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# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

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# In this week's issue

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# FERC, NERC Set Probe on Xmas Storm Blackouts

## *TVA, Duke Under Scrutiny for Rolling Blackouts*

*By Amanda Durish Cook, Tom Kleckner, Holden Mann, John Norris and Sam Mintz*


A winter storm blanketed downtown Buffalo, N.Y. on Dec. 26. | *Gov. Kathy Hochul*

FERC and NERC will conduct yet another inquiry into cold weather grid failures after Duke Energy and the Tennessee Valley Authority cut power to consumers because of insufficient generation during December's winter storm.

FERC *announced* Dec. 28 it would conduct the joint investigation with NERC and its regional entities after millions of customers were left without power following the storm's snow, frigid temperatures and high winds.

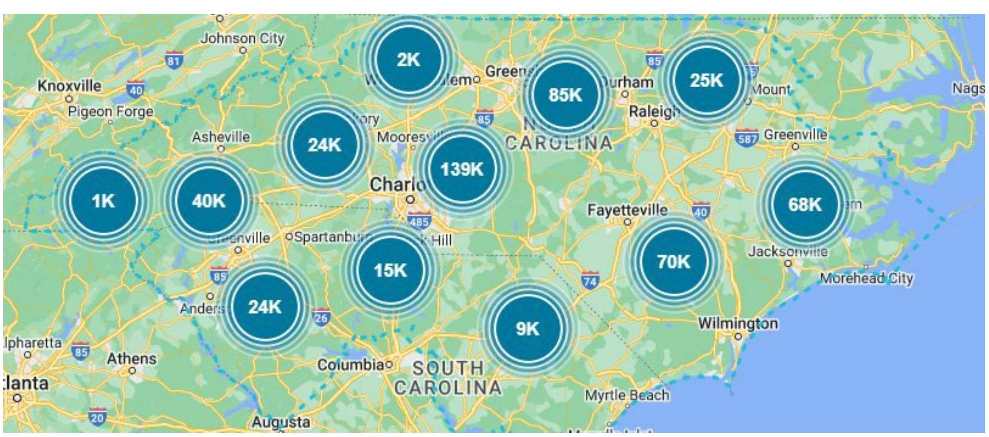
"Although most of these outages were due to weather impacts on electric distribution facilities operated by local utilities, utilities in parts of the Southeast were forced to engage in rolling blackouts and the bulk power system in other regions was significantly stressed," the agencies said.

FERC Chair Richard Glick said the behavior of the bulk power system during the storm shows that the BPS "is critical to public safety and health."

NERC CEO Jim Robb noted that December's storm was the fifth major winter event in the last 11 years.

"In addition to the load shedding in Tennessee and the Carolinas, multiple energy emergencies were declared and new demand records were set across the continent. And this was in the early weeks of a projected 'mild' winter," Robb said. "This storm underscores the increasing frequency of significant extreme weather events ... and underscores the need for the electric sector to change its planning scenarios and preparations for extreme events."

NERC's *2022-2023 Winter Reliability Assessment*, released in November, warned that while most areas were prepared for average winter temperatures, multiple regions — including North and South Carolina — were at risk of insufficient electric supplies during peak winter conditions. (See *NERC Warns Winter Margins Tight in Multiple Regions*.)




Duke Energy's outage map for North and South Carolina, shared by spokesperson Jeff Brooks on Twitter at 8:24 a.m. Dec. 24. | *Duke Energy*

Outside of the Southeast, the winter storm prompted conservation calls and emergency alerts in the Eastern Interconnection, while ERCOT and SPP joined TVA in setting new demand records. In PJM, where load hit 135.3 GW on the evening of Dec. 23, calls for conservation limited the peak to less than 129 GW on Dec. 24.

Some 500,000 customers who lost power during the storm across New York had their service restored as of Dec. 28, the New York Public Service Commission reported. The Buffalo area was pummeled by more than four feet of snow and winds as high as 70 miles per hour; more than three dozen deaths were attributed to the storm. Gov. Kathy Hochul called it the "most devastating storm in Buffalo's long storied history."

### Southeast Struggles

Duke said in a *release* that it "was forced to interrupt service" to around half a million customers in North and South Carolina the evening of Friday, Dec. 23, and Christmas Eve morning, because of both increased demand from the below-freezing temperatures and "a

# FERC/Federal News

shortage of available power in the Southeast." Separately, a high-wind event Dec. 24 left about 40,000 customers without power.

Duke spokesperson Jeff Brooks told *WRAL News* in Raleigh that generator failures also played a part, along with challenges "in our ability to secure additional power from outside of our service area" because the extreme cold affected neighboring utilities as well.

While the utility *reported* it was back to normal operations in both states by Dec. 26, its customers — which Duke had thanked for helping reduce demand through voluntary conservation efforts — were less than pleased. Several Twitter users noted that major buildings in downtown Charlotte — including Duke's own headquarters — appeared fully lit despite pleas for conservation. Others complained they had gotten no notice before Duke cut their power, even those relying on electricity for medical devices.

North Carolina Governor Roy Cooper *tweeted* that he was "grateful for those who conserved energy" but also "deeply concerned" about the alleged lack of notice for rolling blackouts. He said he had "asked Duke for a complete report on what went wrong and for changes to be made." The utility is also scheduled to brief the North Carolina Utilities Commission on the outages at a *meeting* today.


Twitter users complained about being asked to conserve energy while corporate offices — including those of Duke Energy in Charlotte — remained fully lit. | *Michael Konen via Twitter*

## TVA Takes 'Full Responsibility' for Outages

Meanwhile, TVA said in a *statement* on Wednesday that it would "take full responsibility for the impact we had on our customers" and promised a "thorough review" of the holiday outages.

The utility acknowledged that it had ordered local power companies to reduce consumption by 5% on Dec. 23 and again on Dec. 24 by up to 10%. The Dec. 23 curtailment lasted two hours and 15 minutes, while the Christmas Eve cuts lasted more than five hours. TVA said that during the 24-hour period that began on Dec. 23, it "supplied more power than at any other time in its nearly 90-year history," providing 740 GWh. The utility set its highest winter peak power demand, at 33.4 GW, at 7 p.m. the same day.

Dec. 23 also marked "the first time in TVA's 90-year history that we've had to direct targeted load curtailments due to extreme power demand." While TVA did not mention generation outages in its statements, data from the *Energy Information Administration* showed that output from coal plants in Tennessee dropped significantly during the same period, from 4.5 GW the morning of Dec. 23 to a low of 1.4 GW Christmas afternoon.

As with the Duke outages, considerable criticism ensued in TVA's service territory over the lack of warning. Nashville Mayor John Cooper said on Twitter that Nashville Electric Service "received only an eight-minute warning from TVA" on Dec. 23 about the coming blackouts. Fifty thousand Nashville residents were without service at one point, according to *local media*, along with 226,000 in Memphis, where Mayor Jim Strickland said the utility was "not as reliable as they said they were."

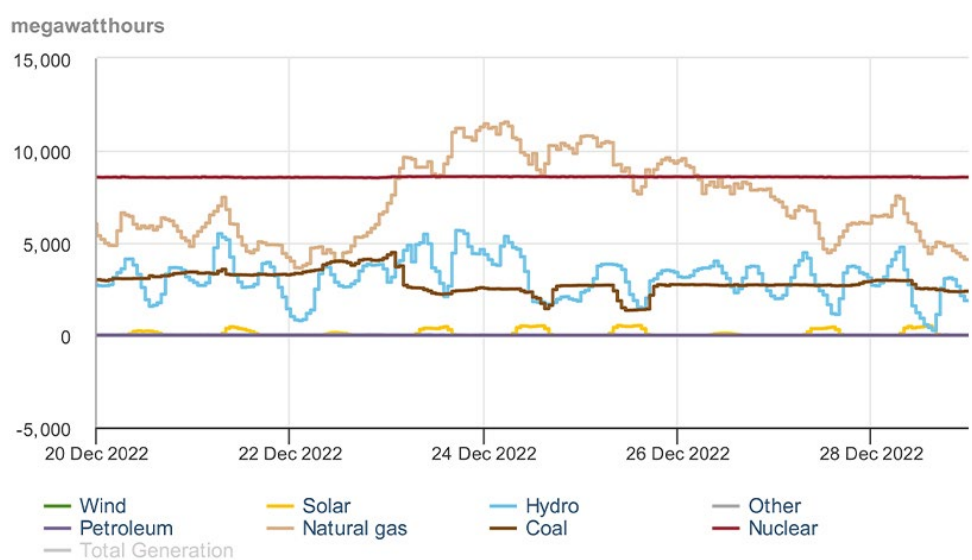
## DOE Grants ERCOT's Emergency Request

Battling some of the same problems that almost brought down its grid during February 2021 — thermal outages and derates, forecasts that underestimated load, gas supply issues — ERCOT went so far as to ask for help from the federal government as temperatures dipped into single digits in Texas' northern regions.

New ERCOT CEO Pablo Vegas sent a letter to U.S Energy Secretary Jennifer Granholm on Dec. 23 requesting permission to ignore air quality or other permit limitations and run the grid's power plants at their maximum output levels during Energy Emergency Alerts level 2 (load management procedures in effect) or EEA3 (firm load interruption is imminent or in progress) conditions. Vegas cited "natural gas delivery limitations" in saying the grid operator might not be able to avoid curtailing firm load.

He said about 11 GW of thermal generation were offline or derated, compared to 4 GW of wind and 1.7 GW of solar resources. Vegas said ERCOT "understands the importance of the environmental permit limits."

"However, in ERCOT's judgment, the loss of




Electricity generation by energy source for Tennessee from Dec. 20-28, showing a significant drop in coal generation in the early morning of Dec. 23, along with smaller drops in gas and hydro resources. | *EIA*

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power to homes and local businesses in the areas that may be affected by curtailments presents a far greater risk to public health and safety than the temporary exceedances of those permit limits that would be allowed under the requested order," Vegas wrote.

The Department of Energy agreed an emergency existed and quickly granted the grid operator's request that same day (*202-22-3*).

"The DOE order was a tool to have at our ready should we need it, which we did not," ERCOT spokesperson Trudi Webster said in an emailed statement. "ERCOT had sufficient generation to meet demand … and had additional tools left to deploy should additional generation been needed."

Staff used all available import capacity on the DC ties, deployed additional capacity enrolled in emergency response service, suspended charging by energy storage resources, and directed load resources providing responsive reserve service to curtail demand. Online reserves exceeded 11 GW at times.

ERCOT's average hourly demand peaked at 73.96 GW during the morning of Dec. 23, smashing a six-year-old December record of 57.9 GW.

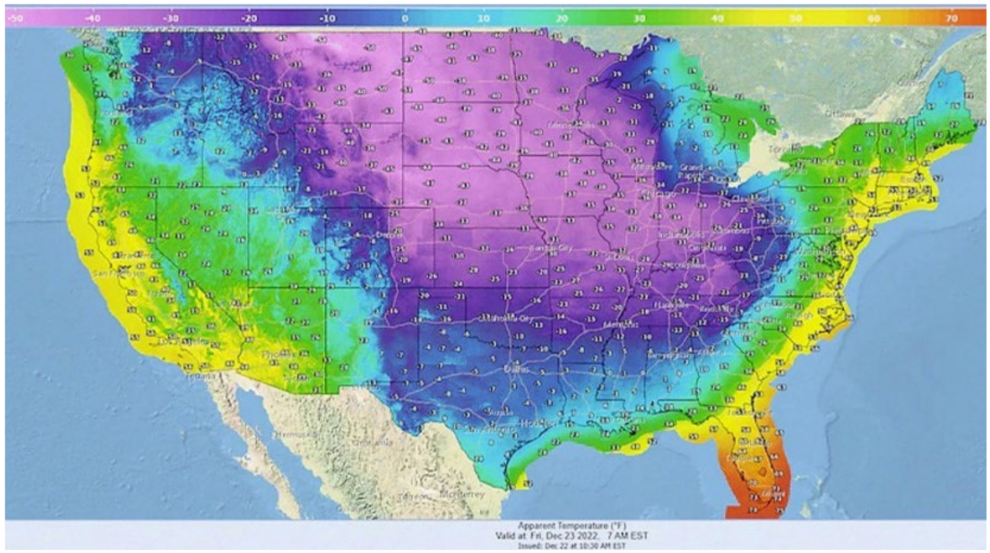
The grid operator's final seasonal resource adequacy assessment had projected demand to peak this winter at 67.4 GW, although models upped that to nearly 71 GW as the storm approached. (See *ERCOT Says 'Sufficient' Capacity to Meet Winter Demand*.)

Austin-based Stoic Energy consultant Doug Lewin said poorly insulated homes led to the "crazy high" demand. He *pointed out* that FERC and NERC identified energy-efficient homes as one of the fixes after the ERCOT grid came within minutes of collapsing during the 2021 February winter storm. "Lots more work to do," he said.

Demand officially peaked at 69.8 GW during the 2021 storm, but Texas A&M University's Texas Center for Climate Studies has *said* demand would have reached 82 GW had not more than 50 GW of generation been unavailable.

At one point on Dec. 23, more than 77,000 Texas customers were without power, according to *PowerOutage.us*. The cold front's wind gusts reached 40 miles per hour at times and accounted for most of the localized outages. They also resulted in wind production that provided nearly half of ERCOT's fuel mix.

Average prices that were still settling below -$1.00/MWh as late as 5 p.m. Dec. 22 went as high as $4,084.62/MWh during the interval ending at 7 a.m. Dec. 23. By 9:15 that night, prices dropped back into the triple-digit range, with a high of nearly $140/MWh on Dec. 24.



Forecast wind chills for the morning of Dec. 23 | *National Weather Service*

### SPP Calls EEAs, Sets Demand Mark

SPP set a new mark for winter demand when load peaked at 47.1 GW on Dec. 22, smashing the previous record of 43.7 GW set during the February 2021 storm.

The persistent cold led to tightening reliability conditions in SPP's 14-state Midwestern footprint and forced it to declare two EEA1s (all available generation resources in use) on Dec. 23 that lasted for more than four hours.

The grid operator called the first EEA1 at 8:27 a.m. CT and ended it at 10:00 a.m. SPP issued the second EEA1 at 5:20 p.m. as load exceeded staff's forecast and generation dropped off heading into the evening peak. The RTO called off the alert at 8:20 p.m.

SPP also extended a previously issued conservative operations advisory for its Eastern Interconnection balancing authority footprint from 12 a.m. CT Dec. 25 to noon Dec. 25.

### ISO-NE Handles Christmas Eve Capacity Deficiency

An unexpected generator outage and a reduction in imports from other regions led to a somewhat tense Christmas Eve for ISO-NE.

The New England grid operator was forced into a series of actions to respond to the Dec. 24 capacity deficiency, going into its *Operating Procedure 4* for the first time since Labor Day 2018.

The problems weren't closely connected to the worst-case scenario that ISO-NE has laid out in recent years, where an extended cold snap challenges energy supply. The weather wasn't especially cold on the Saturday, and demand was only very slightly above its predicted level at the peak hour.

Instead, it was unplanned outages and reductions at multiple generators, including an unidentified "large generating station" that pushed the grid operator into action. ISO-NE spokesperson Matt Kakley said the grid operator won't release information on which specific units were knocked out or reduced.

In total for the day, New England unexpectedly lost 2,150 MW of generation and neighboring regions under-delivered energy by about 100 MW compared to the grid operator's morning plans — and 1,100 MW less than what had cleared in the day-ahead market.

According to ISO-NE's *report* on the deficiency, it first declared an abnormal conditions alert at 4 p.m. Dec. 24., with escalating actions coming

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

# FERC/Federal News

subsequently until peak load had passed and the conditions eased by 6:30.

While the system was briefly strained, ISO-NE said, "only a small amount of day ahead cleared export transactions were curtailed and no emergency purchases were scheduled."

Along with the warnings of an imminent energy shortage, the skyrocketing real-time wholesale prices (to over $2,000/MWh) at the peak hour raised eyebrows in New England, with one *commenter noting* that in the ISO-NE app, the whole region was colored a bright Christmas red.

## MISO South Dodges Emergency

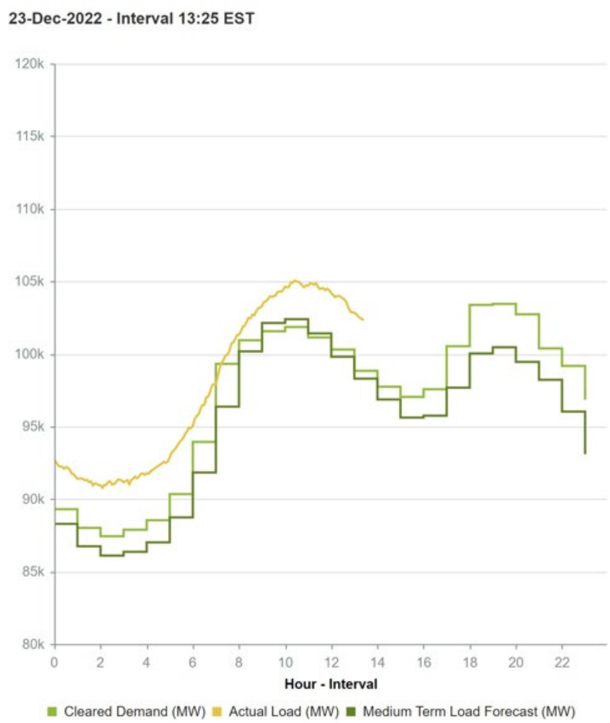
MISO managed to avoid an emergency in its South region despite issuing a maximum generation warning during the fierce cold blast Dec. 23.

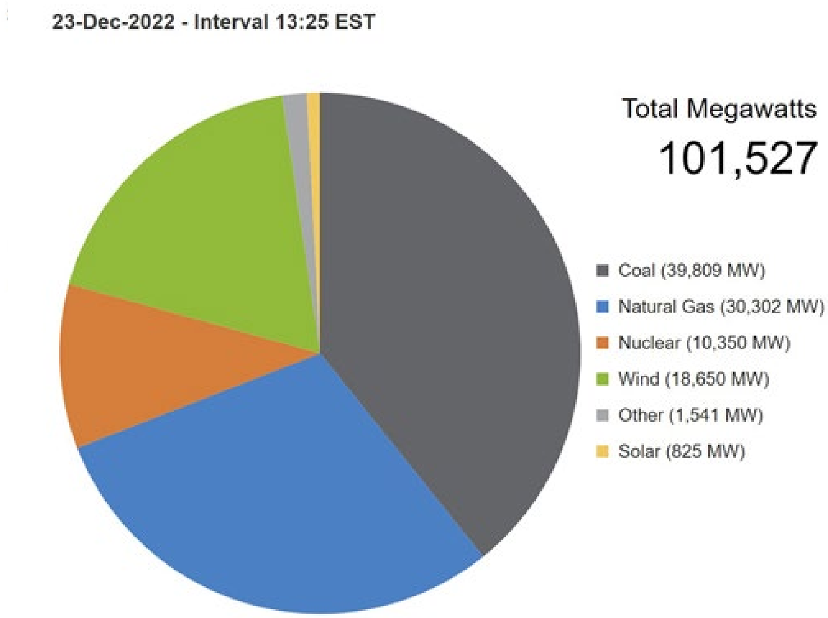
MISO issued a maximum generation warning around 9 a.m. ET for the South as the storm intensified into a bomb cyclone and lifted the warning before 1 p.m. MISO said its South region was facing higher than forecasted load and significant generation outages.

