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# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

MISO ERCOT

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# In this week's issue

Counterflow

By Steve Huntoon

# Holiday Happy Talk

By Steve Huntoon

It's the time of the season for some happy talk. Real happy talk.

Let me start with a rock concert almost 40 years ago. For you kids, this was Live Aid, a 16-hour concert split between London and Philadelphia.

It was the greatest assemblage of rock royalty in history. By far. Thank you, Bob Geldof, for this miracle.

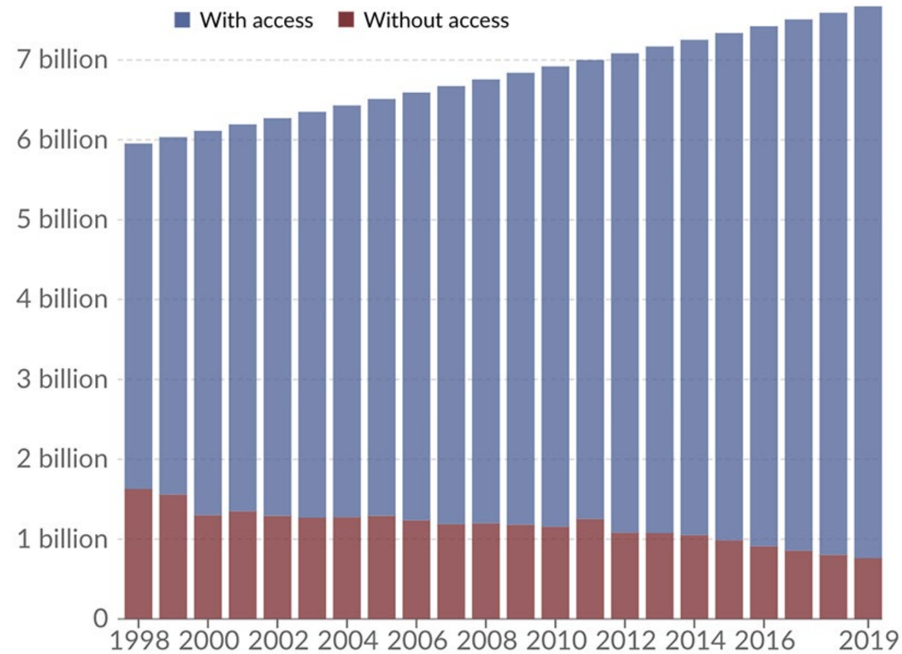
In no particular order: Elton John, George Michael[1], Queen, Dire Straits, Sting, David Bowie, and Bob Dylan with Keith Richards and Ron Wood (introduced by Jack Nicholson).[2]

Eric Clapton, Phil Collins, The Beach Boys, The Who (also introduced by Jack Nicholson),[3] Led Zeppelin and Mick Jagger.

Tina Turner, the Pretenders, Madonna, Tom Petty and the Heartbreakers, Hall & Oates, the Cars.

U2, Paul McCartney[4], REO Speedwagon[5], Crosby, Stills & Nash[6], Boomtown Rats and Black Sabbath.

The Hooters (introduced by Chevy Chase and Joe Piscopo),[7] the Four Tops, Joan Baez, Elvis Costello, Rick Springfield and Neil Young.




Number of people with and without access to electricity | *Our World in Data (CC-BY-SA)*

Bryan Adams, George Thorogood & The Destroyers, Simple Minds, Santana, Ashford & Simpson with Teddy Pendergrass, Kenny Loggins and Run-D.M.C.

And the all-star Band Aid closing London with "Do They Know It's Christmas?"[8] OMG. And the all-star U.S.A. For Africa closing Philly with "We Are the World."[9] OMG 2.

Yeah, that's what I'm talking about. Just plug Live Aid and your favorite rock star into YouTube and turn it up to 11.[10] Or get the 4-disc DVD set (which sadly came out 20 years late and left out 6 hours of performances).[11]

How much would tickets go for these days? Maybe even more than Taylor Swift's!

## Global Famine

The theme of Live Aid was "Feed the World."

Here's a graph showing global famine mortality over the decades.[12]

Did Live Aid help, or more generally, did the human sentiment leading up to and highlighted by Live Aid help? I'd like to think so. Not to diminish in any way the importance of the Green Revolution and Norman Borlaug's role in it.[13]

Here are three more charts we should toast this season.

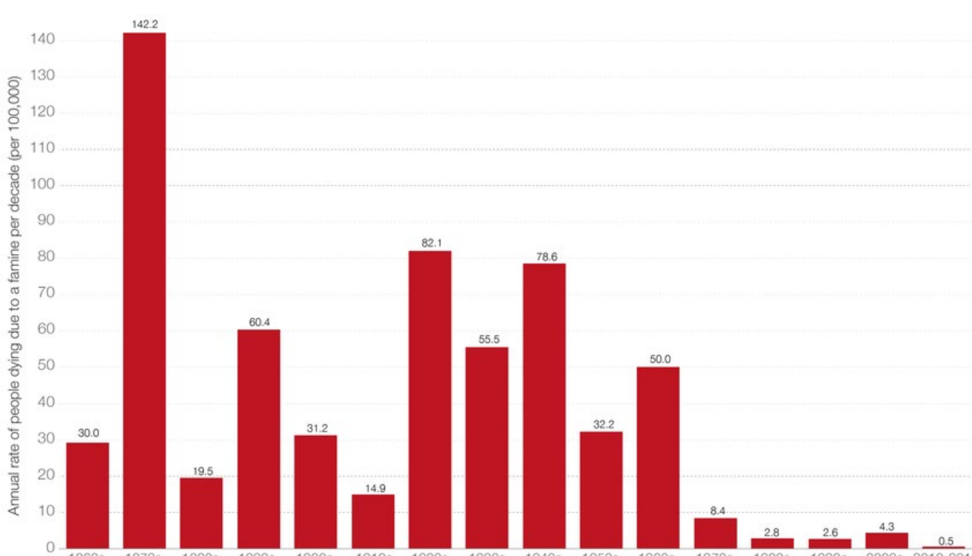
## Global Life Expectancy

Global average life expectancy has basically doubled over the last 100 years. A miracle.[14]

## Global Average Income

How about global average income from 1960 to date?[15]

In current U.S. dollars, global gross domestic product (GDP) per capita increased from $457




Annual deaths per 10,000 from famine | *Our World in Data (CC-BY-SA)*

# Counterflow

By Steve Huntoon

in 1960 to $12,647 in 2022. That is incredible.

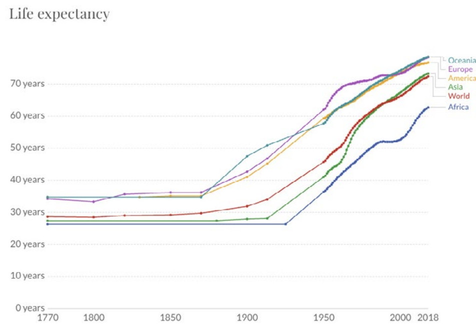
## Electricity Access

And apropos of our industry, global access to electricity has gone from 73.4% in 1998 to 91.4% in 2021 — little more than 20 years — as this chart illustrates.[16]

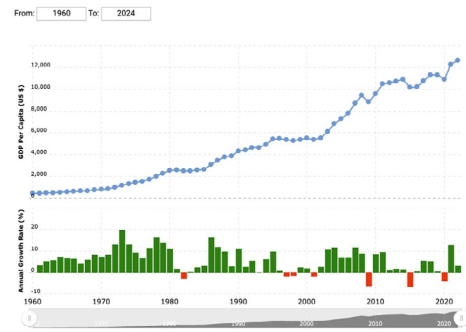
## Holiday Cheer

It's understandable to be concerned with the state of the world these days, but let's take some comfort in these points of light. We'll get through this.

I wish you and yours the happiest of holidays. ■




Average life expectancy | *Our World in Data (CC-BY-SA)*




Global average income | *Macrotrends.net*

[1] Elton John and George Michael together are here, https://www.youtube.com/watch?v=ECN_wgw55lc.

[2] https://www.youtube.com/watch?v=u0Lx3supRTQ. Dylan at first says he doesn't know where they are. Then Dylan breaks a string and Ronnie hands him his guitar. How cool is that?

[3] https://www.youtube.com/watch?v=PMxwPOoZm_c

[4] With a little help from his friends, https://www.youtube.com/watch?v=CSoYvI9t3ug

[5] The Beach Boys sing background vocals on "Roll with the Changes," https://www.youtube.com/watch?v=YsvXe0vKmxA. How cool is that?

[6] I just learned that their song "I Don't Like Mondays" is traced to a school shooting in 1979 where the 16-year old perpetrator had given "not liking Mondays" as her reason. https://www.economist.com/business/2023/12/07/why-monday-is-the-most-misunderstood-day

[7] https://www.youtube.com/watch?v=-GiS6yMxGlA (video posted in 2020).

[8] https://www.youtube.com/watch?v=Gifrd7ljNL4

[9] https://www.youtube.com/watch?v=00OeznNG4hM. Led by Lionel Ritchie and Harry Belafonte. Patti LaBelle hits the high notes. The spectacular studio version with even more rock royalty is here, https://www.youtube.com/watch?v=9AjkUyX0rVw.

[10] There are a few videos missing from YouTube, like Bryan Adams' songs, but at least one is on Facebook, https://www.facebook.com/RockandRoll-Nation1/videos/bryan-adams-cuts-like-a-knife-broadcast-of-live-aid-from-mtvjuly-13-1985/2218823795025652/.

[11] https://www.amazon.com/Live-Aid-4-Disc-Set/dp/B0002Z9HT8/ref=sr_1_1?crid=YHCBG819DNNL&keywords=live+aid+concert+d-vd+1985&qid=1702070340&sprefix=live+aid+d%2Caps%2C154&sr=8-1

[12] https://ourworldindata.org/famines. https://sites.tufts.edu/wpf/files/2021/05/1_Famine_mortality_decade.pdf. Deaths from hunger and malnutrition continue, but the Global Hunger Index, which measures this, has declined from 28.0 in 2020 to 18.3 in 2023. https://www.globalhungerindex.org/

[13] https://www.nobelprize.org/prizes/peace/1970/borlaug/biographical/

[14] https://upload.wikimedia.org/wikipedia/commons/9/9a/Life_expectancy_by_world_region%2C_from_1770_to_2018.svg

[15] https://www.macrotrends.net/countries/WLD/world/gdp-per-capita.

[16] https://ourworldindata.org/energy-access

## FERC/Federal News

# Grid Planners Predict Sharp Increase in Load Growth

## *5-year Projection Rises to 4.7% from 2.6% Last Year*

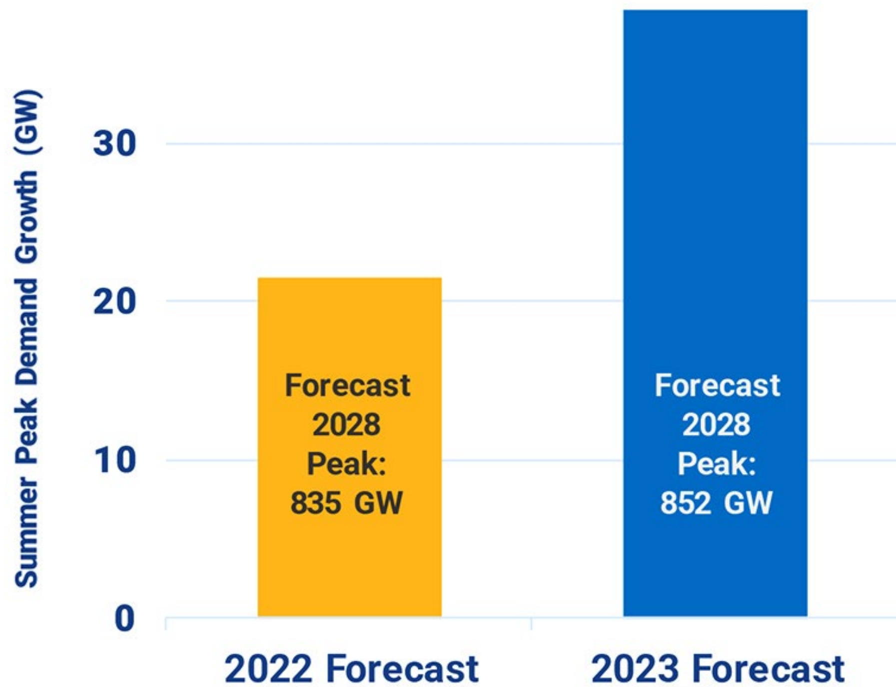
*By James Downing*

After years of low load growth, U.S. grid planners now predict a sharp increase in electric demand, according to a report released Dec. 12 by consulting firm Grid Strategies.

The nationwide forecast for the next five years has nearly doubled to 4.7% from 2.6% last year, Grid Strategies said, citing data compiled from FERC filings.

The increased load growth translates to an additional 38 GW of demand through 2028, which will require new transmission and generation to be met reliably, Grid Strategies said in the report, "The Era of Flat Power Demand is Over."

"Over the past decade, grid planners have been forecasting a mere 0.5% annual growth rate, as summarized by NERC," the report said. "Yet in 2023, annual peak demand growth is up to at least 0.9%, driven by data centers, industrial facilities and other near-term investments."




Five-year nationwide growth forecast | *Grid Strategies*

That is likely to be an underestimate, the report said, noting that since the forecasts were filed with FERC, Puget Sound Energy, Duke Energy, Georgia Power and the Tennessee Valley Authority have stated that their load expectations have grown even higher.

Since 2021, commitments for industrial and manufacturing facilities have totaled about $481 billion, and more than 200 manufacturing facilities have been announced in the past year. Data center growth is forecast to exceed $150 billion through 2028.

The data across the industry are uneven, with some regions like MISO not clearly explaining how large load development will impact peak demand, whereas PJM and Georgia Power's latest forecasts include higher investment in industrial sites and data centers.

| | Data Centers | Industrial Facilities | Hydrogen Plants | Electrification |
|---|---|---|---|---|
| ERCOT | ● | ● | | |
| PJM | ● | | | |
| Duke Energy | ● | ● | | |
| Georgia Power | ● | ● | | |
| NYISO | ● | ● | ● | ● |
| Arizona Public Service | ● | ● | | |
| CAISO | | | | ● |
| Portland General Electric | ● | ● | | |

Drivers of load growth by region| *Grid Strategies*

Only some utilities factor in the impacts of higher temperatures and more extreme weather in their projections. As those practices spread to more firms, the load growth figures should go up, according to the report's authors, John D. Wilson and Zach Zimmerman.

Major new loads can take only one or two years to connect to the grid, compared to at least four years for new generation and even more for new transmission, the report said.

"It's worrisome that a resurgent American manufacturing sector may face headwinds from the limited ability of the nation's electricity systems to respond," the report said. "Electricity systems need to supply new generation, connect that generation to load and — of course — connect new load to the system. There are real risks that some regions may miss out on economic development opportunities because the grid can't keep up."

Transmission investments to meet the new demand are a particular challenge, as they will have to be sped up to meet the new demand

# FERC/Federal News

after seeing declines in overall investment in the last couple of years.

"Transmission takes years to build, and current planning and regulatory practices make interregional transmission particularly difficult to build," the report said. "Even though investing in transmission could save tens of billions of dollars in bringing on the new 38 GW of electricity demand, changes in policy and practice are required across the country to make this possible."

The Inflation Reduction Act and Infrastructure Investment and Jobs Act are leading to an increase in industrial demand, while the computing power of artificial intelligence is driving increased demand from data centers. Longer-term electrification of heat and transportation is adding to growth as well.

Other potential sources of demand growth include new hydrogen fuel plants and the impact of more extreme weather.

"If grid planners are not accounting for these drivers, load forecasts will be too conservative, and the system will not be ready to meet growth in electricity demand," the paper said.

The new sources of load growth are not uniform across the country with new industry favoring the Southeast (especially Georgia and the Carolinas), MISO (especially Michigan and Indiana) and the Southwest (especially Arizona and Nevada).

Data centers currently represent 2.5% of total electricity demand, but it could grow to as much as 7.5% by the end of the year, according to the Boston Consulting Group. That sector's growth depends on land and power availability, and it can be located in specific regions, with the report highlighting "Data Center Alley" in Loudoun County, Va., outside D.C.

Virginia has the largest data center market in the world, with more than 35% of all known hyperscale data centers worldwide. (See related story, "PJM 2024 Load Forecast Sees Jumps from EVs, Data Centers, Heat Pumps," *PJM PC/TEAC Briefs: Dec. 5, 2023*.)

Ten planning areas are home to most of the projected demand increase with 18 GW: ERCOT, PJM, SPP, Duke Energy, Georgia Power, NYISO, Arizona Public Service, TVA, CAISO and Puget.

APS and Puget are expecting demand to grow more than 10% in the next five years, while ERCOT sees the highest growth among organized markets at 6.6%.

"In 2018, ERCOT's peak load record was 69.5 GW. This has grown by over 16 GW to 85.6 GW this summer," the paper said. "The record-setting demand has been largely driven by industrial growth and extreme temperatures. While ERCOT continues to forecast most types of loads to remain relatively flat through 2028, its forecast for new large loads spiked up to 7.4 GW over the past year."

The new large loads are evenly split between new industrial facilities and cryptocurrency miners, the latter of which are only expected to run when ERCOT's energy market prices make that activity profitable.

The paper focused on summer peak demand because that is most closely related to transmission development, and on average across the country, it is larger than winter peaks. It acknowledged, however, that focusing on summer peak demand "may obscure important planning issues related to winter peak demand and overall energy resources." ■

| Planning Area | 2022 Forecast (GW) | 2023 Forecast (GW) | Increase (GW) | Percent Increase |
|---|---|---|---|---|
| ERCOT | 83.6 | 89.1 | 5.5 | 6.6% |
| PJM | 152.7 | 155.7 | 3.0 | 2.0% |
| SPP | 56.3 | 59.3 | 3.0 | 5.2% |
| Duke Energy (North & South Carolina) | 33.8 | 35.8 | 2.0 | 5.9% |
| Georgia Power | 16.2 | 17.2 | 1.0 | 6.4% |
| NYISO | 31.3 | 32.3 | 1.0 | 3.2% |
| Arizona Public Service | 8.6 | 9.5 | 0.9 | 10.9% |
| Tennessee Valley Authority | 31.7 | 32.3 | 0.6 | 2.0% |
| CAISO | 49.3 | 49.8 | 0.5 | 1.1% |
| Puget Sound Energy | 4.4 | 4.9 | 0.5 | 10.7% |
| All other planning areas | 367.2 | 366.6 | -0.6 | -0.2% |
| Total | 835.1 | 852.5 | 17.4 | 2.1% |

Planning areas with greatest increases in in summer 2028 peak demand | *Grid Strategies*

## FERC/Federal News

# FERC Gets Growing Calls to Finish Transmission Rule in 2024

*By James Downing*

| © RTO Insider LLC

A growing chorus of stakeholders is hoping to see a final transmission planning rule from FERC sometime in the New Year, with a set of letters sent to the commission last week.

A group of nongovernmental organizations including Advanced Energy United, American Clean Power Association, Earthjustice, Environmental Defense Fund and Sierra Club said finalizing the transmission planning rule was important to ensuring the incentives from the Inflation Reduction Act actually get used and increasing the resilience of the grid to extreme weather.

"The electric industry is undergoing a major transformation driven by consumer, utility and corporate preferences, state public policies and the cost-competitiveness of renewable energy," said the letter sent to FERC Dec. 8. "The commission's transmission planning and cost allocation standards must be up to the challenge of enabling this transition while ensuring the continued provision of reliable and affordable electricity at just and reasonable rates."

Another letter largely signed by power companies and labor including Ameren Transmission, Consolidated Edison, Exelon, the Blue-Green Alliance and the IBEW International also urged FERC to act.

"We support the commission's proposal for regional, long-term, scenario-based transmission planning and urge the commission to issue, as soon as practicable, a final rule that will facilitate needed transmission investment," the letter said. "The commission should ensure that the final rule is sufficiently robust to achieve the commission's goal of ensuring just and reasonable rates and 'remedy[ing] deficiencies in the commission's existing regional transmission planning and cost allocation requirements.'"

FERC still has one more meeting this year, but it is unlikely to move the final transmission rule, as it has yet to issue a substantive order on rehearing for Order 2023, in addition all the other work before its staff, said consultant Rob Gramlich at a press event Dec. 8 hosted by Americans for a Clean Energy Grid.

"The chairman and his staff have been saying, 'We want this to be durable, legally, you know, we've got to dot every I and cross every T and make sure,'" Gramlich said. "You know, most rules like this do get challenged and, so, they're planning for that. And ... that's all competing against time. We don't have time. It feels to me like 18 months is enough. It's time to get the order out."

The last time FERC issued major transmission reforms was Order 1000 in 2011, and that was meant to be an iterative process, said ACEG Executive Director Christina Hayes. A major issue driving the change then was state policies, especially renewable portfolio standards.

"I think it's a matter of kind of evolving the process and evolving the analysis, where things right now are very focused on the silos — economic reliability, and policy silos — and kind of breaking free of those and recognizing that renewable requirements are being driven by customers, by utilities, who are getting out ahead of their states," she added.

Gramlich said Congress also could move forward on transmission proposals, including a bipartisan permitting reform effort led by Sens. Joe Manchin (D-W.Va.) and John Barrasso (R-Wyo.).

While transmission largely is a priority for Democrats in this Congress, it was not always that way. The Energy Policy Act of 2005, with its reforms on transmission, came out of a Republican Congress and was signed by a Republican president. There's reason to believe the party might get on board with transmission reforms this time.

