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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Your Eyes and Ears on the Organized Electric Markets
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In this week's issue

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When is a MWh not a MWh?

By Tony Clark and Vince Duane

The energy policy hive is having a healthy discussion of late taking up a question we raised 18 months ago. (See *Is Decarbonization an 'Existential' Challenge for RTOs?*) Can the single marginal price construct in ISO markets continue to work effectively given important changes to generation technologies?

ISOs and proponents of the status quo have risen to defend the single locational marginal price (LMP), at least when applied in energy and related ancillary service markets. They assure that reform and expansion of the construct is possible to meet new challenges, and they quickly dismiss any notion of a fundamental rethinking. Their arguments extolling LMP are not wrong; they're misplaced.

And they're the same arguments raised since LMP was introduced. Indeed, a recent report, prepared by Professors William Hogan and Scott Harvey for the NYISO, walks step by step through more than 30 years of LMP history to conclude that:

> economic theory and extensive practical experience demonstrate why the real-time locational marginal price is the only real-time pricing system that supports an efficient wholesale electricity market.

Vince Duane | *PJM*

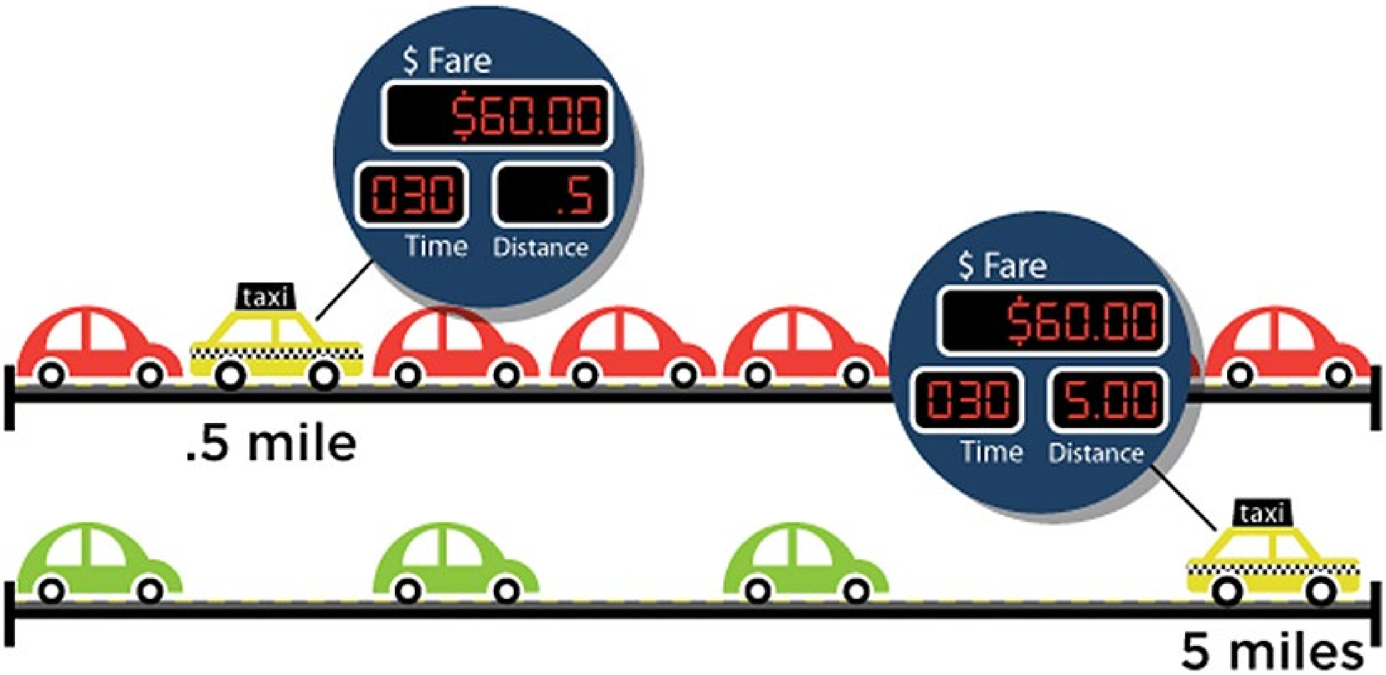
In comments last month to FERC and in reply to our prior writings, PJM's market monitor endorses Hogan and Harvey's recent paper. Much of the paper and comments in support simply recite (once again) the benefits that LMP offers as an efficient mechanism to dispatch, balance and schedule generation resources, price transmission congestion and reveal locational incentives and signals. We don't disagree.

