptions of conflicts of interest or favoritism."

Morris said the board has declined multiple meeting requests from separate MISO sectors in the past and said it is "best that MISO's Principles of Corporate Governance align with the Board's practice of not meeting separately with MISO stakeholder groups."

"The changes do not change or limit in any way the interaction that MISO's Board has with MISO stakeholders today," he added.

During the grid operator's March board meeting, Michigan Public Service Commission Chair Dan Scripps and Indiana Utility Regulatory Commissioner Sarah Freeman expressed disappointment with the rule change.

The Organization of MISO States, which is comprised of regulatory representatives from the 15-state footprint, said it does not have a position on the removal of regulator-scheduled meetings with MISO board members. The organization did not provide further comment.

FERC representatives did not return *RTO Insider's* request for comment as to whether federal regulators will be affected by the changes.

Another governance rule change clarifies the Nominating Committee's recommendation that the board pursue waivers to seat certain directors past MISO's three-term limit. Board Chair Todd Raba warned last month that the board will likely have to authorize waivers to avoid an institutional knowledge gap, as multiple directors are on track to reach their term limits over the next few years. (See "Waivers May be Necessary to Retain Directors Past Term Limits," *MISO Board of Directors Briefs: March 23, 2023*.)

The Nominating Committee vets and selects board candidates for the membership's consideration. It is comprised of select board members and two MISO stakeholders, one of whom is typically from a state regulatory commission.

The board will meet privately for a strategy planning session today and tomorrow in Nashville, Tenn. The meeting won't be open to stakeholders because the topics involve attorney-client privilege. ■

Most of MISO's Board of Directors meets in March in New Orleans | *© RTO Insider LLC*

MISO News

# Montana Court Halts NorthWestern's Plant Construction

## *Judge Finds Facility's Air Quality Permit Lacking*

*By Amanda Durish Cook*

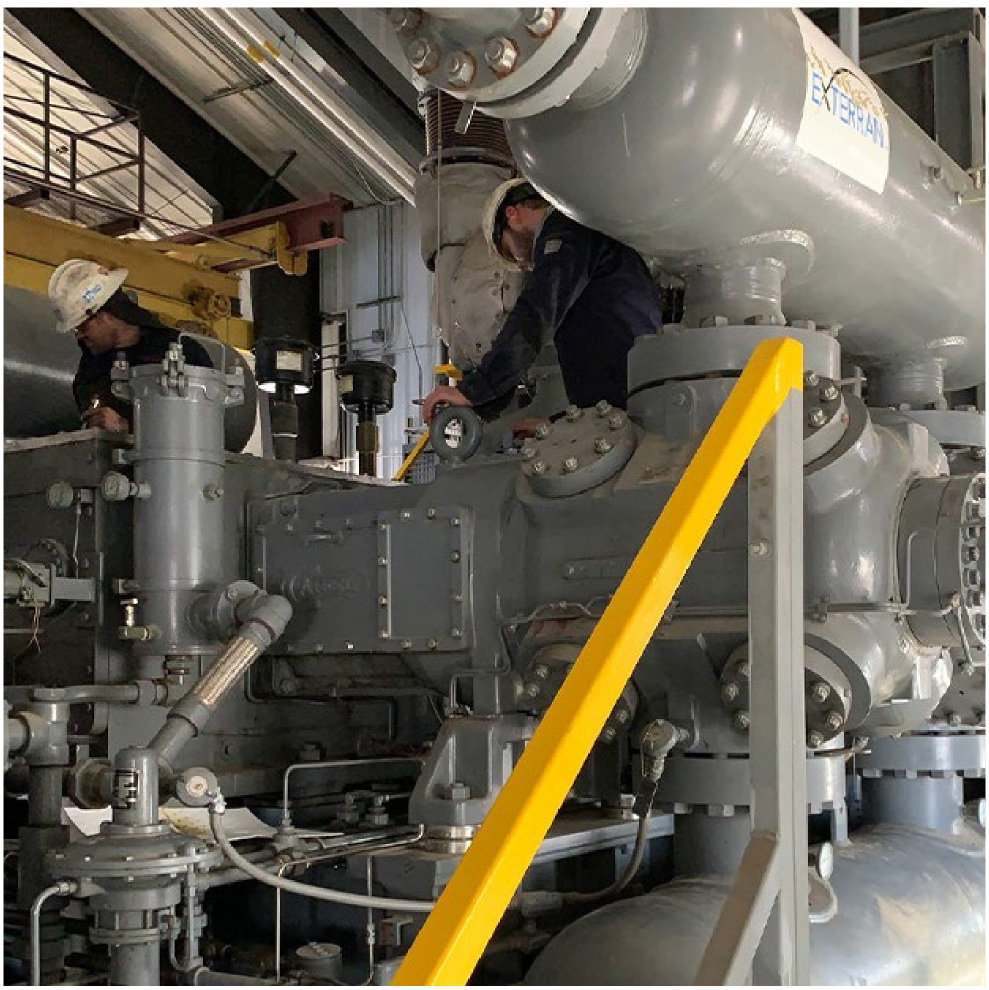
A Montana court this month invalidated an air quality permit and ordered construction to halt on NorthWestern Energy's planned methane gas plant, citing insufficient analysis of greenhouse gas emissions.

The 13th Judicial District Court in Yellowstone County ruled April 6 that the Montana Department of Environmental Quality's 2021 issuance of a permit for NorthWestern's 175-MW Laurel Generating Plant did not fully evaluate the facility's environmental consequences and was not within the law (DV 21-1307).

The Montana Environmental Information Center (MEIC) and Sierra Club challenged the DEQ permit, saying the 20-page environment assessment didn't adequately consider greenhouse gas emissions and climate repercussions. They said the permit ignored the plant's sulfur dioxide emissions, and it did not analyze water-contamination risks of drilling under the Yellowstone River to build a pipeline to Laurel.

The court said DEQ's exclusion of the pipeline's environmental impact was appropriate because the State Land Board has that purview. However, it agreed that the agency violated the Montana Environmental Policy Act by issuing the permit without considering the full environmental harm caused by the plant's construction and operation.

The court found that DEQ "reasonably examined" the plant's impact on regional sulfur dioxide levels, but it did not conduct a substantive analysis of the plant's greenhouse gas emissions. The agency argued that because it cannot regulate carbon emissions, it should not have to evaluate those pollutants.




Interior of a NorthWestern Energy gas plant in Montana | *NorthWestern Energy*

District Court Judge Michael Moses said that counter to DEQ's claims, the agency was not absolved from analyzing emissions.

"DEQ misinterprets the statute. They must take a hard look at the greenhouse gas effects of this project as it relates to impacts within the Montana borders. They did not take any sort of look at the impacts," Moses wrote.

The court determined that DEQ must take another "hard look" at the project.

"This project is one of NorthWestern Energy's largest projects in Montana. It is up wind of the largest city in Montana. It will dump nearly 770,000 tons of greenhouse gases per year into the air. The pristine Yellowstone River is adjacent to the project," Moses said. "This project will have a life of more than 30 years. That amounts to in excess of 23 million tons of greenhouse gases emissions directly impacting the largest city in Montana that is less than 15 miles down wind. To most Montanans who clearly understand their fundamental constitutional right to a clean and healthful environment, this is a significant project."

NorthWestern did not respond to *RTO Insider's* request for comment concerning the next steps it will take.

The MEIC and Sierra Club worked with the Thiel Road Coalition, a local group of landowners. The groups celebrated the ruling.

"My business, my family and my home will be directly impacted by NorthWestern's proposed project. We have raised our concerns every step of the way, and state and local governments keep ignoring us," Thiel Road Coalition's Kasey Felder said in a press release circulated by MEIC. "We were worried we would get a 'Braveheart' ending to this story. It's a relief to know the scales of justice are still in balance, and the little guy can be heard."

"For too long it's felt like a David-versus-Goliath battle. I'm so tired of the government and NorthWestern ignoring us. We live here. We have raised concerns time and time again about the impacts of this plant," Carah Ronan, another coalition member, said. "When the government breaks the law and refuses to listen to the folks who live in the area, we have nowhere else to turn but the courts. We are thankful that the courts are willing to side with average Montanans who are just concerned about their health, property, businesses and future generations." ■

## MISO News

# DER Experts Give MISO Aggregation Pointers

By Amanda Durish Cook

| © RTO Insider LLC

With MISO still years away from allowing distributed energy resource aggregators to fully participate in its markets, the RTO hosted experts last week to discuss best practices in registering DERs and data sharing.

Voltus' Emily Orvis said she thought it was valuable to talk about MISO's current DER registration process even if the grid operator may be six years away from final compliance with FERC Order 2222.

The RTO has requested that the commission allow it to wait until nearly 2030 to introduce a wholesale participation model for DER aggregation. It said it first needs to replace its market platform before staff have the technological capability to comply with the order. (See *MISO Stakeholders Protest RTO's Order 2222 Implementation Timeline*.)

Orvis said MISO should standardize its enrollment processes for demand response, emergency demand response, load-modifying resources and dual-enrolled resources.

"The fact that there are disparate registration processes has a cascading effect," she told stakeholders during a MISO DER Task Force conference call April 11. Orvis said that market participants must sometimes email sensitive customer data for LMR and emergency demand response registrations; she recommended staff adopt a single web portal for DER enrollments.

"The future is in some ways already here. We cannot wait until 2029 or whenever 2222 compliance is to figure out a more secure and streamlined registration process," Orvis said.