"Everybody cares about reliability," Gramlich said. "Everybody will soon be aware of massive load growth that's happening for the first time in over two decades. And that's a reason to build transmission. So, there's a lot of nonclimate reasons if climate isn't your priority."

Even once all the policies are put in place, the industry and regulators will have a massive job working to expand the grid. Princeton University has said the grid needs to expand by 60% by 2030 and triple by 2050, but that does not even take into account the amount of industrial reshoring and other sources of demand growth, Hayes said.

"I think we can do it," Gramlich said. "And we know that because we did do it 10 years ago. If you look at, like, 2013: the MISO MVPs come online, the SPP Priority Projects, ERCOT CREZ (Competitive Renewable Energy Zones), the Tehachapi buildout — all in one year. That happened to be in the same year when there was another period of time when everybody was talking about big transmission ... and we got a lot done. And then ... we kind of like just lost our momentum for a variety of reasons." ■

## FERC/Federal News

# Industry Considers Building its Own Generation to Decarbonize

*By James Downing*

While the power and transportation sectors can highlight some success in cutting emissions, hard-to-decarbonize industry is severely lagging behind them, with the sector likely to become the biggest emitter in coming decades, according to a *report* released by the Rhodium Group Nov. 30.

"As other sectors decarbonize, industry very likely remains the biggest source of emissions by a wide margin," Rhodium said. "In fact, by 2050, industrial emissions exceed all emissions from power, transportation and buildings combined in our projection mean. Without meaningful solutions to decarbonize industry, global emissions will remain stubbornly high for the foreseeable future."

The lack of viable alternative technologies to power industry means Rhodium's projections are based largely on pure economic considerations, such as China's decadeslong growth slowing down. The legacy industries such as steel, chemicals and cement are already built out in the U.S., so they are going to change over to cleaner energy production measures when their equipment needs to be replaced, Intersect Power CEO Sheldon Kimber said in an interview.

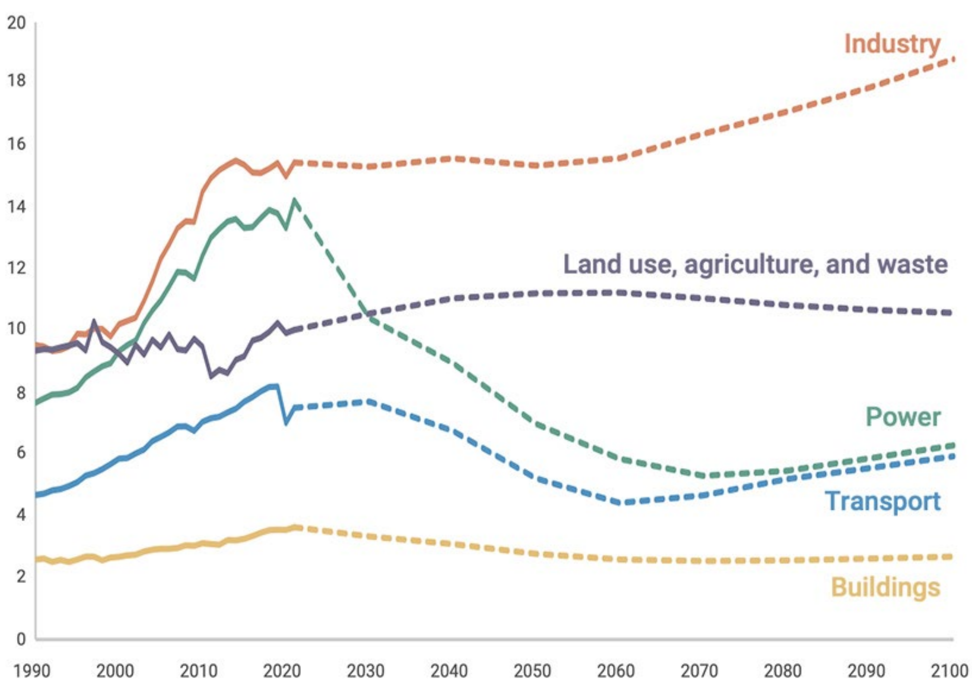
"We see emerging electrification of whole new industries that don't even exist today," Kimber said.

Kimber's firm wants to attract new industries such as clean hydrogen, artificial intelligence data centers and direct air capture to areas such as the Texas Panhandle, where both wind and solar resources offer high-capacity factors.

Bringing industry to where clean energy resources can produce the most power at the best price also gets around the issue of needing to build out the transmission grid, which to successfully decarbonize needs to expand by 60% by the end of this decade and triple by 2050, according to widely cited estimates from Princeton University. That is a massive political, regulatory and economic lift; Kimber doubts the grid can grow that much on that time scale.

Getting the equipment to meet that 2030 target given the realities of the supply chain is going to prove difficult, with Kimber saying it would take five to seven years to even start construction on major new lines even if the policy questions were all answered correctly tomorrow.

"So, you're talking about mid-2035, before even the first trickle of transmission comes online, if you get it perfect right now," Kimber said.




A Rhodium Group from its latest Climate Outlook showing emissions projections by sector | *Rhodium Group*

That would likely require additional legislation because the kind of lines that need to get built are not shipping power across one state, but across multiple jurisdictions to bring renewables to market.

"The big projects we need are to get essentially the really high-capacity factor, low-cost cheap renewables into the load pockets," Kimber said.

It is not just about connecting any kind of clean power, but getting to those areas where the wind and the sun can offer 60 to even 70% capacity factors without battery storage, he added. It will make sense for big industries to move to areas where they can get wind and solar nearby and then ship their products, rather than transmitting electricity across multiple jurisdictions.

Creating new jobs and economic growth in rural areas, which are largely conservative, also can bolster the political consensus around clean energy.

"This country needs a durable, sort of political consensus around clean energy," Kimber said. "And the only way we're going to get that is if everybody can participate in the clean energy industry: across the political spectrum, socioeconomic spectrum, different parts of the country. And I think we're starting to get that now under the" Inflation Reduction Act.

The IRA has showered the clean energy industry with incentives just as the era of worry-free, cheap solar panels from China is slowing down, with a renewed focus on stable supply chains. Intersect has domestic supplies of panels lined up through deals with First Solar.

"We're going to build $20 billion of infrastructure before the end of the decade," Kimber said. "And we're going to get all those modules from Ohio, Alabama and Louisiana."

Building out high-quality renewables to directly serve new sources of load also avoids the issue of finding space on the grid, which is becoming increasingly crowded. Data center growth in Northern Virginia has made it so some sites have to run their on-site, inefficient gas generation as baseload to keep running, Kimber said.

"I think that hydrogen is going to be very similar, in that a lot of these folks are expecting to see an availability of interconnection that just

# FERC/Federal News

isn't going to be there," he added.

Even if a large customer can plug into the grid, the only generation they will be able to find could be too far away.

"Any generation you can possibly source in the wholesale market is so far away from you on a basis perspective that you're going to be paying four times as much, and you'd be better off building a pipe from the panhandle to that site than you would be building a wire from the panhandle to that site," he added.

Producing clean hydrogen is a good example of an industry that Intersect wants to support because the electrolyzers to produce the fuel are costly, so the more they run, the greater amount of product those costs can spread around.

"That's why I think in the near term, you'll see a lot of those folks moving to places where you can get high-capacity factors from renewables only so you can get to 65 to 70% in the Panhandle of Texas; you add some batteries, [and] you can start getting closer to 80, 90 or 100%," Kimber said.

### Big Customers are Considering Going Nuclear

Renewables are not the only way to decarbonize. Lately industry has focused on building out its own nuclear plants for uses historically reserved for combined heat and power systems. Even Microsoft posted a job *notice* in September looking for a nuclear expert to help its energy strategy for data centers.

On the other side of Texas from the panhandle, Dow is developing small modular reactors at its Seadrift facility near the middle of the state's coastline.

The firm is working with X-energy to deploy four 80-MW SMRs to supply its factory with power and steam, which will replace the more traditional cogeneration units on the site, Edward Stones, Dow's vice president for energy and climate, told a Senate hearing recently. (See *Senate Energy Committee Examines the State of Advanced Nuclear Reactors*.)

Dow's Seadrift facility is massive, covering 4,700 acres and producing 4 billion pounds of materials a year that go into applications ranging from food packaging and preservation, to wire and cable insulation, to packaging for medical and pharmaceutical products.

"Advanced nuclear provides a huge opportunity for industrial users of power and steam," Stones testified. "Navigating the deployment challenges will require continued engagement between the private sector and federal government, particularly around the financial and operating risks to early adopters of this technology."

One key consideration is timing because the SMRs Dow plans to install will replace aging cogeneration facilities so they cannot be tied up in regulatory processes that drag on so long the old plants break down, he added.

While 80 MW is small compared to the major nuclear plants with two or more reactors producing 2,000 MW or more, even smaller reactors are being developed that could help cut carbon from remote facilities such as mines.

NANO Nuclear Energy CEO James Walker said the market for "micro-reactors" — nuclear reactors that can fit inside a standard shipping container and be easily transported to sites that need power — was largely untapped when the company was forming.

"So, it's almost like a nuclear battery and you're competing with a diesel generator, and you could ship that anywhere in the world using conventional transportation infrastructure: trains, trucks, helicopters," Walker said in an interview.

That kind of easily transportable reactor could serve mining sites, oil and gas production, data centers and car-charging stations, or it could replace the fossil fuel engines used on commercial ships around the world, he added.

Similar-sized reactors have been used in naval applications since the *1950s*, so it is a matter of taking what is known from their use and adapting it for commercial purposes. The micro-reactor space is new, and it will take some time to win regulatory approval for such technologies, but Walker said they should be ready to start deploying by the end of the decade.

"We know that there are a lot of industries that were very keen on, say, wind and solar like that, but it was too intermittent," Walker said. "The storage costs involved were enormous. The land usage required was prohibitive, often so prohibitive that it actually looked like it had increased their carbon footprint by the amount of land they would need."

### The Grid Will Still Serve Many Industrial Loads

While industry is considering building its own generation to help decarbonize, plenty of big customers will continue to draw power from the grid as they reach for net-zero emissions, but that is no longer just a matter of matching up some renewable energy credits with the amount of power consumed.

A shorthand for the new concept of deep decarbonization is "power to X," which Lancium Director of Regulatory Affairs Andrew Reimers explained on a webinar hosted by the Energy Systems Integration Group. It refers to taking electricity and making something else with it, which is easily understood when it comes to clean hydrogen.

"If these loads can be operated in a flexible or controllable way, they can play a big role in allowing greater adoption of intermittent renewables," Reimers said. "And so there is a pro to the con of the reliability impact they pose."

The reliability impact is that many of these loads are very big, so if they were to unexpectedly trip offline, it could lead to grid stability issues. Reimers highlighted the plans for the "*Hydrogen City*" project in Texas that could scale up to 60 GW — while ERCOT's all-time peak demand record is just 85.5 GW.

"The reliability issue is very significant, particularly because of how big some of these facilities are," Reimers said. "And it's going to take a lot of kind of creative thinking about how to deal with all of that as far as maintaining the reliability of the grid."

Even beyond reliability issues, electricity is going to be difficult to plan for by grid operators who are ill equipped to monitor global commodity prices for different industries. Some industrial load might curtail significantly when residential air conditioning drives up the demand curve, but others might have contracts they need to meet or inflexible industrial processes incapable of responding to shifts in power prices, Reimers said. ■

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*RSTC Sends DER Proposal Back to Working Group*

ERO Insider

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# FERC/Federal News

# FERC Rejects Wabash Valley Contracts, Sets Tariff for Proceedings

*By James Downing*

FERC on Nov. 6 rejected new contracts the Wabash Valley Power Alliance had filed for its members and a distributed generation policy proposed by the generation and transmission cooperative (*ER24-36*).

The commission said the rejections were without prejudice and opened a show cause proceeding (EL24-16) to determine whether Wabash's tariff is just and reasonable and not unduly preferential.

Indiana-based Wabash serves wholesale customers in both MISO and PJM, meaning it has to buy transmission and ancillary services from both RTOs. However, two of its members — Tipmont Rural Electric Membership Cooperative and Citizens Electric Corp. — alleged that Wabash failed to separate out those purchases in contracts with those customers, running afoul of FERC's unbundling rules.

The new contracts, filed in 2023, should be subject to FERC Order 888 because its unbundling rules have been in effect for all contracts since July 1996, the complainants argued.

Wabash argued that, while Tipmont and Citizens are members of the alliance, the two co-ops declined to sign 2023 contracts and should not be allowed to participate in the FERC proceeding. The pair's arguments are based on existing contracts and should not have an impact on FERC's review of the 2023 deals, Wabash said.

FERC found that the contracts do not run afoul of the commission's unbundling rules because they do not establish a bundled rate, but merely incorporate the rate established by the Wabash tariff, which is on file with the commission.

But the commission said it could not accept the contracts as written in part because they require member co-ops to provide 31 years of notice to avoid an automatic five-year extension.

"While we do not here decide whether it might ever be just and reasonable to include a provision requiring 31 years of notice to avoid an automatic five-year extension in a requirements agreement, it is incumbent on the applicant in an FPA section 205 proceeding, i.e., Wabash, to affirmatively demonstrate that such a provision is just and reasonable with regard to the agreement presented to the commission for its approval," FERC said.

"Wabash does not support this proposal other than to observe that the executing members desired the long-term stability of their contractual relationship with Wabash and that they signed the 2023 contracts."

Wabash did not adequately show its proposal to be just and reasonable, instead focusing more on Tipmont's arguments against it and claiming that the co-op failed to prove the 31-year notice requirement was unjust and unreasonable, the commission said.

Tipmont and Citizens also argued that several policies that should be included in the tariff are not. In any future filing, Wabash will have to include them or show that they do not affect rates and service significantly.

The two members also filed protests against "Buyout Policy D-2" in the contract, which determines the amount of money a member would owe Wabash when departing from the cooperative. Tipmont is pursuing exit from Wabash in a separate, ongoing proceeding, and Citizens complained that Wabash just applied the methodology from that case to all members even though it was only designed for Tipmont.

FERC also rejected Buyout Policy D-2, saying Wabash failed to make clear how it will use any methodology developed in Tipmont's exit case and instead relied on unclear language saying it would take the case "into account" when dealing with future exits.

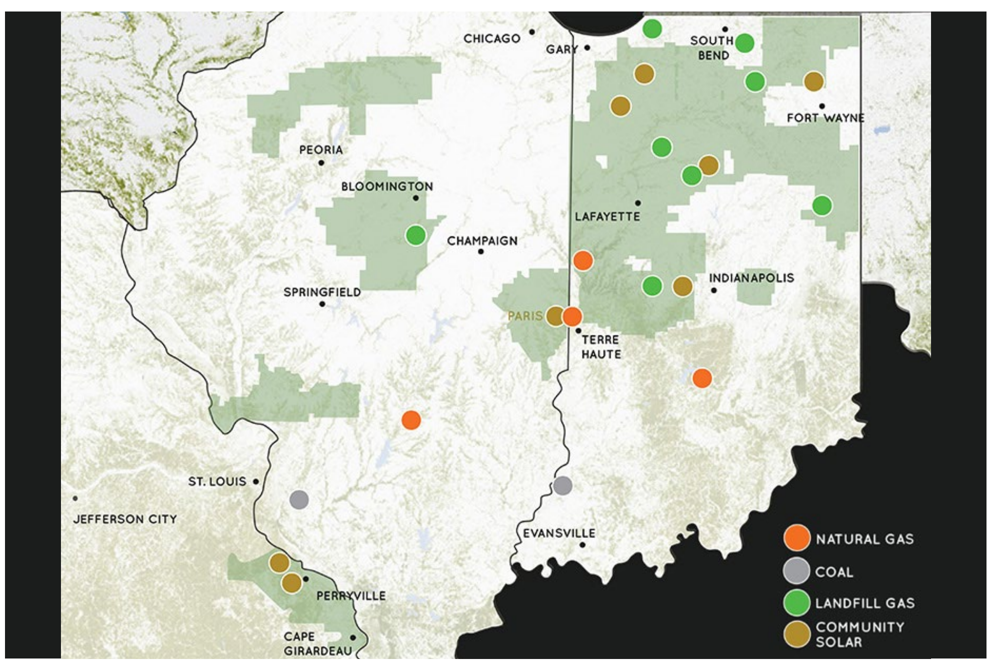
FERC additionally rejected Wabash's Distributed Generation Policy, which determines how much of that type of resource its members can use. The commission found fault with Wabash's proposal that it could waive that policy for any given member based on 75% approval of its board.

The rule "would give the board unfettered discretion when considering a member request to waive the terms of a policy that the commission had otherwise found just and reasonable," FERC said.

While none of the contracts ran afoul of FERC's unbundling rules, the commission said it could not say the same for the tariff, which will be the subject of the show cause proceeding. Unbundling is needed to implement non-discriminatory open access transmission, and it is unclear whether the tariff provides it, FERC said.

Wabash will have to come back to FERC within 60 days to either alter the rules in question or explain why they do not run afoul of unbundling requirements. Interested parties will be able to file comments 21 days later.

Wabash can revise its tariff to deal with the unbundling issues under Section 205 of the Federal Power Act, which would place the Section 206 show cause proceeding in abeyance, FERC said. ■



Wabash Valley Power Alliance power supply generation | *Wabash Valley Power Alliance*

## FERC/Federal News

# Overheard at Gridwise Alliance's gridCONNEXT 2023

WASHINGTON — The energy transition will require new sources of power as more of the economy is electrified and new investments in information technology are made to help balance the increased loads, speakers said at the Gridwise Alliance's gridCONNEXT conference Dec. 5.


A panel on Data Standards with (from left) Landis+Gyr's Marguerite Behringer, Wi-Sun Alliance's Phil Beecher, National Grid's Craig Rutfield, DOE's Chris Irwin and Tipmont CEO Ron Holcomb. | *© RTO Insider LLC*

Rep. Bob Latta (R-Ohio) said he always asks how much more power the grid will need in the future when industry representatives come before the House Energy and Commerce Committee on which he sits. Responses vary, Latta said, but he contended that more supply — and particularly baseload resources — are needed to keep vital industries like steel manufacturing running.

"The question always becomes is if you're going to have to have more power, how do you get there?" Latta said.

Latta co-chairs the bipartisan Grid Innovation Caucus with Rep. Marilyn Strickland (D-Wash.), and while they might have different visions on the future of the grid, some common ideas help them work across the aisle.

"We don't snap our fingers and suddenly put in a bunch of charging stations and change how we are providing energy to people," Strickland said. "We have to make sure that the infrastructure that we have is reliable, that we understand that this is as much about transmission and distribution as anything else, and making sure that we have adequate resources to make these investments."

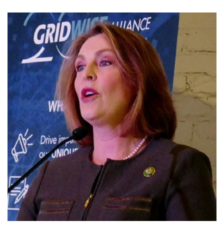
Transportation is one of the sectors poised for greater electrification, and while the government offers plenty of subsidies for EVs, charging infrastructure is holding things back, Strickland said.

"Automobile dealers have told us that the United States ranks at the bottom when it comes to EV sales," she said. "And that's not because people hate electric vehicle charging stations; we don't have the infrastructure that makes someone feel as though they can trust how long the charge will last, or that is easily accessible to as many people as possible."

### Taking Risks

The conversations in D.C. and other policymaking circles must eventually get past arguments about whether the energy transition is a good idea, said Gene Rodrigues, assistant secretary for electricity at the U.S. Department of Energy.

"We need to get away from those people who are saying this is a terrible idea and those people saying this is a wonderful idea," Rodrigues said. "But we need to get to a culture where people are trying to figure out how to make it work."



Rep. Kathy Castor (D-Fla.) | *© RTO Insider LLC*

Rodrigues said cultural changes around the issue could take a decade. Rep. Kathy Castor (D-Fla.) noted that congressional Republicans have tried to repeal parts of the Investment Reduction Act and Infrastructure Investment and Jobs Act, which are heavily funding the clean energy transition.

"We simply don't have time for that," Castor said. "Notwithstanding the attempts by the oil and gas industry to take us backwards, the clean energy transition is happening swiftly."

As the share of energy demand served by electricity grows, so will consumers' bills, and that is going to require an educational effort from the industry, Exelon Senior Director of Federal Policy Suzanna Mora-Schrader said.

"The affordability piece of this is huge," she said. "And part of that is not only about us being able to spend money, whether it's federal dollars, or investment dollars from our rate base, it's about making customers understand that more and more of their life is a function of electricity. And so, you've got to start driving people into understanding share of wallet as opposed to the increase in the bill."

Part of the transition is going to require utilities taking some risk, something Mora-Schrader said she learned about in previous jobs in less risk-averse industries.

"If you want to do fast, we're going to have to take some chances," she added. "And that's something for utilities to hear and that's something for our regulators to hear."

Some of the investments utilities make will have less certainty than others, but they will still need to make them even if the risk cannot be eliminated, Mora-Schrader said.

Maryland Public Service Commissioner Bonnie Suchman pushed back on the notion that regulators will have to embrace more risk.

"I have to recognize reliability," said Suchman. "We have got to keep the lights on; we have to keep them on now. Recognizing that we have to do [transition-related activities] in five and 10 years, that's really important."

But on top of reliability, regulators need to ensure the grid is resilient against extreme weather and that affordability is not lost in the shuffle either, she added.

"A third of Maryland's residential customers are considered low- or moderate-income. We cannot leave them behind as we continue to deploy these various assets," Suchman said.

### Sharing the Opportunity

One way to ensure the grid is resilient and affordable throughout the energy transition is to make demand more flexible through advanced meters, price signals and participation in markets as FERC Order 2222 contemplates.