LMP is great — let's get that out of the way. Our criticism is not with LMP in theory. Instead, we're seeking a dispassionate assessment of how LMP is actually performing today and its prospects for success in the future. Since its inception, the single marginal price market for energy has delivered on much of its promise, although only a zealot would deny its limitations, as evidenced by what our initial *paper* calls those "compensating fixes" (typically complex, imperfect and contentious) that tinker with or supplement LMP prices depending on circumstance. But can this delicate construct effectively manage a transforming grid?

Our writings pose several questions, most ignored in rebuttal, suggesting why past performance might not be indicative of future results. But on one point we seem to be talking past each other.

Tony Clark | *Wilkinson Barker Knauer*

Electricity today is physically injected onto the grid by an array of generating and storage technologies having disparate operating attributes. These injections vary in character from one another (not to mention they're poles apart from "virtual injections" offered by financial traders and demand response providers). Although these various injections each present a different profile to the system operator charged with keeping the lights on, from a market settlement perspective all are regarded as equal and paid the same. As the physical and virtual supply stack further evolves, can we continue to treat these injections as sufficiently homogenous in character to justify a single market, with a single clearing price paid to all? As we have said previously, the only thing fungible (or in the parlance of economists, "perfectly substitutable") when it comes to electricity is the electron itself. But no buyer, including particularly the system operator, is buying mere electrons. The megawatt-hour is in fact a high-



PJM likens locational marginal pricing to a taxi ride. When traffic is light, one can expect a consistent and predictable fare, like a period with little congestion on the grid. Heavy traffic means a higher fare, similar to pricing during congestion on the transmission system. | *PJM*

Stakeholder Soapbox

ly bundled product with varying operational attributes such as its constancy (or variability) over time, its ramping and load following attributes, its stability and inertia properties, its on-demand availability/dispatchability, etc. All these properties, in the right balance, are critically important to the operator in maintaining system reliability.

Some dismiss the question of megawatt-hour fungibility or substitutability as an empty formalism. And if we insisted on perfect fungibility, we'd agree with the characterization. Although treating electricity in LMP markets as fungible has always been a problematic exercise in applying "compensating fixes," it's been workable enough to unlock much of the benefit summarized by Hogan, Harvey and others. But make no mistake, the very basis underpinning the law of single price is a presumption of commoditization.

Here lies the problem. The debate isn't about the merits of LMP. It's about whether the penetration of new and transforming supply-side technologies (and demand response resources) permits us to continue to hold to a necessary predicate underlying LMP.

The following *statement* to *RTO Insider* from Professor Severin Borenstein, board member at CAISO, illustrates the communication gap:

> The idea that everybody gets paid a uniform price is how commodity markets work, not just for electricity — for natural gas, for gold, for oats, for everything. There's a market price, and people will get paid that market price because they're selling a homogeneous good.

Similarly, Hogan and Harvey's paper includes the oft-repeated admonition about the 1970s-era misadventure in pricing "new" and "old" oil differently. These responses miss the point. Of course, commodities should transact at a uniform price — assuming they are commodities, which is to say essentially homogenous like oil, gold, oats or anything else meeting the definition of a commodity. But equally, a market that pays the same price for different things has a problem.

Presuming we can treat equally all injected megawatt-hours regardless of the unique operational attributes associated with these injections deserves scrutiny considering changing technologies. Comments *filed* recently with FERC in Docket No. AD21-10 by Professor Leigh Tesfatsion offer the same, but expanded, explanation for why electricity is not like oil, gold and oats and thus why:

> all attempts to justify the (day-ahead/real-time market) two-settlement system (based on LMP pricing) by means of the efficiency and optimality properties of competitive commodity spot markets (based on competitive marginal cost = marginal benefit pricing) are conceptually unsupportable.