She said MISO should modify its registration process so it doesn't reject entire aggregation enrollments if a single site's data are incorrect or change. "For example, if one small site of 100 in an aggregation changes [its load-serving entity], the entire aggregation loses eligibility," Orvis said.

Creation Energy founder and CEO Chris Hickman said DERs will be more useful to the grid if better data sharing is in place. He said he has always assumed an entity would step up to create and manage a collaborative tool for DER data sharing. Eventually, he said, he realized it was up to his team to establish the nonprofit registry it *debuted* earlier this year.

When DERs trigger grid issues, it's because they're incorporated with little to no operational visibility and control, Hickman said. He said DERs integrated with utility or RTO visibility and control can solve issues like poor power factor and phase balance.

"Regions like Australia, Germany, Ireland, California and Texas that have high penetrations of DERs have experienced cascading outages … and have identified a registry as the key component to help resolve issues," Hickman said.

He said the industry has an opportunity to collaborate on a data exchange source, his organization's Collaborative Utility Solutions, that could save billions of dollars. The nonprofit is funded by utilities' memberships based on their size and competitive aggregators who pay for the data services. DER owners or operators are responsible for registering their assets' information.

RTOs, state regulatory commissions, equipment vendors and other industry members are eligible for free subscriptions. Hickman said he plans to keep the subscriptions free, saying that if charged, the entities would recover their costs through utilities or consumers, effectively charging the consumer twice for the registry.

Hickman said membership costs will drop as the enrollment grows and administrative costs are dispersed.

"The more members we attract, the lower the costs go," Hickman said. He said the system aims to replicate the Electric Power Research Institute's (EPRI) Common Information Model.

EPRI's Tanguy Hubert said the MISO region could house a program similar to the U.K.'s Flexible Power Initiative, where some DERs provide grid services by adjusting their power imports or exports.

Hubert said most of the U.K.'s DER-provided flexibility services are contracted without an advance capacity reservation for unplanned conditions. Only a fraction of capacity is contracted for planned situations under firm reservations, he said. ■

## MISO News

# MISO Unveils New Seasonal Auction Timeline, Ratio

By Amanda Durish Cook

MISO has circulated a new timeline for its first seasonal auction after a FERC order to rework a capacity value ratio forced it to delay the auction last month.

The grid operator opened its offer window at 8 a.m. ET today. It will accept offers until 6 p.m. Friday and then begin the 20-day planning resource auction on April 24.

MISO anticipates sharing clearing prices in a stakeholder workshop May 19, about a month after it usually posts auction results. The planning year begins June 1.

The auction was on hold as MISO recalculated its unforced capacity-to-intermediate seasonal accredited ratio that it uses to determine supply in the auction. The new ratio stands to lower some thermal resources' accredited capacity values. (See *FERC Order May Delay MISO's 1st Seasonal Capacity Auction and Vistra, EPSA Protest MISO's Show-cause Order*.)

The RTO said it published the new ratio for review on March 30. Staff said they gave stakeholders two weeks to confirm revised seasonal-accredited capacity and zonal-resource credit values based on the reworked ratio.

MISO said that after it wraps the auction, it will initiate stakeholder dialogue in Resource Adequacy Subcommittee (RASC) meetings "to investigate opportunities for future improvement." It said it will reserve the July RASC meeting to examine 2023/24 auction data and discuss trends. Later in the year, it said it will likely begin work on a process to "codify publishing, updating, and locking down" the ratio in future auctions.

MISO's Carmel, Ind., headquarters | © RTO Insider LLC

The delayed auction means MISO's 2023 joint resource adequacy survey with the Organization of MISO States will also have a later timeline than usual.

The OMS-MISO survey form is open to utilities through May 9. The organizations expect to publish their findings, normally posted at the end of spring, in late June or early July.

During an OMS board meeting Thursday, Executive Director Marcus Hawkins said the survey's new seasonal aspect should give stakeholders "more granular" adequacy estimates.

This year's survey will reflect MISO's seasonal auction format and project capacity values across four seasons for the next four years; count future capacity according to the grid operator's seasonal accreditation method; and use seasonal planning reserve margin requirements to compare against capacity values. The 2023 survey will also allow for one- to three-year lags beyond developers' stated commercial operation dates when counting potential new resources in the generator interconnection queue. MISO said its queue data shows that future generation has historically come online up to three years — and sometimes beyond that — after proposed commercial operation dates.

Hawkins said it's critical that utilities complete the survey so that stakeholders have the best snapshot of the footprint's near-term resource adequacy landscape. The survey is MISO's only annual footprint-wide adequacy survey.

Hawkins said it's up to states to decide how to use survey results and said OMS strives to communicate with regulatory staffs before the survey's reveal to manage expectations and ease the "drama" of unexpected results.

He said because the OMS-MISO survey is delayed, it will also postpone the kickoff of OMS' annual distributed energy resources survey, which seeks to get an annual count of the RTO's DERs.

Hawkins said the double survey delays are meant "to avoid survey fatigue and confusing emails about multiple surveys." ■

## PJM News

# PJM Seeks Settlement over Elliott Nonperformance Penalties

### *$1.8B in Penalties Assessed*

*By Rich Heidorn Jr.*

PJM asked FERC on Friday to initiate settlement judge procedures in its dispute with generators over nonperformance penalties for the December 2022 winter storm.

The RTO asked the commission to establish a "global settlement procedure" for the eight complaints filed by generators (*EL23-53 through EL23-60*) and "for any similar complaints that may be filed."

PJM officials told stakeholders last week they had assessed more than $1.8 billion in performance penalties on generators that underperformed during the Christmas weekend storm dubbed Winter Storm Elliott. (See related story, *PJM: Elliott Nonperformance Penalties Total More Than $1.8B*.)

The RTO told FERC it properly implemented its emergency procedures and that the nonperformance charges follow its tariff and are just and reasonable.

"At the same time, however, PJM recognizes the potential benefits of a prompt resolution, to the extent possible, of the disputed assessment of these charges," it said. "These disputes, considering the complaint, rehearing and appeal processes, could hang over the PJM market for years, affecting market participants' conduct in ways that may be irreparable and not always desirable. The capacity market also is designed in large measure to signal the need for new capacity resource investment, and the expectations of the financial and investment community accordingly are an important backdrop to the operation of this market. Timely, consensual resolution of these disputes thus could, potentially, help support the long-term health of the resource adequacy construct in the PJM region."

PJM noted that several of the complainants have also requested settlement procedures or alternative dispute resolution.

"A global proceeding would best provide, to the extent possible, a measure of principled consistency in any settlement outcomes of these multiple complaints," it added. "To that end, PJM seeks a single overarching settlement process, led and coordinated by the commission's administrative law judge(s), for all of these complaints." ■

# PJM: Elliott Nonperformance Penalties Total over $1.8B

### *FERC Approves Changes to Mitigate Risks*

*By Devin Leith-Yessian*

VALLEY FORGE, Pa. — PJM has assessed more than $1.8 billion in performance penalties on generators that underperformed during the December 2022 winter storm, the RTO told the Market Implementation Committee on Wednesday.

The penalties are being levied against 187 members through PJM's Capacity Performance (CP) system, which charges generators that underperform during performance assessment intervals (PAIs) and allocates those funds to generators that overperformed. (See *PJM Weighs Options for Winter Storm Elliott Follow-up*.)

A significant share of companies assessed with nonperformance charges during the storm, also known as Winter Storm Elliott, are also receiving bonuses, leaving a net total of $1,296,628,015 in penalties allocated among 116 members whose penalties outweigh their bonuses. PJM Director of Market Settlements Initiatives Lisa Morelli told the MIC that 260 members are set to receive bonuses, 182 of whom will be receiving payments that outweigh any penalties they've been assessed.

The net figures assume that every generator pays their penalties, but two companies have

Lisa Morelli, PJM | © *RTO Insider LLC*

already filed for bankruptcy because of their inability to pay: Lincoln Power and Heritage Power Marketing. PJM is holding back 25% of monthly bonus payments to account for the possibility of nonpayment; any penalty payments made above that in a given month will be trued-up in the following payment. (See "Lincoln Power Declares Bankruptcy Because of Penalties," *Complaints to FERC over PJM Performance Penalties Multiply*.)

### FERC Approves Alternative Billing Schedule

About 70% of members facing nonperformance charges have elected to make their payments under the standard three-month billing schedule. The remaining companies — which account for the bulk of the gross penalties — have elected for a longer nine-month payment period approved by FERC this month.

In an April 7 order, the commission said that allowing the payments to be spread out could reduce the number of defaults as a result of the penalties. The approval, effective April 4, was conditioned on PJM making a compliance filing within 30 days aligning the proposed tariff revisions to reflect language in the filing stating that when extensions in the billing period are approved by PJM, the longer period will be applied to all resources — rather than being granted on a unit-specific basis (*ER23-1038*).

The filing allows those saddled with penalties stemming from Elliott to opt for a nine-month alternative, with the tradeoff of being subject to interest charges. For future PAIs, the proposal allows PJM to spread all payments over nine months, with no interest, when an emergency event occurs near the end of the

# PJM News

delivery year, resulting in a shortened billing schedule. Under the status quo rules, nonperformance charges must be paid by the end of the relevant delivery year.

"Allowing members to pay their nonperformance charges over nine months instead of three should reduce the immediate risk of defaults, especially given that the tariff requires members to pay their monthly bills within one week and the first bill will be invoiced on April 7," the commission said. "Although overperformers during Winter Storm Elliott may have their bonus payments delayed, we find reasonable PJM's assessment that the transitional rule will maximize the total bonus pool by reducing the probability of defaults."