MISO South remained in conservative operations mode and under a cold weather alert until Dec. 26. The storm also forced MISO Midwest into conservative operations overnight into Dec. 24. MISO's conservative operations instructions request members defer or cancel generation or transmission maintenance and return facilities to service as soon as possible.

The grid operator issued a cold weather alert for its South region ahead of the frigid weather on Dec. 20. On Dec. 22, central Mississippi and Arkansas recorded low temperatures around 10 degrees Fahrenheit.

Entergy Texas said its crews restored damage from "strong winds and gusts that swept across Southeast Texas" on Dec. 22. ■




MISO systemwide load and fuel mix on Dec. 23 | *MISO*

## FERC/Federal News

# FERC's Work in 2022 Left in Doubt by Manchin

*By Michael Brooks*

2022 was a busy year for FERC, with a series of rulemaking proposals and technical conferences that covered practically everything over which the commission has jurisdiction.

But it was Congress that passed the most consequential changes to U.S. energy policy last year, in the form of the Inflation Reduction Act. Most of FERC's work was preliminary, meant to set up final rulemakings this year.

Because of that, the most significant event for the commission in 2022 may end up being the refusal of Sen. Joe Manchin (D-W.Va.), chair of the Senate Energy and Natural Resources Committee, to hold a confirmation hearing for Chair Richard Glick. That will leave the commission evenly split between Republicans and Democrats for at least part of 2023, casting a cloud of uncertainty over the work Glick did in his two years as chair. (See *Glick's FERC Tenure in Peril as Manchin Balks at Renomination Hearing*.)

President Biden named Glick chair upon taking office in 2021 and nominated him for a second term in May, but Manchin said in November that he would not consider him. Glick's tenure on the commission *will end* at noon today, when the current Congress adjourns. (See *Glick Bids Farewell to FERC*.)

As a result, Biden will need to choose between Democratic Commissioners Allison Clements and Willie Phillips to be the new chair. Having joined in December 2020 and December 2021, respectively, Clements and Phillips have spent less time the commission combined than Glick, who joined in November 2017.


FERC Chairman Richard Glick speaks to reporters at his last post-open meeting press conference. | *© RTO Insider LLC*

# FERC/Federal News

The president will also have to nominate Glick's replacement — a pick that will have to go through Manchin, who will remain a wild card this year even after Democrats gained a Senate seat during the midterm elections.

And Biden will need to decide whether to nominate Commissioner James Danly for a second term or choose another Republican to succeed him. Danly's term expires June 30. Senate Republicans — as well as Manchin, perhaps — will likely insist that the nominees for Glick's and Danly's seats be paired. That could leave the commission split for more than half of the year.

At his final post-open meeting press conference Dec. 15, Glick suggested this would likely be the case, but he expressed optimism that the commission would not deadlock frequently.

"I would also say there's an opportunity here [when] Commissioner Danly's position becomes open," Glick said. "The Senate can confirm my replacement and Commissioner Danly's replacement at the same time. ... I very much hope that the president nominates our replacements and moves forward as quickly as possible."

On Monday, Glick released *a letter* he had sent to Biden thanking him for naming him chair and listing what he viewed as the commission's top accomplishments during his tenure, the first of which was reversing "policies adopted during the previous administration that discriminated against state-supported zero-emissions electric generation facilities located in the eastern half of the United States."

## Pending Proposals

Manchin was angered by the commission's plans to consider greenhouse gas emissions in natural gas infrastructure certificates.

The two proposals — to update its 1999 policy statement on natural gas infrastructure certificates (PL18-1) and guidance on how it will evaluate the impacts of projects' greenhouse gas emissions in its environmental analyses (PL21-3) — were originally not proposals at all. Over the objections of the Republican minority, they were issued as final documents in February, but the commission rescinded and rereleased them as drafts the next month. The Democrats said they were persuaded by stakeholders who expressed confusion and their criticism that the policies would apply retroactively to projects already pending before the commission. (See *FERC Backtracks on Gas Policy Updates*.)

Those are just two of the proposals that the commission will continue to consider this year. Also pending are proposals to overhaul generator interconnection queue processes (*RM22-14*) and transmission cost allocation and planning rules (*RM21-17*).

Each set of rule changes have elements that are supported by certain stakeholder sectors and those that are opposed by others. (See *RTOs, Utilities Push Back on Interconnection Deadlines, Penalties* and *Battle Lines Drawn on FERC Tx Planning NOPR*.)

Given the controversy surrounding each, and the split commission, FERC may approve those elements it can achieve consensus on rather than attempt to pass the proposals wholesale. For example, there seems to be wide support among both commissioners and stakeholders for a provision in the interconnection proposal to replace the serial "first-come, first-served" study procedure with "first-ready, first-served" cluster studies.

Both proposals are being watched closely not just by RTO/ISO stakeholders, but by environmentalists and climate hawks as well. Most of the resources in utilities and grid operators' clogged queues are renewables, and there is increasing acknowledgement among state policymakers and environmentalists that large-scale transmission buildout is needed to accommodate those resources.

Even Danly — who always keeps FERC Secretary Kimberly Bose busy listing his many concurring and dissenting opinions at open meetings — said it was obvious that the queue processes needed fixing by FERC, rather than RTOs and utilities. He said he supported "a number of meritorious" provisions in the interconnection proposal. Danly's support was also notable because of his frequent criticism of both federal and state policies that favor renewables over natural gas, which he argues is explicitly stated in U.S. law to be a necessary public good.

It was for that reason he opposed the transmission planning proposal, arguing that "it is designed to encourage buildout of transmission specifically for the purpose of encouraging the development of certain types of resources."

Commissioner Mark Christie (R) may end up being the swing vote in many dockets, and key to what provisions make it into any final rules passed out of the interconnection and transmission proposals. Highly independent, Christie last year joined Danly in dissenting on high-profile cases perhaps as many times as he joined Democrats in support — though sometimes tepidly in the latter. The former chair of the Virginia State Corporation Commission, Christie often speaks up for states' right to choose their resource mix and supports policies that protect that right. ■

## FERC/Federal News

# Passage of the IRA Reshapes US Clean Energy Transition

## *But 2023 Will be Pivotal Year for Delivering IRA and IIJA Program Benefits*

*By K Kaufmann*

The biggest clean energy story of 2022, hands down, was the passage of the Inflation Reduction Act, rising improbably and miraculously from the ashes of President Joe Biden's Build Back Better Act of 2021.

The IRA and its $369 billion in clean energy funding, builds on the foundation laid by 2021's Infrastructure Investment and Jobs Act, which included another $62 billion in funding for clean energy initiatives that began rolling out this past year.

The full impact of the two laws will likely be incremental, unfolding over the next five to 10 years, but 2023 will be pivotal as the Biden administration continues to push forward with its clean energy agenda, and private industry and finance make decisions about adding their own dollars to the billions in clean energy grants, tax credits and other incentives contained in the two laws.

The administration's focus will be on delivery. In a series of appearances at recent energy conferences, National Climate Advisor Ali Zaidi has called on corporations and private investors to get off the sidelines and put steel in the ground. "For folks in the private sector, the time to make decisions is now. Boards can't commission study committees; they've got to greenlight capital projects," Zaidi said in a keynote address for a Resources for the Future conference in October.

But implementing the IIJA and IRA also raises complex issues as federal and state agencies hash out the details of legislative language and the intent of the lawmakers who crafted it. Other headwinds include inflation, Russia's war on Ukraine and the lingering effects of the COVID-19 pandemic on clean energy supply chains.

### The NEVI Example

While the IIJA and IRA are both trimmed-down, compromise versions of the original bills Biden and Democratic leaders hoped to pass, getting the laws through a deeply divided Congress was an extraordinary achievement. The often-tense negotiations, in particular for the IRA, required a fine balance between the Democrats' progressive wing and the swing votes of conservative Democrats Sen. Joe Manchin and Sen. Krysten Sinema, now an independent.

President Biden signs the Inflation Reduction Act into law in August. | *The White House*

What matters now, with the next presidential election already on the horizon, is the impact the laws will have on the way the U.S. produces and consumes energy and how such changes are perceived by individual consumers. Will they deliver new, cleaner technologies, emission reductions and cost savings — as well as the sense of urgency and mission that is required to curb the mounting impacts of climate change?

The IIJA's National Electric Vehicle Initiative (NEVI) provides an early look at the complexly layered issues that will likely surface as each new program is rolled out. With $7.5 billion from the IIJA, the goal of NEVI is to create a national network of 500,000 EV chargers over the next five years, with 150 kW DC fast chargers located along interstate highways, as well as in rural, tribal and disadvantaged urban communities.

The law provides millions in yearly allocations to individual states, which must submit plans to the Federal Highway Administration, showing how they will use the funds and the specially designated routes and other locations where chargers will be installed. A joint effort of the Department of Transportation and the Department of Energy, the first guidelines for NEVI were announced in February, followed by more detailed technical standards in June.

As required, all 50 states, the District of Columbia and Puerto Rico submitted their plans by an Aug. 1 deadline, which the FHWA approved, also on deadline, by the end of September. (See *US Completes Review of State EV Charging Plans*.)

But many state plans raised a range of concerns about the program's requirements, such as the mandate for the EV chargers to be located every 50 miles on key interstate and state highways, with charging stations installed no more than one mile off these roads. Highways running through remote or rural regions simply may not have the electric distribution system needed for the high-powered fast chargers or the traffic needed to make the installation of fast chargers pencil out.

Utilities have warned that building out the poles and wires in remote areas will need to occur in stages over several years and could come at a high cost to consumers. Making sure chargers are installed in areas where potential EV owners may live in multifamily apartment houses or other affordable housing is another area where many states are still developing policies and plans.

Installation of the first NEVI-funded charging stations should start this year, but Biden's vision of a seamless, national network of chargers that will make topping up EV batteries as easy as stopping at a gas station, and banish drivers' range anxiety, will likely encounter more than a few bumps and detours.

Implementing the IRA's wide range of tax credits and other incentives could be even more complex, as states and industry stakeholders wait for the federal guidelines needed to put the cash incentives for electric vehicles, heat pumps and other energy efficiency technologies in consumers' hands.

The Internal Revenue Service ran up against a year-end deadline for issuing guidelines for the IRA's EV rebates, without providing detailed guidance on domestic content requirements called for in the law. Manchin quickly called for a hold on the rebates and threatened additional legislation to ensure the IRS follows the letter of the law.

In other words, both sides of the aisle have major stakes in the IIJA and IRA, and the amount of money and scope of the programs involved almost ensure that mistakes will occur, and individuals and businesses will try to game the system.

Federal and state agencies face steep and slippery learning curves in the months ahead, and a small army of whistleblowers and gadflies will be watching their every step.

## Inflation, COVID and the War in Ukraine

Even before the IRA was passed, congressional Republicans were talking up plans for whittling away at some of its provisions following November's midterm elections, in which they had hoped to regain control of both the House and Senate. But, with the Democrats holding the Senate and the GOP winning only a slim majority in the House, efforts to slow or sideline implementation of the IRA will be limited to general political sniping and oversight hearings.

At the same time, the combined effects of inflation and Russia's war in Ukraine, and the lingering impacts of the COVID-19 pandemic, could present additional obstacles to the implementation of the laws, and Biden's clean energy agenda in general.

COVID-19 had been an early trigger for inflation as factory closings and the resulting production slow-downs hit supply chains, not only in clean energy, but across the economy. After years of steady decreases, prices for solar panels and storage started to inch up, and installations slowed down. According to figures from *Wood Mackenzie*, solar installations in 2022, estimated at 18.6 GW, fell about 23% from 2021, with new utility-scale deployments falling 40%.

The war in Ukraine triggered a worldwide "dash to gas" as both European and Asian countries faced the immediate and potentially disastrous cutoff of their supplies of Russian natural gas, looking instead to the U.S. to keep their economies fueled and their consumers warm through cold winters. With mounting pressure from Republicans to "unleash" U.S. fossil fuels through increased leasing on public lands and approval of new or unfinished pipelines, the Biden administration and congressional Democrats have had to walk a fine line balancing the immediate needs of U.S. consumers and overseas allies with the impacts of climate change.

Biden and other energy leaders worldwide argued that the short-term need to boost natural gas production should not be used to slow or stop the global move to clean energy, which would provide the best defense against both inflation and Russia's weaponization of vital energy supplies.

While inflation is nosing down, price increases and supply chain challenges could continue to slow critical clean energy projects. Biden's goal of installing 30 GW of offshore wind by 2030 prompted a surge of activity last year with the Bureau of Ocean Energy Management holding a series of high-profile offshore lease auctions for sites on both the Atlantic and Pacific coasts.

The auction of six sites in the New York Bight, a curve in the New York-New Jersey coastline, produced record-breaking bids totaling $4.37 billion. At the same time, states up and down the Mid-Atlantic coast are expanding port facilities and drawing in new OSW manufacturers, all vying to become major hubs for offshore construction and operations.

For example, New Jersey's ambitious plans for a purpose-built offshore wind port could cost between $500 million and $550 million and could create up to 1,500 manufacturing, assembly and operations jobs, according to figures from the state's Economic Development Authority. (See *NJ to Expand Wind Port with Land Purchase*.)

But the economics of developing and financing these offshore wind projects — and building the necessary transmission — remain uncertain. The West Coast sites will require floating turbines, which will present another level of technical and financial challenges.

## PPAs and Supply Chains

The Massachusetts Department of Public Utilities ended the year with Friday's approval of contracts for the 1.2 GW Commonwealth offshore wind project and the 840 MW Mayflower project, despite petitions from both project developers to allow them to renegotiate due to rising costs, as reported in *The New Bedford Light*.

Following the DPU decision, Craig Gilvarg, a spokesperson for Commonwealth developer Avangrid, said, "The current Power Purchase Agreements do not allow the company to secure the significant financing needed to construct this critical project, and thus the project cannot proceed under these contracts."

A joint project of Shell New Energies US and Ocean Wind, the Mayflower project will move forward, but the developers have signaled their current plans will focus on completing only an initial 400 MW.

Building out domestic supply chains for offshore wind, electric vehicles, batteries, solar panels and other technologies was yet another major flash point in 2022 — and an easy target for Republican criticism of the clean energy sector's dependence on China and Russia for critical minerals, including lithium, cobalt and uranium.

Biden has promoted "Made in America" initiatives as a top priority in the IRA's manufacturing and clean technology tax credits, and the auto industry, in particular, has responded with a series of announcements on plans for new factories and for the retooling and expansion of existing facilities for EV and battery production.

But building out an extensive U.S. clean energy supply chain, especially for critical minerals, will take years, billions in private investment and making the hard compromises and tradeoffs on the essential issue of permitting reform.

Both parties know reform is critical, but whether they will put politics aside and hammer out a deal could be one of the biggest stories of 2023. ■

## CAISO/West News

# Plans to Make CAISO a Western RTO Revived

### *ISO Seeks Approval of WEIM Extended Day-ahead Market*

*By Hudson Sangree*

California lawmakers are planning a new effort in 2023 to allow CAISO to become a multi-state RTO under conditions that have changed greatly since the last attempt failed five years ago, while the ISO is hoping to win approval for a day-ahead extension of its real-time Western Energy Imbalance Market, increasing its role in the West.

The potentially big changes come as California is contending with regionalization efforts by SPP, which plans to launch a Western version of its Eastern RTO, and the Western Power Pool, which is seeking FERC approval for its Western Resource Adequacy Program, a possible launchpad for an RTO.

Developments in the past five years are fueling the efforts, including strained grid conditions in Western heat waves, the need for new transmission to carry renewable power, legal mandates for Colorado and Nevada transmission owners to join RTOs by 2030, and more states adopting clean energy and emissions reduction targets.

Collaborating to meet those needs in organized markets would be far less expensive than going it alone, a number of studies have shown.

"There's a strengthened recognition of the need to work together in the West and the benefits of working together," CAISO CEO Elliot Mainzer said in an interview with *RTO Insider*.

Last year's California Assembly Concurrent Resolution 188, authored by Assemblyman Chris Holden, chair of the Assembly Appropriations Committee, asked CAISO to report on studies of the benefits of regional markets by the end of February. The measure passed the state Senate and Assembly by unanimous bipartisan votes.

"This is an important precursor to what's likely to be a legislative push in California's legislature next year for broader governance reform," Mainzer said in a Dec 13 meeting of the WEIM Governing Body. "We look forward to following up with Chair Holden in the early new year to start thinking about the timing and the coordination and the choreography of that important initiative."

Assemblyman Chris Holden (right) seen here with Gov. Gavin Newsom, authored last year's ACR 188 and is said to be readying another attempt to expand CAISO's governance. | *California Assembly*

Holden, the former chair of the Assembly Committee on Energy and Utilities, authored bills in 2017 and 2018 to pave the way for CAISO to become a multi state RTO, but those bills failed. He asked CAISO for the ACR 188 report to show lawmakers the value of regional cooperation.

Since 2018 "states across the West and utilities have adopted their own policies to achieve a clean resource mix and reduce greenhouse gas emissions, which are generally consistent with the policy direction of California," Holden said in a statement on the bill. "Two states [Nevada and Colorado] have mandated participation in a West-wide market.

"As tens of thousands of megawatts of renewable resources are slated for development in the West, and thousands of megawatts of coal-fired resources are retired and continue to be shut down, momentum is building for greater regional coordination to ensure that electricity is available at all hours of the day," Holden said. "Consequently, I think it's time for California to revisit a broader regional market."

### Restarting the Conversation

In the interview with *RTO Insider*, Mainzer said, "We don't have any specific details and certainly haven't seen any legislative language … but we certainly think that Chair Holden, having led the earlier efforts on this a number of years ago, believes that the time is right for another examination of this issue. So, I think the 188 [report] was his effort to start getting folks engaged and get good information and good facts … and to start reinitiating that conversation."

CAISO commissioned the National Renewable Energy Laboratory to produce the study in partnership with the ISO and California's eight other balancing authorities, including the Los Angeles Department of Water and Power, the

# CAISO/West News

Balancing Authority of Northern California and PacifiCorp. CAISO had planned to release a first draft of the report before the end of 2022 but postponed it until mid-January to give the drafting team more time.