As the legion of rulemakings pending before FERC attest, there's no shortage of argument and opinion about the type of institutions/structures, electricity market design and transmission policy we need to facilitate grid transformation. Which is why it's puzzling to see the intellectual architects and master builders of the current ISO structure avoid engaging on this question of electricity as a commodity. Yes, the consequences that follow from finding that a bedrock presumption no longer holds will be profound and provoke a wholesale rethinking. Here again we say read Professor Tesfatsion's comments where she explains — ironically given how economists largely populate the field of electricity market design — that we might be ignoring the dictum of "sunk costs as sunk." Her comments introduce the "Ptolemaic Epicycle Conundrum," drawing on history's long and difficult road in accepting a Copernican sun-centric solar system by thinkers (and institutions) invested in Ptolemy's earth-centric system. This conundrum arises once we've all invested heavily in a certain model and layered on fix after fix as problems present, only to arrive at a sad place where "the correction of the fundamental conceptual inconsistencies in the core design principles is persistently deemed to be too costly to correct."

So, let's challenge the leading lights of energy economics and academia to prove that single clearing price LMP energy markets have not become "too big to fail." Let's examine the many ways electricity is being injected onto the grid today and the different operational attributes attendant to these injections, to ask whether a bedrock principle that directs us to pay all injections the same marginal price (varying potentially only by location) continues to hold. Answering this question is what we're looking for from these folks — rather than a rote repetition of LMP benefits. ■

Former FERC commissioner Tony Clark, a senior adviser at Wilkinson Barker Knauer, has represented several vertically integrated utilities in matters regarding utility deregulation and has authored several papers critiquing retail restructuring of the electric utility industry.

Vincent Duane, the former SVP for law, compliance and external relations for PJM, is principal of Copper Monarch, which provides advice on electricity market design, governance and strategy for system operators and companies that work with them. He also is a senior adviser to Market Reform, an international consultancy.

FERC/Federal News

Report: IRA Makes Renewables Cheaper than Virtually All US Coal Plants

Local Solar, Wind and Storage can Provide Reliability for Grid, Investment for Coal Communities

By K Kaufmann

If money were the only object, most coal plants providing power to the U.S. grid could be replaced today with regional or local renewable energy made cheaper by tax credits and other funding in the Inflation Reduction Act, according to a new study from industry analysts Energy Innovation.

Based on 2021 costs for operating 210 coal plants across the U.S., the new *Coal Cost Crossover 3.0* report found that all but one of those plants "are more expensive to run than replacing their generation capacity with either new solar or wind."