In comments supporting the proposal, the PJM Power Providers said that extending the payment period nine months will allow generators that incur charges over the winter to make payments through the summer, allowing those that run more frequently in those months to earn revenue to put toward the penalties.

Invenergy protested that imposing interest on nonperformance charges for generators that choose the longer payment period for penalties stemming from Elliott is unreasonable and goes against the purpose of the filing: to reduce the risk of defaults and therefore maximize bonus payments.

The commission pointed to PJM's argument that interest is necessary to balance the settled expectations of generators that based their operations on the tariff language in place at the time of the storm.

## Commission OKs New Bankruptcy Provisions

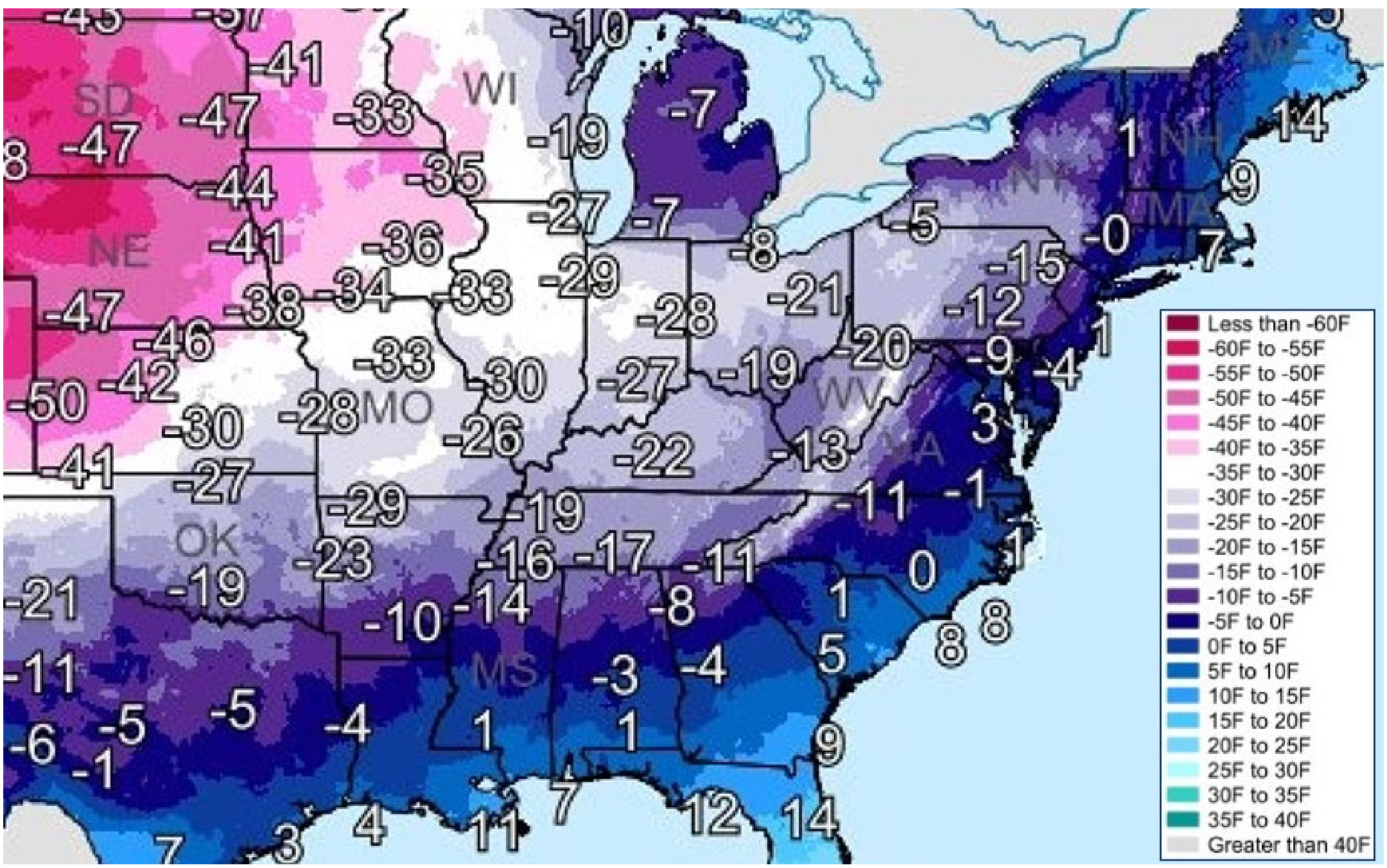
FERC also approved two PJM filings modifying its provisions for market participant bankruptcies, providing flexibility to allow members to continue operating in the markets while in default and requiring members filing for bankruptcy to clarify the RTO's rights in a first-day motion (*ER23-1058*, *ER23-892*).

PJM's proposal to allow continued market participation for members in default is limited to a handful of circumstances: when that participation supports reliability; the member is a net market seller; the market participant has demonstrated the ability to post collateral; and when participation cannot be terminated without regulatory approval. (See "Deficiency Notice Interrupts Timeline on CP Penalty Payments," *PJM MRC/MC Briefs: March. 22, 2023*.)

PJM argued that the proposal would allow it to maintain resource adequacy and generators with characteristics required by the grid, such as black start, while providing generators an opportunity to pay any obligations while earning revenue.

In an April 7 order approving the RTO's filing, the commission agreed that it could "minimize relative risk to the PJM markets and provide PJM an opportunity to recover funds on behalf of the PJM membership."

In response to comments on the filing, PJM committed to notifying the Risk Management Committee when these provisions are exercised and codifying that practice in the Credit Overview *supplement*. The RTO also stated it would work with the Independent Market Monitor and stakeholders to consider additional clarifications and changes. ■




Wind chill temperatures during Winter Storm Elliott | *NOAA*

## PJM News

# PJM Seeks to Delay Capacity Auctions Through 2028 Delivery Year

*By Rich Heidorn Jr.*

PJM asked FERC on April 11 to delay its next four Base Residual Auctions to give the RTO time to incorporate rule changes to address reliability concerns (*ER23-1609*).

The RTO initiated an accelerated stakeholder process in February to respond to concerns that the region could fall short of resources because of increased demand from electrification and a "timing mismatch" between plant retirements and new entries. It has promised to file the changes by Oct. 1. (See *PJM Presents Alternative Capacity Auction Schedule*.)

PJM's Reliability Pricing Model (RPM) calls for the BRA to be held in May, three years prior to the start of the delivery year. But the schedule has been suspended since 2018 as the RTO has considered repeated changes to its capacity market rules.

The 2026/27 BRA currently is scheduled to open on June 14, 2023.

"While further delay of the upcoming RPM auctions is not ideal, continuing to conduct the auctions under the existing rules further exacerbates the challenge of procuring the necessary resources to facilitate the imminent energy transition while maintaining reliability," PJM said. "In short, since the current tariff provisions … may be unjust and unreasonable and require change, it does not appear reasonable to continue to lock in resources on a forward basis to such provisions, particularly when they exacerbate the reliability issues that PJM has identified."

The RTO requested to hold a BRA every six months through delivery year 2028/29.

| Delivery Year | Illustrative BRA Schedule | Incremental Auctions Scheduled | IAs Cancelled |
|---|---|---|---|
| 2025/2026 | Jun 2024 | 3rd IA | 1st and 2nd IAs |
| 2026/2027 | Dec 2024 | 3rd IA | 1st and 2nd IAs |
| 2027/2028 | Jun 2025 | 2nd and 3rd IAs | 1st IA |
| 2028/2029 | Dec 2025 | 2nd and 3rd IAs | 1st IA |
| 2029/2030 (back on Tariff schedule) | May 2026 | 1st, 2nd, and 3rd IA | None |

PJM proposed a revised capacity auction schedule assuming a FERC order approving its market rule changes by Dec. 1, 2023. | *PJM*

PJM proposed the following "illustrative" BRA timeline, assuming the commission approves its proposed tariff revisions without material changes by Dec. 1, 2023:

- 2025/26: June 2024
- 2026/27: December 2024
- 2027/28: June 2025
- 2028/29: December 2025

The three-year forward schedule would resume for the 2029/30 BRA in May 2026.

PJM also proposed continuing its current practice of maintaining all third Incremental Auctions for each delivery year and canceling all IAs that fall within 10 months of the associated BRA.

"It is reasonable to cancel those Incremental Auctions that are within 10 months of a Base Residual Auction in these limited delivery years because there would be little, if any, need for such auctions under a compressed Base Residual Auction schedule, as very little time would pass between the Base Residual Auction and Incremental Auctions," PJM said. "Moreover, market participants will always have the opportunity to buy back and offer additional capacity in the third Incremental Auction before the start of the delivery year under this proposal."

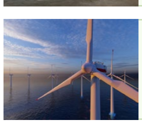
### Board's Directive

The PJM Board of Managers called for action to enhance the modeling of winter risk and correlated outages; ensure sellers can reflect nonperformance risk in their offers; improve capacity accreditation for all resources; and ensure synchronization between capacity and fixed resource requirement rules. (See *PJM Board Initiates Fast-track Process to Address Reliability*.)