"We're actually seeing transformers failing because of three people plugging in their EV at the same time," said Mike Phillips, CEO of Sense, a home energy monitor company. "We're seeing that happen in real time. And there's two solutions: You either replace all the transformers that can handle these EV loads, or you see that this is happening and you start to make these things intelligent and responsive."

While some consumption is inflexible, ensuring a car has a full charge for the next day's commute or the water heater is ready for the morning are not, and both can be controlled given the right technology and policy, he said.

Either utilities or an independent distribution system operator (DSO) will have to coordinate all that activity at the distribution level, ensuring that nodes — or neighborhood circuits — can operate reliably with the new demand, said Curtis Tongue, chief strategy officer at OhmConnect.

"All the devices within that node are able to do their optimization, and the single demand signal is output from that node," he said. "And then there's the node-to-node kind of optimization that the DSO or some market operator will be working with," which would require an interface between the DSO and transmission system operator.

Getting a dynamic system at the edge of the grid to tap into distributed resources can ensure that the utilities do not have to spend so much money that the transition becomes unaffordable, said Chris Irwin, DOE's transactive energy program manager.

"We cannot accomplish electrification of all loads without a monumental investment in grid infrastructure," Irwin said. "If the utility is the sole investor in that control surface, we will suffer because of a high price tag. So, as we lift ourselves up, as we lift up grid infrastructure, we must contact those distributed energy resources; we must share the opportunity that exists." ■

*— James Downing*

# CAISO Discusses Year-ahead Requirements for RA Program

*By Ayla Burnett*

CAISO staff and stakeholders on Dec. 6 again dove into the details of the ISO's resource adequacy construct, including increasing visibility, creating year-ahead requirements and refining the existing capacity procurement mechanism (CPM).

The ISO's Resource Adequacy Modeling and Program Design Working Group is getting into the weeds of how to plan for RA in different time horizons, including the year-ahead, two- to four-year and five- to 10-year time frames. During its third meeting, the group focused on the year ahead.

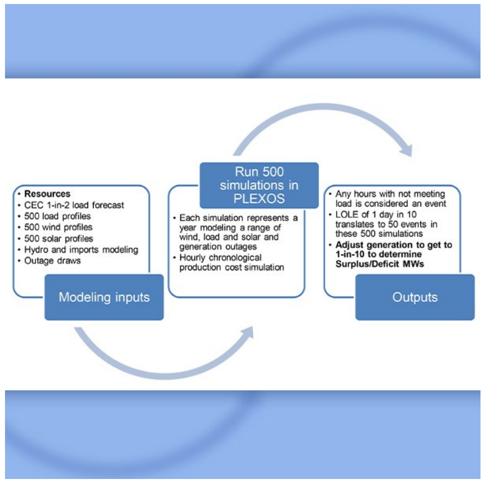
Aditya Jayam Prabhakar, lead resource assessment and planning analyst with the ISO, presented a proposed assessment of RA showings, designed to determine if load-serving entities have procured enough resources for the ISO to meet the one-in-10-year standard. Staff discussed potential modeling inputs for determining sufficiency, questioning what resources should be included in the assessment.

"As the world is changing and you have a lot more variable energy resources, probabilistic modeling of risks is necessary," Prabhakar said. "Ensuring reliability is the responsibility of the ISO, and that's what we're trying to assess here."

CAISO proposed a variety of inputs to be put into a stochastic production cost model that would run simulations and determine surplus and deficit megawatts, including information on when a shortfall is occurring and for how many megawatt-hours. They include the California Energy Commission's one-in-two load forecast, 500 load profiles, 500 wind and solar profiles, hydro and imports modeling, and outage draws.

There was some disagreement surrounding the resources the ISO chose to include in the modeling. In particular, some stakeholders thought strategic reserves and other emergency resources should be included.

"I'm curious about the decision to exclude the strategic reliability reserve and the reliability demand response resources from this assessment," said Doug Boccignone, principal with Flynn Resource Consultants. "We're treating these as hidden resources that we are not acknowledging exist, but we know we will rely on them and have relied on them in the past, and that just seems like we're now creating a




CAISO staff presented inputs and outputs into a stochastic production cost model that would determine resource adequacy in the year-ahead time frame. | *CAISO*

standard that is much higher than a one-in-10."

Prabhakar answered that the intent of the RA program is to ensure operation under normal conditions and to avoid emergency events.

"Accounting for resources that are only accessible for us under emergency conditions, I think in our opinion, defeats that purpose because that essentially means that we're planning to get into emergency conditions," Prabhakar said.

Still, Boccignone suggested including extreme load events and the resources they expect will be available to meet those loads in the stochastic modeling so they can ensure they've "got it covered" in the event of bad conditions. He was also concerned with how this modeling could affect the decision to backstop should the ISO choose not to include emergency resources in modeling.

"If you weren't considering those resources when you're deciding to CPM something, that would be a mistake. If you know you can count on them, they're going to be there; there's no point in CPMing," he said.

However, Nuo Tang of Middle River Power pointed out that emergency reserve type resources are generally used only after the RA program exceeds a 0.1 loss-of-load expectation, and therefore shouldn't be included for the purposes of reaching 0.1.

Kallie Wells, senior consulting with Gridwell Consulting, also questioned if energy-only resources that can be used to charge batteries should be included in modeling.

"I think it makes as a good question as to whether or not there is a way to maybe include them only so that they can charge the batteries," Wells said. "Then the batteries are able to discharge up to the amount that they've been shown for, but not necessarily include those resources to also be discharged to the grid." Not including them could impact storage resource availability, she added.

## Closing the Gap Between 90-100% Showings

The year-ahead time frame considers both shown capacity and forecast eligible capacity. Currently, the framework requires LSEs to provide 90% showings from May to September for system RA requirements, with the remaining 10% not shown because of the wide range of varying local regulatory authority requirements, leaving room for assumptions. As a result, CAISO questioned how to close the gap between 90 and 100% showings, assuming the remaining 10% could be RA-eligible resources held back for substitution or non-RA resources.

Kyle Navis, senior analyst with the California Public Utilities Commission's Public Advocates Office, questioned if CAISO could request a nonbinding showing of the 90% requirement in the year-ahead showing process.

"If LSEs at the time of the showing are contracted to a compliance position that is above 90%, would they be able to show those additional resources without that additional capacity being bound by rules to acknowledge that there may be some movement in the market until the month-ahead showing process?" Navis said. "It seems like it would maybe close the assumption gap a little bit so that it's not just ISO staff trying to come up with your best guess."

Prabhakar answered that, if the process is effective, no one will have to make guesses on what resources will be available.

"If we have an approach where we can get 100% shown capacity for each month, and we don't have to make any assumptions — that's the idea of this entire process: We want to limit the number of assumptions that are made."

The group will discuss the two– to four-year time frame during its next meeting, tentatively scheduled for Jan. 16. ■

# 'Missing Pathway' Advancing Through Approval Steps in West

## *Cross-Tie Project Nears End of BLM Environmental Review*

*By Elaine Goodman*

The proposed Cross-Tie transmission project — a 214-mile line across Utah and Nevada that's seen as a missing link in the Western transmission system — is moving through the federal approval process with a targeted in-service date in 2027.

TransCanyon LLC has proposed the 500-kV HVAC line connecting PacifiCorp's Clover substation in Utah with NV Energy's Robinson Summit substation in Nevada.

The U.S. Bureau of Land Management, the lead federal agency for the project, released a *draft environmental impact statement* for the proposal last month. BLM expects to decide in 2024 whether to grant the developer's right-of-way request.

TransCanyon is a joint venture between Berkshire Hathaway Energy's BHE U.S. Transmission and Pinnacle West Capital, the parent company of Arizona Public Service (APS).

The 1,500-MW Cross-Tie transmission project will cost an estimated $750 million and is expected to begin service in 2027, according to TransCanyon's website. TransCanyon plans to develop, own and operate the transmission facilities.

### Delivering Renewables

TransCanyon called Cross-Tie a "missing pathway" in the Western transmission system that would enhance resilience and reliability and boost the delivery of renewable energy.

At its eastern end, Cross-Tie would connect to the southern tip of PacifiCorp's 416-mile Gateway South transmission line, which runs across Wyoming, Colorado and Utah.

At Cross-Tie's western end is the Robinson Summit substation, the northeastern vertex of NV Energy's planned transmission triangle around Nevada. The triangle consists of the proposed Greenlink North and Greenlink West lines and the existing One Nevada Line.

TransCanyon said that Cross-Tie, in concert with PacifiCorp's Energy Gateway projects, the Greenlink projects and the Harry Allen-to-Eldorado project in southern Nevada, would provide needed transmission capacity between the Intermountain West and the Desert Southwest.

"This additional transmission capacity would facilitate access between the significant existing and planned renewable resources, primarily wind in Wyoming and wind or solar resources in central Utah and eastern Nevada, to the diverse utility load profiles in the Desert Southwest/California," TransCanyon said in a *development plan* submitted to the BLM.

In addition, Cross-Tie might reduce solar curtailments and battery storage needs in California and the Desert Southwest, the plan said.

During a virtual public meeting hosted by BLM on Dec. 5, one attendee asked whether any contracts are in place that would guarantee Cross-Tie will deliver renewable energy.

TransCanyon representative Roger Yensen said the developer plans to complete the environmental review process with BLM before entering into contracts.

But given its strategic location, Yensen said, "we anticipate there will be a significant portion of energy that will be carried on the Cross-Tie [project] that will be from renewable resources."

In October, the U.S. Department of Energy announced it would become an anchor off-taker for three interstate transmission projects, including Cross-Tie. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.) Yensen said negotiations with DOE are underway.

TransCanyon isn't currently planning to connect Cross-Tie to the Intermountain Power Plant in Utah, even though the transmission project's path runs near the facility. But that could be considered in the future, according to the development plan.

### Alternative Routes

In its environmental review of Cross-Tie, BLM is examining the developer's proposed transmission path as well as several alternatives that would add four miles to about 150 miles to the route. BLM staff said the transmission project will cost roughly $3.5 million per mile.

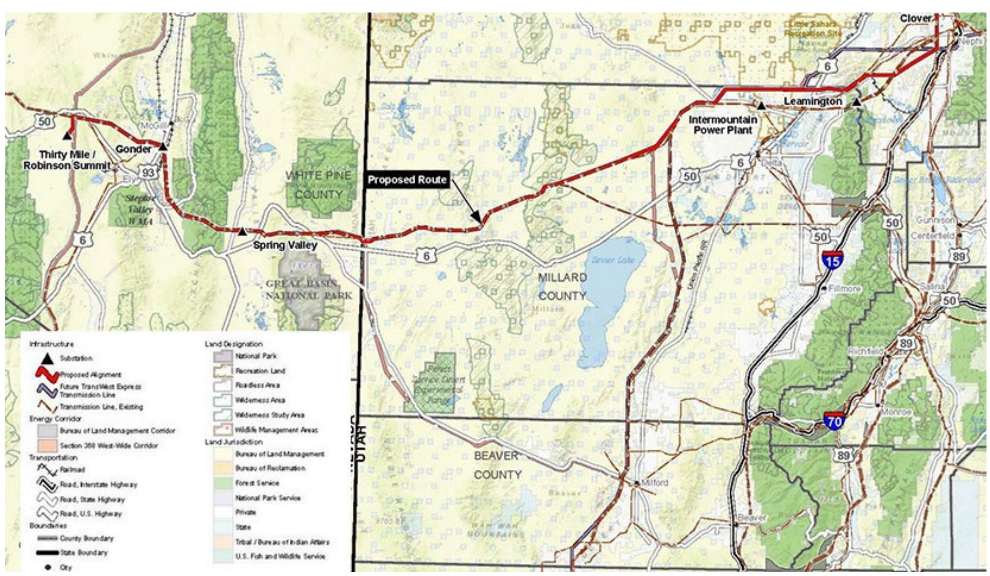
One alternative route addresses concerns from the town of Leamington, Utah, about the project's impacts on scenic views.

"Why would any project be proposed that destroys the view the residents of Leamington have enjoyed and cherished for over 150 years when a viable alternative is readily available?" Leamington's mayor said in a written comment submitted for the virtual meeting.

Other alternatives were designed to reduce impacts to cultural resources, environmentally sensitive areas or the U.S. Department of Defense's Utah Test and Training Range. BLM has not yet selected a preferred alternative.

In addition to the virtual public meeting, BLM held four in-person meetings on Cross-Tie in late November.

The deadline to comment on the draft environmental impact statement is Jan. 2. ■




The proposed Cross-Tie transmission line would run 214 miles from Clover substation in Utah to Robinson Summit substation in Nevada. | *TransCanyon LLC*

## ERCOT News

# SCOTUS Won't Take up Texas Appeal of ROFR Law

*By Tom Kleckner*

The U.S. Supreme Court on Dec. 11 declined to take up an appeal of a lower court's ruling that a Texas law giving incumbent transmission companies the right of first refusal (ROFR) to build new transmission lines was unconstitutional.

The Texas Public Utility Commission, with then-Chair Peter Lake as the lead petitioner, requested a writ of certiorari last December after the 5th U.S. Circuit Court of Appeals' decision earlier in 2022. (See *Texas Petitions SCOTUS to Review ROFR Ruling*.)

The appeals court found for NextEra Energy in its challenge to a 2019 Texas law (*Senate Bill 1938*) that set up a ROFR within state lines. It ruled the legislation violated the U.S. Constitution's dormant Commerce Clause, and it remanded the case back to the U.S. District Court for Western Texas. (See *5th Circuit Finds in Favor of NextEra's ROFR Appeal*.)

The Supreme Court gave no reason for not taking up the appeal, as is typical. It included the rejection (22-601) among dozens of *other appeals* it will not take up this term.

The high court says it receives about 10,000 requests for *certiorari* each year. Only about 100 of those are granted, allowing petitioners to make oral arguments before the justices on why the lower court was wrong.

U.S. Solicitor General Elizabeth Prelogar in October *recommended* the Supreme Court not to take up the ROFR case. She said the petition is not a "suitable vehicle" for reviewing the constitutionality of ROFR laws.

"The 5th Circuit got it right that the Texas law was unconstitutional," Paul Cicio, chair of the Electricity Transmission Competition Coalition, said in an email to *RTO Insider*. "Blocking new entrants from competing on transmission projects isn't just unconstitutional; it's anti-consumer, anti-free-market policy that costs consumers billions of dollars in higher electricity rates."

The coalition said FERC should see the denial as a "clear signal in support of transmission competition." It said FERC has an opportunity to take action now in a pending complaint under Section 206 of the Federal Power Act against MISO to ensure the grid operator no longer applies ROFR laws when conducting transmission planning (*EL22-78*). (See *Big Savings for Tx Competition Claimed as FERC Considers a New ROFR*.)

Most recently, an Iowa court struck down that state's ROFR law, saying the procedure used to pass the bill was unconstitutional. (See related story, *Iowa ROFR Law Overturned, Throwing Multiple MISO LRTP Projects into Uncertainty*.)

NextEra Energy Capital Holdings, NextEra Energy Transmission (NEET), NextEra Energy Transmission Midwest, Lone Star Transmission, NextEra Energy Transmission Southwest, Southwestern Public Service, Entergy Texas, Oncor, LSP Transmission Holdings II and East Texas Electric Cooperative were also named as respondents in the petition.

NextEra subsidiaries were involved in two projects in Texas' non-ERCOT footprint that ran afoul of the ROFR law. NEET Midwest won a competitive bid in 2018 for a $130 million, 500-kV project in East Texas. MISO said last year that planned capacity in the region had negated much of the project's economic benefits. (See *MISO on Verge of Cancelling Hartburg-Sabine Tx Project*.)

NEET Southwest also applied to the Texas PUC in 2018 to transfer ownership of 30 miles of 138-kV facilities from Rayburn Country Electric Cooperative in SPP's East Texas footprint. That application was withdrawn in 2020 after SB 1938 became law (*48071*). ■


The U.S. Supreme Court | *Shutterstock*

## ERCOT News

# ERCOT Technical Advisory Committee Briefs

### *Members Support 2024 Ancillary Services Methodology Despite Costs*

ERCOT stakeholders endorsed the grid operator's proposed ancillary *service* methodology for 2024, but only after extracting a commitment from staff to bring the proposal back for further review by April 30.

The approval came after ERCOT's *Independent Market Monitor,* Potomac Economics, said the methodology has generated artificial shortages that produced "massive" inefficient market costs totaling about $12.5 billion this year through Nov. 27.

The Monitor also told the Technical Advisory Committee that the methodology diminishes reliability by withholding units needed to manage transmission congestion, is not based on sound reliability criteria, and has led to excessive reserves procurements that far exceed those by other grid operators.

"I don't want to exaggerate how bad this is, but this is the worst performance we've ever seen since the beginning of organized electricity markets almost 25 years ago," Potomac's David Patton said. "I've been racking my brain to try to figure out whether I've ever seen anything like this, and I really haven't."

Patton, whose firm also monitors the MISO, NYISO and ISO-NE markets, said there's no way to pretend the costs are "efficient," as ERCOT was not experiencing shortages during periods with $5,000 capped prices.

"We weren't close to being in shortage and yet the market, with this large increase in 10-minute reserves that gets held out of the energy market, perceived a shortage that didn't really exist," he said.

"Inefficiency is not how we operate in this market and provide reliability. Our objective is to provide reliability at lowest cost," said MD Energy Consulting's Mark Dreyfus, who represents the city of Eastland and 154 other commercial consumers. "Since the very beginning of this market, commercial consumers have been very clear. They support competitive market outcomes, wherever possible. By supporting competitive market outcomes, we will get the lowest cost reliability possible."

ERCOT Technical Advisory Committee's December meeting | *ERCOT*

At issue is ERCOT contingency reserve service (ECRS), the grid operator's first new ancillary service in 20 years that was deployed early this summer. Dreyfus called for a commitment to reconsider how the service is used and to better understand the Monitor's report.

The service is economically dispatched within 10 minutes of deployment, using capacity that can be sustained at a specified level for two consecutive hours and supplementing the ISO's conservative operations posture of setting aside ample reserves.

The IMM has said ECRS essentially meets the same reliability requirements that previously were met solely by responsive reserve service. In its initial assessment of ancillary services, the monitor said ECRS "likely" raised the real-time market's energy value by at least $8 billion. (See *ERCOT Board, IMM Debate Ancillary Service Costs*.)

ERCOT disputed the Monitor's analysis, noting the $12.5 billion figure is not the direct cost of procuring ECRS, but a study that estimates how much lower real-time energy costs would have been if resources were not reserving capacity to provide ECRS. It said in a statement that actual costs were likely much less than that and other factors, such as the historically hot summer, contributed to increased prices.

Potomac urged stakeholders to reject the AS methodology and requested that ERCOT use a reliability analysis that models the uncertainties that drive reliability problems and then quantify the needed reserves. It said staff could mitigate its concerns with several changes, including reducing ECRS' deployment back to one hour.

ERCOT staff has made minor changes to the 2024 AS methodology. It said the ECRS proposal reflects the minimum volume of 10-minute reserves needed to cover the risks should a large unit trip offline or frequency losses occur.

However, the grid operator also allowed that a "separate, broader discussion is warranted" to identify improvements to the ECRS market.

Given that caveat and as required by the protocols, TAC endorsed the 2024 methodology

# ERCOT News

with a 21-3 vote. Six members abstained. An earlier vote to approve the methodology as recommended by ERCOT failed 12-7 with 11 abstentions.

Potomac's four-year contract as ERCOT's Independent Market Monitor expires Dec. 31. It remains the only listed applicant to the Public Utility Commission's request for a new four-year contract, but no announcement has been made (*55222*).

## Staff Withdraws DRRS Change

The committee approved ERCOT's request to withdraw a nodal protocol revision request (*NPRR1203*) implementing a new ancillary service that faces a tight statutory timeline.

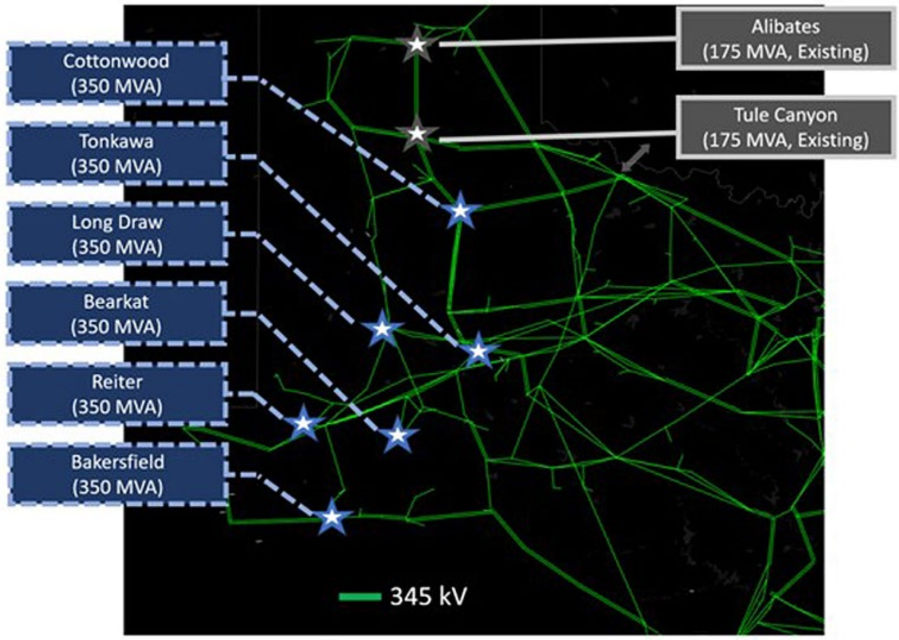
Staff had proposed adding dispatchable reliability reserve service (DRRS) as a subtype of non-spinning reserve, saying it was the only way to meet a Dec. 1, 2024, deadline set by state law. TAC tabled the NPRR in October after lawmakers objected to ERCOT's plans and said the standalone service should be developed even if it fails to meet the deadline. (See *ERCOT Technical Advisory Committee Briefs: Oct. 24, 2023*.)