A stakeholder process in the fall identified 41 relevant studies on legal, technical and market issues. They included a study by CAISO in 2016 that it conducted pursuant to Senate Bill 350, a measure that declared the legislature's intent to "provide for the transformation of [CAISO] into a regional organization to promote the development of regional electricity transmission markets in the Western states."

The five members of CAISO's Board of Governors are all Californians appointed by the governor and confirmed by the state Senate. Changing that to allow governors from other states would require legislative action, SB 350 noted. The bill told CAISO to study the potential impacts of becoming a multistate, regional organization before any governance changes could occur.

The *SB 350 study* found that "a larger ISO-operated regional market [could] create significant value to California ratepayers, decrease overall [greenhouse gas] emissions inside and outside of California, reduce environmental impact in California and elsewhere, increase jobs and economic activities in California and improve the conditions of California's disadvantaged communities."

The benefits to the state and the West "increase significantly with the expansion of the market footprint, reducing emissions and the costs associated with the integration of larger amounts of renewable generation resources," it said.

Holden characterized the ACR 188 report as an update of the SB 350 study.

Another study published last year found an RTO covering the entire U.S. portion of the Western Interconnection could save the region $2 billion in annual electricity costs by 2030 and cut carbon dioxide emissions by 191 million metric tons. A group of Western states led the study, which was financed by the U.S. Department of Energy. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

Other *studies* identified for the ACR 188 report looked at the potential effects of regionalization on resource adequacy and transmission development.

Kellie Smith, a special consultant to Holden hired to work exclusively on Western regionalization in 2023, said the "critical question and the primary focus of ACR 188 is, 'Is it good for California?' Mr. Holden thinks the results are going to say, yes, it's needed."

CAISO CEO Elliot Mainzer | © *RTO Insider LLC*

"Since 2018, the perspectives and momentum are building," Smith said in an interview. "I think it's pretty obvious that the ISO has the best system around. It's been working on integration and renewables and [greenhouse gas] tracking for years. The others just don't have that. So, it makes a lot of sense for the ISO to be the lead" in Western market formation.

A bill to accomplish that, she said, would probably be similar to Assembly Bill 813, which Holden introduced in 2017 and advocated for until it languished in the Senate Rules Committee at the end of the 2017/18 legislative session. The measure passed by a vote of 74-0 in the Assembly and cleared three Senate committees. It never reached a Senate floor vote because some key lawmakers worried it could relinquish control of CAISO to out-of-state interests and jeopardize the state's climate agenda. (See *CAISO Expansion Bill Dies in Committee*.)

AB 813 would have instructed CAISO to continue to develop a proposal, originally drafted in 2016, to establish a two-step process for selecting regional board members including a "stakeholder-based nominating committee that selects nominees with the assistance and support of a professional search firm and an approval committee, consisting of the voting members of [a] Western states committee, which would confirm each slate of nominees."

The Western states committee would have included representatives from each state with transmission owners in CAISO.

The process for selecting members of the CAISO Board of Governors would have then been similar to the process for selecting members of the WEIM's Governing Body, which includes members from California and other Western states.

The WEIM, which spans much of the Western Interconnection, has been popular with other states, in part, because of its inclusive governance and CAISO's efforts to share power over WEIM matters with the market's Governing Body. In contrast, energy leaders from across the West have said they would not join a CAISO-led RTO controlled by California politicians.

## EDAM Moves Forward

The other major effort to broaden CAISO's reach across the West in 2023 is its proposal for an extended day-ahead market (EDAM) for the WEIM. CAISO has promoted the EDAM this year as a way to bring greater cooperation to the balkanized Western Interconnection, which has 38 balancing authorities.

As a real-time-only market, the WEIM has produced more than $3 billion in benefits for its participants since 2014. The real-time market, however, represents only a fraction of the Western market. The day-ahead market is much larger.

The EDAM could generate $1.2 billion a year in benefits, or 60% of the savings of a West-wide RTO, if it encompassed the entire U.S. portion of the Western Interconnection, a new study commissioned by CAISO and performed by consultant firm Grid Strategies found. (See *West Could Save $1.2B a Year in CAISO EDAM*.)

CAISO fast-tracked the EDAM stakeholder initiative in 2022 amid competition for Western market share by SPP, which is pursuing its own day-ahead Markets+ program in addition to its RTO West. It published the final EDAM plan Dec. 7 and expects to seek approval from its Board of Governors and the WEIM Governing Body in February. The plan will also require FERC approval. (See *PacifiCorp to Join EDAM, Final Plan Released*.)

"An amazing amount of hard work and robust stakeholder engagement are coming to fruition with publication … of our final extended day-ahead market design," Mainzer said in his year-end written report to the CAISO Board of Governors and WEIM Governing Body. "The strong stakeholder participation and engagement have helped shape the design through its various iterations, and we are committed to working with stakeholders in making any necessary adjustments that might be needed once the market is up and running."

"We want to go and see some big things happen in 2023," Mainzer said. ■

CAISO/West News

# WestConnect Tx Cost Allocation Plan Rejected by FERC

*By Robert Mullin*

FERC on Dec. 15 rejected a proposed settlement agreement intended to resolve a longstanding appeals court dispute over how to implement Order 1000 in the WestConnect planning region (*ER22-1105*).

WestConnect covers parts of Arizona, California, Colorado, Nebraska, Nevada, New Mexico, South Dakota, Texas and Wyoming. It includes FERC-jurisdictional public utilities that are subject to the requirements of Order 1000 as well as several nonpublic utilities not subject to the order.

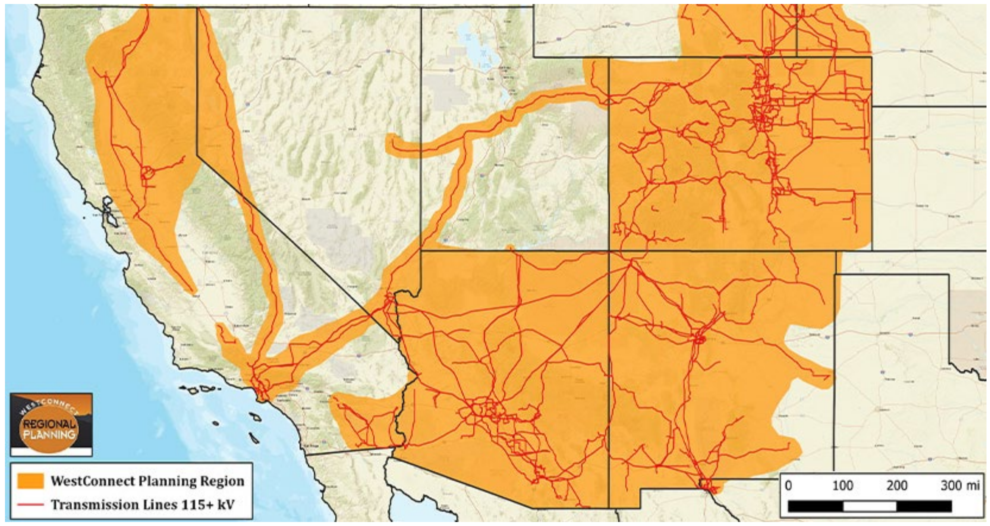
Order 1000, which FERC issued in 2011, requires jurisdictional utilities to participate in regional transmission planning and to develop a process for allocating costs for projects selected through the planning process.

The settlement agreement rejected by FERC on Thursday was negotiated by nine WestConnect public utilities, including Arizona Public Service; Black Hills Colorado; Black Hills Power; Cheyenne Light, Fuel and Power; El Paso Electric; Public Service Company of Colorado; Public Service Company of New Mexico; Tucson Electric Power; and UNS Electric.

The dispute at issue in the settlement agreement originated in 2012, when WestConnect public utility transmission providers submitted a series of compliance filings in response to Order 1000. FERC rejected several filings related to how the planning group would handle regional cost allocation, but it accepted a proposed participation framework that allowed non-jurisdictional utilities to choose to participate in the WestConnect planning region as either enrolled members subject to binding regional cost allocation or as "coordinating transmission owners" (CTOs) not subject to allocation.

In 2016, the 5th U.S. Circuit Court of Appeals vacated FERC's decision to accept that framework, concluding that the commission had failed to provide a reasoned explanation for doing so.

The commission provided its explanation in an order on remand, saying that, after considering alternatives, it continued to believe the approved framework could "ensure just and reasonable rates while taking into account the uniquely integrated nature of the transmission systems of public and nonpublic utility transmission providers in WestConnect." It also



WestConnect regional planning area. | *WestConnect*

explained that nonpublic utilities in the region would be incentivized to participate in cost allocation because projects from which they would receive benefits would be less likely to advance without their participation.

In December 2017, the commission denied a request by the WestConnect utilities to rehear the order on remand. The utilities, contending that the original issues had not been resolved, then petitioned the 5th Circuit, where their appeal is still pending, having been subject to a stay until Dec. 20.

## New Process

Last month's ruling dealt with a proposal by the WestConnect public utilities to resolve the appeals court case by establishing a new framework that seeks to address concerns about free-ridership by nonpublic utilities, which the parties to the agreement believe is at the heart of the 5th Circuit case.

The proposal outlines a process by which nonpublic utilities can opt in and contractually bind themselves to regional cost allocation for projects from which they receive benefits. The plan would allow a nonpublic utility to vote on a project after opting in to cost allocation. It would also include "processes and protections" to ensure that more than one WestConnect public utility would benefit from selected projects and seeks to clarify through "defined criteria" the types of projects that are eligible for regional cost allocation.

Under the proposed plan, if the regional transmission planning process identifies a transmission need for more than one enrolled member, WestConnect will solicit proposals to address the need. The WestConnect Planning Management Committee (PMC) would then develop a comprehensive list of solutions, with each being analyzed to determine whether a CTO is a beneficiary. Any benefiting CTOs could then opt in as a "cost-bound" beneficiary.

Thereafter, any cost-bound beneficiaries for projects on the comprehensive list could vote to decide which of the projects move to a short list of potential solutions.

"The Planning Management Committee then evaluates all the transmission projects on the short list under regional cost allocation criteria to determine if each project is eligible for selection in the regional transmission plan for purposes of cost allocation," the commission explained. Projects that meet the criteria then move to final consideration by the PMC.

The proposal also stipulates that if one or more CTOs identified as beneficiaries do not opt to become cost-bound entities for a project, but two or more enrolled transmission providers in at least two balancing authority areas are also identified as beneficiaries, then those remaining beneficiaries may unanimously vote to either allow the project to advance through the planning process, choose an alternative or request the PMC convene a new solicitation.

## Inconsistent with Order 1000

In rejecting the proposal, FERC noted that a late-filed protest by LS Power obligated the commission to consider the agreement to be a contested settlement, making it subject to review under the approach outlined in FERC's

# CAISO/West News

*Trailblazer* decision. Citing that precedent, the commission said it could not find the "overall package" in the agreement to be just and reasonable.

The commission noted that WestConnect's current process allows a nonpublic utility to participate in the transmission planning process as a CTO without being bound to cost allocation for a selected project. However, if the CTO finds that it would benefit from a project, it can voluntarily agree to accept its share of the costs. If the CTO does not agree to accept cost allocation, the PMC reruns the cost-benefit analysis for the project after removing the benefits the CTO would have received. If the project continues to meet the required cost-benefit analysis, it remains eligible for regional cost allocation.

But in the settlement agreement's revised process, the commission explained, the decision by a beneficiary CTO not to opt into cost allocation for a transmission project means the project cannot move ahead without unanimous approval by the remaining beneficiaries.

"Instead, the remaining beneficiaries can identify an alternate transmission project (either from an existing list or newly proposed), but if the alternate project provides benefits to any coordinating transmission owner or enrolled transmission owner that was not identified as a beneficiary of the original transmission project, the entire process begins again," the commission wrote. "This proposed process makes it highly unlikely for a transmission project to move forward if any potential coordinating transmission owner beneficiary does not agree to become cost-bound, regardless of the potential project benefits."

The commission also found that the proposed criteria for determining whether a project is eligible for regional cost allocation was inconsistent with the intent of Order 1000.

The commission first rejected the requirement that an eligible project must physically interconnect one or more transmission providers in more than one BAA.

"We find that this criterion is inconsistent with the requirements of Order No. 1000 because, given the large size of several BAAs within the WestConnect transmission planning region, this criterion would preclude from consideration transmission projects (including those of significant size and scope) located within a single BAA that could more efficiently or cost-effectively address the needs of multiple transmission providers," the commission wrote.

The commission also rejected another provision in the agreement that would require that cost-bound beneficiaries must receive 90% or more of the total benefits for a project in order for the project to be eligible for regional cost allocation. FERC pointed out that the provision was similar to an earlier WestConnect proposal the commission had already rejected.

"The commission rejected this requirement because it could eliminate from consideration for selection in the regional transmission plan for purposes of cost allocation transmission projects that, even after accounting for any cost shift to the remaining beneficiaries, are the more efficient or cost-effective transmission solution for remaining beneficiaries compared to other alternatives," FERC said.

The commission also found fault with the agreement's requirement that a supermajority of 80% of cost-bound beneficiaries must vote in favor of making a project eligible for regional cost allocation, which proponents said was consistent with NYISO's policy.

The WestConnect proposal omitted two provisions included in NYISO's process, the commission noted, including requirements that a beneficiary of a project that votes against it provide a written explanation for its rejection, and that NYISO submit an informational report to FERC detailing the vote.

"Without such requirements, we are concerned that beneficial transmission projects could be eliminated from consideration without explanation or justification," the commission said, adding that the NYISO supermajority voting requirement applies only to economic transmission facilities.

"Altogether, we find that the proposed process under the settlement agreement would impose significant restrictions on the pool of transmission projects that could be considered as more efficient or cost-effective transmission solutions for potential selection in the regional transmission plan for purposes of cost allocation, even in situations where those projects would provide significant benefits to public utility transmission providers in WestConnect that outweigh their costs," the commission wrote. ■

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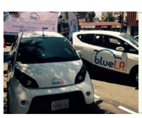

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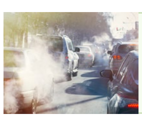

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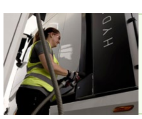

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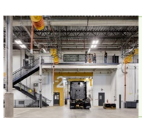

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*RTO Insider* subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

# Hawks Key Concern in Draft EIS for Proposed Wash. Wind Farm

*By John Stang*

The draft environmental impact study for a proposed southeast Washington wind and solar farm has turned up concerns about nesting areas for the region's ferruginous hawks.

The Washington Energy Facility Site Evaluation Council released the *draft EIS* on Dec. 19 and will accept public comments through Feb. 1. No date has been set for when the final environmental impact report will be released. EFSEC will eventually make a recommendation to Gov. Jay Inslee on whether to approve the project.

The report looks at a proposal by Scout Clean Energy of Boulder, Colo., to build up to 224 wind turbines — each about 500 feet tall — on 112 square miles of mostly private land in the Horse Heaven Hills region four miles south of Kennewick. About 294 acres of that land would also contain solar panels.

The wind and solar project is expected to have a nameplate capacity of 1,150 MW, roughly the same output as Columbia Generating Station, a commercial nuclear reactor just north of the Tri-Cities area, which includes Kennewick.

Many Kennewick residents oppose the project because the turbines would be seen by residents on the south side of the city.

Residents also cited concern about the turbines' effects on ferruginous hawks. While ferruginous hawks are not listed as a threatened or endangered species by the federal government, they are listed as endangered by the state of Washington. The birds are among the nation's largest hawks, with average wingspans of 56 inches. They live in grasslands and shrub steppes, which are found extensively in south-central and southeast Washington. Shrub steppe is a mostly treeless semi-desert filled with sagebrush and a complicated ecosystem at ground level.

About 60% of the nesting pairs are found in Washington's adjacent Benton and Franklin counties. The Horse Heaven Hills are in Benton County.

The draft EIS identified potential impacts on ferruginous hawk habitat and populations through loss of habitat and potential mortality from collision with wind turbines.

"As these impacts could result in a high-magnitude impact on ferruginous hawks, EFSEC has proposed additional mitigation measures specific to avoiding and reducing project-related impacts on ferruginous hawks, including exclusion of turbines within core ferruginous hawk habitat and curtailing turbine operation while ferruginous hawks are present," the draft report said.

Mitigation measures would include avoiding siting turbines and solar panels within two miles of ferruginous hawk nests. Another measure would be to stop the turbines from operating during breeding season.

The draft recommended a two-year survey of the turbines' impacts on the area's birds, including American white pelicans, eagles, burrowing owls, great blue herons, Sandhill cranes, tundra swans, loggerhead shrikes, sagebrush sparrows, prairie falcons, sage thrashers, Vaux's swifts and ring-necked pheasants. The draft also recommended surveys of the area's striped whipsnakes, sagebrush lizards, Townsend's big-eared bats and Townsend's ground squirrels. ■

Opponents to a large wind farm in Horse Heaven Hills have cited concerns about threats to the ferruginous hawk, listed as an endangered species in Washington. | *Red Cliffs Desert Reserve*

CAISO/West News

# NM Rings in New Year with Reconfigured Utility Commission

By Elaine Goodman

New Mexico PRC offices in Santa Fe, N.M. | *New Mexico Public Regulation Commission*

New Mexico Gov. Michelle Lujan Grisham has appointed three members to the state's revamped Public Regulation Commission, a panel that up until late December had five elected members.


Gabriel Aguilera | *NIPCC*

The new PRC members are Gabriel Aguilera, Brian Moore and Patrick O'Connell. The appointments were effective Jan. 1.

The switch from a five-member elected PRC to a three-member appointed commission is the result of a change to the state constitution proposed by the legislature and ratified by voters in 2020.

The governor chose the new commissioners from a pool of nine candidates selected by a seven-member nominating committee.

Aguilera had worked for FERC since 2007, most recently serving as senior policy adviser in the commission's Office of Energy Market Regulation Western region. He was appointed to a four-year term.


Brian Moore | *New Mexico Legislature*

Moore served in the state House of Representatives from 2001 to 2008 representing eastern New Mexico. He served on the state's Renewable Energy Transmission Authority Board and the governor's Economic Recovery Council. Moore, who is president and CEO of Ranch Market supermarket in Clayton, was appointed to a two-year term.

O'Connell was the Clean Energy Program interim director at Western Resource Advocates. He worked for Public Service Company of New Mexico, New Mexico Gas Co. and the Sangre de Cristo Water Co. He was appointed to a six-year term.

"These appointees are experienced professionals who have the skills needed to oversee an energy transition that is affordable, effective and equitable for every New Mexico community," Lujan Grisham said in announcing the appointments on Dec. 30.

The PRC Nominating Committee accepted applications for the PRC positions through the end of September. The committee chose 15 applicants to interview. During a Dec. 2 meeting, the committee voted to forward nine of those names to the governor for consideration.