"That does not mean that the other topics PJM and stakeholders have been examining since April 2021 in the Resource Adequacy Senior Task Force may not be included in the upcoming enhancement filing," the RTO told FERC. ■

## Mid-Atlantic news from our other channels

*Maryland Legislature Ends Session with Big Wins for Clean Energy* NetZero Insider



*NJ to Update OSW Strategic Plan* NetZero Insider

*NJ To Accelerate RGGI Fund Expenditures* NetZero Insider

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

# PJM News

## Virginia SCC Approves 800 MW of Renewables for Dominion

*By James Downing*

| Dominion Energy

The Virginia State Corporation Commission on Friday approved Dominion Energy's 2022 Renewable Energy Portfolio Standard plan, which includes more than 800 MW of carbon-free electricity.

The utility has to file such a plan every year in compliance with the Virginia Clean Economy Act. The SCC approved Dominion's $89.154 million revenue requirement for VCEA-related costs in the rate year of May 2023 through April 2024.

"This is another big step forward in delivering reliable, affordable and cleaner energy to our customers," Dominion Energy Virginia President Ed Baine said in a statement. "These projects will bring jobs and economic opportunity to our communities, and they will deliver fuel savings for our customers. That's a win-win for Virginia."

The projects approved on Friday are expected to lead to $250 million in fuel savings for customers over their first decade of operation. They include nine solar facilities and one energy storage project, which total nearly 500 MW and will be owned by Dominion itself. Kings Creek Solar and Ivy Landfill Solar are being built on previously developed land, with the latter being the first solar plant Dominion has built on a former landfill.

The commission also approved power purchase agreements with 13 solar and energy storage projects, which total more than 300 MW and are owned by independent developers.

Construction of the projects is projected to support thousands of jobs and more than $920 million in economic benefits across Virginia. The projects will cost the average residential customer an extra 38 cents on their monthly bill, with construction of the new renewable projects expected to be complete by 2025.

The SCC directed Dominion to provide additional analysis with its next RPS plan due later this year, including an assessment of the impacts of the federal Inflation Reduction Act and modeling that shows Virginia both inside and outside the Regional Greenhouse Gas Initiative's cap-and-trade system for power plants.

The commission sided with the utility and against its own hearing examiner's report, which recommended the rejection of cost recovery for the Shands Storage project. The project will be the largest storage facility in Virginia at nearly 16 MW once completed, but the report found it would cost consumers $36.8 million without corresponding benefits, especially given the so-far light development of renewables in PJM, though Dominion argued that was changing.

"The extent to which Shands Storage can take advantage of any such market evolution would depend in part on both the actual market design changes (which cannot be known at this time) and timing," the examiner said in their report filed in early March. "As Shands Storage degrades over time, each year this project is operational under PJM's current market design seemingly means it will have less product to sell in PJM if and when a market redesign occurs."

The SCC disagreed, noting that the VCEA includes targets for storage and that Dominion will benefit from starting to roll out the resource in Virginia. ■

## PJM News

# AEP, Liberty Call off Sale of Kentucky Operations

*By Amanda Durish Cook*

American Electric Power and Liberty Utilities have shelved their plans to exchange AEP's Kentucky operations for $2.6 billion, ending two years of attempts to gain the transaction's approval.

AEP announced Monday that it and Canada's Algonquin Power & Utilities, Liberty Utilities' parent company, have mutually agreed to cancel the deal two weeks before either party could independently pursue termination rights. In a *press release*, AEP characterized the sale's collapse as a reaffirmation "of its commitment to Kentucky customers."

The company said it now must take "swift and decisive action to be best positioned in the near term while continuing to develop a long-term strategy for Kentucky." That means filing a base rate case with the Kentucky Public Service Commission for 2024 that will include securitizing retired coal generation.

"As a partner in Eastern Kentucky for more than 100 years, we're renewing our focus on bringing opportunities to the region and supporting the communities we serve," AEP CEO Julie Sloat said. "We are working diligently to reimagine our strategy with the goal of not just supporting Kentucky but being an essential part of its economic and energy future. "We


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

believe there are opportunities ahead for our Kentucky operations, and we will focus our efforts on economic development, reliability and controlling cost impacts to customers."

Late last month, the Kentucky PSC, the Kentucky Office of the Attorney General and Kentucky Industrial Utility Customers urged FERC to halt the sale for a second time. They argued that Kentucky customers would pay larger bills through increased zonal transmission rates under Liberty ownership. (See *Kentucky Officials Ask FERC to Deny AEP-Liberty Deal*.)

FERC first rejected the sale in late 2022, indicating that the companies needed to pledge more consumer protections.

In a separate press release, Algonquin Power CEO Arun Banskota said the management team and board of directors decided "after careful consideration" that the transaction was not in Algonquin's best interest "in light of the evolving macro environment."

"I would like to thank the teams who have worked tirelessly throughout this entire process. Looking forward, [Algonquin] remains supported by a high-quality asset base [and] a strong balance sheet, and is well positioned to deliver sustainable, long-term growth, capitalize on the energy transition and create value for shareholders," Banskota said.

AEP also announced it had elevated interim Kentucky Power President and COO Cindy Wiseman to permanent president and CEO.

"Wiseman's experience overseeing customer service, economic development and government affairs positions her well to redefine the company moving forward," AEP said.

AEP reaffirmed its 2023 earnings guidance range of $5.19 to $5.39/share and an annual long-term growth rate of 6 to 7%. It said proceeds from its recently *announced* plan to sell its 1,365-MW unregulated, contracted renewables portfolio to IRG Acquisition Holdings for an expected $1.2 billion will compensate for previously forecasted proceeds from its Kentucky operations sale. AEP also said its equity financing forecast remains unchanged absent the transaction. ■

## PJM News

# FERC Approves Termination of FTR Trader's Member Status

*By Devin Leith-Yessian*

FERC on Friday granted PJM's request to terminate the membership of Hill Energy Resource & Services following the company's failure to pay several invoices for financial transmission rights transactions on time in 2022 (*ER23-423*).

PJM declared Hill to be in default on its credit obligations three times in January 2022 totaling more than $18 million, as well as being in default on five payments between January and February totaling $4,301,233.96, according to the RTO's filings.

The company argued that PJM's approval of the Lanexa-Dunnsville transmission line into Virginia's Northern Neck peninsula led to volatile pricing in the region, compounded by tariff violations that Hill alleged PJM committed by issuing collateral calls and subsequently preventing the company from liquidating FTR positions. (See *PJM Weighs Options on Hill Energy FTR Default*.)

"Essentially, PJM took actions that resulted in abnormal market conditions, those actions led to unjust and unreasonable rates, and PJM now asserts that Hill Energy's failure to post collateral for the unjust and unreasonable rates is a legitimate basis upon which to terminate Hill Energy's membership," Hill stated in its protest. The company did not provide comment on the order Monday.

After work began on the Lanexa-Dunnsville line in January 2022, Hill said prices began fluctuating between the energy offers of the limited number of combustion turbines sited on the peninsula and the $2,000/MWh transmission constraint penalty factor (TCPF), leading to "substantial losses leading to payment defaults that otherwise would not have occurred." It argued that given the unique circumstances — which led to a separate PJM stakeholder process and FERC filing to permit the RTO to temporarily suspend the TCPF in the region — a permanent termination of the company's membership was not warranted. (See *FERC Approves Pause of PJM Tx Constraint Penalty Factor in Va.*)

"Absent the application of the TCPF and the resultant unjust and unreasonable rates, Hill Energy believes it would have had positive returns or much smaller and manageable losses, and defaults likely would not have occurred," Hill's filings say.

The protest also argued that that PJM's first $921,500 collateral call on Jan. 11, 2022, constituted a tariff violation, citing section VI.C.7, which states that the RTO could only declare a credit default after a market participant failed "to satisfy a request for collateral for two consecutive auctions of overlapping periods, e.g., two balance of planning period auctions, an annual FTR auction and a balance of planning period auction, or two long-term FTR auctions."

The collateral call created a "cascading effect" once the company did not supply the additional funds by leading PJM to revoke the company's ability to sell open FTR positions and prevent it from accessing market data to continue mitigating its obligations. The company stated that by liquidating open positions, it aimed to reduce its collateral requirement under section VI.C.7, but that action was not immediately taken by PJM after the company made its request. The third collateral call on Jan. 13 for $17 million "crippled" the company's operations, as it believed it was required to first pay its collateral before addressing invoices.

"The timely sale or liquidation of these positions would have reduced its collateral requirement, thereby allowing Hill Energy to pay its January and February 2022 invoices on time, avoiding any payment defaults," the company said.

Responding to the protest, PJM stated that section VI.C.7 is limited to particular FTR auctions, rather than general credit defaults and is not applicable to Hill's circumstances. It described the issues raised by the company as "attempts to confuse the issues and raise disputes that do not stay PJM's obligation to terminate Hill Energy's membership."

PJM also said that any appeals to a membership termination must be done through its dispute resolution process, although the initiation of an appeal does not stay the ability to seek termination. Though Hill added an alternative request to its protest asking for the commission to consider instead approving a suspension of its membership while it engaged in that process, the order did not address the request.

In approving the request to terminate Hill's membership, FERC focused on the five invoices the company failed to pay between Jan. 25 and Feb. 23, finding that the company did not provide any tariff provisions supporting its case for excusing its nonpayment. Provided that is reason enough for termination, the commission said it does not need to address whether PJM followed its tariff in issuing the collateral calls. Responding to the company's argument that it would have been able to use revenues from its sell-only FTR bids to pay its invoices if PJM had submitted them when originally requested, the commission said it found that to be "speculative and uncompelling." ■

| © RTO Insider LLC

# PJM PC/TEAC Briefs

## CAPS Pushes for More Transmission Upgrade Data

VALLEY FORGE, Pa. — State advocates would like to see more details when supplemental transmission projects are proposed to the Transmission Expansion Advisory Committee (TEAC), Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said in a presentation to the committee on April 11.