The PUC last month linked its approval of the budget to meeting several performance metrics. They included implementing the DRRS product "aligning it with the real-time co-optimization plus battery project (RTC+B). (See *Texas PUC OKs Smaller Budget, Admin Fee Increases for ERCOT*.)

Kenan Ögelman, ERCOT's vice president of commercial operations, said staff plans to develop DRRS as a standalone service "as expeditiously as possible" and will file a draft NPRR by April that aligns with real-time co-optimization's (RTC) implementation. He also agreed with stakeholders' requests for a workshop to review the NPRR's details.

"The goal would be to make sure everybody is fully informed on the functionality and features that we were putting into the NPRR and that we absolutely got stakeholder feedback on making that better or adjusting it, such that we had a product that the stakeholder community was comfortable with and that also met the statutory goals," he said.

The DRRS work will also align with the *Real-time Co-optimization plus Batteries Task Force*, which is developing the market tool that procures energy and ancillary services every five minutes. The team is developing business requirements for RTC and single-model batteries, with plans to complete its project in 2026. (See *ERCOT Technical Advisory Committee Briefs: Aug. 22, 2023*.)




ERCOT's proposed synchronous condensers at six 345-kV substations in West Texas. | *ERCOT*

"The feedback I've gotten so far from the commission is RTC+B is the priority," Ögelman said.

TAC endorsed ERCOT's plan 28-0, with Luminant and Lower Colorado River Authority (LCRA) both abstaining over the statutory deadline concerns. Luminant's Ned Bonskowski said his company did not want to stand in the way of those wanting to move forward.

"I am a little worried about certain policy decisions being driven by secondary timeline goals," LCRA's Emily Jolly said.

Staff also withdrew two other binding document requests (*OBDRR049*, *OBDRR050*) related to NPRR1203.

## West Texas Projects Endorsed

TAC endorsed two Tier 1 transmission projects in the West Texas weather zone projected to cost a combined $1.17 billion, placing both on the combination ballot.

The Regional Planning Group's *West Texas Synchronous Condenser project* accounts for the bulk of the costs at $892.2 million. It involves installing synchronous condensers at six 345-kV substations to address reliability risks in West Texas driven by the region's increased penetration of inverter-based resources (IBRs). ERCOT expects more than 42 GW of IBR capacity by 2026 in the zone.

Staff said the prevalence of IBRs coupled with the lack of conventional synchronous resources has further weakened the system and increased the likelihood of potential instability issues, such as the recent Odessa disturbances. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

The project, involving Wind Energy Transmission Texas, LCRA Transmission Services Corp. and Oncor, has an in-service date of May-October 2027.

The second project, submitted by Texas-New Mexico Power, is projected to cost $273.1 million. The upgrade involves the construction of two 345-kV substations, two 345/138-kV substations and 20 miles of 138-kV line to address reliability needs. The project is expected to be completed by June 2027.

With capital costs exceeding $100 million, the Tier 1 projects must be approved by ERCOT's board, which next meets Dec. 18-19.

## TAC Remembers Brad Jones

Members shared the memories of the late Brad Jones, who chaired TAC at one point and served as ERCOT's interim CEO and COO. Jones, who also served as NYISO's CEO, passed away Nov. 8. (See *Brad Jones, Former ERCOT, NYISO CEO, Dies at 60*.)

Reliant Energy Retail Services' Bill Barnes, who attended a memorial service Dec. 2 in Austin along with many other stakeholders, said ERCOT's membership was one of his most important families.

"We heard a lot about Brad's optimism," he said. "The thing that I will take with me forever is the spirit of compromise. That's why we're

# ERCOT News

here, to hear from different perspectives, hear from other segments, each other's opinions, and think about how we can work together as a team to solve the very challenging problems that face us."

"You could argue with Brad up and down, back and forth, and respect was always maintained through that entire process," said Engie's Bob Helton, whose relationship with Jones goes back to the market design work of the late 1990s. "That's one of the things that was wonderful about Brad. He would listen to you, argue with you, and we'd come to a good decision."

"Brad is one of the core reasons we have what we have today," Golden Spread Electric Cooperative's Mike Wise said. "He's one of the godfathers of our market."

"Obviously, Brad was a very special and influential person at ERCOT. He had two stints with us, made amazing contributions, and brought a lot of joy and laughter to the folks at ERCOT," Ögelman said. "In some of our darkest moments, he was our shining light as we were trying to deal with the aftermath of Winter Storm Uri. I certainly miss him every day and appreciate all that he's done for everybody in this room and in the industry and ERCOT as well."

## Retail Choice Coming to Lubbock

TAC's unanimous endorsement of the combo ballot resulted in approval of a change to the retail market guide (*RMGRR176*) that lays out the processes Lubbock Power & Light must use when it begins offering customers their choice of electric providers March 4.

Oncor's Debbie McKeever, chair of the Retail Market Subcommittee, told the committee that more than two dozen electric retailers are preparing to offer plans in LP&L's service territory.

The municipal utility is migrating the final 30% of its load from SPP to ERCOT by Dec. 11. LP&L first announced its intention to join ERCOT's competitive market in 2015. Texas regulators approved the transition in 2018. (See *Six Years in the Making: LP&L Migrates Load to ERCOT*.)

The combo ballot included three other NPRRs that, if approved by the board and the PUC, would:

- *NPRR1181*: Require qualified scheduling entities representing coal or lignite resources to submit to ERCOT a seasonal declaration of coal and lignite inventory levels and to notify ERCOT when the inventories drop below target and critical-level protocols.
- *NPRR1201:* Reduce exposure from resettlements and default uplift invoices for historical operating days by limiting resettlement timelines due to errors that are discovered and a market notice is provided to the market within one year after the operating day. This limit does not apply to alternative dispute resolution resettlements, a procedure for return of settlement funds or a board-directed resettlement addressing unusual circumstances.
- *NPRR1204*: Implement the state-of-charge (SOC) concepts necessary for awareness, accounting and monitoring energy storage resources' SOC within the RTC+B project. ■

*— Tom Kleckner*

# Overheard at the ISO-NE Consumer Liaison Group Meeting

*By Jon Lamson*

Dialog between community members and ISO-NE CEO Gordon van Welie and board member Steve Corneli. | © RTO Insider LLC

BOSTON — A year removed from the takeover of the ISO-NE Consumer Liaison Group (CLG) Coordinating Committee by a group of climate activists, the CLG's return to Boston brought an intense focus on the need to rapidly cut emissions while centering the needs of front-line communities. (See *Climate Activists Take Over Small Piece of ISO-NE*.)

The "Community Welcome," a new feature of CLG meetings, was provided by the Rev. Mariama White-Hammond, Boston's chief of environment, energy and open space.

"Let's be honest: Five years ago, I'm not sure I would have been the person here speaking," White-Hammond told attendees while starting her address.

White-Hammond highlighted the importance of environmental justice in the planning and siting of new energy infrastructure.

"We have to be honest about the fact that for many years, we have put the most polluting facilities in black and brown communities and in poor and working-class communities," White-Hammond said. "The question is: How can we build an energy system that repairs those harms while also recognizing that the consensus is clear … that climate change is happening because of our use of fossil fuels."

Speaking to the climate advocates at the meeting, White-Hammond emphasized that electrification of heating and transportation will require a significant amount of new electricity infrastructure, including substations and transmission lines.

Turning to policymakers and other stakeholders, White-Hammond called for greater imagination in planning and siting to avoid replicating the mistakes and injustices of the past.

When considering the needs for new infrastructure, White-Hammond said energy efficiency and demand reductions should come first, followed by building up infrastructure in areas that have not historically been asked to host energy infrastructure, or are driving the need for the infrastructure. Only as a final resort should major projects be sited in vulnerable communities that already host a disproportionate share of infrastructure, White-Hammond said.

In these cases, the community benefits of hosting the infrastructure must well exceed any detrimental impacts, she added. These local benefits could include increased access to renewable energy, lower electricity costs and improved grid resilience.

## Reliability, Affordability and Sustainability

Matt Christiansen, general counsel for FERC, stressed the importance of maintaining grid reliability and affordability, then took a series of public questions that focused largely on FERC's ability to speed up the retirement of fossil fuels.

Judith Black, a climate activist and member of 350 Mass, pushed back against Christiansen's framing, arguing sustainability should be included among FERC's top priorities.

"There's a scientific consensus that we are at the edge of our extinction, and just saying reliability and affordability is like putting on huge blinders," Black said. "Sustainability has got to be a third prong of this work."

Christiansen said while FERC must remain fuel neutral, the commission will play an essential role in ensuring the grid can manage the increasing number of distributed weather-dependent renewables.

"Wind and solar are probably going to be the predominant part of our resource mix before too long," Christiansen said. "The best thing anyone can do if you're an advocate of those resources is making sure that the infrastructure and the market rules are in place so that those resources can contribute to a reliable grid that people can afford."

Climate advocates also pushed representatives of ISO-NE to do more to expedite fossil fuel retirements and emissions reductions, to which representatives of the RTO also stressed their resource neutrality. However, ISO-NE CEO Gordon van Welie said the RTO is open to implementing a carbon pricing mechanism in the RTO's markets if all six New England states can reach an agreement.

"We've talked a lot internally about how we could implement carbon pricing," van Welie said. "In my view, this is the quickest way to accelerate the clean energy transition."

Also, van Welie highlighted the role that active demand response could play in reducing emissions associated with the daily peak load but said this "needs to be activated at the retail level" and therefore would be the jurisdiction of the states.

With peak loads on the grid expected to rise dramatically in the coming decades, "we have to really scale up demand response in this region," van Welie said.

Several audience members echoed the need for accelerated demand response efforts but contended ISO-NE could play a larger role in engaging the public to reduce demand during times of peak load.

"I think I can speak for more than just some of the people in this room when I say we would rather turn everything in our apartments off than see a coal plant get called on for the peak," said Rebecca Beaulieu of 350 New Hampshire.

In response, Anne George of ISO-NE said the RTO calls for conservation only during last-resort efforts to prevent forced outages, and that sending out frequent conservation requests would dull their effects when they are needed most. ■

## ISO-NE News

# Affordability Must not Lose out in Energy Transition, NE Regulators Say

*By Jon Lamson*

BOSTON — New England policymakers and stakeholders must not overlook the need for electric affordability in the energy transition, officials from Massachusetts, Rhode Island and Connecticut told attendees of the New England Power Generators Association's fifth annual New England Energy Summit on Dec. 6.

Rhode Island Public Utilities Commission Chair Ron Gerwatowski compared juggling the priorities of decarbonization, reliability and affordability to "adopting a coyote, a wolf and a bunny rabbit, putting them in the same corral, and asking how you can get them to get along without harming each other."

"The coyote and wolf might find a way to coexist, but that bunny rabbit, I don't know about it," Gerwatowski told attendees.

The bunny rabbit, in Gerwatowski's analogy, is affordability. With decarbonization and reliability considered nonnegotiable in the region, affordability is being overlooked, he said.

"When we add up the combination of rising costs from distribution, transmission, regional markets and renewable procurements, electricity rates are driven upward, and affordability gets severely strained," he explained.

To prevent rates from skyrocketing, Gerwatowski said that policymakers should consider impacts on ratepayers when weighing different decarbonization strategies, and potentially avoid funding transportation and heating decarbonization initiatives through electric rates.

Additionally, states should consider providing stronger price signals and demand response incentives for consumers to reduce their electricity consumption during times of peak loads to limit the overall demand on the system and bring down prices, he said.

"I'm not suggesting that we slow down our pursuit of a carbon-free future," Gerwatowski said. "What I'm saying is that it's not too late to adjust the way we plan for our future."

Rebecca Tepper, secretary of Massachusetts' Executive Office of Energy and Environmental Affairs, agreed with Gerwatowski's concerns about affordability and noted that the Massachusetts Department of Public Utilities is planning to open a docket focused on rate affordability.

"Addressing things on the demand side is extremely important," Tepper said, pointing to the results of ISO-NE's 2050 Transmission Study, which found that reducing the 2050 winter peak load from the projected 57 GW to 51 GW would save the region roughly $8 billion. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.) Tepper floated the idea of a "6-GW Earthshot challenge."

Tepper added that the region should "think as creatively as we do about generation with demand response. We've all started thinking about energy efficiency as our first fuel; reducing demand needs to be our second fuel."

From left: Carol Holahan, Foley Hoag; Connecticut DEEP Commissioner Katie Dykes; Massachusetts EEA Secretary Rebecca Tepper; and Rhode Island PUC Chair Ron Gerwatowski | © *RTO Insider LLC*

Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection, said collaboration between Northeastern states around clean energy generation and infrastructure will be "the key to addressing affordability challenges."

Dykes added that collaboration can both enable states to unlock lower prices through larger contracts and help states share the costs of projects that provide regionwide reliability benefits.

"We're benefiting in Connecticut from the investments that Massachusetts is making in transmission to import hydropower," Dykes said. "The entire region is freeriding on the support that Connecticut ratepayers are providing to prevent the Millstone nuclear facility from shutting down."

### Building Local Support

The officials and other industry speakers also stressed the importance of building local support for clean energy projects by communicating the climate benefits and providing tangible local incentives for communities to host infrastructure.

"We need to get communities excited about the energy infrastructure that's in their towns," Tepper said.

The "fundamental question," said Mike Cuzzi of Cornerstone Government Affairs, is whether "the social and political will is there to build these things."

Cuzzi added that building community partnerships early in the development process and speaking to the self interest of local communities are essential aspects of building support for projects.

"Listening to the people, early, upfront and understanding where you're going to have problems … all those pieces are very important," Cuzzi said. "Even that may not lead to success, but you're at least going to win some degree of the public relations war."

Gerwatowski called upon environmental activists and organizations that advocate for clean energy legislation to support clean energy infrastructure in regulatory proceedings and help communicate the climate benefits of electric infrastructure to local communities.

"They're noticeably absent in these proceedings," Gerwatowski said. "Why aren't you coming out in droves like when it's time to pass a bill?" ■

## ISO-NE News

# Clements Outlines Further Steps to Ease Interconnection Woes

*By Jon Lamson*

BOSTON — Order 2023 is just the first step in addressing the interconnection backlogs in New England and across the country, FERC Commissioner Allison Clements said at Raab Associates' New England Electricity Restructuring Roundtable on Dec. 8.

"It would be silly and naive to think that we would fix the interconnection queue just by taking a first step," Clements said. She outlined several next steps that were detailed in her concurrence on Order 2023.

The commissioner said addressing transmission planning issues will be key to reducing backlogs. FERC has been working on a final rule on transmission planning, which has generated significant interest from environmental, industry and labor groups. (See *FERC Gets Growing Calls to Finish Transmission Rule in 2024*.)

"Fundamentally, we're not going to fix the interconnection queue process if the transmission system planning process doesn't anticipate and doesn't recognize what's in the queue," Clements said.

Clements highlighted the potential of a default cost-sharing mechanism for large transmission projects that would prevent disagreements between states from hindering progress.

"If the states can agree on a cost-allocation approach, great. But what happens if they can't?" Clements asked. "There's a lot of support for a default mechanism so that the infrastructure that comes out of this robust planning process can then get cost-allocated and we don't worry about a single-state veto or free-ridership concerns."

Regarding state clean energy solicitations, Clements told attendees that "resource planning processes across states should be aligned with the interconnection queue … if you can't get your state-solicited resources online, then we have an immense problem."

### New Technologies

Clements also spoke about the potential of grid-enhancing technologies (GETs), calling them the "cheapest, nearest term, shortest payback investments that we can make related to getting more efficiency out of our existing system."

She added she's considering which GETs should be included in a final rule on transmission planning.

FERC Commissioner Allison Clements | © RTO Insider LLC

Hudson Gilmer, CEO of the grid monitoring and analytics company LineVision, said the adoption of dynamic line ratings has accelerated across the country, in part because of the pressures of load growth and the availability of federal funding from the Department of Energy's *Grid Resilience and Innovation Partnerships Program*.

However, Gilmer said the Northeast has lagged in its adoption of GETs.

"The U.S. is behind the rest of the world … and let's be honest, New England is behind the rest of the country," Gilmer said. He added that GET adoption "can be accelerated by incentives that level the playing field with more capital-intensive traditional grid upgrades."

Sarah Jackson of the multiday battery storage company Form Energy highlighted the potential benefits of long-duration storage to New England, detailed in a white paper published by the company in September. (See *Form Energy Wants to Bring Long-duration Storage to New England*.)

Jackson said the lack of recognition in ISO-NE's capacity market of the reliability benefits of multiday battery storage is one of the factors holding back the technology in New England.

"This is a place where the markets have not caught up to the technology," Jackson said. She added that state procurements of long-duration storage could help speed up its commercial development in New England.

"We don't have the luxury of waiting for the technology to mature, we need this energy storage yesterday," Jackson said.

### Gas Decarbonization

Two days prior to the Roundtable, the Massachusetts Department of Public Utilities (DPU) released a major ruling following a multiyear investigation into the Future of Natural Gas in the state (DPU 20-80-B).

The release of the ruling came as a surprise to many stakeholders in the state and generally was applauded by environmental groups for its emphasis on weaning the state off gas. (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

"The focus is on setting a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of current technologies and commercial applications," DPU Chair Jamie Van Nostrand told the Roundtable.

Van Nostrand said the order is intended to bring the state's gas industry and heating sector into compliance with the state's statutory emissions targets, including the sector-specific sublimits established in the state's *Clean Energy and Climate Plan* for 2025 and 2030.

"We're either serious about addressing climate change in Massachusetts, or we're not. We're either serious about meeting the sector sub-limits for greenhouse gas emissions, or we're not," Van Nostrand said.

Despite the state's climate goals, the gas utilities have continued to operate as if it is "business as usual," Van Nostrand said. "We're still seeing 1-1.5% annual growth in gas load."

Nikki Bruno, vice president of clean technologies at Eversource Energy, one of the major gas and electric utilities in the state, said she is "really excited about the guidance in the order."

Bruno highlighted Eversource's ongoing networked geothermal pilot project in Framingham, Mass. (See *Networked Geothermal Breaks Ground in Framingham*.)

The pilot project "positions Massachusetts as a state leader in this technology, and we're looking forward to more," Bruno said. "It doesn't matter that it's not gas, we want to do right by the customer."

Zeyneb Magavi, co-executive director of HEET, a climate nonprofit that's been working with Eversource on the project, said geothermal networks could be a significant tool in decarbonizing dense environmental justice neighborhoods.

"The hardest places for us to decarbonize today are often the ideal places for geothermal networks," Magavi said.

Looking ahead, several speakers at the Roundtable spoke about the need to address state laws that require utilities to provide gas to existing customers who request it. Under these laws, individual gas customers could prevent the decommissioning of parts of the gas network.

"I do think we need to revisit that obligation to serve, to make it clear that customers are still going to be provided the essential utility service of heat, but it may be provided in some way other than gas," Van Nostrand said. ■

# MISO News

## Iowa ROFR Law Overturned, Throwing Multiple MISO LRTP Projects into Uncertainty

*By Amanda Durish Cook*

ORLANDO, Fla. — An Iowa court has formally struck down the state's right of first refusal law, deciding the procedure used to pass the bill is unconstitutional.

The decision stands to affect $2.6 billion in projects that are located at least partly in Iowa from MISO's $10 billion long-range transmission plan (LRTP) portfolio.

The Polk County District Court's decision Dec. 4 stops any current permitting processes on Iowa's portion of five of MISO's LRTP projects where incumbent developers had benefited from the law (*CVCV060840*). Incumbents ITC Midwest, MidAmerican Energy and Cedar Falls Utilities all exercised their option to build the LRTP projects, shutting out competition from other developers, including LS Power, which instigated the case.

The court said that since the March remand of the ROFR, "no party has presented any additional information that would lead this court to reach a different conclusion than the one reached by the Iowa Supreme Court when it issued the preliminary injunction in this case."