Patrick O'Connell | *Western Resource Advocates*

In addition to Aguilera, Moore and O'Connell, the nominating committee's list included James Ellison, principal grid analyst at Sandia National Laboratories; Carolyn Glick, a former PRC hearing examiner; Joseph Little, the former general counsel to the Pueblo of Zia; Art O'Donnell, a former senior analyst with the CPUC; law professor Amy Stein; and Cholla Koury, chief deputy in the New Mexico Attorney General's Office.

Since its formation in 1996, the PRC consisted of five elected members representing different regions of the state. With the change to a three-member appointed PRC, Native American advocacy groups say indigenous people are losing their voice on the PRC.

"For our voice to be eliminated in this way is unjust," Krystal Curley, executive director of Indigenous Lifeways, told the nominating committee on Dec. 2.

Indigenous Lifeways and two other groups — Three Sisters Collective and the New Mexico Social Justice Equity Institute — filed a petition with the New Mexico Supreme Court in September to overturn the change, saying the ballot language was misleading and voters weren't aware they would lose the ability to elect commissioners. But after hearing arguments in the case, the court rejected the petition in November.

In announcing the PRC appointments last week, Lujan Grisham acknowledged concerns about a potential lack of Native American representation on the commission.

To address those concerns, the governor signed an executive order on Dec. 30 creating a Tribal Advisory Council to advise the PRC. Lujan Grisham will appoint the advisory council's first set of four members by Jan. 30.

"It's extremely important that we ensure tribal voices are heard on issues before the PRC, regardless of who is appointed to the commission now and into the future," the governor said. ■

## ERCOT News

# ERCOT Survives One Test, Faces Another

## *Texas Lawmakers Waiting on Final Market Design from PUC*

*By Tom Kleckner*

The ERCOT grid, tweaked since the disaster of 2021, twice proved its mettle during 2022, meeting record demand during the summer's sizzling early months and then again during the pre-Christmas winter storm.

That gave Texans a chance to *chortle* when another state institution, Southwest Airlines, ran into difficulties over the holiday. It also gave Texas Gov. Greg Abbott an opportunity to pause his daily tweets about the southern border and praise ERCOT for not failing during two "extremely cold nights."

"No Texan has lost any power because of the ERCOT grid," Abbott *tweeted*.

While there were localized outages at the distribution level, the grid held firm and set a new winter demand peak of 73.96 GW on Dec. 23 that was a 27.7% increase from the previous mark. Demand officially peaked at 69.8 GW during the February 2021 winter storm, but Texas A&M University's Texas Center for Climate Studies has *said* demand would have reached 82 GW had not more than 50 GW of generation been unavailable.

ERCOT experienced many of the same issues that plagued it during the deadly 2021 storm, as *chronicled* by Stoic Energy principle Doug Lewin. The grid operator's staff underestimated demand during the storm by 4 to 6 GW. Thermal plants again had problems staying on, with almost half the coal fleet offline Dec. 23 and gas plants again facing "fuel limitations" despite the lack of snow and ice.

At times, as much as 12 GW of generation was offline. ERCOT asked for, and received, the Department of Energy's permission to ignore air quality and other permit limitations and run the grid's power plants at their maximum output levels in the event of emergency conditions.

Fortunately for ERCOT, the storm, delivering single-digit temperatures but dry conditions, hit right before a holiday weekend, when demand tends to drop. Clear skies and wind gusts in the 40-mph range generated half of energy production at times.


From left: Texas PUC chair Peter Lake; Gov. Greg Abbott; Nim Kidd, director of the Texas Division of Emergency Management; and ERCOT CEO Pablo Vegas hold a press conference in advance of the winter storm. | *KSAT-TV*

Attention now turns to the Texas State Legislature, which opens its 88th session on Jan. 10 and where lawmakers are waiting to pass judgment on the Public Utility Commission's proposed market redesign.

Following months of public work sessions, closed-door discussions and a consultant firm's analysis of six different options, PUC staff urged the commission to adopt a performance credit mechanism (PCM). In public hearings, legislators joined some ERCOT stakeholders in criticizing the concept for being overly complicated, lacking a reliability standard and doing little to attract new baseload generation to Texas. (See *Stakeholders Respond to ERCOT Market's Proposed Redesign*.)

The PCM would require load-serving entities to buy performance-based credits from generation resources in a voluntary forward market. The credits are awarded to resources through a retrospective settlement process based on availability during the 30 hours of highest risk, according to their load-ratio shares during those same periods. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

While generators largely support the PCM and its emphasis on dispatchability, the renewable sector and consumer groups argue it would harm further development of low-cost wind and solar energy.

ClearView Energy Partners, a D.C.-based independent research firm, said in a *report* that while the PCM is designed to be "resource agnostic," it would "seem to financially benefit dispatchable conventional resources." ClearView did allow that some renewables coupled with energy storage could also earn some performance credits.

New ERCOT CEO Pablo Vegas staked out staff's support of the PCM during the December meeting of the grid operator's Board of Directors. He said the concept will be critical to "incentivize and retain dispatchable generation" and to meet increased reliability goals.

"Based on our analysis, the performance credit mechanism option strikes a good middle ground that maintains the best parts of the energy-only market while providing new incentives to improve reliability and put steel in the

# ERCOT News

ground," Vegas said, noting several generators have told lawmakers that the PCM is one of the better options and will result in expected new generation investment.

The Texas Competitive Power Advocates (TCPA), a trade association representing generators, wholesale marketers and retail providers, *has said* it is prepared to add more than 4.5 GW of additional thermal generation to ERCOT if the PCM is adopted under the "right framework."

The need to meet growing demand is obvious. ERCOT set an all-time demand peak of 80.04 GW in July, one of the summer's more than three dozen demand records. Seven years ago, the grid almost peaked at 70 GW. Given ERCOT's measure that 1 MW can power about 200 Texas homes during peak demand periods, that would mean about 2.1 million homes have been added to the grid during that time.

Vegas and PUC Chair Peter Lake have taken to using Corpus Christi — the eighth largest city in the state at 317,863 residents, according to the 2020 census — as an example of the state's exploding growth. They say Texas is adding that many people every year, placing additional pressure on developing dispatchable generation resources.

"One of our clear goals this legislative session is to help members understand the resource adequacy challenges that Texas faces in the future," Vegas said. "The dispatchable gap that is growing between ever increasing load and dispatchable generation is a real issue and is vital. Addressing this issue with clarity will give investors the certainty that they need to build dispatchable generation of Texas needs."

Lawmakers are expected to be open to the message with the gas industry's prominence in the state. (See *PUC, ERCOT Face More Heat from Texas Lawmakers*.)

"Ultimately, we think legislators and/or regulators could approve a new reliability mechanism next year that benefits gas-fired plants, potentially at the expense of renewable resources," ClearView said. "This could slow deployment of solar and wind in the largest U.S. renewables market."

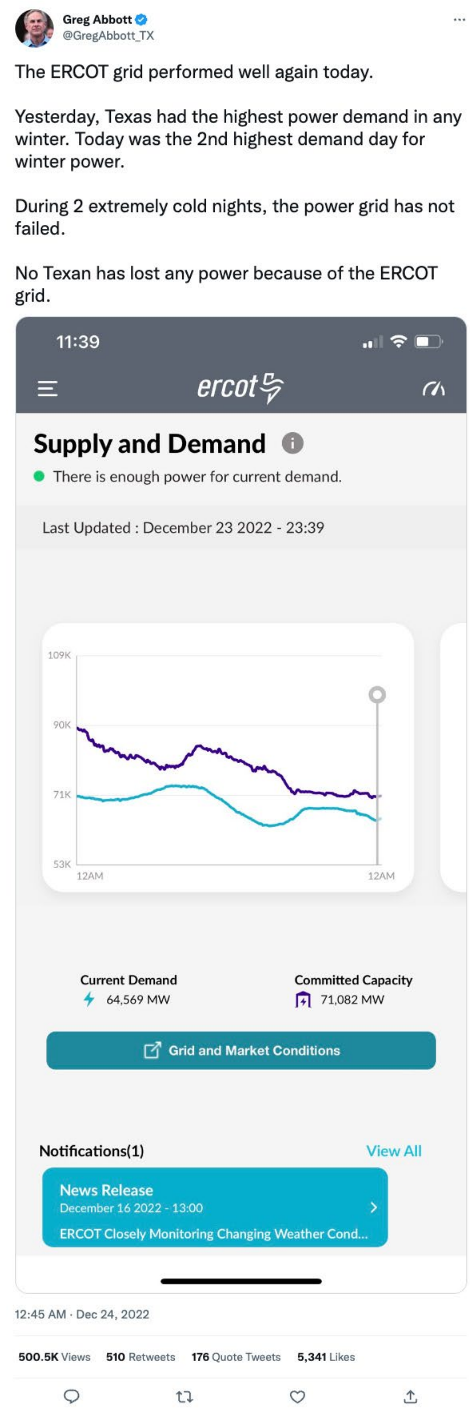
The PUC has scheduled a work session for Jan. 12 to discuss the design proposals and stakeholder feedback. A vote is not expected on the proposals during that meeting, but a plan is expected to be adopted later in the month and then passed on to the legislature. The commission also has open meetings scheduled for Jan. 19 and 26.

ERCOT has already made several changes as a result of laws passed during the 2021 session. Generation and transmission facilities have been required to weatherize, and the grid operator's staff have been conducting compliance inspections, something that didn't happen after rolling blackouts during a 2011 freeze.

Generators have been required to keep additional fuel sources on site in case of emergencies, and several ancillary services have been added to the energy-only market. At the same time, ERCOT's price cap was nearly halved, from $9,000/MWh to $5,000/MWh.

During a summer of tight margins and several conservation calls, ERCOT's conservative operations posture relied on reserves and reliability unit commitments to keep thousands of megawatts in reserve. The grid operator's market monitor has said that has added hundreds of millions in costs as electricity *costs rose more than 70% year-over-year* in June.

In December, ERCOT announced a new voluntary curtailment program for crypto miners and other large flexible loads, effective with the new year. It later expanded the program's scope, designed to reduce power use scare periods, to include loads qualified to provide ancillary services or emergency response service but that don't have an active obligation to provide those services. (See *ERCOT Opens Curtailment Program to Crypto Load*.) ■




Gov. Greg Abbott tweets during the winter storm. | *Greg Abbott via Twitter*

Dispatchable generation such as this gas-fired facility are seen as key by some to ERCOT's market redesign. | *WattBridge*

ERCOT News

# ERCOT Board of Directors Briefs

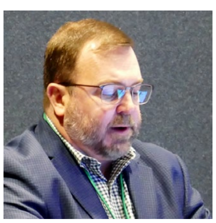
## Members, TAC Stripped of Responsibilities for Policy Development

ERCOT's Board of Directors on Dec. 20 stripped away the right of corporate members to vote on future changes to the grid operator's bylaws, rejecting an alternative stakeholder recommendation in the process.

The directors approved *bylaw amendments*, drafted by staff at the board's direction, that remove ERCOT's corporate members' ability to vote "on any matter submitted to the general membership." The amendment does allow members to comment on any such proposals and to propose amendments themselves.

The bylaw revisions take away the Technical Advisory Committee's ability to recommend policy and procedural changes to the board. It leaves that top stakeholder group with doing little more than managing the process for changing market rules and document guides.

Stakeholders have expressed their opposition to the change since the draft amendments became public late this summer. The revisions are designed to align ERCOT's governance with legislation, passed in the wake of the deadly 2021 winter storm, that created an independent board and removed market representatives from participating. (See *ERCOT Stakeholders Wait on Bylaw Amendment Changes*.)



Chris Hendrix, Demand Control 2 | © *RTO Insider LLC*

"There's no real avenue to meet with the board," Demand Control 2's Chris Hendrix told *RTO Insider*. "It makes it more like a PJM model or an ISO-NE model, where you have no access to the board."

Hendrix represented the membership and six of the seven market segments (investor-owned utilities were not involved) in offering up an alternative recommendation that agreed with much of the bylaw revisions but carved out three exceptions: retaining members' voting rights, removing staff's language that gives the board authority to amend TAC's procedures without a vote of its representatives and removing language that allows the directors to disband TAC.

"Keep corporate members voting because it is a corporate membership," he said. "It's an incentive. We pay to be a member, and that comes along with voting rights."

ERCOT CEO Pablo Vegas (foreground), board members open their December meeting. | © *RTO Insider LLC*

Several directors pointed to revised language giving members a 21-day window to comment on any proposed changes and noted that TAC can't be disbanded without the Public Utility Commission's direction.

Hendrix said the changes allow the board to set TAC's policies and procedures, which could lead to extreme measures such as meeting once a year or eventual disbandment. He said that its only "the good word of the PUC" that prevents drastic changes.

The commission in November issued a statement that helped set the stage for this week's discussion. The commissioners agreed that ERCOT's board is "empowered to amend its bylaws without obtaining the affirmative vote of the corporate members. It is necessary for ERCOT to amend its bylaws such that the ERCOT board of directors has the sole authority to change the bylaws, subject only to the approval of the commission."

The statement also called for preserving market participant input in developing market functions by amending the bylaws such that the board "cannot eliminate [TAC] without specific direction from the commission." (See "PUC Sides with ERCOT Board," *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

"I believe the proposed bylaws changes represent something that is not dissimilar to the organizational structures that we see in the rest of the country," PUC member Will McAdams said before the commission's separate vote to approve the bylaw changes. "Ultimately, the commission has an appellate jurisdiction to approve all policies, and there's an obligation on the part of stakeholders, the board and the commission under this contract … to collaborate and work through operational issues as they become apparent so that we can provide the best outcome for the public in Texas."

Hendrix, who admitted he faced an uphill battle, said the revisions will only help ERCOT's larger members who can afford to lobby legislators and regulators and might lead some market participants to forego memberships.

ERCOT held a 20-minute annual membership meeting following the board's executive session, with only a handful of members present. ERCOT CEO Pablo Vegas promised a return to an in-person annual meeting next year and "better opportunities to connect with fellow corporate members, with the ERCOT board of directors … with staff, with commissioners and with other invited guests."

"I think it's an opportunity to really connect on the issues that are important to the industry and have an opportunity to get to know each other through that and have a higher-value discussion," he said.

Board Chair Paul Foster also expressed desire for a "stronger engagement opportunity" next year and said the bylaw amendments represented "another milestone" in ERCOT's changing governance structure.

"Each board director has now had time over the past year to see the TAC membership and the stakeholders in action and the role they provide in the policy development of the rules that helped run a reliable grid and a fair efficient market," he said.

## Grid Prepared for Winter Weather

Vegas reassured directors and stakeholders that the grid operator continues to expect adequate supplies and reserves in advance of sub-freezing temperatures forecast for the Christmas weekend. He said staff expect to have more than enough generation to handle a projected peak of nearly 68 GW with nearly 90 GW of capacity online. Wind and solar account for 20 to 22 GW of the available capacity.

During a press conference with Gov. Greg Abbott Wednesday morning, Vegas reduced the online capacity estimate to 85 GW, with wind and solar accounting for 12 GW. He was joined by PUC Chair Peter Lake, who said the ERCOT grid is "ready and reliable."

"Things are looking good to get through the weekend," Vegas said.

ERCOT ended up having to request waivers of federal air regulations from the Department

# ERCOT News

of Energy, with demand peaking at 73.96 GW. (See related story, "DOE Grants ERCOT's Emergency Request," FERC, NERC Set Probe on Xmas Storm Blackouts.)

ERCOT meteorologist Chris Coleman leans into his weather forecast. | © RTO Insider LLC

At last month's board meeting, Chris Coleman, ERCOT's lead meteorologist, said the cold front, part of a *powerful winter storm* that has settled over the Midwest, will not be as severe as the deadly 2021 winter storm that almost brought down the ERCOT grid.

"We're several degrees warmer than that, and we will also not have the precipitation associated with it," he said.

North Texas and the Panhandle will likely see snow, Coleman said. He predicted low temperatures of about 12 degrees Fahrenheit in Dallas and 17 F in Austin. Freezing temperatures could extend as far as the Rio Grande Valley before conditions begin returning to normal during the weekend.

"We could see 70 degrees [next week], so there's something encouraging to look forward to," Coleman said.

Coleman is sticking by his *winter outlook*, which predicts that this winter will not be as warm as last year's, but not as cold as 2020/21. This is the third straight winter with the La Niña system in place and will deepen Texas' drought conditions. Coleman said 52% of the state has drought concerns, up from 46% last year.

"I think the drought will remain in place and potentially expand and worsen here over the next few months," he said. "I don't think we're going to get through this winter, saying, 'Boy, we had a lot of fun. It was just never warm.' It'll likely turn around here, so I'm not closing the door beyond this week on more cold opportunities."

## TAC Membership Set for 2023

A cast of familiar faces will be back for TAC next year following the board's approval of the committee's *2023 representatives*.

The Office of Public Utility Counsel's Nabaraj Pokharel, CenterPoint Energy's David Mercado and Garland Power and Light's Russell Franklin are the only new additions to the 30-person stakeholder group.

Current TAC Chair Clif Lange, with South Texas Electric Cooperative, has offered to again lead the group next year. Members will vote on leadership during their Jan. 24 meeting.

## ERCOT Gets 1st Adjunct Member

The directors approved an *adjunct membership* for Pine Gate Renewables, a utility-scale solar and storage developer headquartered in Asheville, N.C., with five projects in its Texas pipeline. ERCOT staff said the company does not currently meet any segment requirements but will align with the independent power producers in the stakeholder process.

In other actions, the board approved:

- *Robert Black's hire* as vice president of public affairs following a short stint with AEP Texas and a 30-year political career on the Republican side of the aisle;
- *ERCOT's 2023 methodologies* for determining minimum ancillary service requirements, previously endorsed by TAC;
- the Finance and Audit Committee's *acceptance of a system and organization control audit* of ERCOT's market settlements operations that found no reportable exceptions; and
- the Reliability and Markets Committee's *charter*, outlining its responsibility to review the grid operator's core functions and *disbanding* the Credit Working Group. TAC will add the credit reporting functions to its structure.