The data currently provided by transmission owners tends to be inconsistent and lacking enough information to allow for proposal of alternatives, Poulos said.

"I'd like to get that information in a way that's most efficient" for transmission owners and advocates, he said.

In particular, he pushed for a breakdown of project costs beyond an overall estimate; increased clarity about whether a project falls under state jurisdiction; and the inclusion of contact information for a TO's relevant planning staff.

He also argued that the long period of time between the presentation of a need and a proposed solution suggests the timeframe for submitting alternatives could be lengthened. Currently, comments and alternatives must be submitted within 10 days, which Poulos said is inadequate if there are follow-up questions about a proposed project or for a prospective developer to evaluate a need and create a solution.

Tom Schmidt, principal planning engineer at Buckeye Power, said alternative proposals are welcome, especially when expensive repairs are needed, but they're not always feasible for a variety of reasons, such as when equipment fails. He noted that TOs provide a spectrum of information on projects, often providing a large amount of documentation.

Pauline Foley, PJM | © RTO Insider LLC

"Some have plenty of details to support their spending and others it seems a little bit lighter," he said.

## No Plan to Extend Accreditation Uprate Study Application Deadline

PJM's Pauline Foley told the committee that the RTO does not plan to lengthen the application period for generators to seek temporarily higher accreditation while PJM transitions to the modified effective load-carrying capability (ELCC) methodology FERC approved last week. The studies allow an existing or planned generator that is re-entering the transmission queue in order to increase its capacity interconnection rights to undergo annual transitory studies to determine if it can temporarily increase its capacity rating by utilizing existing transmission headroom. (See *FERC Approves Revisions to PJM's ELCC Accreditation Model*.)

In its order accepting the ELCC changes, the commission recommended that PJM consider leaving applications open longer should it seek a delay to the 2025/26 Base Residual Auction, currently scheduled for June 2023. PJM filed with FERC to make that delay on April 11. (See *PJM Seeks to Delay Capacity Auctions Through 2028 Delivery Year*.)

Protests against the ELCC filing argued that PJM's original intention of setting applications to close on March 3 violated noticing requirements under the Federal Power Act and left insufficient time for generators to make complicated decisions about unit accreditation. In a dissent, Commissioner Allison Clements agreed with those concerns and said the majority's decision to allow applications through April 10 was also insufficient.

Foley told the PC that extending the application period would not conform to stakeholders' intentions when they endorsed the filing's language.

## Reliability Analysis Update

Dominion proposed a $7.7 million upgrade to address a 300-MW load drop violation in the 2027 Regional Transmission Expansion Plan around the area of Dulles International Airport in Virginia.

The upgrade would cut the existing Brambleton-Poland Road 230-kV line and create a new 0.59-mile-long, double circuit 230-kV line between the Brambleton and Evergreen Mills substations. Both original substations would remain connected. ■

*— Devin Leith-Yessian*

PJM News

# PJM Operating Committee Briefs

## Gas Supply Issues During December Storm Reviewed

PJM *presented* the Operating Committee a review of the issues that contributed to insufficient natural gas supplies during Winter Storm Elliott, one of the leading causes of generation being offline during the storm.

Gas pipelines took numerous actions in the days leading up to the storm, PJM's Brian Fitzpatrick said, including restrictions on non-firm contracts and requiring daily balancing of supply and demand. But the actions were insufficient as the storm rolled in and caused force majeure declarations and losses in upstream supply. PJM was aware of the precautionary actions through its daily updates with pipeline operators, however the scale of the production loss was unforeseen, he said.

"We've never seen that level of supply loss in the history of Marcellus and Utica," Fitzpatrick said of the gas producing regions.

One stakeholder said insufficient gas supply is an issue for other RTOs as well, in part because the reliability analyses conducted by pipeline operators are minimal. Pipelines were originally sited to provide fuel for building heating, rather than for delivery to gas-fired generators. With the future of gas uncertain, the stakeholder said, it's unlikely there will be sufficient investment to simultaneously meet both needs.

Though the majority of generators that experienced outages related to gas fuel supply had non-firm delivery contracts, many generators with firm fuel also experienced interruptions. On Dec. 24, the day with the most outages, generators with non-firm fuel accounted for nearly half of offline capacity by percent of installed capacity (ICAP), while those with firm fuel represented more than a quarter.

Mike Bryson, PJM senior vice president of operations, said PJM generators with all forms of gas supply contracts saw their deliveries curtailed. The RTO is exploring ways of addressing the issue in its critical issues fast path (CIFP) proposal. (See *PJM Presents More Detail on CIFP Proposal.*)

"This needs to be part of a flexibility attribute going forward," he said.

Gregory Poulos, executive director of the Consumer Advocates of PJM States (CAPS), questioned whether there will be similar analysis on other major causes of forced outages

Brian Fitzpatrick, PJM | *© RTO Insider LLC*

during Elliott, noting that boiler issues across generation types accounted for more offline capacity than fuel supply for gas generators alone. Fitzpatrick said physical failures constituted around two-thirds of outages and will be the topic of future presentations.

## Proposals Seek to Address Transmission Outage Coordination

Stakeholders continued discussion on two *proposals* to address how PJM and utilities coordinate extended transmission outages. The proposals seek to avoid the surge in congestion pricing caused by line work in Virginia's Northern Neck peninsula. (See "*Transmission Outage Coordination Proposals Discussed," PJM OC Briefs: March 9, 2023*.)

A joint *package* from PJM, DC Energy and Public Service Enterprise Group (NYSE:PEG) would direct RTO staff to review approved Regional Transmission Expansion Plan (RTEP) projects for any extended outages that may be required and work with the utility to evaluate the impact of any such outages and expand outage information shared by PJM. Upgrades to facilities may be considered if outages are expected to cause significant operational issues.

The Independent Market Monitor's proposal would aim to identify congestion impacts in advance of projects being approved and request proposals from TOs. It would also treat a request to reschedule an outage as a new request or as a late submission if TOs try to reschedule too far out, seek to reduce or eliminate approval of outage requests after FTR bidding opens and prevent TOs from bypassing rules for long duration outages by breaking them into smaller segments.

Both proposals require that enhanced rating information be consistent with FERC Order 881, which is set to be implemented by July 12, 2025.

Jim Davis, of Dominion Energy (NYSE:D), said the Monitor's proposal is overly prescriptive and approaches transmission upgrades solely from a markets perspective without taking construction realities into account. Upgrading a large line in one project without segmenting it could create significant impacts on reliability and markets, he said. Other provisions in the Monitor's proposal would slow the outage process further and increase the risk of projects not being completed on time, he said.

"We as transmission owners need this flexibility because the transmission outage process is dynamic … especially as conditions change in the real time. As for the [Monitor's] recommendation that PJM not permit transmission owners to segment long duration transmission outages, that's just not how things work in reality," Davis said.

## Other OC Discussions:

- Stakeholders discussed sunsetting the Synchronous Reserve Deployment Task Force following an August 2022 FERC order rejecting PJM's Intelligent Reserve Deployment (IRD) proposal. Since the order, the task force has found that the scope of its issue charge and problem statement limit its ability to address the commission's concerns. PJM's Vijay Shah stated that there are no proposals currently before the task force.
- PJM Chief Information Security Officer Steve McElwee encouraged members to ensure their software patches are up to date to avoid falling victim to hackers. He noted that a Canadian utility was attacked on Thursday, with a pro-Russian group claiming responsibility in retaliation for the nation's backing of Ukraine. ■

# PJM MIC Briefs

## Stakeholders Endorse Manual Revisions for Real-time Values

VALLEY FORGE, Pa. — The PJM Market Implementation Committee overwhelmingly voted to endorse *manual revisions* to put limits on when generators can submit real-time values.

The revisions would only permit real-time values to be used for physical unit limitations or circumstances outside the generation owner's control. Documentation of those factors would be required to be submitted to PJM and the Independent Market Monitor within three days. If real-time values are improperly submitted, PJM's Lauren Strella Wahba said the RTO would have the ability to reject them after the fact and the option to refer the seller to FERC.

Real-time values are meant to be a temporary way for generators to provide PJM its operating capabilities when it cannot satisfy its unit-specific parameter limits or approved parameter-limited exceptions. The RTO has found that the values have been used to override parameter limits or exceptions in some instances, Wahba told the MIC, while in other circumstances dispatchers would only become aware of a deviation from operating parameters when they called upon a unit.

FERC rejected a previous proposal to codify real-time values in the tariff, stating in a May 2021 order that submissions would not have been based on actual physical or operational constraints. The commission also stated that PJM's status quo governing documents could contain market power issues (*EL21-78*).

Several stakeholders questioned why PJM sought endorsement of new manual language rather than embarking directly on making tariff revisions. PJM's Chen Lu said real-time values currently exist in the manuals without a requirement for physical constraints and by making manual revisions now, the changes can be implemented while stakeholders work toward a FERC filing on tariff revisions.


Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

Phil D'Antonio, PJM | © *RTO Insider LLC*

## Quick Fix Proposed to Address Falling Synch Reserve Deployment Response Rate

PJM *proposed* initiating a quick-fix process to address synchronized reserve deployment times exceeding PJM's 10-minute internal standard since it implemented an overhaul of the reserve market on Oct. 1, 2022. Nonperformance rates have also increased to around 49% during the eight reserve deployments since the implementation, excluding those during the December 2022 winter storm.