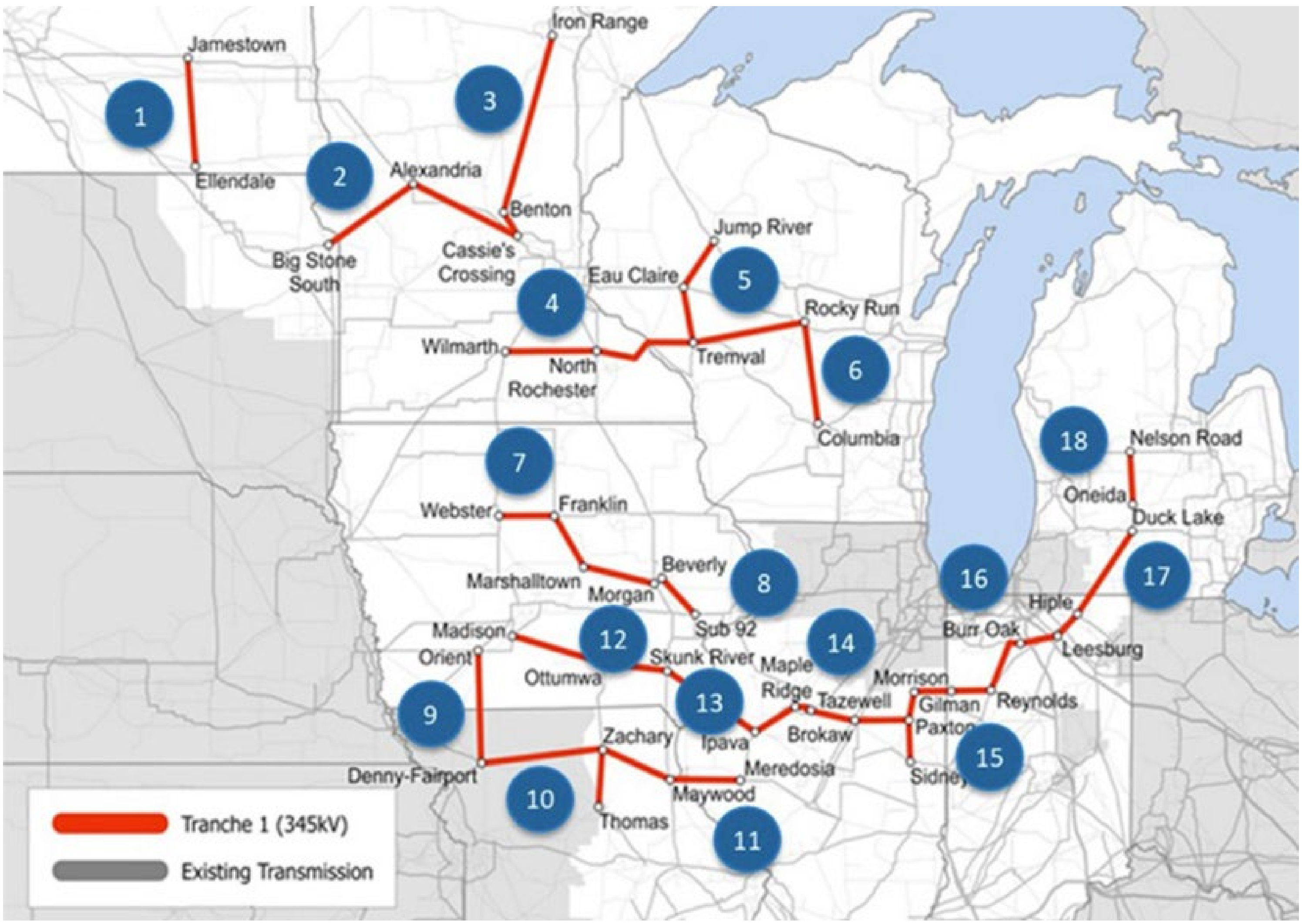
That means the state Supreme Court's rationale that the ROFR's passage ran counter to Iowa's rule that an act should address just one subject in the title stands unchanged. (See *Iowa Regulators Ponder MISO Tx Projects After ROFR Ruling*.)

"As the parties concede, this court's analysis of plaintiffs' constitutional claims must begin and end with the title and text of H.F. 2642," the court said, referencing the name of the 2020 appropriations bill that contained the ROFR law.

Through spokesperson Brandon Morris, MISO said it's reviewing the court's decision. The grid operator did not elaborate on whether it's communicating with the incumbent transmission owners or whether it might be preparing to issue requests for proposals on the affected LRTP projects.

"I would love to say I have a firm grasp of the order [already]," Deputy General Counsel Kristina Tridico told MISO members at a Dec. 6 Advisory Committee meeting during the RTO's quarterly Board Week in Orlando.

Tridico said MISO will "be more responsive" once it pores over the decision and has a clearer idea of the implications. She reminded members MISO is not a party to the proceeding, and it will track closely defendants' and




Projects approved under MISO's $10 billion LRTP portfolio | *MISO*

# MISO News

intervenors' next steps and how those will impact the timeline of the LRTP projects.

In a joint statement, MidAmerican and ITC Midwest said they're disappointed with the decision and are discussing their options.

The two said it's important to remember the district court's decision is predicated on the ROFR's inclusion as part of a larger appropriations bill and not on the merits of the ROFR itself. They also said the Iowa legislature for years has rolled laws together using appropriations bills without incident, and the ROFR "is no exception."

"As public policy, the ROFR protects Iowa landowner interests, meets the needs of energy consumers, and ensures a coordinated approach to planning and safely operating the electric grid to support a growing Iowa economy," MidAmerican and ITC Midwest said.

The five 345-kV LRTP projects located at least partly in Iowa likely to get a regulatory restart in the Iowa Utilities Board are:

- The Webster-Franklin-Marshalltown-Morgan Valley line.
- The Beverly-Sub 92 line.
- The Orient-Denny-Fairport line.
- The Madison-Ottumwa-Skunk River line.
- The Skunk River-Ipava line.

Seemingly before it was aware of the ruling, MISO *reported* at its Board Week that four of the first cycle of LRTP projects have entered regulatory processes for approval, including the Webster-Franklin-Marshalltown-Morgan Valley line.

At a Dec. 6 System Planning Committee of the MISO Board of Directors, Executive Director of Transmission Planning Laura Rauch said she was excited to begin delivering status updates on LRTP projects as they progress in permitting.

The other three lines that have been introduced to regulators are located in and near Minnesota.

"Kudos to Minnesota," Rauch said.

Rauch said MISO has seen good outreach and preparation work from all the developers of its LRTP projects. She said MISO has coordinated with developers on how best to manage the outages of existing transmission that must take place during LRTP construction. The lines under the first LRTP portfolio made extensive use of existing rights of way, so outages will be necessary, Rauch said.

"That is a technical challenge that we are stepping forward and engaging on," she said.

## MISO Moving Toward 2nd Portfolio of LRTP Projects

MISO is conducting analyses that will yield a second LRTP portfolio that again will focus on MISO Midwest.

Vice President of System Planning Aubrey Johnson said MISO is striking a balance between devoting due diligence on concerns the Independent Market Monitor has raised and moving forward with badly needed planning. (See *IMM Criticizes MISO's Modeling Software Used for Long-range Tx Planning*.)

Johnson said MISO's initial reliability and economic modeling shows MISO will need more "arteries" on the system to flow power and avoid overloads.

"Our system is like 5 p.m. at the 405, and we're going to add more cars," Johnson said, referencing an Amtrak route.

Johnson said if MISO doesn't incorporate another major transmission buildout, MISO members will have to add significantly more generation than already planned to serve load. The transmission future MISO is using to plan the second LRTP portfolio predicts load will be 125% of current levels by 2042.

Johnson added that MISO will test a "lower bound" of fleet transition on the second LRTP portfolio to make sure the lines demonstrate value under a variety of settings.

With the first stage of analyses out of the way, Johnson said MISO is beginning to feel out what lines it might recommend. (See *MISO Says Overloads and Congestion Loom Without 2nd Long-range Tx Portfolio*.)

"We're at the phase where our engineers are at Disneyland, excuse me, SeaWorld. You get the idea, an amusement park," he joked with a nod to MISO Board Week's location at the Renaissance Orlando at SeaWorld.

Johnson said he borrows a phrase from a song in the movie "Smokey and the Bandit" to sum up planning in MISO: "We've got a long way to go and a short time to get there."

Yvonne Cappel-Vickery, the clean energy organizer for the Alliance for Affordable Energy, urged MISO to move quickly on planning the second LRTP portfolio,

"Every delay in building this grid costs customers," she said.

Cappel-Vickery said new, long-range lines will provide benefits to consumers for decades by reducing congestion, avoiding generation outages and allowing access to low-cost renewable energy. ■

## MISO News

# MISO Board Approves $9B MTEP 23, Members Deliberate on Possible New Expedited Review Rules

*By Amanda Durish Cook*

ORLANDO, Fla. — MISO board members last week greenlit the $9 billion, 572-project 2023 Transmission Expansion Plan (MTEP 23), which contained the most expedited project reviews MISO has ever conducted.

MISO directors unanimously approved the 2023 collection of transmission projects at a Dec. 7 board meeting. MTEP 23 more than doubles the spending of last year's MTEP package and triples that of MTEP 21.

Executive Director of Transmission Planning Laura Rauch has said MISO expects bigger MTEP projects to continue in future cycles. She said MISO will perform economic screens on projects that may have regional potential on a case-by-case basis and will conduct alternatives analysis on large, complex projects.

Regarding MTEP 23, Rauch said MISO is "confident" it landed on an appropriate alternative for the largest MISO South project to help relieve the strained Amite South load pocket in southeast Louisiana.

"Facilities that propose new lines or are larger in cost and potential impact on the system are prioritized for analysis. Roughly 75% of MTEP 23 projects didn't meet criteria for alternative solution analysis, as they address needs with no cost-effective alternatives," Rauch said during a November System Planning Committee meeting of the MISO Board of Directors that was held in preparation for last week's vote.

Just three of MISO's 11 member sectors voted to support the MTEP 23 package of projects. (See *3 MISO Sectors Vote to Recommend MTEP 23, Majority Silent*.)

Since MTEP 03, $35 billion in transmission investment has gone into service in MISO, with $23 billion planned or under construction. The $23 billion includes the $10 billon first portfolio of long-range transmission plan projects approved last year.

MISO members, meanwhile, mused about how the process behind expedited project reviews under the MTEP cycle might change.

MISO has said the growing number of expedited project review requests it studied under its MTEP 23 planning cycle means it should rethink its expedited review process for transmission projects that can't wait until the usual December MTEP approval to begin construction. (See "MISO: Expedited Review Process Needs Revamp," *MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects*.)

The System Planning Committee of the MISO Board of Directors meets Dec. 5 at the Renaissance Orlando at SeaWorld during Board Week. | *© RTO Insider LLC*

MISO said it fielded more than 30 expedited project review requests — double the number it received in 2022 — predominantly because of new load interconnections.

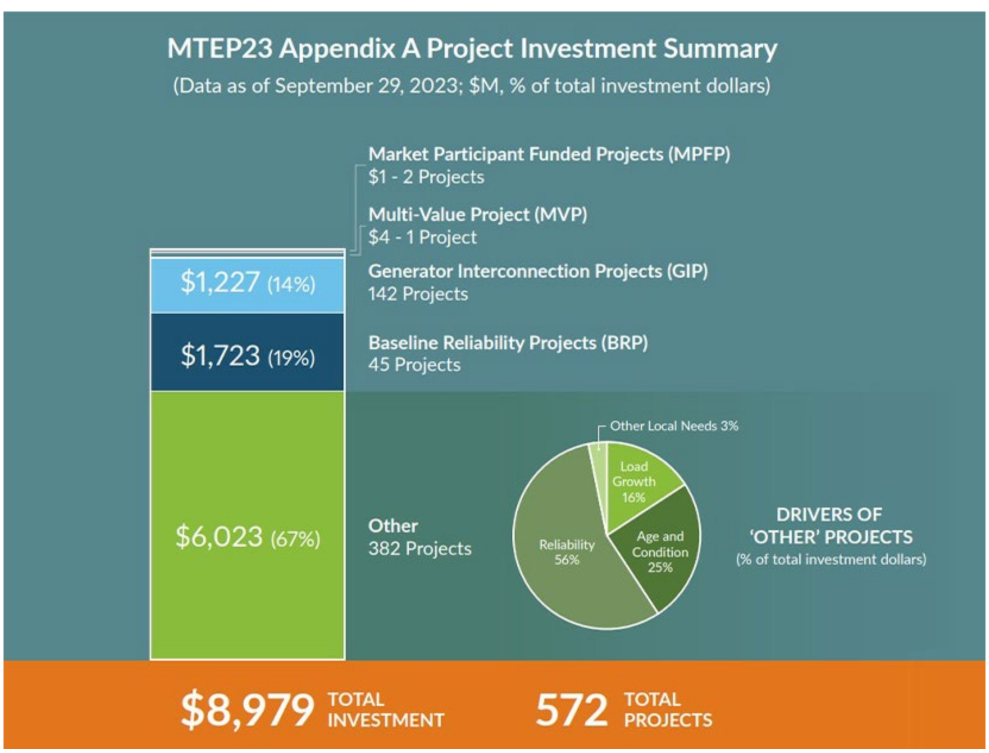
Some members said the increasing number and growing sizes of projects requested for expedited treatment cause concern.

"The size, the magnitude of the projects are becoming a bigger deal," Clean Grid Alliance's Beth Soholt said. She said MISO might consider increased transparency around project requests and its review.

ITC's Brian Drumm said MISO could raise its minimum $1 million threshold for projects to be vetted when they're built out of the usual MTEP cycle. He said the dollar limit has been in place for years and hasn't been adjusted for inflation. A higher threshold would scale back the projects that require expedited review and mean MISO isn't spending time reviewing insignificant projects, Drumm said.

LS Power's Brenda Prokop said MISO might consider more proactively planning transmission for new load so fewer expedited reviews are needed.

MISO will hold more discussions on how it might overhaul its expedited review process in public stakeholder meetings next year. ■




MTEP 23 Investment breakdown | *MISO*

## MISO News

# Grain Belt Express Asks FERC to Overrule MISO on In-service Date

### *RTO Seeks to Delay Operation, Citing Network Upgrades*

*By Rich Heidorn Jr.*

Invenergy asked FERC on Nov. 7 to order MISO to allow it to energize part of its Grain Belt Express project in 2028 despite delays in upgrades needed in Ameren's territory (*EL24-35*).

The approximately 800-mile, 600-kV high-voltage direct current transmission line will have the capacity to deliver up to 5,000 MW of renewable generation from Western Kansas to the Midwest and PJM.

Grain Belt Express (GBX) asked the commission to add a limited operation provision to Attachment GGG of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff.

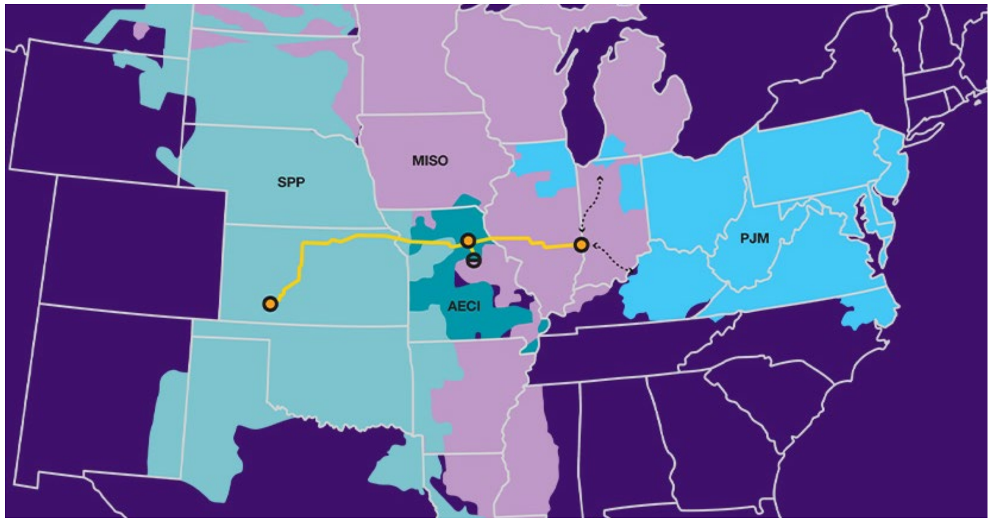
Invenergy said it will be able to put Phase I of its project into operation in 2028 because it has obtained siting permits in all four states on its route and has nearly completed right-of-way acquisition.

However, on Sept. 15, MISO informed GBX that it was delaying the in-service date from Dec. 1, 2027, to Dec. 1, 2030, because two network upgrades Ameren will build require regulatory permits, extending the time for their completion.

GBX said it asked MISO to incorporate into its transmission construction agreement (TCA) an option for limited operations "comparable to the limited service options included in the commission's *pro forma* large generator interconnection agreement (LGIA) for generator interconnections, and which some RTOs have explicitly expanded to merchant transmission."

GBX said MISO rejected its proposal because it is not a provision in its current tariff. The RTO told GBX it would add the proposal to a list of issues to be discussed with stakeholders but that "it would not be something pursued in the near term as it is working through other pending initiatives, including completion of its Order No. 2023 compliance requirements … activities that can be expected to extend throughout 2024 and likely 2025 as well."

GBX said that meant "by the time it finishes its pending initiatives, starts stakeholder proceedings, develops a tariff proposal, and then files it with and obtains commission acceptance, it will likely be close to or past GBX's planned 2028 operations date."




The Grain Belt Express will be an approximately 800-mile, 600-kV HVDC transmission line with capacity to deliver up to 5,000 MW of renewable generation from Western Kansas to the Midwest and PJM. | *Invenergy*

"As such, MISO's promise to look into this at a later date may not result simply in a delay, but in practical terms, a denial of limited operation. It is important that GBX have certainty as it is lining up customer commitments and moving forward on obtaining financing, and that the potential for limited operation prior to 2030 be managed now."

GBX said it will also ask FERC to modify the TCA, which MISO is expected to file unexecuted this month.

MISO did not immediately respond to a request for comment.

## Limited Operation

Phase I of GBX will interconnect its Kansas converter station with a converter station in Monroe County, Mo. A 40-mile AC tie-line will connect that station to the MISO system along an Ameren Missouri 345-kV AC transmission line connecting the McCredie substation and the Montgomery substation and interconnecting with the Associated Electric Cooperative Inc. system at the McCredie 345-kV substation.

GBX said MISO should modify the TCA to allow limited operation of the project without the Ameren upgrades for whatever lower amount of capacity could be connected and injected prior to the upgrades' completion.

It cited FERC's *pro forma* LGIA, which says that, if upgrades are not expected to be completed prior to the commercial operating date of a generating facility, the transmission owner will perform studies to determine the extent to which a customer may operate prior to the completion of those upgrades.

GBX said it has commissioned studies "which, on a preliminary basis, are indicating that there should be some potential for operating at less than full capacity prior to the completion of the two Ameren lines."

Invenergy said FERC's "policy of providing a limited operation option to generator interconnection customers applies equally to MHVDC connection customers."

It said PJM has merged its procedures for all types of new service requests, including merchant transmission interconnection, and explicitly permits limited operation of merchant transmission facilities if there is a gap period between the completion of the transmission and network upgrades.

"MISO's rejection of GBX's request for limited operation while it awaits completion of network upgrades for three years after the GBX facilities are completed is unreasonable given the urgent need for transmission in the U.S. and the harm to GBX," it said.

It said the delay would require it to carry the financing cost of its projects for an additional three years before beginning service to paying customers.

It asked FERC for an expedited order by March 15, 2024. ■

## MISO News

# Board OKs MISO Budget Increase for 2024

*By Amanda Durish Cook*

ORLANDO, Fla. — MISO's base operating budget will increase 15% in 2024, mostly due to the grid operator adding about 70 staff positions so it can keep up with the pace of change and emerging issues in the footprint.

MISO's Board of Directors approved the nearly $400 million budget for 2024 at a Dec. 7 meeting, continuing a trend of budget increases year-over-year.

MISO is proposing a $370 million 2024 operating budget, which contains a nearly 15% increase in base operating spending over 2023. It also is eyeing approximately $27.3 million in capital spending.

MISO has said it struggles to keep up with its current workload under existing staff levels and the hires will help it accomplish projects under intended timelines.

MISO will up its $0.44/MWh tariff rate for members to $0.47/MWh next year.

The grid operator is poised to end the year with base expenses about 1.8% over budget, or $4.3 million. MISO said the cost overruns are mostly due to a $5 million cost overrun in salaries and benefits this year, due to hiring more staff, market pressures, and more overtime and on-call work.

MISO CFO Melissa Brown said MISO has returned to a more normal 3% employee vacancy rate after experiencing a 6% vacancy rate at the beginning of the year. She said the COVID pandemic was a "very strong lesson in how labor market dynamics can substantially impact [MISO]."

Brown said MISO is trying its best to get expenses down before year's end, but the salary component is somewhat out of MISO's control.

"Quite honestly, we're talking about $50,000 line items right now, asking, 'Do we really need to do that?'" Brown asked during a Nov. 30 meeting of the Audit and Finance Committee leading up to Board Week.

Brown said anticipating future budgets, especially on the five-year horizon into 2028, is becoming more challenging as the resource transition ensues and stubbornly high inflation sticks around. ■

MISO Board Week was held at the at the Renaissance Orlando at SeaWorld. | *© RTO Insider LLC*

## MISO News

# MISO Expecting Quiet Winter

By Amanda Durish Cook

Executive Director of Market Innovation and Strategy Zak Joundi (left) and Executive Director of Market Operations J.T. Smith at Board Week in Orlando | *© RTO Insider LLC*

ORLANDO, Fla. — MISO leadership predicted adequate supply paired with a temperate winter at the final Board Week of the year.

"Under normal conditions, we should be flush this year. If everything goes as planned, you won't hear much from me come March," Executive Director of Market Operations J.T. Smith told the Markets Committee of the MISO Board of Directors Dec. 5. "We have El Niño out there, keeping the Pacific Ocean waters warm. While we're expecting this winter is going to be mild, we're preparing for a significant drop in temperatures. … Winter Storms Uri and Elliott are great examples of how cold can blast into the footprint."

MISO has said its winter demand could top 106 GW, with about 121 GW of supply available under normal grid and generation outage conditions. However, the RTO hasn't ruled out the possibility of an emergency sometime in January. (See. *MISO: Possibility of Winter Emergency in January*) MISO's record winter power demand, 109 GW, occurred Jan. 6, 2017.

Smith said it isn't surprising NERC's 2023-24 Winter Reliability Assessment highlighted fuel supply issues throughout the footprint and MISO South's risk of high outages from inadequate weatherization if a deep freeze strikes southern states. Smith said MISO South generators rarely experience sub-zero temperatures, so they don't prepare as if they're an everyday occurrence.

"There is a risk that cold extends into the South, and that could be an issue," he acknowledged.

Smith also said MISO members have access to healthy stores of natural gas and coal stockpiles heading into winter.