## Board Approves 10 Changes

The board approved a consent agenda that included six nodal protocol revision requests (NPRR), single changes to the Nodal Operating Guide (NOGRR), other binding documents (OBDRR) and the Resource Registration Glossary (RRGRR), and a system change request (SCR):

- *NPRR1128*: Sets an ancillary service offer floor 1 cent/MW lower for fast frequency response (FFR) than for other RRS categories to allow FFR procurement up to the current limit, without proration with other RRS categories.
- *NPRR1132*: Specifies that during local cold weather conditions, each qualified scheduling entity (QSE) must update its generation resources' and energy storage resources' current operating plans, real-time telemetry, and outage and derate reporting to reflect any limitations. It also requires each resource entity to provide resource-specific cold weather minimum temperature limits, hot weather maximum temperature limits, and alternate fuel capability information in its submitted resource registration data and update this information as necessary.
- *NPRR1138*: Requires each resource entity to ensure the reactive capability curve for any intermittent renewable resource accurately reflects its reactive capability when it is not providing real power or is operating at lower levels of real power output.
- *NPRR1148*: Resolves protocol gaps found during emergency contingency reserve service's creation of its system change requirements.
- *NPRR1152*: Removes the protocol requirements to submit emergency operations plans (EOPs), weatherization plans, and declarations of summer/winter weather preparedness; revises procedures for submitting declarations of natural gas pipeline coordination with natural gas generation resources; revises the list of items considered protected information to remove references to weatherization plans and add protections for information relating to weatherization activities; and revises the list of ERCOT critical energy infrastructure information to clarify language concerning EOPs and add protections for information relating to weatherization activities.
- *NPRR1154*: Updates language to allow for a qualified alternate resource to be considered in calculating the availability reduction factor for the firm fuel supply service (FFSS) resource and provides a new settlement billing determinant providing the FFSS award amount per QSE per FFSS resource by hour.
- *NOGRR226*: Adds provisions for transmission operator "anti-stall" automatic firm load shedding at 59.5 Hz to mitigate the risk of a total system-wide blackout.
- *OBDRR043*: Aligns the operating reserve demand curve's methodology with *NPRR1148*'s revisions, approved in August, in calculating the real-time reserve price adder.
- *RRGRR032*: Adds data required to be shared with ERCOT as the reliability coordinator, balancing authority and transmission operator in considering cold weather limitations in its operational planning analysis, real-time monitoring, real-time assessments, and other analysis functions. The ISO also requires this information for hot weather limitations and making this a requirement for distributed generation resources and distributed energy storage resources.
- *SCR821*: Allows transmission and distribution service providers to set the voltage set point target information provided to distribution generation or distribution energy storage resources. ■

*— Tom Kleckner*

# ISO-NE News

## Winter Problems, Capacity Accreditation, New Faces on the Docket for ISO-NE in 2023

*By Sam Mintz*

ISO-NE will start 2023 like it starts every year: worrying about the winter weather.

But from there, the New England grid operator will have to move on quickly to the longer-term concerns that will dominate the year, including imminent challenges with gas supply in the region and the complex project to update the way ISO-NE's capacity market measures resource adequacy.

And the organization will be doing all that while facing tough questions and challenges, from new faces leading the states to a little closer to home, where an upstart group of climate activists has carved out a piece of the grid operator for its own.

### Winter, Winter, Winter

In the first few months of 2023, grid officials will be closely watching the winter weather for extended cold spells that could spell danger for the region's energy supply. So far, both weather and future forecasts have been mild, the only blip a brief shortage on Christmas Eve that was handled by reserve resources.

ISO-NE will be using a *newly updated (and beautified)* 21-day energy forecast, a tool that helps it and the public understand what risk lies in the coming weeks.

In the longer term though, the forecasts and solutions aren't proving so neat.

Both outside experts and the RTO itself say that the Everett LNG facility north of Boston has to stay in operation in order to ensure that there's enough gas to send out to generators in the region and keep the lights on in winter. (See *ISO-NE: Reliability Still Depends on Mass. LNG Import Terminal*.)

But the end of the reliability-must-run agreement keeping that facility's "anchor tenant," the Mystic Generating Station, alive has caused immense worry among energy policymakers.

"The clock that's running is going to force us into another set of stopgap solutions," ISO-NE CEO Gordon van Welie said at a recent conference put on by the New England Power Generators Association. "I don't think we can design the elegant, long-term resource neutral solutions in a timely fashion to deal with the clock that's running on Everett right now."

With the Mystic contract ending in 2024, much of the New England energy world's focus in 2023 will be on sorting out those solutions.

Winter weather is issue number one for ISO-NE going into 2023. | *© RTO Insider LLC*

### Capacity Accreditation, and Beyond

Meanwhile, in the NEPOOL stakeholder process undergirding ISO-NE's policy decisions, there's a debate underway about capacity accreditation that will burst into full bloom in 2023.

In the RTO's own words, the *project* is designed to "identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the Forward Capacity Market."

More broadly, it's a key part of the region's energy transition: As more renewable resources come onto the grid, ISO-NE needs a better way to fairly measure the contributions of both them and the incumbent generators like natural gas plants.

But it's also a highly complex process that has and will continue to strain the capabilities of even the most experienced energy policymakers in NEPOOL (let alone the journalists tasked with translating it to their readers).

In its early work on the concept, ISO-NE has pushed forward with using a metric that sets a resource's accredited capacity based on the "marginal reliability impact of an incremental change in size." (See *ISO-NE Firms up its Support for Marginal Capacity Accreditation*.)

Its preliminary proposals have already earned pushback from stakeholders including the Natural Resources Defense Council and LS Power, who are worried, respectively, that it *undervalues the contributions* of clean energy resources and *doesn't adequately account* for the limitations of gas resources.

Much more of that debate is set to come in 2023, along with *other key projects* like developing a day-ahead ancillary services market and studies to examine 2050 transmission needs and the impacts of extreme weather.

### Healey to the Fore

ISO-NE's relationship with the New England states has been strained in recent years over disagreements about the speed and degree of the clean energy transition and responsibility for the region's failings.

That's not likely to change in 2023, but there is a new variable that could shake up the relationship further: Maura Healey.

The former Massachusetts attorney general was elected governor and is set to be sworn in as Charlie Baker's replacement on Thursday. She's likely to continue and build on what was, in the end, a fairly robust set of climate policies put forward by Baker. (See *Healey Focuses on Climate in Mass. Gubernatorial Race*.)

# ISO-NE News

One area to watch where Baker took criticism was on environmental justice and project siting. But she also could take aim at ISO-NE. As AG, Healey and her office spent lots of time and energy navigating the NEPOOL process and helping to organize consumer advocacy responses to ISO-NE's work.

And significantly, her chief energy aide as AG, Rebecca Tepper, is coming on to join her in the governor's office as secretary of energy and environmental affairs.

Tepper has been a regular thorn in the side of ISO-NE and regularly pushed it to collaborate more with the states.

### The Call is Coming from Inside the House

2023 will be a year when climate activists, for the first time ever, have control of a small piece of ISO-NE.

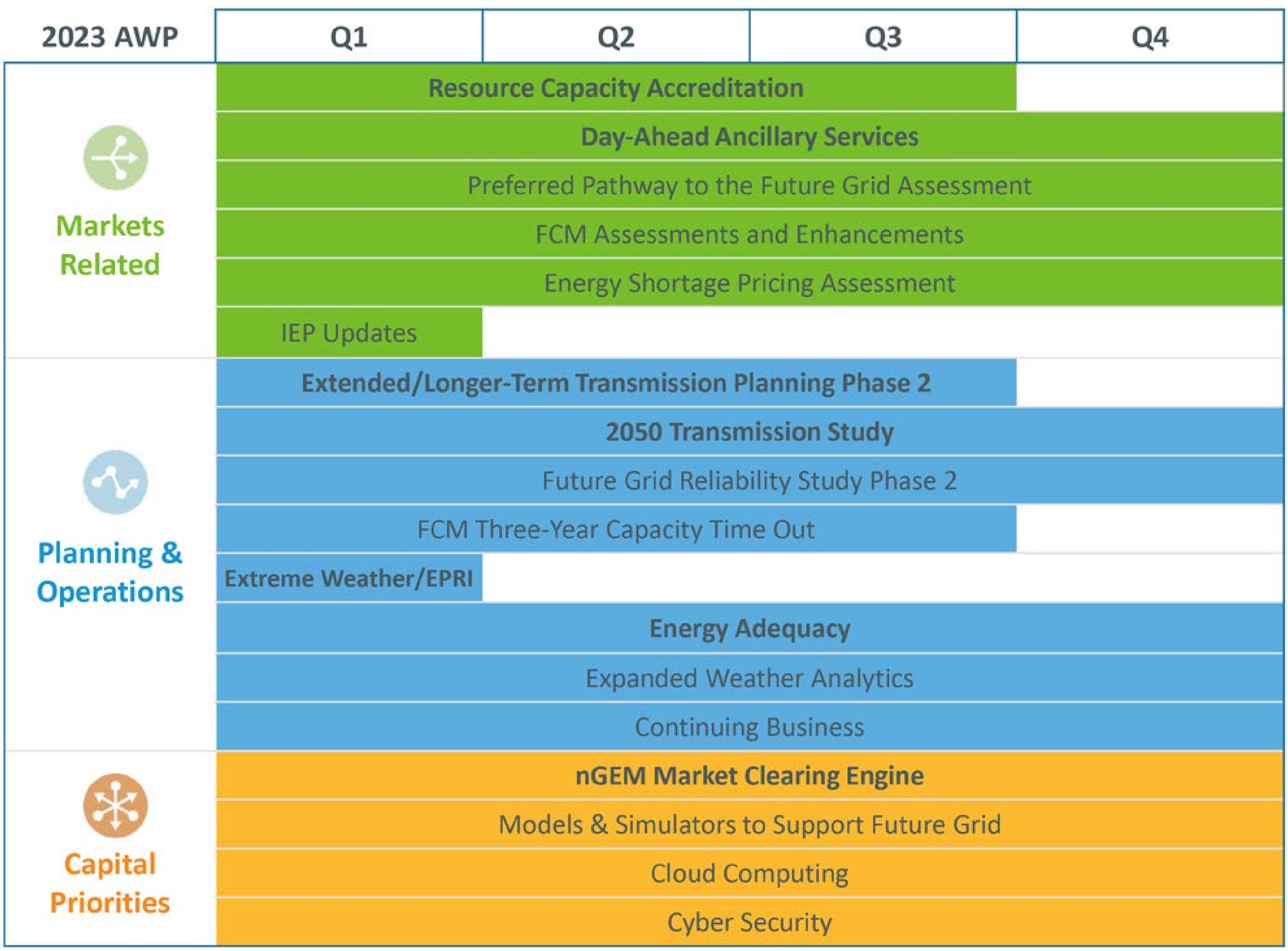
New Massachusetts Gov. Maura Healey could be a thorn in ISO-NE's side. | *© RTO Insider LLC*

A group led by the group No Coal No Gas won election to several seats on the coordinating committee of the Consumer Liaison Group, a forum that ISO-NE is required to use for communicating with the public. (See *Climate Activists Take Over Small Piece of ISO-NE*.)

CLG holds no formal policymaking power, but the committee sets agendas for its four quarterly meetings, which have become increasingly high-profile and well attended.

In 2023, those meetings will look a bit different than they have in the past, with the group promising to focus on connecting the issues that ISO-NE works on more closely to ratepayers (and potentially even pushing for a name change for the group).

"It will now be much harder for ISO New England to keep the CLG from getting feisty," said Donald Kreis, New Hampshire's consumer advocate. ■




ISO-NE's work plan for 2023 | *ISO-NE*

# MISO Concludes Turbulent 2022, Commences Busy 2023

## RTO to Plan More Tx, Address Capacity Shortage, Process Record Interconnection Queue

*By Amanda Durish Cook*

MISO made several maneuvers in 2022 to position itself for a majority-renewable portfolio while attempting to take the sting out of an escalating capacity deficit in its entire Midwest territory.

After years of warnings from MISO leadership, the portfolio transition is in full swing in the footprint.

And MISO's 2023 docket includes planning the next round of long-range transmission projects, navigating expected capacity shortfalls, attempting a sloped demand curve in a newly revamped seasonal capacity auction and managing an unprecedented number of new renewable resources queuing up for interconnection.

"There are going to be more things happening in the next five years than in the past 20 years," CEO John Bear began a Nov. 28 executive update.

Bear thanked stakeholders for their assistance on MISO efforts. He said he understood the magnitude of work "takes a toll" on them, but that they and the RTO accomplished a lot over 2022 "in really trying times."

"The urgency of course is always high," Bear said, noting that decarbonization goals are always intensifying.

MISO's most attention-grabbing headline of 2022 was the Midwest region's 1.2-GW capacity shortage exposed in the RTO's 2022/23 Planning Resource Auction. The shortfall triggered a $236.66/MW-day cost of new entry (CONE) clearing price for the Midwestern subregion. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.) MISO had said the capacity deficit might force it to order temporary, controlled load sheds, and it predicted insufficient firm resources to handle summer peak forecasts under typical demand.

"We have a resource adequacy problem. We have challenges to delivering energy when we need it," Bear said simply during the Board of Directors' meeting Dec. 8.

However, MISO cleared 2022 without dipping into its most serious maximum generation procedures, though it issued summertime and early fall alerts. (See *Monitor Critiques MISO's Commitment Usage During Summer*.)

The Badger Hollow Solar Farm in Iowa County, Wisc. | *Madison Gas and Electric*

With a week left in 2022, MISO managed to avoid an emergency in its South region during a fierce cold blast Dec. 23. The late December winter storm also forced MISO Midwest into conservative operations overnight into Dec. 24.

At the time, MISO said its South region was facing higher-than-forecasted load and significant generation outages. MISO South remained in conservative operations mode and under a cold weather alert until Dec. 26.

### Queue Bursting at the Seams

As it rounded out September, MISO received a record-setting 171 GW of proposed renewable generation and storage projects across 956 interconnection requests. Those requests could bring the total interconnection queue to the brink of 300 GW, triple that of just two years ago. Five years ago, a nearly 300-GW queue was unthinkable. In 2017, MISO planners *said* processing the then-60-GW queue was a tall ask.

MISO has said it's up to the task and — what's more — said it will stick to its pared-down 375-day study schedule for the queue's definitive planning phase (DPP). The RTO got FERC permission in February to swap the new timeline for its previous 500-day DPP.

However, MISO has pushed back the DPP start of its record-setting 2022 cycle of entrants until Feb. 27 because of the multitude of requests.

At an October planning meeting, MISO's Andy Witmeier said the RTO plans to study the current queue in a "timely manner" using the new deadlines.

"We do obviously have a backlog that needs to be worked through as well," Witmeier said, predicting MISO will play catchup on the queue's existing delays through 2023.

The queue is further evidence the footprint is marching toward more weather-dependent resources and fewer resources able to be called upon at a moment's notice. MISO has said that while it expects an increase in installed capacity, accredited capacity values will plunge. Consulting firm McKinsey & Company has *said* the MISO footprint could see a nearly 50% increase in overall capacity by 2030.

In September, Chief Digital Officer Todd Ramey said MISO will notice the loss of ramp-up capability the most acutely.

## MISO News


Board Chair Todd Raba (left) and CEO John Bear at December Board Week | © *RTO Insider LLC*

"We're moving away from the worst hour of the year to the worst day of a season," Ramey said of MISO peak demand planning in the years ahead. "In the future, it might be the worst week or the worst two weeks of a season."

But during an October executive update, Ramey said MISO is "excited and honored to be working on so many reliability initiatives."

As of late 2022, MISO had about 30 GW worth of registered wind capacity and 3.6 GW in registered solar capacity.

The grid operator also officially opened its wholesale markets to energy storage beginning in September. It's the first time in years MISO has added a new resource type to its energy market portfolio. (See *MISO Officially Opens Markets to Storage Resources*.)

### Seasonal is in

MISO is gearing up to simultaneously conduct four seasonal capacity auctions this spring, with accreditation values that vary by season. In late August, the grid operator got FERC's approval to simultaneously clear four separate auctions once per year and use an availability-based resource accreditation that relies on the riskiest hours in a season. (See *FERC OKs MISO Seasonal Auction, Accreditation*.)

The new design is a reaction to MISO's proliferating emergency declarations and a desire for more accuracy on when capacity is available.

However, MISO has yet to land on a separate, availability-based accreditation for its renewable generation. It plans to spend 2023 refining capacity values with stakeholders.

Without a new renewable capacity accreditation in place, MISO will use an 18.1% effective load carrying capability accreditation for wind generation in summer, a 23.1% accreditation in fall, 40.3% in winter and 23% in spring.

In a June presentation to the board, MISO said that it's "on the front edge of insufficient supply, and coordinated action is needed to ensure sufficient resources with accredited attributes are available throughout the fleet transition."

"The MISO region is experiencing continued resource transition acceleration and tight system conditions, which are expected to endanger reliability and market efficiency. Ongoing resource transition trends will likely lead to scarcity of certain essential resource attributes that require evaluation and collaboration with stakeholders," MISO Director of Policy Studies Jordan Bakke said in August.

Since then, MISO has been trying to pin down what and exactly how much of certain system attributes it needs from its generating units.

### The Attribute Debate

Against the resource turnover and capacity shortfalls, some environmental proponents

# MISO News

have alleged that MISO employees are inappropriately appearing in front of state commissions to urge the construction of new natural gas-fired generation. (See "Unease over MISO Support for Gas Plant," *MISO Executives Spotlight Fleet Evolution Planning, Risks*.)

At a Nov. 28 executive update, Sustainable FERC Project attorney Lauren Azar said MISO's role is to be fuel-agnostic.

"MISO is of course using euphemisms for natural gas," Azar said. "I'm just questioning how much you guys are looking into creative solutions."

CEO Bear countered that MISO has been "very consistent" that it is in desperate need of "controllable, long-duration resources" quickly to cover the capacity shortfalls the grid operator foresees through 2027.

"Those comments always seem to get taken out of context," Bear said, adding that MISO is angling for dependable resource attributes, not a certain fuel type.

MISO has defined six system reliability attributes as necessary, including availability, the ability to deliver long-duration energy at a high output, rapid start-up times, providing voltage stability, ramp-up capability and fuel assurance. (See *MISO Considers Resource Attributes as Thermal Output Falls*.)

MISO Independent Market Monitor David Patton said the RTO's quantifying requirements for resource attributes isn't helpful. He said MISO would be better served by a combination of a sloped demand curve in the capacity auction, a marginal capacity accreditation for non-thermal resources and improved shortage pricing so the quickest and most available resources are rewarded for their performance.

"There's no answer to the question, 'how many peakers do we need?' or 'how many long-duration resources do we need?'" Patton said during a Dec. 6 meeting of the board's Markets Committee. "You're positing a question that has no answer. There's an infinite combination of attributes that would achieve the same reliability objective."

But some stakeholders have said a discussion of resource attributes is overdue as portions of the Midwest fast approach levels of intermittent resources that will complicate grid operations.

## LRTP Becomes Reality

Whether MISO's grid will be able to support the influx of intermittent resources is an open question. The grid operator in July approved slightly more than $10 billion in long-range transmission planning (LRTP) and is embarking on a second portfolio to accommodate further resource turnover. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

MISO said its second of four LRTP portfolios could run as much as $30 billion; stakeholders have voiced apprehension with the estimated price tag. (See *'Conceptual' Tx Planning Map Troubles MISO Members*.)

The new transmission won't arrive in time for MISO to avert a pair of system support resource (SSR) agreements to maintain system reliability.

Over 2022, MISO took steps to seek approval for two SSR agreements — a coal plant in Missouri and another in Wisconsin. (See *MISO Proposing 2nd SSR Agreement for Retiring Coal Unit*.)