The quick-fix process allows for a problem statement and issue charge to be endorsed concurrently with a proposed solution. Under the proposed manual revisions, PJM would be able to extend the second step of the operating reserve demand curve (ORDC) process by taking nonperforming reserve resources into account, allow the addition of on- and off-peak periods, and require that the extended values be posted as they're changed.

PJM's Phil D'Antonio said the RTO believes that the issue lies in market participant training, rather than in the pricing of reserves, and ongoing outreach to generators will yield progress. Glen Boyle, also of PJM, said that because penalties are based on synchronized reserve revenues earned and clearing prices are low, penalties are also low at this time.

Monitor Joe Bowring said he believes the issue is not appropriate for a quick-fix solution, as there is no demonstrated reliability issue that would be addressed by the proposed change.

He noted that PJM's proposal would nearly quintuple the second step of the ORDC, from 190 MW to 890 MW, without any quantitative support for that significant a change, which he argued would trigger shortage prices more often and increase the price of synchronized reserves. Bowring also pointed out that the Oct. 1, 2022, change in the reserve market design increased the supply of synchronized reserves and included a must-offer requirement. He argued reserve prices since Oct. 1 have not been too low but have appropriately reflected the balance of supply and demand.

Under the applicable NERC standards, only one spinning event has exceeded the limit, and that is under investigation, Bowring said. He agreed with PJM that individual unit response times have been a problem and that both the Monitor and PJM are contacting individual unit

# PJM News

owners to investigate the reasons for the poor performance. Bowring also stated that PJM's rules for not paying resource owners for non-performance were too weak and contributed to the performance issues.

### Stakeholders Fine-tune Design Components on Local Considerations for Net CONE

Stakeholders continued the identification of *design components* to include in the drafting of proposals on whether and how to include regional factors impacting the net cost of new entry (CONE), such as environmental regulations or taxes. The MIC also discussed interests and design components during the February and March meetings, with the next phase being the creation of packages. (See "Discussion on Local Considerations for Net CONE," *PJM MIC Briefs: March 8, 2023*.)

James Wilson, a consultant for five state consumer advocates, recommended two design components: a transition mechanism when net CONE is updated, potentially capping any increase at 20% during years between Quadrennial Reviews; and consideration of changes to the variable resource requirement (VRR) capacity demand curve shape — the latter of which he acknowledged had previously been ruled out of scope, which he suggested could ultimately result in any proposal to just change net CONE rules being rejected by FERC.

James Wilson, PJM | *© RTO Insider LLC*

Stakeholders discussed whether CONE values and the reference resource should be reviewed whenever an impact, particularly signed legislation, is identified, including in between Quadrennial Reviews.

The discussion also looked at whether the creation of a new CONE area should result in the original region parameters being recalculated to account for the different footprint, particularly if the reference resource was based in the excised area.

### Discussion on Co-located Load Packages

Several *proposals* to define how configurations in which load is directly connected to generators fit into PJM's rules continued to be discussed by stakeholders.

Much of the discussion was centered on whether generators co-located with load that does not have a direct interconnection to the transmission grid should be required to relinquish a portion of their capacity interconnection rights (CIRs) equal to the energy consumed by the load, as they currently are, or if they should be permitted to retain that capacity, as well as whether interconnection and ancillary services charges should be assessed. (See "Proposals on Rules for Generation with Co-located Load Presented," *PJM MIC Briefs: March 8, 2023*.)

Exelon's Sharon Midgley said the company's *proposal* would allow generators to retain their CIRs, but the facility would be classified as a load-serving entity for the co-located load and all applicable LSE charges and credits would be applied to it. She noted the package currently only focuses on capacity resources, but it will be expanded in the future to consider energy-only generation, given the interest expressed by other PJM members as well.

"Our primary interest is having more clarity in PJM's rules," she said.

A proposal from the Advanced Energy Management Alliance would codify all status quo rules and practices, with the addition of creating penalties for the host generator if the co-located load is not curtailed when the generator is dispatched.

Two proposals from the Monitor and a joint package from Constellation Energy and Brookfield Renewable remain largely unchanged since the MIC showed less than 20% support in a *November poll*. Following the poll, Bowring — whose package largely codifies existing practices and adds administrative requirements and charges — suggested discontinuing the discussion, but stakeholders felt that clarified rules are needed.

The Constellation-Brookfield *proposal* would allow generators to retain their full CIRs without making either the generation or the load subject to ancillary service charges, under the argument that the load does not benefit from grid services. Former Constellation Director of Wholesale Market Development Jason Barker stated that the arrangement the company envisioned under the rules would be a nuclear facility supplying power for highly interruptible load, such as hydrogen electrolyzers. (See "Limited Support for Co-located Load Proposals," *PJM MIC Briefs: Dec. 7, 2022*.)

Bowring argued that PJM should be required to assess the impact of diverting a significant amount of low-cost energy off the grid to meet new load added to the grid behind the generators. He also said that emissions would increase as a result because nuclear energy would be dedicated to the new loads while existing load would be met by the emitting resources at the top of the supply stack. A related result would be an increase in energy market prices that the Monitor had previously estimated as exceeding a billion dollars, Bowring said.

"Nuclear plants were never built to provide energy for a few hours per year. The promise to provide energy from the resources for a few peak hours a year is not consistent with the obligation of capacity resources."

### First Read on Smooth Supply Curve Quick Fix

PJM *presented* a proposal to initiate a quick fix process to clarify that the informational smoothed supply curves PJM publishes after Base Residual Auctions will not be created for Incremental Auctions (IAs). PJM's Skyler Marzewski told the committee that PJM cannot create smoothed supply curves for IAs because of the lack of demand curves in those auctions and the risk that they could be used to expose market sensitive data. ■

*— Devin Leith-Yessian*

SPP News

# SPP Markets and Operations Policy Committee Briefs

### Staff, Stakeholders See Resource Adequacy as Key Issue

SPP staff and stakeholders spent much of last week's virtual Markets and Operations Policy Committee meeting discussing resource adequacy and the various initiatives the grid operator has rolled out to address the issue.

"Resource adequacy is a critical area for us," SPP's Casey Cathey said. "The regional fuel mix is consistently changing. The state of the future grid is extremely important. Loads are changing; pretty much everything's changing that we know of in our industry, even HR."

As director of grid asset utilization, Cathey runs a department responsible for planning a reliable and efficient bulk electric transmission system, with an eye on economically preparing SPP for the future grid. His staff facilitates generation interconnection and transmission service functions and operates resource adequacy across both the Western and Eastern interconnections.

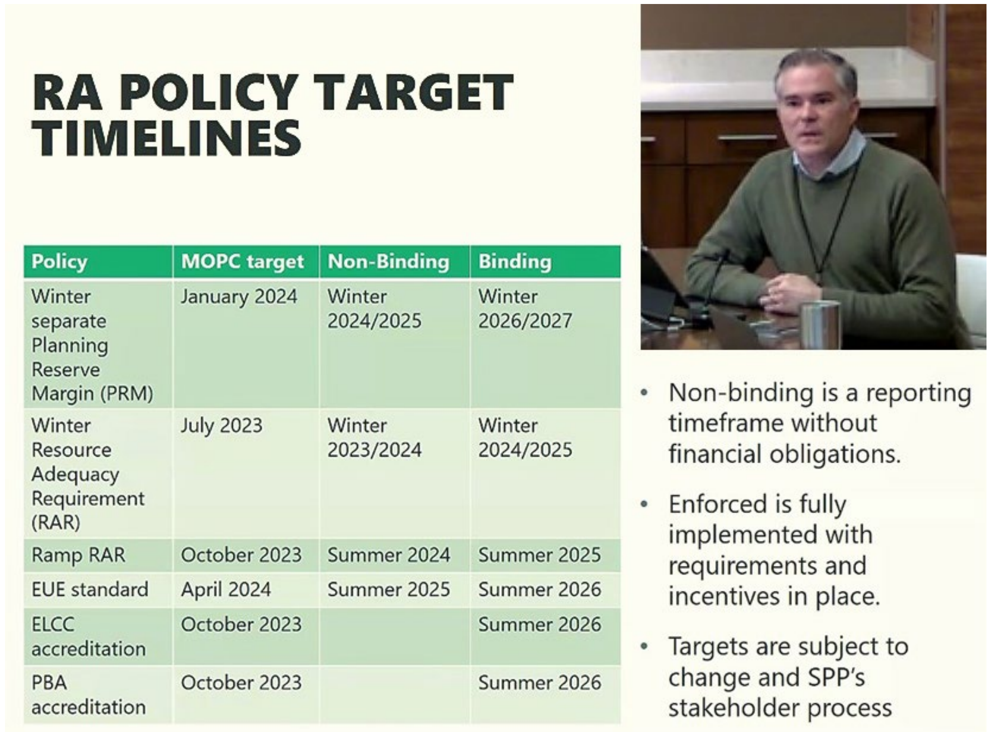
Cathey's department is not alone.

"Everything we're doing related to resource adequacy is critical, which is why we have a number of different groups that are focusing on various aspects of resource adequacy," COO Lanny Nickell said.

SPP's Supply Adequacy Working Group (SAWG) handles immediate resource adequacy issues and the technical aspects of various studies. The *Improved Resource Availability Task Force* was formed after the February 2021 winter storm and is working on fuel assurance and resource planning and availability recommendations identified in the RTO's review of the storm. (See *SPP Board of Directors/Members Committee Briefs: July 26-27*.)