MISO's 2023/24 generator winterization *survey* showed that 97% of MISO units responding to the survey have undergone winter preparations, 97% have recently reviewed NERC's winter readiness guidelines and 96% have a severe cold weather checklist. The response rate of the survey was 92% of MISO generators. MISO said the reported level of preparedness generally is better than last year's. The RTO uses its winter preparedness survey to inform its real-time market operations.

MISO also is preparing draft emergency trading rules for neighbors Louisville Gas & Electric/Kentucky Utilities and East Kentucky Power Cooperative, Smith said.

MISO's Independent Market Monitor recommended MISO draw up emergency supply agreements with its non-RTO neighbors after MISO flowed a few gigawatts of power exports to utilities in the Southeast during winter storms last Christmas.

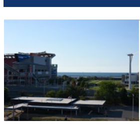
Monitor David Patton said he concurred with MISO's take on the upcoming winter. However, he said an extreme winter event could drive forced generation outages to 29 GW and have MISO nearly draining its reserves. He qualified that MISO's wind fleet usually performs well during winter weather events, so MISO experiencing a near-zero margin is unlikely, even if utilities' gas scheduling becomes a problem.

"We should be OK this winter," Patton concluded, though he added, "Thinking through fuel security is going to become a lot more important in the future."

Smith also said MISO thankfully experienced a "wholly unremarkable" fall, with normal load, coal and fuel prices remaining inexpensive at about $2/MMBtu and no hurricane activity affecting the southern footprint.

MISO's fall peak arrived early in the season on Sept. 5 when late summer heat drove 115 GW in load. ■

## Midwest news from our other channels



*Pioneering Lake Erie OSW Plan Placed on Hold*

NetZero Insider

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

# MISO and IMM: M2M Flowgate Issue with SPP not Sustainable, May Require Litigation

*By Amanda Durish Cook*

ORLANDO, Fla. — MISO and its Independent Market Monitor agree that legal action is likely on the horizon concerning the RTO's payments to SPP for a market-to-market flowgate.

Monitor David Patton said congestion costs remain high at nearly $600 million over the fall in MISO. At a Dec. 5 Markets Committee of the MISO Board of Directors, he singled out the 230-kV Charlie Creek-Watford line, a market-to-market flowgate with SPP, as a major source of congestion.

The line recently began delivering power to 220 MW in new load from a cryptocurrency mining operation in northwest North Dakota. Patton said Charlie Creek-Watford's status as an M2M constraint should be revoked because MISO can offer SPP little relief.

Patton also suggested MISO's millions of dollars in firm flow entitlement payments to SPP involving the constraint might be improperly calculated by SPP. He added SPP has had challenges in modeling use of the line.

"This is a mess," Patton said. "This is really a bad scenario for MISO customers … I think there's a good chance we head to litigation at FERC because we can't keep these payments up."

Patton said the line accounts for most of the current funding shortfalls in MISO's financial transmission rights market.

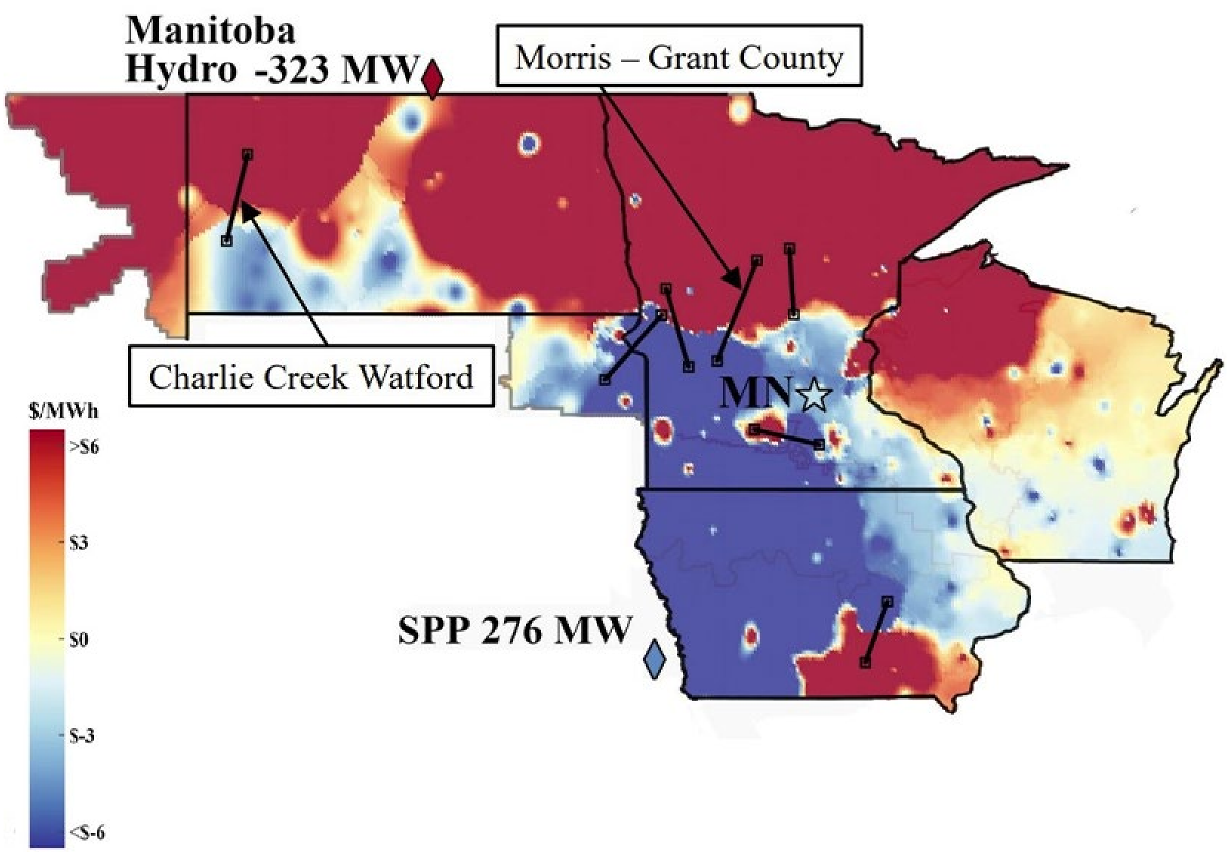
"This one is going to be a legal issue in how we interpret the joint operating area, and we just need to sit down with SPP to work it out," MISO CEO John Bear said.

MISO Executive Director of Market Operations J.T. Smith said new load was allowed to be activated in an already constrained SPP load pocket. Smith said while transmission upgrades are planned for the area, they're not yet in place to help the situation. The load pocket is served by several other lines in addition to the line in question.

SPP maintains it and MISO have "robust coordination procedures in place to ensure the market-to-market congestion management processes are working as intended" and in accordance with the RTOs' joint operating agreement.

"Over the last few months, the RTOs have extensively discussed the congestion issues associated with the Charlie Creek-Watford market-to-market flowgate that is being impacted by the operation of both markets," SPP spokesperson Derek Wingfield said in an emailed statement to ***RTO Insider***.

Wingfield said if SPP and MISO are unable to reach a solution through informal discussion, SPP is still optimistic that it and MISO will be able to leverage the formal dispute resolution procedures contained in their JOA. SPP is hopeful for a "mutually agreeable outcome prior to this becoming a legal matter at FERC," Wingfield said. ■




The MISO Independent Market Monitor's depiction of congestion on the Charlie Creek-Watford and Morris-Grant County constraints | *Potomac Economics*

# MISO News

## MISO Champions Queue Crackdown as Stakeholders Blast MW Cap on Project Entries

By Amanda Durish Cook

ORLANDO, Fla. — Several MISO stakeholders took exception to MISO's proposal before FERC to cap the volume of interconnection requests it accepts annually.

MISO made two filings with FERC last month to establish an annual megawatt cap on projects, enforce stricter proof of land use, enact automatic and escalating monetary penalties for withdrawals, and increase milestone fees for its generator interconnection queue (*ER24-340* and *ER24-341*). (See *MISO's More Stringent Interconnection Queue Rules Go Before FERC*.)

DTE Energy said a queue cycle cap would be "unprecedented" and argued it won't address "the root cause of MISO's inability to timely process interconnection requests."

DTE said it's not the number of projects overall, but the percentage of speculative projects in the queue that's the problem. Developers have resorted to "over-saturating the interconnection queue with projects as an insurance strategy to secure a position" because of long wait times in the queue, DTE argued. DTE supported the other aspects of MISO's queue rule changes.

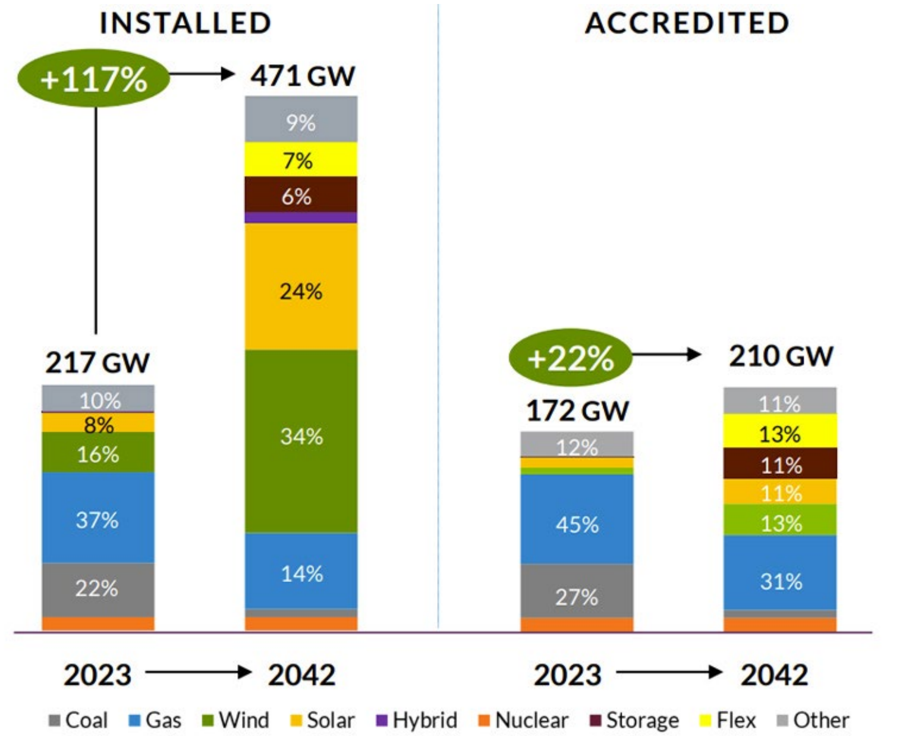
MISO has said there are only so many potential generation projects it can simultaneously consider in interconnection studies while still achieving accurate results. (See *MISO Relaxes Proposal on Stricter Queue Ruleset*.)

But the Coalition of Midwest Power Producers argued MISO wants to impose a megawatt cap "without articulating how a lower volume will ensure accelerated queue processing." The coalition said MISO didn't detail "unique processes or additional computing power to resolve the volume and study pace issues that have been the albatross of the MISO queue process."

NextEra Energy agreed MISO didn't provide evidence to show a cap will "remedy or mitigate the factors leading to its unwieldy, inefficient and untimely interconnection queue." It said the cap will stymie competition and create barriers to entry for smaller generation developers.

Ameren said it thought the cap "is a blunt tool that is not fully thought out and may result in unjust outcomes."

Xcel Energy, on the other hand, said MISO has sufficiently explained a megawatt cap is key to alleviating the overstuffed queue. Entergy agreed the sheer size of the interconnection queue is interfering with "realistic" study results and not giving developers a clear picture of whether they should proceed with generation projects.




MISO's prediction of installed capacity versus accredited capacity by 2042 | *MISO*

The Organization of MISO States also threw its support behind the cap, saying a "backstop mechanism is needed — at least temporarily — to ensure MISO can produce realistic network upgrade studies based on a smaller, more manageable queue size."

"MISO's queue is oversaturated with projects that are vying to identify the cheapest locations to interconnect, causing MISO to choose to effectively shut down its interconnection queue," OMS told FERC.

MISO's current generator interconnection queue contains more than 1,300 projects at nearly 230 GW — nearly double MISO's summertime peak demand.

"It is not reasonable to expect MISO to continue to try and work through this level of requests in its queue process," Xcel said.

In a joint protest, the American Clean Power Association, the American Council on Renewable Energy, the Solar Energy Industries Association and Clean Grid Alliance argued that limiting projects annually is diametrically opposed to the rapid transition of clean energy resources. They said it's only natural MISO's queue has expanded rapidly in recent years.

"If accepted, the cap proposal would create perverse incentives that will create havoc, increase uncertainty and discriminate against the very clean energy resources that the region needs," the clean energy groups contended.

Alliant Energy argued MISO's proposal to cap queue cycles is an odd choice when the grid operator has been telling stakeholders new capacity additions are crucial. Alliant referenced the Organization of MISO States' most recent resource adequacy survey showing the footprint runs the risk of a 9-GW capacity shortfall by 2028.

### MISO Leadership Hopeful for 'More Confident, Less Speculative' Projects

At MISO Board Week in Orlando, Executive Director of Resource Planning Scott Wright said even though there are some complaints, stakeholders' comments reveal "a broad consensus that the staggering queue line was unsustainable."

Wright said an annual megawatt cap on projects, an automatic penalty scheduled for withdrawal and increased milestone fees will

# MISO News

encourage a "more confident, less speculative" class of projects to enter the queue.

"Many of the projects in the queue are highly speculative despite our past rule changes to use a 'first-ready, first-served' approach," he said. Wright also said MISO's existing withdrawal process are too "low-consequence."

Wright added that the "staggering" number of queue projects is developers' "rational" response to more favorable economic conditions for renewable energy development. He said it's natural MISO found itself having to tighten requirements, so its historically "high-quality" queue isn't compromised.

Wright said since the last Board Week in September, members have announced more retirement plans, with Michigan *adopting* a clean energy pledge by 2040.

MISO predicts it will add about 250 GW in installed capacity over the next 20 years, but it will only amount to a 38-GW increase to MISOS's current 172 GW in accredited capacity.

Scott Wright, MISO | © *RTO Insider LLC*

## 50 GW in Greenlit and Unfinished Projects Haven't Budged

Wright added that the prospective projects in the queue still face inflation and supply chain headwinds. MISO's large number of approved but unbuilt generation projects hasn't budged since the summer. (See *MISO: Reliability Risk Upped by 49 GW in Approved but Unbuilt Generation*.)

Today, 50 GW across 316 projects are awaiting construction, with 50% of those developers saying wait times will average 650 days until commercial operation. Most of the on-hold projects are solar generation, accounting for 32 GW.

By year's end, Wright said that amount could grow to nearly 60 in approved but unbuilt generation projects.

Vice President of System Planning Aubrey Johnson said nationally, 260 GW in generation projects have signed interconnection agreements in the organized markets and yet remain unconstructed. Johnson said that side of the issue deserves more awareness in conversations about the country's interconnection woes, when usually, inadequate transmission planning is emphasized.

"This is something that needs national attention. It's something that we call attention to at every turn," Johnson said. ■

# NYISO News

## FERC Orders Settlement Procedures on NY Utilities' Tx ROE Filing

### *NYSEG and RG&E Filings Support Upgrades Needed to Meet State Climate Laws*

*By John Norris*

FERC has ordered two New York utilities into hearing and settlement judge procedures over their proposed return on equity (ROE) on transmission investments to support the state's renewable energy goals (*ER23-1816, ER23-1817*).

The commission's Dec. 4 order accepts for filing Rate Schedule 19 formula rate protocols and templates for Avangrid's New York State Electric & Gas (NYSEG) and Rochester Gas and Electric (RG&E) effective July 3, 2023, subject to refund.

In response to a protest by the New York Association of Public Power (NYAPP), FERC called for hearing and settlement proceedings on the utilities' proposed 10.87% "ceiling base" ROE — a fixed value in the formula rate that would be subject to a lower ROE authorized by the New York Public Service Commission.

NYAPP said FERC should adopt the ROE and capital structure approved by the New York commission in the most recent retail case for NYSEG — 9.2% for 2024, with a capital structure of 52% equity and 48% debt and customer deposits.

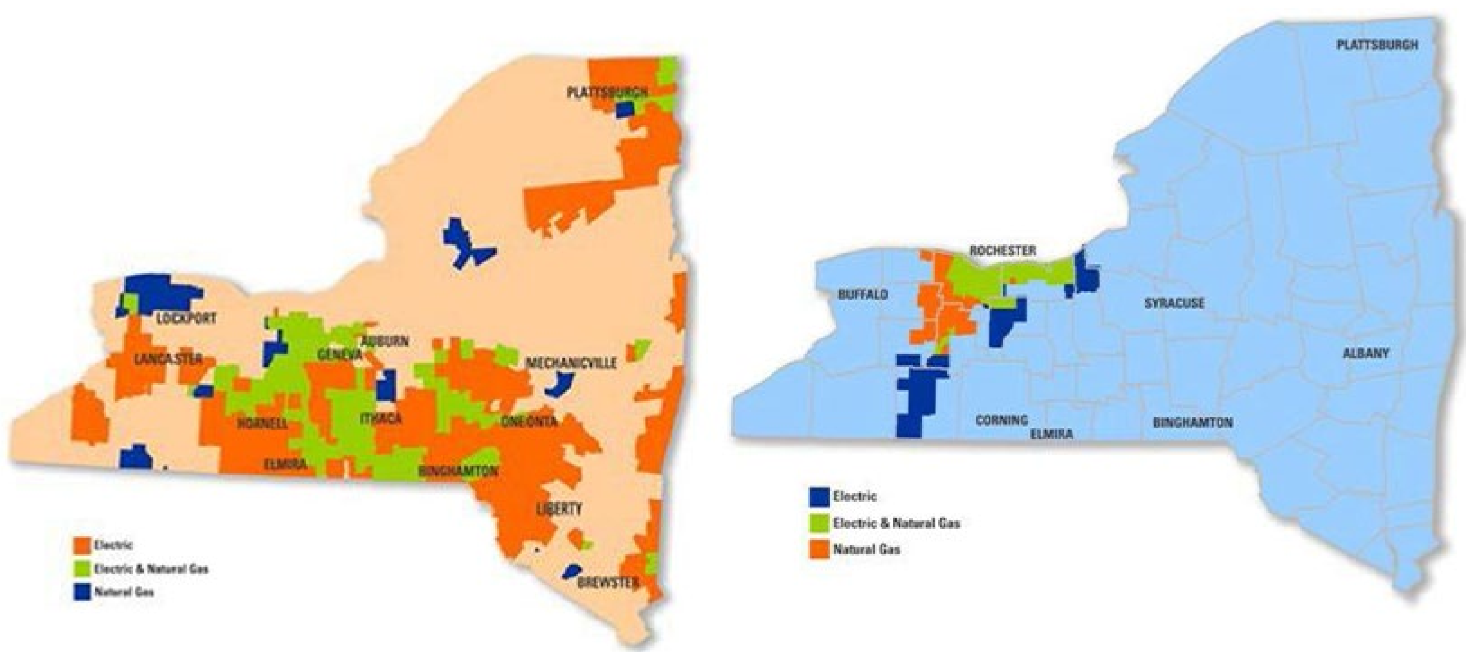
FERC agreed that the 10.87% ROE had not been shown to be just and reasonable. "We find that applicants' proposed ceiling base ROEs raise issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered below," it said.

Schedule 19 and the Cost Sharing and Recovery Agreement (CSRA) — a voluntary participant funding agreement among the six New York state-regulated public utility transmission owners — are intended to provide a cost recovery and allocation framework for local transmission upgrades needed to meet the state's Climate Leadership and Community Protection Act and the Accelerated Renewable Energy Growth and Community Benefit Act.

Historically, local transmission upgrades have been funded via bundled, local transmission and distribution rates. Under the CSRA, the costs are instead shared statewide and recovered on a volumetric load-ratio share basis from load-serving entities.

FERC's order requires the settlement judge to file a report on the status of the settlement discussions in 60 days after the judge's appointment.

While FERC sided with NYAPP on the ROE issue, it rejected the group's contention that the formula rate misallocates administrative and general expenses. ■




Service areas of New York State Electric & Gas (NYSEG) and Rochester Gas and Electric (RG&E) | *Avangrid*

# NYISO News

# NY Reliability Council Approves 22% IRM for 2024/25

## *IRM Initially Recommended to be Set at 23.1%*

*By John Norris*

ALBANY, N.Y. — After four rounds of voting, the New York State Reliability Council Executive Committee agreed Dec. 8 to set the installed reserve margin (IRM) for the state's 2024/25 capability year at 22%, up from 20% for the previous year. (See *New York PSC Approves 20% Installed Reserve Margin*.)

The IRM represents the additional supply capacity NYISO mandates load-serving entities maintain as a precaution against unexpected outages or demand surges.

Following a yearlong examination, the NYSRC's Installed Capacity Subcommittee (ICS), in collaboration with NYISO, published a technical study *report*, which originally found that an IRM under base conditions of 23.1% would satisfy the resource adequacy criteria without violating a loss of load expectation (LOLE) of no greater than 0.1 events-days/year in the next capability year, extending from May 1, 2024, through April 30, 2025.

### NYSRC Report

The ICS' report studied how several sensitivities, including new topology changes, transmission security limit (TSL) floor inputs and increases in renewable generation, might impact the final base case modeling and the final IRM necessary to meet the state's future requirements.

For instance, the ICS noted that a reduction in emergency assistance import limits increased the IRM by 2.24% and expected updates in the performance of special case resources raised the IRM by 0.14%. Conversely, the ICS observed that expected increases in the amount of behind-the-meter solar caused the IRM to decrease by 0.5%.