During a Dec. 6 meeting of the board's System Planning Committee, Witmeier said MISO believes that SSRs are the best route to "protecting the system" as thermal output falls and intermittent generation rises.

Stakeholders have asked how MISO can simultaneously juggle an unprecedented queue volume, long-range transmission planning, a shifting resource mix, the upcoming move to a seasonal-based capacity auction and testing use of a sloped demand curve in said auction.

"A shortage of work to be done has never been a challenge," Ramey said in September. He said MISO plans to add manpower and devote more resources to projects where needed. ■

MISO News

# Memphis Turns Down 20-year TVA Supply Contract

*By Amanda Durish Cook*

The Memphis Light, Gas and Water utility remains on a five-year rolling contract with the Tennessee Valley Authority after its board of commissioners unanimously rejected a 20-year power supply contract with the federal agency early last month.

The Dec. 7 recommendation eliminates MLGW's potential generation independence and MISO membership for the time being. It also avoids a long-term partnership agreement that would have immediately lowered costs but bound the municipal utility to TVA for at least two decades.

MLGW Board Chairman Mitch Graves said the contract TVA offered was "too long of an agreement."

The contract would have cut base rate charges by 3.1%, kept the savings fixed through 2029, and allowed MLGW to acquire up to 5% of its energy needs from renewable sources. However, the agreement included a stranded-cost obligation that would have held the utility responsible for a percentage of TVA's future investments and followed the utility if it decided to later leave TVA. The contract also stipulated a 20-year termination notice; MLGW's current agreement has a five-year exit notice.

In a press release, the utility said it "will remain a TVA customer for the foreseeable future." It said the decision was made "after months of public and advisory council meetings, work with consultants and internal debate."

TVA spokesperson Scott Brooks said the verdict is a "reinforcement of the longstanding relationship with TVA in delivering affordable, reliable and clean energy to the people and communities across Memphis and Shelby County." The agency said it looks forward to continuing a more than 80-year relationship with MLGW and its incoming CEO, Doug McGowen.

Memphis Mayor Jim Strickland in October appointed McGowen, the city's longtime chief operating officer, as the utility's CEO. He will replace current CEO J.T. Young.

MLGW has considered weaning itself from TVA's supply for several years and building its own generation to tap into MISO's system.

However, consulting firm GDS Associates told the utility that splitting from TVA and participating in MISO's wholesale markets could cost MLGW up to of $25 million annually. The consultants said the escalating cost of materials and labor would soak up any savings when studying an exit from TVA. (See *Memphis Says Staying with TVA is Best Option*; *Inflation Dampens Possible Memphis Exit from TVA*.)

"We believe the people of Memphis and Shelby County deserve a partner that cares about serving their needs and addressing real issues like energy burden and revitalization of the city's core communities," TVA Executive Vice President and Chief External Relations Officer Jeannette Mills said in a press release. "Our continued partnership with MLGW provides the best option for making this happen."

TVA West Region Vice President Mark Yates said the agency plans to invest in the Memphis region. He called MLGW's decision to remain with TVA "a positive step forward."

The TVA did not address MLGW's rejection of the 20-year contract option.

"TVA has been respectful and supportive of the process, and we are glad to see it come to a successful resolution. MLGW's process has been a thorough, disciplined and unbiased consideration of potential energy suppliers," Brooks said.

Southern Alliance for Clean Energy Executive Director Stephen A. Smith said he applauded the decision to "reject the flawed recommendation to sign TVA's onerous long-term contract."

"By not signing the perpetually renewing contract, MLGW maintains maximum flexibility, which we believe is critical in light of the changing utility landscape," Smith said in a statement. "With the passage of the Inflation Reduction Act and the increasing opportunities available to municipal utilities, we believe that MLGW needs to maintain all its options going forward. We hope they'll continue to look for further opportunities to be more independent of TVA and provide better service and power supply options for the customers in Memphis and Shelby County."

Pearl Walker, organizer of the Memphis Has the Power grassroots group, said the MLGW board vote is "historic" and keeps its power supply's future flexible.

During the utility's board meeting Dec 21, Walker urged MLGW to consider "cleaner, more affordable and renewable energy options" and requested it to explore opportunities for generation funding under the Inflation Reduction Act. She said it was imperative that MLGW continue weighing plans because Memphians have some of the highest energy burdens in the nation.

In a statement, Walker said a "never-ending contact would negatively impact our energy future." ■


TVA's Allen Combined Cycle Plant near Memphis, Tenn. | *TVA*

# NYISO News

# NYISO Management Committee Briefs

### Abbas to Join Talen Board

NYISO CEO Rich Dewey announced to the Management Committee on Dec. 21 that Director Gizman Abbas had accepted a position on Talen Energy's board of directors.

Dewey said NYISO has determined that the appointment "does not present a conflict" with FERC's rules and the ISO's own Code of Conduct, as Talen no longer operates, nor owns any assets, in New York. But, he said, the ISO would "continue to watch and monitor the situation," and revisit that determination should Talen move back into New York and "come up with a cure."

Mark Reeder, representing the Alliance for Clean Energy New York, asked whether Talen had any interests in NYISO's neighbors and if that was considered in the ISO's determination.

The company does have interests in PJM and ISO-NE, owning several generators in Pennsylvania, New Jersey, Maryland and Massachusetts. Dewey said "it was considered, and we felt [under] a strict interpretation of the rules, it did not present a conflict."

### Capacity Accreditation

The MC voted to recommend that the Board of Directors approve *proposed* tariff modifications that would implement a new capacity accreditation process and market design.

Having been approved by the Business Issues Committee the previous week, several stakeholders again voiced their reservations about approving measures that they believed were either not fully understood or would be applied to resources unequally. (See *NYISO Capacity Accreditation Implementation Worries Stakeholders*.)

Michael DeSocio, director of market design at NYISO, said the ISO "remains committed" to doing the work required for capacity accreditation implementation and "acknowledges the need" to tackle portions of the project that were raised by stakeholders. DeSocio also assured the committee that these commitments would be reflected in the meeting's minutes.

### Hybrid Storage Resources

The MC voted to recommend that the board approve NYISO's *proposed* tariff revisions that would integrate aggregated HSRs — multiple generators co-located with energy storage behind a single interconnection point — into the ISO's markets.

The revisions were also approved by the BIC the previous week, and NYISO anticipates filing the changes with FERC in the third quarter of 2023. (See "Aggregated Hybrid Storage," *NYISO Capacity Accreditation Implementation Worries Stakeholders*.)

Julia Popova, NRG energy manager of regulatory affairs and vice chair of the committee, asked why the revisions were being filed so late this year.

NYISO officials answered that they are targeting the third quarter because there are other projects that need to be implemented first, such as internal controllable lines. They also said the HSR construct would not be implemented until 2025 anyway, so there is no rush to get it to FERC.

### CAC Scoping Plan

NYISO agreed to brief stakeholders on the New York Climate Action Council's recently approved scoping plan and how it would impact the ISO's work. (See related story, *New York Climate Scoping Plan OK'd*.)

NYPA works on the Moses-Adirondack Smart Path Reliability Project. | *New York Power Authority*

Executive Vice President Emilie Nelson said NYISO is "looking through [the plan] carefully and is very, very interested in working with all stakeholders and state agencies going forward." The ISO also "appreciates the acknowledgement within the plan that there are challenges ahead of us that we need to work together to solve."

Reeder requested a "small," formal presentation from NYISO about aspects of the plan that would affect its markets, though he acknowledged that the plan is just a framework that will take "at least multiple years" of legislation and agency rulemakings to implement. ■

*— John Norris*

# Capacity Auction 'Mismatch' Roils PJM Stakeholders

## RTO Seeks to Change Reliability Calculations for DPL South

By Devin Leith-Yessian and Rich Heidorn Jr.

[Editor's Note: PJM filed the proposed tariff change on Dec. 23 (EL23-19). See related story, *Major Changes in 2022 Continue to Shape PJM Outlook in 2023*]

VALLEY FORGE, Pa. — PJM said Dec. 21 it will ask FERC to modify the rules of its 2024/25 capacity auction to avoid artificially high prices in one region of the RTO.

RTO officials told the Members Committee that they will make a Federal Power Act Section 205 filing asking to change the Base Residual Auction parameters for the DPL South locational deliverability area (LDA), essentially the Delmarva Peninsula.

Senior Vice President of Market Services Stu Bresler *said* PJM will ask FERC to approve a tariff change to avoid an unjust and unreasonable clearing price resulting from a "mismatch" between the generation the RTO expected to offer into the auction and how much actually did.

The reliability requirement for DPL South increased by 373 MW (12%) since the 2023/24 capacity auction, while requirements for other LDAs were flat or declined slightly.

PJM's disclosure, which came the day after it had planned to release the BRA results, resulted in almost three hours of discussion.

### 'Mismatch'

The reliability requirement for each LDA is the sum of its internal generation and the capacity emergency transfer objective (CETO), the imports needed to maintain reliability based on the region's load profile and anticipated outages.

Internal generation consists of existing units with must-offer obligations and planned generation with interconnection service agreements (ISAs) and commercial operation dates before the delivery year begins. PJM expected about 1,000 MW of new generation with ISAs to be in operation in DPL South by the beginning of the 2024/25 delivery year, June 1, 2024.

In small LDAs like DPL South, the additions of large or intermittent units can paradoxically cause an increase in the reliability requirement because capacity transfers are necessary to account for times when the resources are not available.

"What happened in this case is … we didn't get offers from all planned resources in the resource model," creating the appearance of a "shortage condition that doesn't exist, [producing] much higher prices," Bresler said. "If all the planned generation had offered into the auction, we would have posted the results yesterday."

### FERC Filing

Bresler said the RTO must model all eligible units in the reliability analysis, because if units excluded do offer into the auction and come online, the RTO could procure too little capacity for reliability needs.

As a result, Bresler said, PJM determined it needs to be able to adjust the reliability requirement downward if modeled units don't offer.

PJM will seek FERC approval to allow the RTO, during the auction clearing process, to exclude resources from the LDA reliability requirement if they do not participate and the requirement would otherwise increase by more than 1%.

Bresler said the RTO plans to file "indicative" auction results today under the existing rules and under the proposed change to allow stakeholders to evaluate the impact of the proposal before filing comments on it. The only significant price change resulting from PJM's proposal would be to DPL South, he said, although there "could be some impact" to its

| | 2023/2024 BRA | | 2024/2025 BRA | | Delta | | | |
|---|---|---|---|---|---|---|---|---|
| LDA | Reliability Requirement (UCAP MW) | CETL (MW) | Reliability Requirement (UCAP MW) | CETL (MW) | Reliability Requirement (UCAP MW) | CETL (MW) | Reliability Requirement (Percent) | CETL (Percent) |
| MAAC | 63,819.0 | 6,381.0 | 63,518.0 | 5,965.0 | -301.0 | -416.0 | 0% | -7% |
| EMAAC | 35,590.0 | 8,704.0 | 35,415.0 | 8,594.0 | -175.0 | -110.0 | 0% | -1% |
| SWMAAC | 14,329.0 | 8,389.0 | 14,299.0 | 7,947.0 | -30.0 | -442.0 | 0% | -5% |
| PS | 11,217.0 | 9,022.0 | 11,166.0 | 8,287.0 | -51.0 | -735.0 | 0% | -8% |
| PS NORTH | 5,768.0 | 4,349.0 | 5,715.0 | 4,253.0 | -53.0 | -96.0 | -1% | -2% |
| DPL SOUTH | 3,141.0 | 2,008.0 | 3,514.0 | 2,009.0 | 373.0 | 1.0 | 12% | 0% |
| PEPCO | 7,163.0 | 7,160.0 | 7,151.0 | 7,033.0 | -12.0 | -127.0 | 0% | -2% |
| ATSI | 14,649.0 | 10,213.0 | 14,434.0 | 10,465.0 | -215.0 | 252.0 | -1% | 2% |
| ATSI-Cleveland | 5,363.0 | 4,728.0 | 5,374.0 | 4,941.0 | 11.0 | 213.0 | 0% | 5% |
| COMED | 24,077.0 | 5,781.0 | 23,859.0 | 4,640.4 | -218.0 | -1,140.6 | -1% | -20% |
| BGE | 7,522.0 | 5,615.0 | 7,514.0 | 5,397.0 | -8.0 | -218.0 | 0% | -4% |
| PL | 10,251.0 | 4,916.0 | 10,214.0 | 4,337.0 | -37.0 | -579.0 | 0% | -12% |
| DAYTON | 3,924.0 | 4,022.0 | 3,922.0 | 3,918.0 | -2.0 | -104.0 | 0% | -3% |
| DEOK | 6,847.0 | 5,632.0 | 6,881.0 | 4,999.0 | 34.0 | -633.0 | 0% | -11% |

The reliability requirement for the DPL South locational deliverability area (highlighted) increased by 373 MW (12%) since the 2023/24 capacity auction. The requirements for other LDAs were flat or declined slightly. | *PJM*

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"parent" region.

With FERC Chair Richard Glick about to leave the commission, the remaining members could deadlock 2-2 on PJM's request. By law, that would result in the filing automatically going into effect.

PJM officials said they may also make a filing under FPA Section 206 to establish a refund effective date and allow FERC to consider other options for solving the dilemma if it rejects the 205 filing.

## Short Lead Time

Bresler said it was the first time the situation has occurred. He said it may have resulted because the RTO is running its capacity auctions under a compressed time schedule, with only 17 months until the 2024/25 delivery year, as opposed to the standard three years. That increases the risk that a generator may not go into operation in time to meet its obligations.

Another factor, he said, was that the winter risk for solar resources in DPL South is not much lower than the summer risk because the winter load is nearly equal to summer and "the peak occurs before the sun is up in the wintertime." As a result, the capacity value of solar is smaller in the LDA than in the rest of the RTO.

Bresler told *RTO Insider* after the meeting that he could not disclose how many expected resources failed to offer because DPL South is a small LDA, and disclosure of the information could identify the resources in question. But he said during the meeting that they were "not solely intermittent resources."

## Stakeholders Worried About Precedent

Several stakeholders objected to PJM's proposed fix.

Jeff Whitehead of GT Power Group said load interests should be wary of the proposal. "The next time this comes around, the shoe could be on the other foot and the prices could be moving in the other direction."

"It's really troubling that we could look to change the rules in the middle of an auction," said Neal Fitch of NRG Energy. "That's a really bad outcome."

"We're taking a leap on a solution where perhaps not all the implications have been thought out," he added.

Senior Vice President of Market Services Stu Bresler explains PJM's proposal for addressing the supply-demand "mismatch" in the DPL South locational deliverability area. | © *RTO Insider LLC*

Bresler said PJM will conduct discussions on potential long-term fixes. "This is not a step we take lightly. It's a fix to a hole in the rules that wasn't previously identified."

Arnie Quinn of Vistra said PJM was "opening a Pandora's box by setting a precedent that market rules can change after offers have been submitted." He warned the precedent "will become a quagmire for PJM and FERC."

If the rules change, Quinn added, generators should be able to change their offers.

Michael Borgatti of Gabel Associates suggested PJM request the change for the 2024/25 auction only to avoid making a "snap decision" on a long-term change.

Michael Cocco, of Old Dominion Electric Cooperative, defended PJM's decision as "appropriate."

PJM's proposed resolution was also supported by Independent Market Monitor Joe Bowring.

"The results do not reflect the fundamental economic facts. The results do not reflect the actual balance of supply and demand in the LDA," Bowring said. "PJM's actions are reasonable and rational and proportional to the problem."

However, Bowring said he disagreed with PJM's plan to publish the DPL South results under the current rules, because they are incorrect and not "relevant." ■

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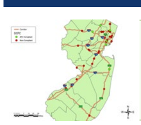

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## PJM News

# Major Changes in 2022 Continue to Shape PJM Outlook in 2023

*By Devin Leith-Yessian*

The close of 2022 finds PJM in a state of flux, with recent FERC orders and pending dockets carrying significant changes to the RTO's expanding interconnection queue and the structure of its capacity markets, as well as ongoing stakeholder discussions on how to account for the capacity from intermittent resources. Many of those discussions that have culminated in solutions will begin their implementation in the new year, while others still in deliberations aim to wrap up in the first few months of 2023.

Here's a review of some of the major stories of 2022 and ongoing discussions continuing into 2023.

Stu Bresler, PJM | © *RTO Insider LLC*

### Finalization of Capacity Auction Pushed into 2023

The first order of business in 2023 will be a review of the "indicative" 2024/25 capacity auction results today, following a concern that the DPL South locational deliverability area (LDA), which is centered around the Delmarva Peninsula, could experience artificially inflated prices. (See *Capacity Auction 'Mismatch' Roils PJM Stakeholders*.)

During the Dec. 21 Members Committee meeting, Senior Vice President of Market Services Stu Bresler said the design of the reliability requirement for each LDA can create a situation where large facilities or intermittent generators cause the requirement to increase as more resources are brought online because of the need to account for when those resources are offline. When those resources are included in the resource modeling and lead to an elevated reliability requirement, but do not ultimately enter into the auction, it can create the appearance of a shortage that doesn't exist.

PJM submitted concurrent Federal Power Act Section 205 and 206 filings with FERC on Dec. 23 seeking that the auction results in DPL South be found unjust and unreasonable and to allow the RTO to adjust the reliability requirement for the LDA "based on the actual supply of resources that submitted offers into the auction" (*ER23-729*, *EL23-19*).

The Section 206 filing argues that this would effectively function as an additional factor in the evaluation of offers into the market before the results are finalized.

"Absent the ability to include this additional factor in the optimization algorithm, PJM would be forced to utilize a materially inaccurate locational deliverability area reliability requirement that does not reflect the actual capacity needs of the particular LDA in question and would result in an unjust and unreasonable outcome," the RTO said.

Several stakeholders raised concerns that the move would establish a precedent of market changes being implemented in the middle of auctions. Those reservations extended to PJM's determination to publish the DPL South results today, which could hamstring the commission's ability to allow market participants to alter their offers to reflect any rule changes.

Bresler said it is not a step being taken lightly, but the scale of the impact to DPL South warrants immediate measures while concrete long-term solutions are sought. In the filings before FERC, PJM said the clearing price for the LDA would be more than four times higher if the proposed changes are not made.

"More particularly, based on preliminary auction data, PJM estimates that as a result of this confluence of events in this small LDA, should PJM complete the auction and award capacity commitments, the clearing price for the DPL-S LDA (and the revenues received by capacity market sellers in this small LDA) would be more than four times what the clearing price should be if the planned generation capacity resources that did not offer in the auction are excluded from the locational deliverability area reliability requirement given that they did not offer into the BRA," PJM told FERC.

The opening of the auction had already been delayed from August to November as part of a FERC-approved adjustment to the capacity auction timeline through the end of 2023 to allow PJM additional time to implement a revised forward-looking energy and ancillary services (E&AS) offset. The commission reversed its approval of the RTO's forward-looking E&AS offset in December 2021 and granted the delayed timeline on Feb. 23, pushing the January 2022 auction to June. (See *FERC Approves PJM Capacity Auction Date Changes*.)