The grid operator has also created the *Resource and Energy Adequacy Leadership (REAL) Team* under state regulators' Regional State Committee. Chaired by Texas Public Utility Commissioner Will McAdams, the REAL Team has been tasked with the more strategic aspects of resource adequacy by assessing SPP's current construct and anticipated challenges from resource mix changes, extreme weather effects, increased demand and evolving consumer behaviors.

Staff and stakeholders will be busy in the near term. SPP's annual tasks include winter and summer season deliverability studies and, this year, a loss-of-load expectation study to help




SPP's Casey Cathey details upcoming resource adequacy initiatives to MOPC. | *SPP*

determine the planning reserve margin for summer. The study will address weather-forecast uncertainty by using 40 historical weather years dating back to 1980. It will also determine a winter resource requirement and PRM and an unforced capacity PRM.

Staff and the REAL Team are both looking at whether an expected unserved energy (EUE) standard needs to be developed. Then there's the SAWG and Operating Reliability Working Group's joint review of the planned and maintenance outage policy and a slew of other work.

Cathey noted SPP and the industry have traditionally followed the one-day-in-10-years LOLE standard, a legacy from a time when generation fleets primarily comprised thermal resources. He said the industry may be leaning toward a combined standard that combines LOLE with EUE and loss-of-load-hours.

"One thing that is missing in our LOLE study is forecasting climate change. There's not a forecast or prediction or aspect to our LOLE study today, so that's another area that we'd like to continue to explore," Cathey said. "We have an urgency for resource adequacy, not the least of which is that resource adequacy is now one of our top corporate risks and also industry-wide. Everyone's trying to figure out the potential policy changes."

Nickell assured stakeholders that they will continue to have a voice in the resource adequacy work.

"I just want to deal with the impression that this is all happening behind the scenes and behind closed doors, and it's just staff collaborating on this stuff," he said. "That's absolutely not true. We have been working with stakeholders along the way. … They will all have an opportunity to provide input."

### Responding to FERC's Rejection

One of the REAL Team's first actions has been to direct the SAWG to modify and "harmonize" two revision requests so they focus on equitable and appropriate treatment of resources in response to FERC's recent rejection of SPP's capacity accreditation methodology for wind and solar resources on procedural grounds.

The commission agreed in March with renewable energy developers' arguments that it had erred with last year's order accepting the RTO's proposed tariff revisions to accredit wind and solar resources based on historical performance using an effective load-carrying capacity (ELCC) methodology (*ER22-379*). (See *FERC Grants Rehearing of SPP*

# SPP News

*Capacity Accreditation Proposal*.)

"This was a surprise to SPP and SPP staff and members," Cathey said, noting the ELCC was expected to be in place this summer.

The SAWG is working to separate the ELCC and performance-based accreditation into two separate RRs, with the ELCC request expected to reflect FERC guidance. The RRs have been targeted for final presentation to the board and RSC in October.

Cathey said the accreditation methodology changes for all resources should be filed together as a policy change and their implementation's timing be consistent across all resource types. He said seasonal net peak demand should be defined in the tariff and modifications considered for ELCC allocation methodology.

FERC said in its filing that it expects staff to provide "sufficient detail in its tariff, consistent with the directives of this order, to allow the commission to act in a subsequent order without the need for additional record development."

"We all know, especially since we passed the performance-based accreditation policy last summer, that we were working to become more equitable in our accreditation process across all fuel types," Cathey said. "However, from a legal perspective, that was not in front of [FERC] in that docket, and so it's certainly a lessons-learned for us."

## 2024 ITP Scope Revisions OK'd

The MOPC approved a pair of Economic Studies Working Group recommendations to the 2024 Integrated Transmission Planning 10-Year Assessment's scope that are more reflective of current grid conditions.

The first revision would include a winter weather analysis because of more frequent extreme conditions, such as the February 2021 and December 2022 storms. The MOPC and the Strategic Planning Committee both directed the ESWG to study extreme winter weather conditions.

The second increases the amount of assumed amounts of renewable capacity in the scope's two futures, based on the amount of renewable interconnection requests in the queue. Both measures passed overwhelmingly, 80% and 93%, respectively.

The ESWG suggests building two distinct winter weather power-flow scenarios: one focused on operational conditions to better understand reliability issues that took place in December, and a generic model based on a set of historical winter regional stressors such as fuel availability, wind output, and transmission and generation outages.

"At the very least for December 2022 … we are going to have some outages baked in to be able to study what exactly happened in Winter Storm Elliot," said ESWG Chair Derek Brown, of Evergy.

Brown said it could take as much as $600,000 for additional staff time to keep the 2024 ITP on schedule.

The ESWG also proposes to increase its assumptions for renewables added to the grid in the futures' year 5 and year 10 scenarios. The studies will assume year 10 highs of 19.1 GW for solar in the reference case and 24.1 GW in the emerging technologies case; 54.9 GW and 59.1 GW for wind; and 5.7 GW and 9.6 GW for battery storage.

## GI Backlog Tracking for 2025 Completion

SPP remains on track to clear its generator interconnection queue's backlog by 2025 despite 599 active requests, Cathey said. The queue's six cluster studies are all green thanks to the grid operator's two-year-old, three-phase approach to processing generator interconnection requests in place since 2022 and its backlog mitigation plan.

The mitigation efforts began in 2022 with 898 GI requests for 171.5 GW of generation in the queue. As of Sunday, the *requests are down to 593* for 118.1 GW of capacity.

"It's mostly around restudies and ensuring that we're not causing too much churn to the GI customers and making sure that we get through the backlog as each cluster of DISIS [definitive interconnection system impact studies] is captured," Cathey said. "So far, it still appears to be effective."

Even with the backlog, SPP has added almost 28 GW of capacity to the system since 2016 and executed 144 interconnection agreements. Complicating matters going forward is that a little over 41% of the queue's requests (48.3 GW) are for solar. Wind (29.9 GW) and energy storage (21.8 GW) — all of it four-hour, lithium-ion batteries, Cathey said — account for much of the rest. Developers have 21 requests for 3.5 GW of thermal capacity in the queue.

"We're trying to thread that needle in terms of where our fuel mix is going five, 10, 15 years in the future, coupled with our load profiles," Cathey said. "We definitely need to work on those particular policies because even if they're all approved, as massive as 119 GW are, it's more than twice our peak load."

## Tx Service RR Remanded

The MOPC remanded a revision request back to the Transmission Working Group after Dogwood Energy's Rob Janssen pulled it off the consent agenda for further discussion and vetting in the stakeholder process.

Dogwood abstained from the Regional Tariff Working Group's vote on *RR534*, which is intended to clarify and correct tariff language that limits transmission service to the amount of interconnection service.

Janssen said 95% of RR534 is "perfectly fine," but the inclusion of point-to-point service along with network service runs counter to FERC Order 888's language that doesn't allow limitations on parties purchasing transmission

| KEY ASSUMPTIONS | DRIVERS | | | | |
|---|---|---|---|---|---|
| | Year 2 | Future 1 – Reference Case | | Future 2 – Emerging Technologies | |
| | 2 | 5 | 10 | 5 | 10 |
| Storage | Existing + RARs | 30% of projected solar (2.8 GW / 5.7 GW) | | 40% of projected solar (7.6 GW / 9.6 GW) | |
| Total Renewable Capacity | | | | | |
| Solar (GW) | Existing + RARs | 9.4 | 19.1 | 19.1 | 24.1 |
| Wind (GW) | Existing + RARs | 48.2 | 54.9 | 52.3 | 59.1 |

Increased renewable energy assumptions in the 2024 ITP's scope | *SPP*

# SPP News

service in the absence of anticompetitive practices.

"While you do try to include both point-to-point transmission service and network service in this set of restrictions, my concern is that you actually increase the probability of gaming, because now you're allowing a third party to buy point-to-point transmission service and effectively block a load-serving entity that might have a deal with a generator for being able to get transmission service for any deal that they put in place," Janssen said. "That could result in a very significant problem for some parties as SPP's grid gets more resource-constrained and parties are fighting for access to generating resources."

The consent agenda, approved unanimously, included seven other RRs that are effective immediately and one, RR530, that requires the Board of Directors' approval:

- *RR530*: identifies consistent criteria for when it is acceptable to implement a transmission reconfiguration and outlines responsibilities for the reliability coordinator and transmission operator.
- *RR532*: removes section 4.5.9.21 (Real-Time Joint Operating Agreement Amount) and adds the variable RtJoaHrlyAmt in the definitions section of 4.5.12 (Revenue Neutrality Uplift Distribution Amount) among other cleanup to revenue neutrality uplift language.
- *RR533*: adds language to clarify how resources will be settled with operational tools downstream from the real-time balancing market and that cleared quantities are updated when a price correction is needed for the day-ahead market.
- *RR535*: corrects the protocols for uncertainty products by clarifying summation for reserve zone additions, settlement variables and if/else replacements.
- *RR538*: ensures the protocols and tariff clearly describe when emergency limits will be used and how market participants can know if the emergency limits are used.
- *RR540*: ensures RR382 (Multi-day Minimum Run Time) is accurately implemented by revising governing language for day-ahead and reliability unit commitment make-whole payments.
- *RR541*: clarifies that the credit customer, not the market participant, is the highest level for exposure tracking.
- *RR544*: modifies the Transmission Owner Selection Process Task Force's changes to the competitive transmission selection process to include cost caps and guarantees in competitive upgrades. ■

*— Tom Kleckner*

# Company Briefs

### Cleveland Browns Drop FirstEnergy Stadium Name

The Cleveland Browns last week ended their stadium naming rights partnership with FirstEnergy Corp. after 10 years and will return to the name "Cleveland Browns Stadium."