The report also documented the observation that using a 23.1% IRM while incorporating higher TSL floors in the locational capacity requirement (LCR) setting process, which is administered the ISO under its tariff, results in a system with a LOLE of 0.069, below the minimum reliability requirement of 0.1.

TSL floors are used in the LCR calculations, conducted by NYISO in its process, as the lower limit beyond which LCRs cannot fall below, resulting in minimum capacity margins that a locality, such as Zone J (New York City), Zone K (Long Island) or Zone G (Lower Hudson Valley), must maintain to ensure grid stability under standard N-1-1 system conditions.

Additional analysis using TSL floors in the LCR study, where the statewide LOLE is readjusted to 0.1, caused "noticeably better" results and produced an IRM of 21.5%.

This adjustment also yielded preliminary LCRs of 81.7% for Zone J, 105.3% for Zone K and 81% for Zone G, which contrasts with the final base case IRM results for these zones that were 72.73%, 103.21% and 84.58%, respectively.

Both NYISO and the NYSRC agree that more analysis, modeling and discussion are needed before the *NYSRC Policy 5* IRM and the ISO's TSL/LCR processes can be merged to ensure no unexpected consequences result from any process change. The NYSRC said at the meeting that this is a priority effort for 2024 and beyond.

The committee members approved the report's base case, data parameters and sensitivities at last month's EC meeting after extensive stakeholder development and feedback. (See "IRM Modeling Updates Approved," *NY Reliability Council OKs Interconnection Standards for Large IBRs*.)

### Comments

The NYSRC, responsible for establishing the IRM, determines the annual ICR that generators must maintain throughout the next capability year. The ICS' report highlighted the disagreements among the EC about how New York should address its future reliability challenges.

Consolidated Edison's Mayer Sasson, former chair of the EC, urged members to carefully consider the report's findings before voting, saying, "make sure to interpret the TSL correctly before we set the IRM."

Mark Younger, president of Hudson Energy Economics, also urged caution, saying, "while 21.5% results in a LOLE event value of 0.1, don't kid yourself that it is reliable, since that is absolutely inconsistent with NYISO's STAR [short-term assessment of reliability] reports and CRP [comprehensive reliability plan]." (See *NYISO's 10-Year Forecast: Challenges Ahead, but No Immediate Needs*.)

On the other side, Roger Clayton, chair of the NYSRC's Reliability Rules Subcommittee, while not explicitly endorsing an IRM of 21.5% appeared supportive, saying, "from a reliability point of view and thinking about nothing else, 21.5% is reliable according to the analysis that has been performed."

Timothy Lynch, senior director of transmission services at Avangrid, concurred, saying, "21.5% is a reasonable step at this time, given ratepayer pressures and so forth." He added, "There's a lot of changes in the study year-over-year, and I think some of that needs to play out to see what the future brings."

Similarly, Michael Mager, a partner at Couch White who represents *Multiple Intervenors*, a group of large industrial, commercial and institutional energy consumers, was comfortable with 21.5% despite it being the highest IRM adopted, saying, "it meets the LOLE requirements … and moves in the right direction that we should be going, but in a more moderate step than the base case result."

Curt Dahl, director of engineering at PSEG Long Island and chair of the NYSRC's Extreme Weather Working Group, although partial to lower IRM values, advocated for a balanced approach, saying, "I always have a range of [IRM values] in my mind."

EC Chair Chris Wentlent, a member of the Municipal & Electric Cooperative Sector, approached the IRM vote from a policy and environmental perspective, saying, "our reliability picture is getting more complicated going forward, not less complicated," referring to how last year's Winter Storm Elliott significantly impacted Northeastern state grids and unexpected costs and risks to energy consumers and triggered emergency operating procedures.

"Based on everything, I see a 22% as a reasonable outcome, because, in my opinion, this balances the cost issues, some of the [emergency operating procedures] issues, and other future risks we need to pay attention to," he added.

In an email to *RTO Insider*, Richard Bratton, director of market and regulatory policy at the Independent Power Producers of New York, said "the IRM is a careful balance between maintaining system reliability and protecting ratepayer costs. Less than a year after Winter Storm Elliott, the NYSRC voted to significantly decrease the IRM from the number produced by the NYISO through its analysis. IPPNY is continually committed to advocating for system reliability through competitive markets." ■

# PJM MIC Briefs

### PJM Steams Ahead with CIFP Filing Timeline After FERC Deficiency Notices

Deficiency notices FERC issued on two filings PJM made to overhaul its capacity market are not expected to interrupt the RTO's plan to implement the changes in time for the 2025/26 Base Residual Auction (BRA) scheduled for June 2024 (*ER24-98*, *ER24-99*).

PJM Associate General Counsel Chen Lu told the Market Implementation Committee that the RTO will not seek any changes to the auction timeline, which was delayed by a year in June 2023. (See *PJM Files Capacity Market Revamp with FERC*.)

The deficiency notices reset the 60-day deadlines for FERC to act on PJM's requests to two months after the RTO's responses. PJM *replied* to the notice in ER24-99 on Dec. 1, resulting in a Jan. 30 deadline, and submitted a *response* in ER24-98 on Dec. 8, carrying a Jan. 6 deadline for the commission.

Lu said staff considered seeking another delay but determined that the pre-auction activities that will be conducted before the commission's deadlines would not be affected by PJM's proposals and can be run while the dockets are in limbo.

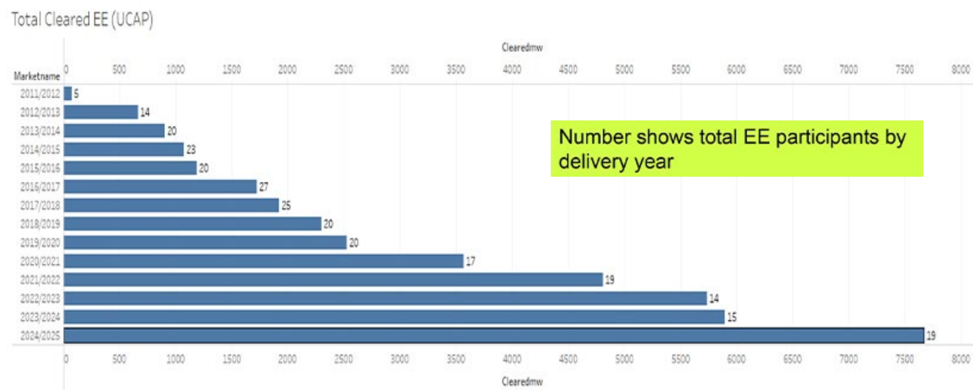
### Stakeholders Begin Review of Energy Efficiency Resources

Stakeholders endorsed an *issue charge* to revisit how energy efficiency (EE) resources participate in the capacity market and began work on identifying stakeholder interests. The document states that its goal is to make EE market participation more effective by improving resource qualifications. Key work activities include eliminating any ambiguity around what qualifies as an EE resource and ensuring that energy savings attributed to resources are "unbiased, accurate and reasonably consistent across providers."

Luke Fishback of Affirmed Energy said EE providers are concerned that the scope of the issue charge is ambiguous and would prefer more specificity.

Stakeholders discussed whether it was necessary to include a sentence specifying that a partial solution may be advanced sooner than the expected nine-month timeline. PJM's Pete Langbein said the language was included to leave the door open to implementing changes in time for the 2025/26 BRA in June 2024.

Several stakeholders argued that the language was redundant, because issue charge timelines do not dictate when solutions may be advanced. The line was struck from the issue charge prior to its approval.




PJM stakeholders opened a discussion of energy efficiency resource participation in the capacity market as the generation class has grown | *PJM*

Initiating the education process of the work, PJM's Tim Bachus said the value of an EE resource is based on the incremental amount of energy reduction above what is required by local building codes.

Stakeholders contributing to the *interest identification* list added avoiding payments for energy efficiency upgrades that would naturally occur, accounting for a "rebound effect" to ensure consumer behavior doesn't undo EE benefits and allowing EE to be eligible for the useful life of the installation.

MIC Chair Foluso Afelumo said the next meeting will continue the education and issue identification processes.

### Temporary Exceptions Supplant Real Time Values

PJM's Lauren Strella Wahba *outlined* how the RTO plans to implement the process FERC approved on Nov. 30 for resources to submit temporary exceptions from their unit-specific parameters. The temporary exceptions replace the real-time values process PJM maintained for resources to reflect changes to their ability to operate according to their parameters during the operating day. The commission's order approving temporary exceptions was effective Nov. 30.

Documentation of why a resource is seeking an exception must be submitted to PJM and the Independent Market Monitor within three days.

Strella Wahba said PJM is working on updating its Markets Gateway software to reflect the changes, with updates beginning over the next few days and expected to be complete by the second quarter of next year. In the meantime, real-time temporary exceptions can be submitted using the real-time values drop-down menu.

Dominion's Jim Davis said the addition of temporary exceptions will improve resources' ability to keep PJM updated of any issues experienced during strained system conditions and alleviate some of the incongruities between the electric and natural gas markets.

"It's certainly a first step to allow resources to reflect their capabilities, especially during these extreme events ... and it's also a first step for addressing the challenges around electric-gas coordination," he said.

### Migration from eDART to Account Manager Nearly Complete

PJM's Chidi Ofoegbu *urged* market participants to ensure that they have completed the transfer of their eDART accounts to the new Account Manager software before Dec. 13, when eDART access will be revoked.

She also encouraged users to begin working in Account Manager prior to Dec. 13 to build up familiarity and give time to work with PJM to resolve any issues before eDART access is terminated.

Several stakeholders encouraged their peers to take the software change seriously, stating that it would be difficult for any market participant to conduct business and meet their obligations without having access to PJM's online tools. ■

*— Devin Leith-Yessian*

PJM News

# PJM OC Briefs

### Generation Operators Urged to Participate in SOS Calls Ahead of Storms

PJM Senior Vice President of Operations Mike Bryson said participation in the System Operations Subcommittee (SOS) conference calls it holds ahead of major storms has been troublingly low, with only a few dozen individuals typically participating. Discussions with generators that did not meet their capacity obligations during the December 2022 winter storm suggested one of the contributors to the strained system conditions experienced Dec. 23-24 was poor understanding of emergency procedures.

Senior Dispatch Manager Donnie Bielak said a recent emergency procedure drill also had much lower attendance than anticipated. He encouraged stakeholders to familiarize themselves with the resource limitations detailed in Manual 13 to ensure resources know how to report any limits to dispatchers during an emergency. While a voltage reduction was not instituted during Winter Storm Elliott, Bielak said it was a close enough call staff might conduct a test of the ability to implement the emergency procedure.

### PJM Reviews FERC and NERC Winter Preparedness Recommendations

PJM Associate General Counsel Mark Stanisz *reviewed* the findings of the FERC/NERC inquiry into the impact of Winter Storm Elliott and the NERC Winter Reliability Assessment for the upcoming season.

The NERC assessment found that much of the Eastern Interconnection is at elevated risk during peak winter conditions, suggesting potential for reserves to be insufficient during an emergency. Generators' winter preparations are improving, but the growing complexity of forecasting demand during cold temperatures remains a concern. So does the potential for generator fuel storage to run dry during long-duration events. Interregional energy transfers to strained areas also are at risk of curtailment, presenting a growing reliability concern.

The NERC/FERC inquiry recommended balancing authorities conduct fuel surveys and state regulators be prepared to respond to any environmental, emissions and transportation waivers grid operators may request during a storm.

Mike Bryson, PJM | *© RTO Insider LLC*

The PJM Markets and Reliability Committee endorsed several additions to its generation winterization checklist during its Nov. 15 meeting, drawing on NERC's *Lessons Learned*. (See "New Winterization Requirements Endorsed," *PJM MRC/MC Briefs: Nov. 15, 2023*.) ■

*— Devin Leith-Yessian*

## National/Federal news from our other channels

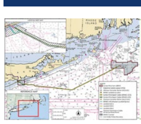
*Panelists Warn of Winter Weather's National Security Risks* ERO Insider

## Mid-Atlantic news from our other channels

*BOEM to Auction Wind Energy Areas in Central Atlantic* NetZero Insider

*NJ Advances Multifaceted Building Decarbonization Strategy* NetZero Insider

## Northeast news from our other channels



*BOEM Backs 10 Fewer Turbines for Sunrise Wind* NetZero Insider

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# PJM PC/TEAC Briefs

## Planning Committee

### PJM 2024 Load Forecast Sees Jump from EVs, Data Centers, Heat Pumps

PJM's preliminary load forecast for 2024 sees higher growth for both summer and winter, driven by electric vehicles, data centers and state incentives for heat pumps.

The 15-year annualized growth rate increased to 1.6%, doubling the 0.8% growth rate in the 2023 forecast, with the difference between the two forecasts accelerating in later years, said Molly Mooney, who *presented* the forecast to the Planning Committee on Dec. 5.

The 2027 preliminary forecast is 4.4% higher than the 2023 forecast (6,600 MW) while the 2038 preliminary figures are 13.9% higher (22,400 MW).

The main drivers behind rising summer loads are EVs and data centers, which respectively contributed 3,700 MW and 4,000 MW in load growth over the 2023 forecast, without which Mooney said summer loads would remain largely flat. Solar generation reduced summer loads by 200 MW and energy efficiency provided a 750 MW reduction.

The 15-year outlook for winter loads increased to a 1.9% annualized growth rate over the 0.9% in the 2023 forecast.

The main policy change affecting the winter load forecast is New Jersey's Executive Order 316, which has a goal of electrifying 400,000 homes and 20,000 commercial buildings by 2030. (See "Transitioning Commercial Buildings," *NJ Advances Multifaceted Building Decarbonization Strategy*.)

Mooney said this is the second year that PJM conducted the study using hourly forecasting rather than the daily peak methodology previously used. The commercial and residential data used in the study is based on 2013-2022 census figures.

This was the first year that S&P Global was contracted to provide estimates of plug-in EV data. The company forecasted that there would be around 7.5 million such vehicles in PJM's footprint by 2030. The Met-Ed territory is expected to see the largest number of medium and heavy duty EVs, owing to the large number of warehouses and shipping corridors in its region.

## Transmission Expansion Advisory Committee

### Second Read of $5 Billion in RTEP Projects

PJM *reviewed* its proposed $5 billion package of transmission projects in the third window of the 2022 Regional Transmission Expansion Plan (RTEP), which is primarily aimed at addressing data center load growth in northern Virginia and generation retirements. (See *PJM Recommends $5B in RTEP Transmission Projects*.)

PJM's Sami Abdulsalam said the proposal is the most efficient, cost-effective and resilient set of solutions of the 80-plus project combinations staff analyzed. The package would construct new 500-kV lines from northern Virginia out to the Peach Bottom substation to the northeast, the 502 Junction substation to the northwest and the Morrisville substation to the south.

When considering the 72 proposals PJM received during the competitive process, Abdulsalam said staff prioritized cost, maximizing use of existing rights-of-way and scalability.

PJM Senior Vice President of Planning Ken Seiler said the concerns members of the public have raised during previous TEAC meetings and letters to the Board of Managers have been noted. Many of the objections centered around siting issues, which he said will be the focus of the routing process transmission owners would go through after possible board approval.

"This is a pretty significant body of work and we've received a lot of pushback and a number of letters from residents ... we've heard from you," Seiler said.

PJM included with its meeting materials an *FAQ* detailing its role in selecting the proposals in the window.


PJM's proposed package of transmission projects for the third window of the 2022 Regional Transmission Expansion Plan. | *PJM*

First Window of 2023 RTEP Set for Board Consideration in February

Abdulsalam *presented* a first read of three projects being added to PJM's recommended transmission expansion in the first window of its 2023 RTEP, which is set to go before the Board of Managers for approval in February.

The window includes a $42.05 million project to address an overload of APS's Belmont 765/345-kV transformer by replacing the equipment with a new transformer bank; a $10.22 million rebuild of Commonwealth Edison's 138-kV Haumesser Road-West DeKalb Tap line; and a $7.75 million proposal to add three 345-kV circuit breakers to ComEd's Cherry Valley substation.

The three proposals join several projects in the first window aimed at addressing reliability issues identified in the Public Service Enterprise Group, PECO, Dayton Light and Power, American Electric Power and Ohio Valley Electric Corp. zones.

Abdulsalam presented a second read of the existing projects, which amount to around $42.4 million. The proposals include:

- Replacing 230-kV and 345-kV fixed shunt reactors with higher rated variable reactors for $29.6 million to resolve high voltage issues around PSEG's Waldwick substation;
- Replacing an over-duty 345-kV circuit breaker at AEP's Olive substation for $1 million;
- Replacing breakers, switches and other equipment owned by AEP and OVEC at the Kyger Creek station for $1.16 million; and
- Reconductoring 8.8 miles of DPL's Silver Run-Cedar Creek double-circuit 230-kV line and replacing infrastructure at both substations for a total of $8.7 million. ■

*— Devin Leith-Yessian*

# SPP's MPEC Approves Markets+ Governance Plan

## 'No' Votes from Independents Sector Leave Proposal with 73% Support

*By Robert Mullin*

SPP met a major milestone in its Western efforts Dec. 7 when the Markets+ Participants Executive Committee (MPEC) approved the day-ahead market's proposed governing document, a key step as the grid operator moves quickly to file a tariff with FERC in early 2024.

The MPEC voted 73% in favor of the document, the product of a half-year of work by the committee to be incorporated into the tariff. Stakeholders approved a large portion of the Markets+ draft tariff language last month at an in-person meeting in Tempe, Ariz. (See *Stakeholders Approve Bulk of SPP's Markets+ Tariff*.)

The proposal now advances to the Interim Markets+ Independent Panel (IMIP), which is expected to vote on it Dec. 19.

Markets+ rules require the MPEC to pass any measures with a super majority of 67% of voting members. The bulk of the votes against the governance plan came from representatives of the "Independents" sector dissatisfied with the proposed voting structure for their group once the market goes live.

The document spells out governance structure and functions for Markets+, including the makeup and roles of the SPP Board of Directors, permanent MIP, MPEC, Markets+ State Committee and other standing committees; the MIP election process; meeting policies; the voting process for market policies; and process for appealing decisions. It also covers the establishment of working groups and task forces, the role of SPP staff in relation to the market, and attendance and proxy voting policies.

The Dec. 7 vote was preceded by the MPEC's approval of a handful of amendments to the


Territory covered by Phase 1 participants in SPP's Markets+ | *SPP* governing document, including:

- An SPP staff proposal that market participants be assigned to geographical regions to enable the MIP to understand the geographical breakdown of MPEC votes for "informational" before voting on issues advanced to the panel by the committee.
- An SPP staff proposal that members of the Markets+ Nominating and Governance Committee (MNGC) be subject to term limits and that the market retain the option to assign MNGC representatives to geographic regions on a rotating basis.
- A Bonneville Power Administration proposal to require that a proceeding to remove a MIP member be supported by a minimum of 35% of the sector-weighted representation on the MPEC, compared with 20% in the original plan.
- A proposal by Western Resource Advocates (WRA) to remove the option for the MPEC to add to the slate of MIP nominees proposed by the MNGC. MPEC members largely agreed with WRA that retaining the option would undermine the role of the nominating committee.

## 'Mom or Dad'

The MPEC downgraded to a future "action item" an amendment proposed by the MSC that would've permitted a majority of the MSC to appeal an action or inaction by the MIP to SPP's board after some committee members expressed concern the rule change would allow the MSC to do an end-run around the MIP, the board most directly responsible for overseeing the Western market.

Ed Garvey, a consultant advising the MSC, said the amendment was intended to address the fact that the governance plan would allow only MIP members the ability to appeal a MIP decision to the SPP board.

Garvey said MSC members had concluded that as a body, they should be able to appeal issues to the SPP board "when they're acting in their umbrella capacity as sort of the public interest representatives and commissioners on the region-wide basis."

"The MIP is the final governance for Markets+; the MIP is the one looking out for Markets+," Joe Taylor, senior director of Western markets at Xcel Energy-Colorado, said in opposing the amendment. "I hate to be condescending, but it's almost like you don't like the answer you got from mom, so you're going to dad."

"If an issue is really important to the region from the MSC's perspective, they wanted to be able to take it to the ultimate authority," Garvey responded. "Not necessarily dad, or mom, but certainly the ultimate authority for the responsibility for Markets+."

Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition (NIPPC), said he was inclined to support some version of the amendment.

"From my part of the market, I kind of view the regulators as mom or dad — pick your parent — so that kind of power dynamic didn't enter into my mind because, in my view, the states do have an important role in voicing a regulator's view."

In moving the amendment to become an action item, the MPEC committed to working with the MSC to determine whether the latter wanted to proceed with the proposal and, if so, what the next steps should be.

The MPEC also approved a handful of other action items, perhaps the most significant of which will deal with how Markets+ governance will function as planning activities around the market move from the current Phase 1 to Phase 2 after the tariff is filed early next year.

During the MPEC meetings held Dec. 6-7, SPP General Counsel Paul Suskie clarified for participants that the governance structure being considered will not actually take effect until Markets+ goes live, likely in the latter half of 2026.

"So then what that leaves is the gap between the end of Phase 1 and the market go-live," meaning participants will need to determine how they'll manage their deliberations in the interim as they work through implementation issues, Suskie said.

"Now just my personal opinion, not SPP's, that it would just seem that the governance we have in place today would make sense to continue until go-live, unless this group chose to change it," he said.

## 'Pretty Fundamental Issue'

Tensions arose during the meeting over NIPPC's proposed amendment to alter the future voting structure for the MPEC's "Independents" member sector, which consists of IPPs, power marketers and "Market Stakeholders" such as public interest organizations and consumer advocates.