The 2023 auctions were postponed from February to June and from August to November. The schedule is set to return to normal with the 2027/28 BRA, in May 2024.

### Capacity Prices Fall for 2023/24

The 2023/24 capacity auction, held in June, saw prices fall by nearly one-half relative to the previous auction, with 144,871 MW of capacity sold for $2.2 billion for the delivery year starting in June 2023. The 2022/23 delivery year saw a total capacity bill of around $4 billion. (See *PJM Capacity Prices Crater*.)

Several market changes likely impacted prices, including a decreased unit-specific market seller offer cap (MSOC), the use of a historical E&AS revenue offset, the introduction of the effective load-carrying capability (ELCC) methodology for measuring intermittent resource capacity and the near elimination of the minimum offer price rule.

The Independent Market Monitor found that

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the auction results were competitive, largely because of the new MSOC. (See *Monitor Finds PJM's 2023/24 Base Residual Auction Competitive*.)

## Accreditation of Intermittent Resources Remains Divisive

Stakeholders are also pushing forward with an effort to have a new accreditation methodology for ELCC resources in place for the 2025/26 BRA in June. (See *PJM Stakeholders Review Proposals on CIRs for ELCC Resources*.)

The often contentious issue has been discussed in more than 25 meetings since a problem statement was adopted in early 2021, a referral to the FERC Enforcement hotline and a complaint to the commission filed by economist Roy Shanker on Nov. 30. At issue is whether PJM has been in violation of its tariff by improperly permitting energy above renewable resources' capacity interconnection rights (CIRs) to be entered into the Reliability Pricing Model (RPM) auctions as capacity.

In his *complaint*, Shanker alleged that the practice results in diminished reliability; load overpaying for "phantom capacity" that does not meet reliability standards; artificial reduction of capacity prices for other resources; and inefficient economic decisions from market participants acting on potentially inaccurate information. Because the resources already have established interconnection service agreements (ISAs) and defined CIRs, the complaint states that an immediate solution can be implemented by capping capacity offers at the rates determined in those agreements with each resource (*EL23-13*).

The commission approved a PJM request for an extension from Dec. 20 to Jan. 10 to provide more time for its response to the complaint.

At the start of the year, the PJM Power Providers (P3) sent a *letter* to the PJM Board of Managers arguing that by allowing resources to acquire capacity obligations greater than their demonstrated deliverability, the RTO has "materially destabilized the market" and is not upholding its tariff. The board responded with a *letter to stakeholders* saying that it believes the accreditation of intermittent resources has been appropriate and compliant with the tariff.

The stakeholder discussions on a long-term solution has resulted in 11 packages of changes being offered as potential solutions, of which six remain under consideration by the Planning Committee. Though they agree on the ultimate methodology for accrediting intermittent resources, the packages vary widely on where to cap capacity offers for resources that already hold an ISA. The transitional measures range from granting ELCC resources higher CIRs and having load pay for the transmission upgrades to capping their current CIR rating and requiring the resource to re-enter the interconnection queue to request a higher accreditation.

The PC is set to consider endorsement of a package on Jan. 10, while the Markets and Reliability Committee and MC are set to vote on Jan. 25. The proposals would also require approval from the board, which is set to take up the issue on Feb. 1. The solutions all look to be implemented for the 2025/26 BRA, but they differ in whether that is a target or mandatory.

## Interconnection Queue Overhaul Approved

Following years of a growing backlog in its interconnection queue, FERC on Nov. 29 approved a proposal from PJM to overhaul how the RTO studies network upgrades for new projects. According to PJM, the number of new service requests it received tripled from 2019 through 2022 to more than 2,700 projects pending in the queue as of May 10 (*ER22-2110*).

The new system aims to reduce completion times by clustering projects together both for studying the upgrades required and allocating costs, as well as by discouraging speculative project submissions by requiring evidence of site control and progressively scaling readiness deposits throughout the process. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

Once again the transitionary provisions were the source of much of the debate around the changes. Under the new system, projects submitted between April 2018 and September 2021 with a price tag above $5 million will be studied under two sequential transitionary cycles, while less expensive projects will be placed in an expedited "fast-track" queue.

Concerns raised by protesters questioned whether the measures would be enough to weed out proposals seeking to offload the work of testing a project's viability onto PJM staff and whether site control requirements could allow viable projects to be forced out of the queue.

During the Organization of PJM States Inc.'s (OPSI) annual meeting on Oct. 18, PJM Vice President of Planning Kenneth Seiler said many of the smaller projects already in the interconnection queue could have their studies complete within six months and that the fast-track could be completed within two years after its approval.

## Division over Design of Capacity Market

As FERC continues to weigh whether to approve PJM's proposed changes to the RPM, generation owners are seizing upon comments made by PJM CEO Manu Asthana — in which he expressed concern about the pace of new generator installations — to argue that the capacity market should be structured to procure additional capacity. (See *PJM MRC Briefs: Oct. 24, 2022*.)

At the RTO's annual meeting on Oct. 24, Asthana said about 40 MW of generation is expected to retire by 2030 as construction of new resources lags behind expectations and load continues to grow.

"We have time, but we don't have time to waste," he said. "We need to take action to ensure we retain an adequate supply of dispatchable generation through the [clean energy] transition."

Protests against PJM's proposed variable resource requirement (VRR) demand curve have pointed to Asthana's statement as evidence that the RPM should be designed to incentivize the retention and development of all types of capacity (*ER22-2984*).

The Quadrennial Review filing proposed changing the reference resource to a combined cycle generator, revising the calculation of the gross cost of new entry (CONE) and changing how it is adjusted in years between reviews, steepening the VRR curve and shifting from a historical E&AS offset calculation to a forward-looking offset.

P3 protested that the changes are not transparent and would disincentivize the sort of generation Asthana said is needed over the coming decade. (See *PJM Defends Quadrennial Review Parameters from Generator Protests*.)

"To P3, this sounds like PJM is indeed on the cusp of a reliability crisis and the impact of the instant filing will coincide directly with the predicted reliability challenges in PJM," the group said.

In response to previous P3 protests, several environmental and public advocacy groups — jointly filing as the Public Interest Entities — said the claims are unfounded and noted that PJM remains well above its "conservative" reliability standards.

"Rather than a market 'on life support,' PJM's capacity market remains robust, procuring — indeed over-procuring — the resources necessary to maintain reliability," they said. ■

PJM News

# FERC Rejects Sale of AEP's Kentucky Operations to Liberty

*By Devin Leith-Yessian*

FERC on Dec. 15 rejected the sale of American Electric Power's Kentucky operations to Algonquin Power & Utilities subsidiary Liberty Utilities, ruling that the companies failed to prove that the transaction would not adversely affect rates (*EC22-26*).

Under the agreement filed with FERC a year ago, and amended in October, AEP would sell Kentucky Power — a vertically integrated utility with 1,075 MW of generation — and Kentucky Transco to Liberty for $2.646 billion. (See *AEP Accepts Lower Price for Kentucky Operations Sale*.)

But the commission found that the companies' commitment to hold customers harmless for all "transaction-related costs" for five years was not sufficient to demonstrate that the sale would not have an adverse impact. The application notes that the pledge is not a rate freeze and that Liberty would be able to seek rate changes to reflect their full costs of service.

The commission said that an "increase in rates that results from a transaction is not the equivalent of a transaction-related cost" and suggested that the applicants could have included a projection of the impact to rates following the sale.

"Applicants' representations do not provide complete information upon which to evaluate the effect of the proposed transaction on rates," the commission said. "To support their position, applicants could have, for example, included a comparison of rates currently in effect to a projection of rates once the proposed transaction is consummated."

Both the Kentucky Public Service Commission and a group consisting of American Municipal Power, Blue Ridge Power Agency and Wabash Valley Power Association filed protests arguing that the application did not contain enough information to show that ratepayers would not be negatively impacted by the transaction.

The PSC itself gave its approval of the transaction in May, though it stipulated numerous conditions to protect consumers. (See *PSC OKs Sale of AEP's Kentucky Operations to Liberty Utilities*.)

The cooperative group argued that Liberty should be required to maintain the companies' current return on equity of 9.85% and the maximum permitted equity component of capital structure of 55%. It also pushed for Liberty to be required to show customer benefits to justify any rate increases during the five-year hold-harmless period and for that pledge to include any cost of debt.

"Applicants further state that, to the extent such costs change as a result of the change of ownership, those changes will not impact customers through the end of 2022 and will be addressed in 2023 and in the future through the formula rate projection and true-up process in the normal course," FERC said.

The commission dismissed the application without prejudice, meaning the companies are free to file a new application "that provides adequate information" on its effects on rates.

"If the effect of the proposed transaction on rates is adverse, applicants should propose adequate ratepayer protection or mitigation to address that adverse effect, or otherwise demonstrate specific benefits due to the proposed transaction that offset such effect," FERC said.

| © RTO Insider LLC

## Danly Concurs, but with Criticism of Commission

Though he concurred with the decision, Commissioner James Danly criticized the time FERC took to rule on the deal and for not requesting additional data or changes to mitigate any rate effects. The companies initially filed the application for the transaction in December 2021; on June 3 they requested that the commission authorize the transaction no later than June 21 to allow the deal to close on schedule in mid-2022.

"Instead, having waited six months to reach the same conclusion we had come to before — that we did not have enough information — we have merely impeded the actions that the applicants could have taken to move ahead with the proposed transaction, such as filing a new application with needed information, perhaps after consultation with commission staff," he said.

Had the commission sought additional information, Danly said, it may have been possible to receive a satisfactory rate commitment within a few months. By requiring the companies to file a new application, the commission made it difficult for companies and investors to make business decisions, he said.

"It is nearly impossible to rationally allocate capital and conduct business responsibly when it is unclear who will own that business or when the decision regarding the disposition of jurisdictional assets will be made. When we delay these decisions, employees and leadership of both entities live under a cloud of uncertainty. Shareholders are unable to properly determine the value of their shares," he said.

## Phillips also Concurs

Commissioner Willie Phillips also issued a concurrence, saying that he would have preferred a conditional approval of the application. He noted the commission has rarely denied similar applications and has instead granted conditional authorization with market power mitigation measures.

"I recognize those cases may be distinguishable in certain respects but would have preferred to have taken that approach here by providing joint applicants with clear guidance on possible mitigation strategies such as a hold-harmless commitment on rates, not just transaction costs, or a rate freeze that assures the commission that transmission customers will not feel adverse effects from this transaction," he wrote. ■

PJM News

# DC Circuit Remands Conowingo Dam Licensing to FERC

*By Devin Leith-Yessian*

The Conowingo Dam is located on the Susquehanna River in Maryland. | © *RTO Insider LLC*

The D.C. Circuit Court of Appeals on Dec. 20 vacated FERC's licensing of the Conowingo Dam on the Susquehanna River in Maryland, ruling in favor of environmental groups who argued that the commission exceeded its authority under the Clean Water Act (CWA) (*21-1139*).

The court remanded the licensing decision back to FERC, ruling that the commission did not have the power to issue the dam a license based on the conditions of a settlement between the Maryland Department of the Environment (MDE) and Constellation Energy, rather than on the department's original CWA certification of the dam in 2018.

Describing the environmental requirements of the original certification as "unprecedented" and "extraordinary," Constellation had filed for reconsideration from the MDE, challenged the original certification in state and federal court, and petitioned FERC to find that the state had waived its opportunity to issue a certification. The settlement was reached through mediation between the company and the department, after which the state agreed to waive the right to issue a water quality certification and allow FERC to issue a license for the dam incorporating the terms of the settlement.

The court found that the MDE backtracking on its original certification and waiving its authority to issue a certification does not fit into one of the two instances in which the CWA allows the commission to issue a license. It only allows FERC to grant a license when the state has issued a certification or "fail[ed] or refuse[ed] to act on a request."

"This leaves no room for FERC's third alternative, in which it issued a license based on a private settlement arrangement entered into by Maryland after the state had issued a certification with conditions but then changed its mind," the court said.

The settlement was objected to by environmental groups in the state, including the Waterkeepers Chesapeake, Lower Susquehanna Riverkeeper Association, ShoreRivers and Chesapeake Bay Foundation, which filed a petition for rehearing before the commission and ultimately with the D.C. Circuit for review.

In rejecting the arguments from the environmental groups on rehearing, FERC argued that the CWA does not prevent a state from affirmatively waiving its authority to certify a project. The court struck down that claim when repeated by commission attorneys during oral arguments.

"Pressed at oral argument, FERC counsel went so far as to argue that 'if we can't conclude that Congress thought of an unnamed [potential course of action],' by resort to legislative or congressional reports, then we must treat the course of action as available to the agency," the court said. "That, however, is not how we interpret statutes. Our court has 'repeatedly rejected the notion that the absence of an express proscription allows an agency to ignore a proscription implied by the limiting language of a statute.'"

Both Constellation and the MDE expressed disappointment with the ruling, with the department stating that it will "work with the Office of the Attorney General on the implications and next steps."

"While we are still reviewing the order, we are surprised and disappointed in the D.C. [Circuit] Court's decision to vacate Conowingo's license renewal," Constellation spokesperson Paul Adams said in an email. "No one who cares about clean air and the health of the Chesapeake Bay should be cheering this decision, which potentially jeopardizes the state's largest source of renewable energy and could disrupt up to $700 million that Constellation pledged for environmental programs, projects and other payments that directly benefit water quality, aquatic life, and citizens living on and near the bay."

The court said that vacating the license also allows further administrative and judicial review to be completed, which could result in invalidation of the original MDE certification or, in the case of its validation, for FERC to be required to license the dam according to the conditions stipulated in the certification.

The 2018 certification required Constellation to develop a plan including the reduction of nitrogen and phosphorus discharge, improvement of aquatic passage, control of debris, and improved aquatic resources and habitat protection, according to the court ruling.

During oral arguments, FERC said vacatur of the license may disrupt environmental protections included in its conditions, but the court noted that the commission's counsel recognized that those concerns could be mitigated through interim annual licenses.

"Equally important, [the environmental groups], which brought this action for the very purpose of strengthening the dam's environmental protections, agree," the court said. ■

## PJM News

# PJM MRC/MC Briefs

## Markets and Reliability Committee

### Two Proposals on 'Circuit Breaker' Fail

The PJM Markets and Reliability Committee on Dec. 21 rejected two proposals that would have created a "circuit breaker" mechanism to limit prices during extended periods of high prices.

Old Dominion Electric Cooperative, Southern Maryland Electric Cooperative and Northern Virginia Electric Cooperative had jointly proposed triggering a breaker when LMPs of at least $1,000/MWh last over the course of a 24-hour period, or $850 over a week. Prices would then be capped at $850/MWh until they remain below the cap for five consecutive business days.

The proposal would have also granted PJM the discretion to invoke the breaker based on conditions it's observing; it would not have had the power to prevent a breaker being triggered. (See "Support for Circuit Breaker Remains Mixed," *PJM MRC Briefs: Oct. 24, 2022*.)

Adrien Ford, ODEC | © *RTO Insider LLC*

Adrien Ford of ODEC said the circuit breaker is intended to be used only under extraordinary circumstances when the markets have gone "haywire." For a small load-serving entity serving 200 MW of load, she said the total annual spending under typical average prices for the PJM footprint could be eclipsed in 2.25 days should prices reach the current $5,700/MWh cap, which includes maximum cost-based offers, reserve shortages and a $2,000/MWh transmission constraint penalty factor.

"The numbers just get cartoonish very quickly, and that's why we're trying to put this in place," she said.

Calpine proposed a breaker triggered by 90 nonconsecutive hours of shortage events in one delivery year and cap prices at $2,000/MWh — a threshold the company's David "Scarp" Scarpignato said is critical to proper price formation. After one breaker had been observed in a single year, any subsequent shortage in excess of three consecutive hours would trigger an additional breaker. The proposal would not provide PJM with the power to initiate a circuit breaker unilaterally.



David "Scarp" Scarpignato of Calpine (right) will take over as chair of the PJM Members Committee at its first 2023 meeting from Erik Heinle (left). | © *RTO Insider LLC*

Prolonged periods of high pricing can cause more harm through revenue issues than provided by the benefits of price formation, Scarp said.

Consideration of the packages was postponed during the November MRC meeting to afford their sponsors additional time the attempt to reach a compromise, but Ford said those efforts were not successful. She said consensus was sought on the circuit breaker alone, as well as by combining the issue with the market seller offer cap (MSOC).

Concerns with the packages included giving PJM staff the ability to initiate a circuit breaker; the impact of uplift payments on small LSEs; the level prices would be capped at; and a lack of detail on some provisions, such as how uplift payments would be allocated.

Constellation Energy's Jason Barker encouraged stakeholders to vote against both packages and to engage in further discourse to find a compromise in the middle.

"It's unfortunate that we're pushing forward with stakeholder packages that we believe are suboptimal at best," he said.

Consumer advocates and load representatives said the impact of sustained high prices necessitates a quick solution being found.

"There needs to be something in place to protect consumers," said Greg Poulos, executive director of the Consumer Advocates of the PJM States, adding that it was hoped that a circuit breaker would be ready in time for the winter season.

Albert Pollard, Illinois Citizens Utility Board | © *RTO Insider LLC*

Albert Pollard, of the Illinois Citizens Utility Board, said the issue could lead to a future Federal Power Act Section 206 filing with FERC if a stakeholder solution is not found. He argued that it might be more advantageous to opponents of the circuit breaker proposals to accept one of the solutions on the table rather than take their chances with a solution the commission may arrive at.

"We don't know what's going to happen if this lands on their desk," he said.

### First Read on Proposals for Accrediting Intermittent Resources

The sponsors of five packages addressing capacity accreditation for effective load-carrying capability resources gave a first read of their proposals, with the discussion focusing on how to address capacity interconnection rights (CIRs) for existing resources in the interim until the new rules can be put in place. (See *PJM Stakeholders Review Proposals on CIRs for ELCC Resources*.)

None of the packages reached 50% support in a poll conducted by the Planning Committee in October. LS Power's Package E received the largest share of support in an October poll, at 44%, followed by Packages D and I from PJM, which received 40% and 28%, respectively. Endorsement of a package from the PC is scheduled for Jan. 10, while the MRC and

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Members Committee are set to vote on Jan. 25. The proposals would also require approval from the Board of Managers, which is set to take up the issue on Feb. 1.

Tom Hoatson of LS Power said Package E is essentially PJM's original Package A, which was withdrawn by the RTO early in the stakeholder process. It would immediately limit generators' accreditation to their current CIR level, require those resources to re-enter the interconnection queue at the end to request higher CIRs and require that they be responsible for any transmission upgrades.

PJM's Package D would grant existing interconnection service agreement (ISA) holders higher CIRs by conducting new deliverability tests in the 2023 Regional Transmission Expansion Plan (RTEP). Some opponents have criticized this as permitting those requests to jump the queue and causing projects in the queue to bear higher costs.