FirstEnergy's partnership with the NFL franchise came under scrutiny after the utility admitted to paying bribes to Ohio lawmakers.

It's not yet clear whether the Browns will re-open bidding for its stadium name.

More: *The Associated Press*

### Tesla to Open Battery Factory in Shanghai

Tesla last week announced it will open a factory in Shanghai, China, that will be capable of producing 10,000 Megapack large-scale batteries annually.

The factory will be built in Lingang, a suburban area of Shanghai, where Tesla's vehicle factory is also located.

Production could start as soon as the second quarter of 2024.

More: *The Washington Post*

### Canoo Purchases Property in OKC for EV Production

Electric vehicle startup Canoo last week announced a long-term lease agreement for a property purchased by an affiliate of AFV Partners, founded by company Chairman and CEO Tony Aquila, for $34.27 million.

The 500,000-square-foot plant in Oklahoma City will begin ramping up in the coming months. Canoo says it expects to employ more than 500 people as EV production is anticipated to begin later this year.

The state of Oklahoma has agreed to buy 1,000 Canoo EVs over five years.

More: *The Journal Record*

# Federal Briefs

### Biden Admin Greenlights LNG Exports from Alaska

The Department of Energy last week approved LNG exports from the Alaska Gasline Development Corp.'s LNG project.

Backers of the roughly $39 billion project hope it will be operational by 2030 if it gets investments and all required permits. The LNG would be exported mainly to Asia.

Alaska LNG includes a liquefaction facility on the Kenai Peninsula in southern Alaska and a proposed 807-mile pipeline to move gas stranded in northern Alaska across the state. The DOE did not evaluate the long-term viability of the project and only approved its exports, a spokesperson said.

More: *Reuters*

### EPA: US Emissions up 6% in 2021 Amid Pandemic Recovery

U.S. greenhouse gas emissions rose 6% in 2021 as much of the country recovered from the COVID-19 pandemic, according to analysis released last week by the EPA.

The agency found that despite the year-over-year increase, the nation's emissions are down 17% from where they were in 2005. However, preliminary data also showed that 2022 emissions increased by about 1% when compared to 2021.

More: *The Hill*

### BLM Offers More Than 23,000 Acres for Solar in Nevada

The Bureau of Land Management last week announced it is auctioning four parcels totaling 23,675 acres for utility-scale solar energy development in the Amargosa Desert in Nye County, Nevada.

The BLM is auctioning leases for two Amargosa Valley Solar Energy Zone parcels consisting of 3,775 acres and 3,451 acres. It will also auction rights to submit development proposals on two other parcels consisting of 10,129 acres and 6,320 acres. If fully developed, the parcels have the potential to produce nearly 3 GW of renewable energy, BLM said.

The bureau will host a live auction on June 27 at 10 a.m. local time offering two parcels in the Amargosa Valley Solar Energy Zone, and 1 p.m. offering the two other parcels.

More: *Bureau of Land Management*

# State Briefs

## ARIZONA

### Power Loss Forces Palo Verde Nuclear Unit Offline

Unit 1 of the Palo Verde Nuclear Plant automatically tripped offline April 8 because of a loss of power to reactor coolant pumps, according to a report filed with the NRC.

Arizona Public Service said that prior to the reactor trip, the main turbine tripped due to a loss of hydraulic pressure. The main generator output breakers did not automatically open on the turbine trip as expected, so control room operators opened the breakers. Once the breakers were opened, the two 13.8-kV distribution buses failed to complete a fast bus transfer, which resulted in the loss of power to the reactor coolant pumps, initiating the reactor trip.

According to the filing, operators manually actuated a main steam isolation signal per procedure, requiring use of the atmospheric dump valves. An investigation into the matter has begun.

More: *POWER Engineering*

# CALIFORNIA

### Lawsuit Seeks to Uphold Closing of Diablo Canyon

Environmental group Friends of the Earth last week filed a lawsuit to block Pacific Gas & Electric from extending federal operating licenses for the Diablo Canyon nuclear power plant.

The complaint filed in San Francisco Superior Court asked the court to prohibit the utility from sidestepping its 2016 agreement with environmentalists and plant workers to close the plant by 2025.

The possibility of a longer operating run emerged last year after Gov. Gavin Newsom and the Legislature opened the way for PG&E to seek an extended lifespan for the twin reactors. The company intends to apply to the NRC by the end of the year to extend operations by as much as 20 years. The operating licenses for Unit 1 and Unit 2 expire in 2024 and 2025, respectively.

More: *The Associated Press*

### PUC Dismisses Sunnova's Micro Utility Application

The Public Utilities Commission last week dismissed Sunnova's plans to install and maintain solar-plus-storage microgrids for new home developments.

In its conclusion, the PUC "granted Cal Advocates' motion to dismiss the application because: (1) Cal Advocates' motion to dismiss is not improper; (2) the exemptions Sunnova Community Microgrids California (SCMC) seeks are unauthorized; and (3) SCMC fails to provide the information required for a Certificate of Public Convenience and Necessity."

Sunnova's September 2022 application was protested by 14 different parties.

More: *Solar Builder*, *California PUC*

# ILLINOIS

### State Selected to Join Advanced Nuclear State Collaborative

The Commerce Commission last week announced it was selected to join the Advanced Nuclear State Collaborative, a partnership that seeks to bring together state utility regulators to discuss the "unique needs and challenges tied to deploying new nuclear generation."

"With 11 nuclear power reactors across the state, Illinois is home to the most nuclear facilities in the country. With that comes a wealth of knowledge and research, and as the ICC's representative to this collaborative, I will be able to draw on the expertise of nuclear experts here in Illinois and the ICC Staff to help the ANSC develop use cases and innovate regulatory treatment models for advanced nuclear reactors," ANSC Commissioner Michael Carrigan said.

A bill currently moving through the legislature would delete language in the state statute that prohibits the construction of new nuclear plants. Illinois is one of only 12 states with a moratorium banning any future construction of nuclear plants.

More: *Illinois Radio Network*

# OHIO

### Judge Denies Request to Pause Law Expanding Fracking in State Parks

Franklin County Common Pleas Judge **Kimberly Cocroft** last week denied a temporary restraining order that would have blocked a new law that enables and, at least temporarily, compels state agencies to accept applications to drill for oil and gas in state parks.

Cocroft cited several factors she said indicate there is no risk of imminent and irreparable harm if she allows the law to stand as the case proceeds. She noted public comments from Gov. Mike DeWine and other officials that no leases would be signed in the immediate future, and that the plaintiffs only just filed suit even though DeWine signed the law in January.

Cocroft's ruling does not terminate the case but marks an early win for the state.

More: *Cleveland.com*

# VIRGINIA

### DEQ Withdraws Proposed Variance for Data Centers

The Department of Environmental Quality last week withdrew its proposed temporary variance to allow data centers to use backup generators during potential strains on the grid.

The DEQ proposed the variance in January after PJM flagged in its five-year forecast an increased demand for electricity due to data center development. The proposal would have suspended short-term air emission limits through July 31 in areas where PJM issued warnings of acute strains on the system, allowing data centers to run the generators temporarily.

"Given further discussion with stakeholders and public comment on the proposal, DEQ believes that these issues are now being addressed between the data centers, the utilities and the regional transmission organization," the agency said in a statement.

More: *Virginia Mercury*

### Franklin County Planning Panel Opposes Solar Farm

The Franklin County Planning Commission last week voted 7-0 to recommend the denial of a Mountain Brook Solar farm.

Lisa Cooper, the county's director of planning, suggested postponing a vote on the project and said it would allow time to work with Mountain Brook Solar to address concerns. However, after listening to public comment at the meeting, commission members did not discuss a postponement.

The planning commission's recommendation will go to the county Board of Supervisors for a final vote on May 16.

More: *The Roanoke Times*

### Henrico Approves Solar-powered Apartments

The Henrico Board of Supervisors last week unanimously approved the construction of 186 solar-powered apartments on the site of an abandoned hotel.

The Ashley Terrace Apartments project will build 186 apartments at the site of a demolished Days Inn; the apartments will run on 100% solar energy.

More: *WRIC*

### South Boston Council Approves Solar Site

The South Boston Town Council last week unanimously approved a permit for a ConEdison Clean Energy solar project.

The 5-MW project will encompass 87.6 acres.

The South Boston Planning Commission recommended denying the original plans submitted late last year; however, ConEdison made concessions and submitted a new plan.

More: *The Gazette-Virginian*

## WISCONSIN

### PSC Approves Portage County Solar Farm

The Public Service Commission last week approved construction of the 250-MW Portage Solar farm.

The 1,700-acre site will consist of between 525,300 and 700,400 photovoltaic panels, a 137.5-MW storage system, and a 115-kV substation. The facility was touted as the state's largest solar farm when Portage Solar filed the construction application in March 2022.

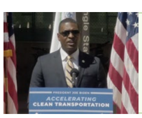
Construction is scheduled for August with the project going into service by late 2024.

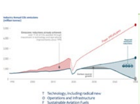
More: *Stevens Point Journal*



## National/Federal news from our other channels


*EPA to Propose Major New Emission Standards for Cars and Trucks* — NetZero Insider


*EPA Releases Emissions Rules Aimed at Boosting EVs* — NetZero Insider


*US Aviation Industry Sees Synthetic Fuel as Crucial to Net Zero* — NetZero Insider


*FPL Lauds Restoration Work After Ian, Nicole* — ERO Insider


*NERC Says Changes Coming to Physical Security Standards* — ERO Insider

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