Under the governance rules adopted by the committee Dec. 7, voting by the MPEC's "Investor-Owned Utilities" and "Public Power" member sectors will be weighted based on those participants' load share. Voting among the Independents will be structured to ensure that participants contributing generation to the market receive two-thirds of the sector vote, while those without generation receive one-third.

NIPPC's amendment sought to continue the status quo practice of each Independent member receiving a single vote within the sector. Gray said his sector was concerned the future depth of the Markets+ market cannot be predicted, and if only one IPP joined the market at go-live, it would represent 22% of the vote for the entire MPEC.

"And that seemed inappropriate for any entity, IPP, or otherwise," Gray said.

Gray also noted the two-thirds/one-third voting structure had not been previously "presented or debated or negotiated within the groups that were active on governance."

Over the course of the two-day MPEC meeting, NIPPC altered the proposed amendment to include a September 2025 deadline to review the "one member, one vote" structure in light of the expected depth of IPP participation ahead of the market commencing operation.

NIPPC's amendment failed with 63% of the MPEC approving, short of the 67% threshold.

In the wake of the vote on the amendment, Gray said NIPPC would consider casting a "no" vote on the entire governance proposal, as did Lisa Hickey of the Interwest Energy Alliance and Scott Miller of the Western Power Trading Forum.

"I think for the majority of our sector [the amendment vote] comes across as more of an intervention in the vote-weighting within the sector from folks likely outside of the sector," Gray said. He added that the move represented "a pretty fundamental issue for the perception in our sector" of how fair Markets+ can be in respecting the internal independence of the sectors.

All three organizations followed through on their threats to vote against the governance plan. Other "no" votes included Advanced Power Alliance, American Clean Power Association, Clean Energy Buyers Association, Natural Resources Defense Council, Northwest Energy Coalition, Pattern Energy, Sierra Club and Western Resource Advocates. ■

SPP News

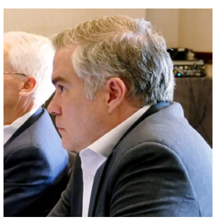
# 'Therapy Session': REAL Team Reviews Draft LOLE Study

*By Tom Kleckner*

DFW AIRPORT, Texas — Texas Public Utility Commissioner Will McAdams promised SPP's REAL Team a "therapy session" in forming a consensus position around its schedule and priorities for 2024.

"Save most of your intellectual bandwidth for after lunch, because that's where we're going to need some discussion and dialogue," the REAL (Resource and Energy Adequacy Leadership) Team's chair said during its Nov. 28 meeting, alluding to a discussion of SPP staff's draft loss-of-load expectation (LOLE) study.

"I think that schedule of priorities will be heavily impacted by the discussion around LOLE, because it shows us what our system needs are in the very near future," McAdams said.


Casey Cathey, SPP | © RTO Insider LLC

"This conversation is going to be the first of many," said SPP's Casey Cathey, senior director of grid asset utilization. "This particular area is a very, very important topic for the region. It's not just the loss-of-load expectation study, but specifically establishing a separate winter planning reserve margin."

SPP conducts a LOLE analysis every two years to determine the capacity needed to meet reliability targets. It follows the industry threshold of one day in 10 years (equivalent to 0.1 days/year). The study also establishes the RTO's planning reserve margin (PRM), currently 15%.

According to the draft 2023 study, maintaining a one-day-in-10 LOLE will require a summer PRM of 16.9% and a winter PRM of 45.2%, with 44% of the year's LOLE allocated to the summer and 56% to the winter. Staff included full incremental cold weather and planned and maintenance outages in its modeling.

Staff extended its historical wind, solar and load profile assumptions, looking back 43 years instead of nine in looking at 2026 and 2029 planning years. The study forecasts 2026 summer and winter non-coincident peaks of just over 58 GW and almost 48 GW, respectively.

Responding to McAdams' call for a more defined policy around outages, Cathey said planned outages should be included in the PRM. He noted that modeling planned outages associated with seasonal years or seasons of risk would increase the PRM.

"You're making that assumption that you're planning for that," Cathey said. "We have to make some assumptions here and determine what are going to be the net effects as we're creating the outage policy."

"I just don't want this to be an exercise where we're going to assume that the planning outages are basically being swept over to the spring and fall season, so we don't have to worry about [them]," the Advanced Power Alliance's Steve Gaw said. "I don't want the model to avoid the problem that we're trying to fix. We need to have an appropriate level of planned outages that are taking place in the wintertime."

Cathey promised to bring back to the team an evidence-based value proposition. "How do we appropriately assess the improvements in correlated outages for extreme events?" he asked rhetorically. "Maybe that helps better isolate where we're going with this this grid and ultimately, a recommendation for next year."

The Supply Adequacy Working Group (SAWG) is working on summer and winter PRM recommendations as part of the final study, due to be released in March or April. The PRM recommendation revision requests will go to the REAL Team and, in July, the quarterly governance meetings.

The daylong "therapy session" concluded with SPP Director Steve Wright telling McAdams his service to the group has been "remarkable." McAdams has said he will resign from the Texas commission, leaving the REAL Team chairmanship as well. (See *McAdams Says He Will Resign from Texas PUC*.)

"Just the time and effort you put into this, you came so incredibly prepared for these meetings, and that set a very high bar for all of us who are participating here," Wright said.

"We would not be where we are on these very important issues for this region without your leadership. You will very much be missed," echoed SPP Engineering Vice President David Kelley.

In a manner reminiscent of his military background, McAdams brusquely cut off further plaudits.

"All right, that's the meeting."

### FERC Rejects Winter Requirement

FERC added to the REAL Team's workload Nov. 30 when it rejected SPP's proposed winter resource adequacy requirement for its footprint. However, the commission said the RTO can address FERC's concerns and resubmit the proposal (*ER23-2781*).


Omaha Public Power District's Colton Kennedy, chair of the Supply Adequacy Working Group | *© RTO Insider LLC*

The commission said the proposal does not contain any requirement that a load-responsible entity's (LRE) resources are expected to be available. It said SPP has not demonstrated it is reasonable to permit LREs to rely on resources that are not expected to be available in the winter season to satisfy their resource adequacy requirements.

SPP's Market Monitoring Unit, as it had throughout the stakeholder process, opposed the tariff revision at FERC. It has pointed out the absence of language requiring a reasonable expectation of availability for resources. It also said an LRE could offer a resource to meet its winter obligation while planning to conduct a maintenance outage.

FERC said that in any future filing, the grid operator should take "appropriate steps" to ensure that resources included in LREs' adequacy workbooks for the winter are expected to be available "just as in the [summer]."

"This would provide a more accurate reflection of the system's capacity to meet winter demands and reinforce the need for LREs to maintain an adequate amount of available capacity," the commission said.

Acknowledging recent extreme winter events in the Midwest, FERC encouraged SPP to consider expedited proceedings for any future filing.

"Delays could result in insufficient preparation for these increased demands, potentially compromising the reliability of the power grid and the safety of the consumers who depend on it," it said.

SPP's board and its stakeholders and state regulators approved the winter obligation in July. The Members Committee, which provides advisory votes to the board, approved the proposal in a 10-9 vote, with four abstentions. (See "Board, RSC Endorse Winter Obligation," *SPP Board/Members Committee Briefs: July 24-25, 2023*.) ■

SPP News

# FERC OKs $150K Penalty on Black Hills for Delayed Filings

## *Company Failed to Submit 103 Jurisdictional Agreements*

*By John Norris*

FERC on Dec. 5 approved a $150,000 civil penalty on Black Hills Corp. (BHC) and its three electric public utility subsidiaries for their failure to timely file 103 jurisdictional agreements (*IN23-10*).

The stipulation and consent agreement between FERC's *Office of Enforcement* (OE) and BHC and its subsidiaries — Black Hills Power; Cheyenne Light, Fuel and Power; and Black Hills Colorado Electric — stems from a prolonged FERC investigation triggered by the utilities' self-reporting of their omissions.

Jurisdictional agreements detail rates, terms and conditions of services regulated by FERC and are essential for ensuring transparency, regulatory compliance and fair pricing.

On July 14, 2017, Black Hills Power reported to FERC that it had failed to submit six jurisdictional agreements as mandated by the Federal Power Act and FERC regulations (*ER17-2095*). This lapse led to Black Hills Power refunding $8,621 to customers.

This incident prompted BHC to conduct a more extensive investigation into its subsidies to determine if there were any other unfiled contracts.

By November 2021, BHC expanded its self-report to include an additional 97 unfiled contracts, leading to an estimated $1.2 million in refunds.

As of October 2021, BHC had filed all 103 previously unfiled agreements with FERC, some of which have been accepted, while others are still under review.

"As a result of these violations," the stipulation said, "Black Hills provided jurisdictional services without an accepted just and reasonable rate on file at the commission."

The agreements consisted mainly of short-term firm and nonfirm transmission service contracts, but also included transmission wires-to-wires interconnection agreements, delivery service to wholesale customers over distribution assets agreements, and joint ownership agreements and operation and maintenance services agreements on transmission assets.

FERC acknowledged BHC's cooperation with the OE throughout the investigation.

In addition to the financial penalty payable to the Treasury, BHC was required to admit its non-compliance and implement measures to prevent future violations.

These measures include submitting semiannual status reports that detail the status of each of the 103 previously unfiled agreements every six months for two years or until FERC has accepted or disposed of all the unfiled agreements. It must also undergo compliance monitoring for two years following the acceptance or final disposition of all filed agreements by the commission.

BHC must pay the civil penalty within 20 days of the agreement's effective date and submit its first semiannual status report six months thereafter.

FERC Commissioner James Danly did not participate in the order. ■

Black Hills Corporation headquarters in Rapid City, South Dakota | *Black Hills Corp.*

## SPP News

# Stakeholders Give SPP Services High Marks

*By Tom Kleckner*

SPP stakeholder satisfaction remained high this year, staff told the RTO's Board of Directors and Members Committee last week during their annual review of organization metrics and feedback.

Mike Ross, senior vice president of external affairs and stakeholder relations, said during the board's Dec. 5 meeting that all of SPP's service ratings increased from 2022 by an average score of 0.33, with generator interconnection (GI) seeing the largest improvement (2.59 to 3.01 on a four-point scale, with three points for meeting expectations and four for exceeding them).

Stakeholders rated SPP's services for GI, stakeholder process, Integrated Marketplace and settlements, operations and reliability, support services, training and transmission planning. Scores were up in all categories and averaged 3.49, with support services part of the survey for the first time.

Staff received a 3.70 score.

SPP distributed 3,220 surveys to its stakeholders, including those in the Western Interconnection. They returned 289 surveys, the most since 2016. However, the 9% response rate was the lowest in recent history.

Staff will distribute the survey results to departments and managers as part of the evaluation process. They will work with Consolidated Planning Process Task Force members to address GI and transmission planning, the two lowest-rated services, Ross said. SPP says it expects to complete a backlog of interconnection requests, dating back to the previous decade, *by the end of 2024*.

Stakeholder comments on the two services included "accelerated GI study times are also acknowledged and appreciated" and "quit holding GI customer concerns above all others."

Staff also said audit, tax and advisory services firm KPMG awarded an unqualified audit opinion to SPP's market operations and transmission service settlements for the 14th straight year. In 2022, the grid operator settled about $49 billion for the Integrated Marketplace and an additional $5.5 billion for transmission.

### 6 WG Chairs Approved

The board approved the Corporate Governance Committee's (CGC) nominations for several stakeholder group chairs, who will begin two-year terms, effective Jan. 1.

- Operating Reliability Working Group: Ron Gunderson, Nebraska Power Public District (NPPD).
- Regional Tariff Working Group: Robert Pick, NPPD.
- Seams Advisory Group: Jim Jacoby, American Electric Power.
- Security Advisory Group: Phil Clark, Arkansas Electric Cooperative Corp.
- Supply Adequacy Working Group: Colton Kennedy, Omaha Public Power District.
- Transmission Working Group: Derek Brown, Evergy.

All six are incumbents.

Directors also approved the CGC's recommendation to revise the Project Cost Working Group's (PCWG) scope. The PCWG now will review transmission service projects where the cost is 100% directly assigned to one or more transmission customers that are not the transmission owner. The scope previously identified only regionally funded projects as being reviewed. ■

| SERVICE | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Change from 2022 |
|---|---|---|---|---|---|---|---|
| Stakeholder process | - | - | 3.54 | 3.26 | 3.14 | **3.40** | +0.26 |
| Generation interconnection (GI) | 2.83 | 2.82 | 2.78 | 2.64 | 2.59 | **3.01** | +0.42 |
| Marketplace & Settlements | 3.38 | 3.42 | 3.40 | 3.25 | 3.29 | **3.52** | +0.23 |
| Operations & Reliability | 3.48 | 3.5 | 3.66 | 3.39 | 3.46 | **3.69** | +0.23 |
| Support services (RMS) | | | | | | **3.59** | - |
| Training | 3.45 | 3.5 | 3.7 | 3.46 | 3.42 | **3.70** | +0.28 |
| Transmission Planning | 2.95 | 2.95 | 3.09 | 2.95 | 3.02 | **3.28** | +0.26 |
| **Average satisfaction rating** | 3.24 | 3.28 | 3.34 | 3.18 | 3.16 | 3.49 | +0.33 |

**2022 Rating Scale:** 1 - Fails to Meet | 2 – Almost Meets | 3 – Meets | 4 – Exceeds in Some Cases | 5 – Exceeds
**2018-2021 Scale:** 1 - Fails to Meet | 2 – Nearly Meets | 3 – Meets | 4 – Exceeds | 5 – Greatly Exceeds

Stakeholder satisfaction with SPP services has increased. | *SPP*

# Company Briefs

### Chevron, Exxon Plan on Expanding Oil and Gas Operations in Permian

Chevron and ExxonMobil both plan to up their oil and gas operations in the Permian Basin next year during a time of rising interest in the fossil fuel region spanning southeast New Mexico and West Texas.

In plans announced last week, ExxonMobil said it plans to increase its oil and gas production to about 3.8 million barrels of oil per day in 2024, and Chevron plans to spend about $5 billion on shale development in the Permian. Both companies have recently acquired or merged with other oil-and-gas companies: Exxon has merged with Pioneer Natural Resources, and Chevron has acquired PDC Energy and merged with Hess.

Both companies also said they would cut emissions even while increasing production. Exxon said it would reach net-zero emissions by 2030, while Chevron said it will spend about $2 billion on "lower-carbon" initiatives and pursue "new energy" projects in the renewable sector.

More: *Carlsbad Current-Argus*

### Solar Panel Company Heliene Expands Iron Range Plant

Canadian solar panel maker Heliene has expanded again, saying it spent $10 million to grow a manufacturing and assembly line at its plant in Mountain Iron, Minn.

The announcement comes on the heels of a $145 million proposal in July for a plant in the Twin Cities metro area. Both projects were spurred by federal incentives and high demand for solar equipment built in the U.S.

The Ontario-based company said this latest project doubled capacity on a production line — one of two at the Iron Range plant — and is expected to create more than 130 new jobs.

More: *Star Tribune*

### RWE Moves into New Headquarters Building in Austin

RWE, the second-largest solar owner and operator in the U.S., has moved into its new headquarters in Austin, with plans to grow its headcount there.

The move is the first of several relocations and renovations underway to accommodate RWE's growing workforce and U.S. operations footprint as it moves toward a goal to be the top renewable energy developer and operator in the country.

RWE has more than 300 employees based in Austin, with nearly one-third having been hired since March. The company employs about 19,000 people worldwide.

More: *Austin American-Statesman*

# Federal Briefs

### EPA Quadruples Social Cost of Carbon Estimate

EPA this month unveiled an updated estimate of the social cost of carbon, an economic estimate that is used by the government to calculate the benefits of mitigating climate change.

The new estimate nearly quadruples the estimated cost of carbon dioxide to the world, to $204 per metric ton. EPA under President Donald Trump had lowered the figure to between $1 and $8, but President Joe Biden temporarily readjusted it to $51 when he began his term.

When the White House first put forward that increase in 2021, it also re-established an interagency working group that was supposed to set forth final numbers for the whole government by 2022; the group has yet to do so.

More: *The Hill*

### Solar Industry Poised for Slower Growth After Record-setting 2023

The U.S. is expected to add a record 33 GW of production capacity this year, up 55% compared with new capacity in 2022, but growth is expected to slow in 2024 amid economic challenges, according to a report by the Solar Energy Industries Association and Wood Mackenzie.

The report shows the U.S. solar industry added 6.5 GW of new electric generating capacity in the third quarter, helped by record installation of residential solar. However, changes to net energy metering policy in California and elevated interest rates across the U.S. are expected to lead to a brief decline next year before growth resumes in 2025, the report said.

Solar accounted for 48% of all new capacity added through the first three quarters of 2023, the report said. By 2028, solar capacity is expected to reach 377 GW, compared with 161 GW now.

More: *Reuters*

### GOP-led States Sue EPA over Expanded Powers to Block Polluting Projects

A group of 11 Republican-led states and energy industry groups have challenged an EPA rule that bolsters state and tribal veto power over pipelines and other major infrastructure projects that might pollute rivers and streams.

In a lawsuit filed in federal court in Louisiana last week, the state argued that EPA's September rule revising its permitting process under the Clean Water Act to let states and Native American tribes block projects over a wider range of expected impacts to water resources exceeded the agency's authority under the law and asked the court to vacate it.

The states warned that the rule will increase the workload of state agencies reviewing projects and would thwart efforts to develop critical energy infrastructure like natural gas export terminals, carbon capture projects and pipelines.

More: *Reuters*

# State Briefs

## GEORGIA

### Kemp Chief of Staff Moving to Georgia Power in Executive Role

Georgia Power this month named Trey Kilpatrick, chief of staff to Gov. Brian Kemp (R), as senior vice president of external affairs effective Jan. 15.

Kilpatrick became Kemp's chief of staff in 2020 after serving the late U.S. Sen. Johnny Isakson in various roles, including deputy chief of staff. Before that, he was vice president for an Atlanta-based investment firm.

"Trey has an obvious passion for helping Georgia grow and thrive, serving all of its citizens and making our communities better," said Kim Greene, the utility's CEO.

More: *The Telegraph*

## ILLINOIS

### Pritzker Signs Bill Allowing New Small-scale Nuclear Technology

Gov. **JB Pritzker** (D) on Friday signed into law a bill that will allow for the limited development of new nuclear power generation technology in the state.

The measure, House Bill 2473, does not allow new large-scale power generation facilities like the six plants that are already operational in the state, but rather allows for new smaller-scale emergent technology.

The state has had a moratorium on any new nuclear power construction since 1987, until the federal government designates a long-term disposal site for nuclear waste — something that has never occurred. The new law will take effect on June 1, 2024, but because permitting nuclear energy takes many years at the federal level, the earliest a nuclear project could be brought online in the state would be in the 2030s.

More: *Capitol News Illinois*

## INDIANA

### Activists Urge State to Act on Pollution Violations at Coal Plant

Groups including Earthjustice, the Sierra Club and the Hoosier Environmental Council sent a letter to the Department of Environmental Management urging it to hold the Merom coal plant in Sullivan accountable for what they say have repeated pollution violations.

The groups said the plant has repeatedly sent excess iron and ammonia into the Turtle Creek Reservoir and that its toxic coal ash pollution is seeping into the groundwater.

The plant was originally slated to close until it was sold to Hallador Power. A new cryptocurrency mining facility owned by AboutBit is set to open next to the plant and get some of its power from it.

More: *IPB News*

## MAINE

### Alna Board Grants Extension to Delayed Solar Farm for CMP Study

The Alna Planning Board last week extended a permit for the Alna Community Solar Farm, now 15 months past its anticipated finish line, while it awaits approval from Central Maine Power through its interconnection study process.

The board approved Sunray Solar's application for a facility on about 15 acres of land west of Route 2018 in February 2022, when the project was anticipated to be completed in September of that year. But Alana Martell, managing member of Sunray, told the board that though CMP's transmission cluster study is complete, the utility has still not given the go-ahead for construction.

"We have experienced nothing but continuous delays with CMP," she said.

More: *The Lincoln County News*

## VERMONT

### Stamford Wind Project Placed on Hold by Developer

A developer considering a 2.2-MW wind project in Stamford has announced it won't continue in the permitting process before the Public Utility Commission.

"The project has had to delay its [permit application] filing multiple times due to the project being fed by a line from outside of Vermont with a utility that is not under Vermont rules," Norwich Technologies said in a statement. "These delays have resulted in significant additional financial impacts that make the project infeasible at this time."

The project was expected to require connections with both Green Mountain Power lines and those of National Grid in Massachusetts. In documents posted with the PUC, the developer had cited negotiation delays in discussions with National Grid as a cause of delays in submission of a full permit application to the commission.

More: *Bennington Banner*

## WYOMING

### State Forgoes Federal Funds to Help Reduce Pollution

The state has chosen to forgo its application for a multimillion-dollar federal grant aimed at reducing pollution, as it felt the rules around the funding were too stringent.

The $4.6 billion was available to states, tribes and territories as part of EPA's Climate Pollution Reduction Grants program. The money can be used for projects such as managing forests, building bike paths and building electric vehicle infrastructure.

"EPA has repeatedly shown an unwillingness to work with the state in advance of proposing multiple new federal rules and given Wyoming unreasonable time frames to comment on the impacts of those rules," Gov. Mark Gordon (R) wrote to the agency. "Wyoming will continue to direct its resources toward removing federal roadblocks that stand in the way of common-sense, lower cost solutions that use innovations tailored to meet the needs of Wyoming's citizens and industry, across the entire energy spectrum."

More: *Wyoming Public Radio*