The RTO's Package I would place existing resources' requests for higher CIRs at the end of the interconnection queue, but conduct a transitional system capability study to allow for the generator to take advantage of headroom on the transmission system, which PJM has estimated will be available for approximately five years.

Package G, from E-Cubed Policy Associates, builds upon LS Power's proposal and expands the deliverability testing to include more months — particularly the fall shoulder months, as there have been increasing reliability concerns at the start of the fall maintenance period. The proposal would also allow generation owners retiring their assets to request an expedited CIR review for new generation being developed on the same site using the existing interconnection point, a component not included in any of the other proposals.

"We need to understand how those shoulder periods are going to be effected," said E-Cubed President Paul Sotkiewicz.

The most recent proposal, Package K, was introduced by LS Power during the Dec. 6 PC meeting and aims to ensure that the provisions within PJM's Package I are actionable for the June 2023 Base Residual Auction. It both specifies that the changes are mandatory to implement in that BRA and asks that the board direct PJM to submit a filing with FERC clarifying that the Reliability Assurance Agreement establishes CIRs as the hourly upper limit for the unforced capacity accreditation.

"We recognize it would only be an indicative vote; we cannot tell the board what to do," Hoatson said.

Ford said that in the event that either no packages are endorsed by the PC or Package I is not among the proposals voted to be brought before the MRC, ODEC would motion for it to be voted upon by the committee.

### Generator Deliverability Test Modifications

PJM provided a first read of proposed manual *revisions* to change how generator deliverability tests are conducted to account for higher variability associated with the growth of intermittent resources on the grid. The proposal would merge the methodology for summer, winter and light-load testing; expand the light-load period; incorporate procedures for ramping of wind and solar; and harmonize dispatch procedures.

The RTO is anticipating seeking endorsement from the PC on Jan. 10, followed by returning to the MRC on Jan. 25 for endorsement. If approved, the changes would be effective immediate and implemented for the 2023 RTEP.

### Other Committee Actions

The MRC also passed with no objections:

- *market suspension rules* to clarify how PJM accounts for suspensions when market results and clearing prices cannot be determined. (See "Market Suspension," *PJM Market Implementation Committee Briefs: June 8, 2022*.)
- Operating Agreement *revisions* to grant PJM the flexibility to permit market participants to continue operating in markets under certain circumstances, including grid reliability; the ability to provide collateral; and future ability to generate revenue. The language also recognizes that certain transmission customers cannot have their service terminated without FERC approval. PJM Associate General Counsel Colleen Hicks told the committee that the OA currently has conflicting language on whether PJM has discretion currently, with some sections using "shall" and others saying that "PJM may limit" and the revisions bring the documents into alignment. (See "1st Read on Proposal to Allow Flexibility for Market Participation During Defaults," *PJM MRC Briefs: Nov. 16, 2022*.)

## Members Committee

### Election of Representatives and Vice Chair

The Members Committee approved sector whips and representatives on the Finance Committee, as well as a new vice chair, during its Dec. 21 meeting.

The sector whips for 2023 will be:

- Electric Distributors: Lynn Horning of American Municipal Power;
- End Use Customers: Greg Poulos of the Consumer Advocates of the PJM States;
- Generation Owners: Calpine's Scarp;
- Other Suppliers: Brian Kauffman of Enel North America; and
- Transmission Owners: John Horstmann of Dayton Power and Light.


Greg Poulos, CAPS | © RTO Insider LLC

The sitting Finance Committee representatives will be joined by Jeff Riley of AMP (Distributors) and John Brodbeck of EDP Renewables (Generation).

Following the rotating schedule of which sector nominates vice chair, the TOs had selected Exelon's Sharon Midgley, whom the MC also elected Dec. 21.

PJM CEO Manu Asthana thanked outgoing MC Chair Erik Heinle, of the D.C. Office of the People's Counsel, for his leadership through many meetings and discussions, including a handful of contentious issues before the committee.

The Generation sector had originally selected Scarp to fill the vice chair position, following the departure of Becky Robinson of Vistra, who as vice chair was in line to become chair this year. Thus, Scarp will become chair this year.

### First Read on Manual Revisions to Allow Direct MC Consideration of Issues

ODEC's Ford provided a first read of proposed *revisions* to Manual 34 that would create an avenue for PJM members to make a motion for the MC to consider issues directly, without going through the typical pathway of the lower committees. The revisions would require that a motion be introduced as a problem statement and issue charge to follow the existing governance process. ■

*— Devin Leith-Yessian*

## SPP News

# SPP Adds Arkansas PSC Commissioner O'Guinn to Leadership

SPP said Dec. 20 that it has hired Arkansas Public Service Commissioner Kimberly O'Guinn as its director of state regulatory policy. Beginning this year, she will be responsible for the grid operator's state regulatory policy efforts and support its work on related RTO policy matters.

An environmental engineer with more than two decades of utility regulatory experience, O'Guinn was nominated to the PSC in 2016. She has presided over SPP's Regional State Committee and is currently a member of the Organization of MISO States.

"I am very excited to be a part of the SPP team," O'Guinn said in a *press release*. "My career has been dedicated to regulatory issues, which provided me an opportunity to work with SPP and its stakeholders during my tenure at the PSC."

O'Guinn has also served in leadership roles with the Entergy Regional State Committee, the National Association of Regulatory Utility Commissioners, the Electric Power Research Institute's Advisory Council, the Women's Foundation of Arkansas, the American Association of Blacks in Energy, and Arkansas Women in Power. She holds a bachelor's of in environmental engineering from the University of Oklahoma.

Kim O'Guinn represents the Regional State Committee during a board meeting. | © *RTO Insider LLC*

Paul Suskie, SPP's general counsel and executive vice president of regulatory policy, said he is "thrilled" to welcome O'Guinn.

"As a former president of the [RSC], Kim is very familiar with SPP, and her experience as a nationally respected commissioner is a great asset to the organization," he said.

O'Guinn previously served as the Arkansas Department of Environmental Quality's director of communications and as permit engineer at the department's Office of Air. ■

*— Tom Kleckner*

## SPP News

# SPP Hands Lucas, Kelley New VP Positions

SPP on Dec. 21 announced it has promoted Antoine Lucas to vice president of markets and David Kelley to vice president of engineering.

Lucas has been SPP's engineering vice president since February 2020. His new role will have him overseeing the development, design and provision of all SPP market-based services. That will include the wholesale markets currently administered under the grid operator's tariff and additional value-added services.

Kelley, previously SPP's director of seams and tariff services, will replace Lucas. He will be tasked with the ongoing development of the transmission expansion plan, administering generator interconnection and transmission service study processes, regional resource adequacy policies, and other engineering studies.

SPP said Bruce Rew, senior vice president of operations, will continue to lead the organization's real-time operations, operational planning and analysis, and reliability coordination efforts. He will also continue to oversee the RTO's expansion into the Western Interconnection.

These changes allow SPP to continue to focus on reliable operation of the bulk electric system while managing its growing markets, it said. The grid operator has administered its day-ahead Integrated Marketplace in the Eastern Interconnection since 2014. SPP added the Western Energy Imbalance Services market in the West in 2021 and is working with Western utilities to design its Markets+ suite of market-related services.

"Our industry is ripe for innovation on so many fronts, and SPP is well positioned to deliver a brighter future for our region," Kelley, a 14-year employee, said in a *press release*. ■

*— Tom Kleckner*

SPP has named Antoine Lucas (left) and David Kelley as vice presidents of markets and engineering, respectively. | *SPP*

# SPP Makes Moves Out of the Southwest

## *Grid Operator Adds International Member, Expands in West*

*By Tom Kleckner*

SPP continues to make a misnomer out of its name. The *Southwest* Power Pool? Really?

In October, it added Canadian utility SaskPower as its first international member.

And this July, SPP's board, state regulators and members will gather in St. Paul, Minn., for their quarterly meetings. After all, who wants to meet in Minnesota in January?

And of course, the grid operator continues to expand its beachhead in the Western Interconnection along several different fronts.

Focusing on the RTO's stakeholder-driven culture as a counterweight to CAISO's market buildout efforts, staff worked closely with potential Western stakeholders to finalize its *Markets+ service offering*. The document lays out the market's governance structure and resource adequacy requirements that will, as SPP says, "ensure Western customers get the products and services they need at affordable rates they help control." (See *Governance, Resource Adequacy Key to SPP's Markets+*.)

"Without you at the table, we simply cannot develop the market the West wants: one that will serve Western needs with the governance that you value so much," CEO Barbara Sugg told Western stakeholders in a holiday email.

The grid operator says Markets+ is a conceptual bundle of services that would centralize day-ahead and real-time unit commitment and dispatch, deploy hurdle-free transmission service across its footprint and reliably integrate renewable generation for utilities that aren't yet ready to pursue full RTO membership.

Several Western organizations have already committed to funding the first development phase of Markets+ that establishes market rules and tariff language. SPP will engage through March with those utilities that have committed to funding Phase 1; staff have projected that will cost $9.7 million and take about 21 months.

Phase 2 will include the day-ahead market's development. Based on SPP's experience in building the Integrated Marketplace, staff has estimated the second phase will take three years and about $130 million to complete. Staff is assuming the market will be about a 50-GW system with up to 30 balancing authorities and 90 market participants.

Sugg said SPP has also seen a "growing interest" in full-scale RTO services. Seven participants in *SPP's Western Energy Imbalance Service* (WEIS) market, which the grid operator has been administering on a contract basis since February 2021, have signed onto a plan to form a Western RTO — dubbed RTO West.

SPP CEO Barbara Sugg addresses western stakeholders during Markets+ meeting in Portland, Ore. | *© RTO Insider LLC*

Western stakeholders are currently developing the RTO's terms, with a review scheduled to wrap up by March. It would then take another two or three years to integrate those utilities into the system. The WEIS market will also welcome Xcel Energy-Colorado, among others, in April.

A Brattle Group study for the grid operator found that a Western RTO would produce approximately $49 million in savings annually for SPP's current and new members. The Western utilities would receive $25 million a year in adjusted production cost savings and revenue from off-system sales, and SPP's Eastern Interconnection members would benefit from $24 million in savings resulting from the expansion of the RTO's market, transmission network and generation fleet.

SPP is also exploring a Markets+ transitional real-time balancing market, similar to the WEIS, that would launch in June 2024. A day-ahead balancing market would be developed at the same time and launch as soon as possible.

"Markets+ won't exist in isolation," Sugg said. "We certainly see opportunities to improve energy coordination within the East today, and we know California is a valuable trade partner in the West. Markets+ can optimize and improve the value of energy trading through carefully negotiated terms of coordination between peers across these seams."

SPP will form a Markets+ seams committee early this year and will work closely with stakeholders to facilitate and advocate for seams coordination "that results in fair, equitable and value-added outcomes, Sugg said.

Already a NERC-certified *reliability coordinator* for 16 Western utilities, SPP will also provide *program operator services* for the Western Power Pool's *Western Resource Adequacy Program* when it receives FERC approval. (See *FERC IDs Deficiencies in Western RA Program*.)

### Meanwhile, in the East...

Sugg said SPP is well on its way to achieving many of its *Aspire 2026* Strategic Plan initiatives, beyond expanding its service offerings in the West. It continues to improve and consolidate its transmission planning process, reduce

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the backlog in its interconnection queue, and define the grid of the future.

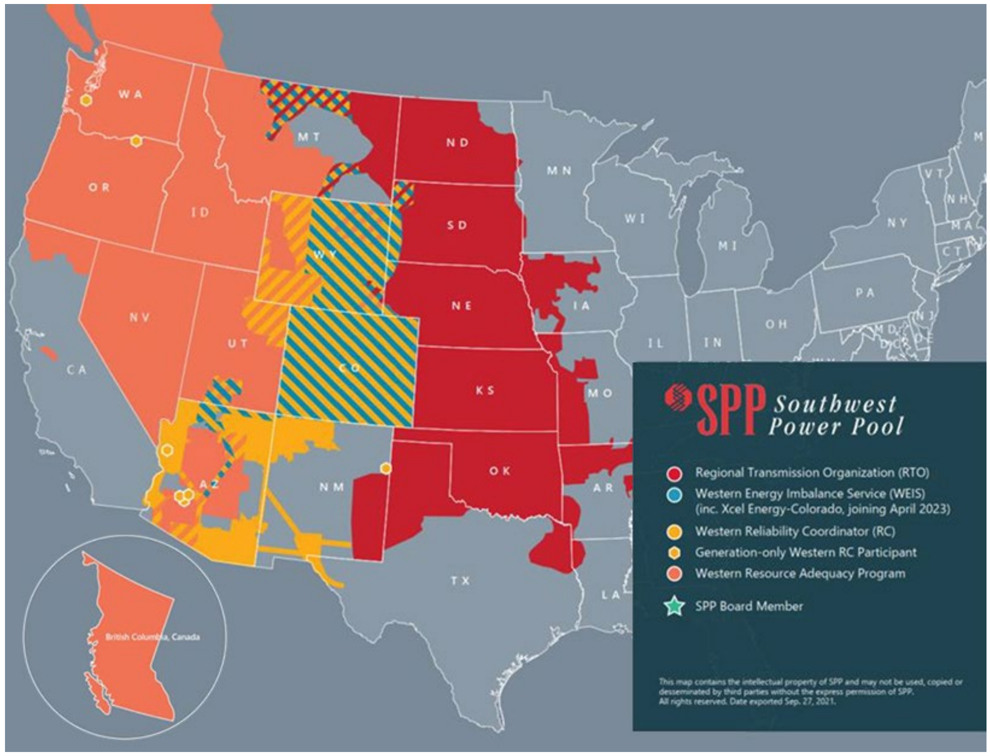
What the RTO was unable to do was find mutually beneficial interregional projects on its MISO seams. The grid operators' staffs said in December they will not pursue any small projects that will relieve constrained flowgates. It was the fifth time the RTOs have come up empty after four fruitless joint studies last decade. (See *MISO, SPP Unable to Find Smaller Joint Tx Projects*.)

In the meantime, demand continues to grow. Staff said increased load assumptions could result in an almost $7 million over-recovery for the year. As it was, SPP set new records for summer and winter peak demand (53.2 GW on July 19 and 47.1 GW on Dec. 22). The highs were 4.2% and 7.9% increases over previous records.

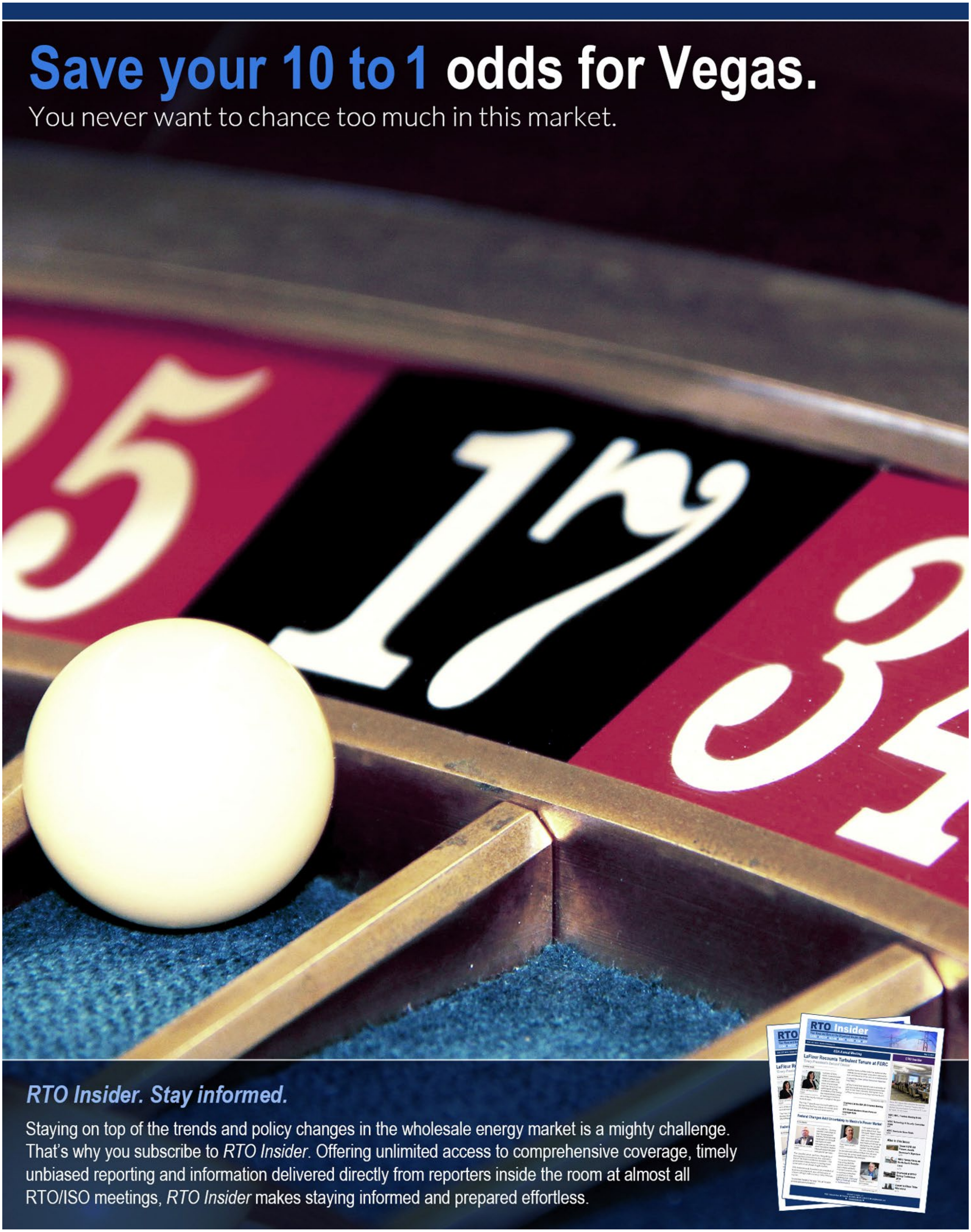
Non-standard loads such as crypto miners, data centers, biofuel and alternative fuel manufacturers, and cannabis grow houses account for much of the growth. SPP said that, since June, it had received more than 7 GW of interconnection requests for the firm and non-firm load, some of which would be behind the meter.

Staff will begin the year attempting to secure approval of a mitigation strategy for load-responsible entities unable to meet the new 15% planning reserve margin (PRM). They could reduce the deficiency payment charge, extend the timeline to cure deficiencies or add mechanisms to assure capacity and make failure to meet the requirements "less costly or less punitive."

The SPP board raised the PRM from 12% to 15%, effective Jan. 1. That left some members complaining they wouldn't have enough time to meet the requirements. (See *SPP Board, Regulators Side with Staff over Reserve Margin*.) ■




SPP's legacy RTO footprint and its western market services | *SPP*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