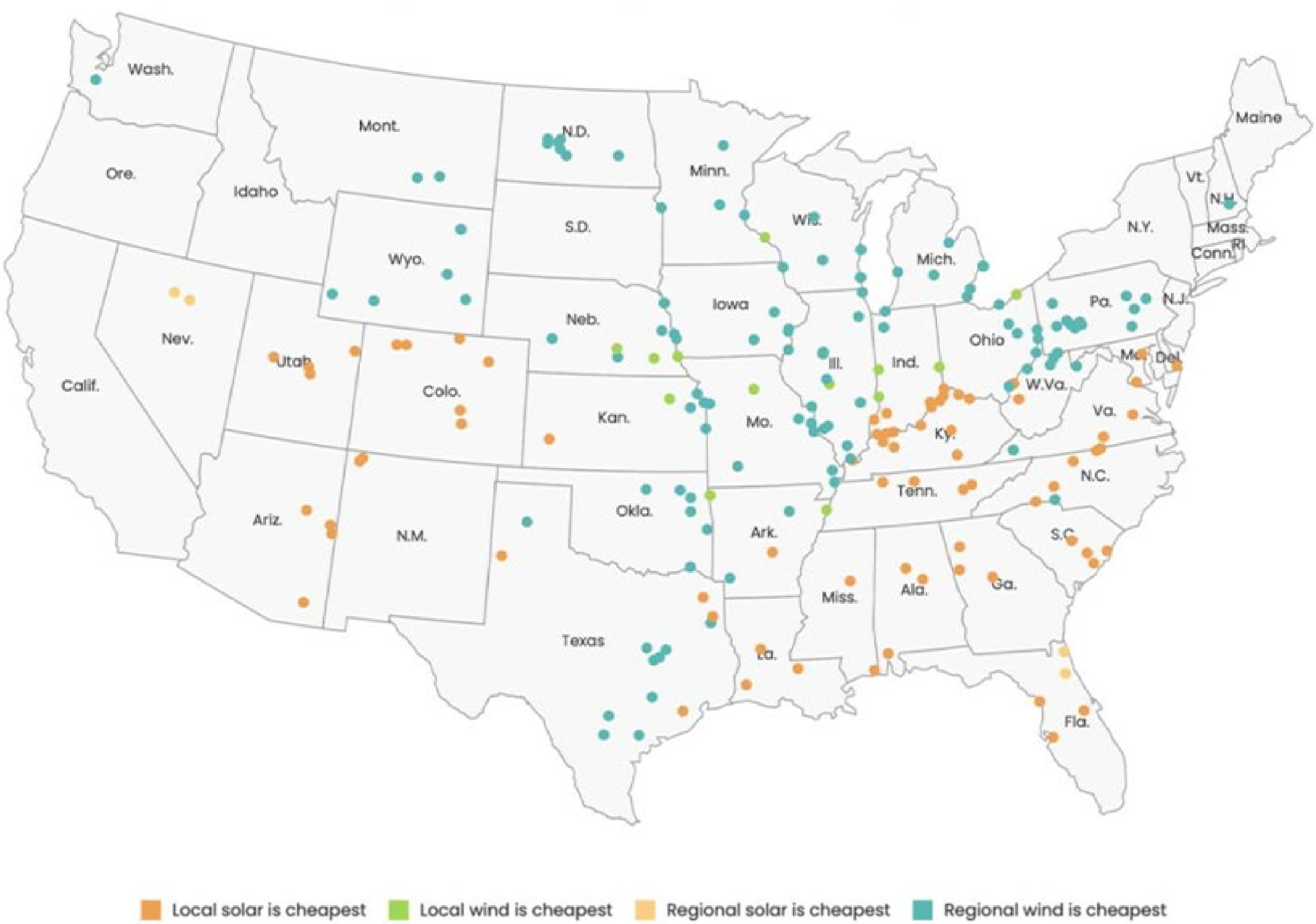
"It costs more to continue to run coal than it would be to build entirely new wind and solar resources," said Michelle Solomon, an Energy Innovation policy analyst and lead author on the report.

Many U.S. utilities are already planning to close their remaining coal plants by 2035, the timeline President Biden has set for the U.S. grid to be powered 100% by clean electricity.

Energy Innovation's previous *Coal Cost Crossover 2.0* report, issued in May 2021, found that 80% of the 235 plants then in operation were more expensive to run than new solar or wind.

With its more dramatic results, the new report does not push for any accelerated timelines, but "it tells every utility in the country that they need to take a hard look at every single coal plant," Solomon said. For "every single coal plant, the energy is more expensive than renewables."

The report also argues for the added benefits



The Energy Innovation study found that installing new renewable energy would be cheaper than keeping more than 200 coal plants in operation across the country. | *Energy Innovation*

FERC/Federal News

of "local" renewables, defined as solar, wind or storage sited within a 30-mile radius of a closed or soon-to-close coal plant. These include the potential jobs and tax revenues for communities as well as the potential for shorter interconnection times.

Both economics and the environment are driving the phaseout of coal in the U.S. In the last decade, the share of U.S. electricity produced by the dirtiest fossil fuel has plummeted from 50% to 21.9%, as coal has been replaced by natural gas and renewables, according to the *U.S. Energy Information Administration*.

But even at that lower level, coal still accounts for *60% of greenhouse gas emissions* from the U.S. electric power sector and 20% of emissions from the nation's energy consumption overall.

Looking ahead, EIA says, "23% of the 200,568 MW of coal-fired capacity currently operating in the United States has reported plans to retire by the end of 2029."

Those plants are in 24 states, including several that have not set targets for utilities to provide a specific percentage of their power from renewable or other clean energy sources, EIA says.

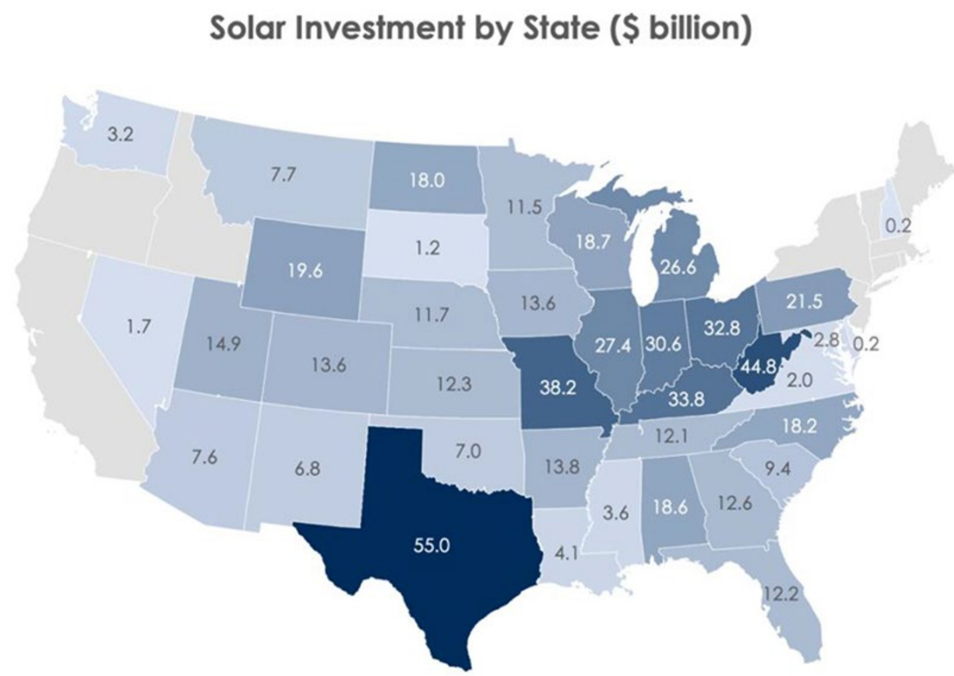
Energy Innovation sees the IRA as providing new economic momentum to take more coal offline. Both solar and wind owners can now choose between a 30% investment tax credit, more of a capacity-based incentive, or a performance-based 2.6-cent/kWh production tax credit, providing they pay workers prevailing wage and offer registered apprenticeships.

The law's bonus incentives for locating new renewable projects close to "energy communities" that have been affected by the closure of coal mines or coal-fired power plants could further cut costs, while driving "up to $589 billion in clean energy investment" in these areas, the report says.

Money saved from coal plant closures could also be used to take advantage of the IRA's energy storage investment tax credit, also 30%, to finance up to 137 GW of four-hour duration storage, which could replace 62% of the coal fleet's 220 GW of nameplate capacity, the report said.

Still another big plus is that new local solar or wind projects could use existing power lines, cutting interconnection time and costs and reducing the need for new transmission and distribution lines, the report says.

"The combined impacts of energy community, labor and domestic content bonuses reshape solar economics in coal communities," the



States across the country could see billions of dollars in new investments by replacing coal plants with solar, according to Energy Innovation. | *Energy Innovation*

report says. "The median cost of new solar in these communities is about $24/MWh with low variance, while the median marginal cost of coal is $36/MWh with higher variance."

In this context, Solomon said, "variance" means "the coal plant costs vary more than solar costs."

Stranded Assets and Reliability

But Michelle Bloodworth — president and CEO of America's Power, a coal industry trade association — called the report "misleading because it does not account for all the costs and challenges associated with replacing the coal fleet with wind and solar."

Replacing coal with renewables could cost at least $1 trillion and another $300 billion for the new transmission that would be needed, Bloodworth said in an email to *RTO Insider*. "Just as important, the report fails to consider the value of reliability, fuel diversity, fuel security and high-capacity value of the coal fleet, none of which can be matched by wind or solar."

Solomon countered that Energy Innovation's calculation of the cost of renewables, based on *computer models* developed by the National Renewable Energy Laboratory, does account for the all-in capital investments that will be required. The report also recognizes that the early closure of coal plants can leave utilities with millions in unpaid debt on their balance sheets and embedded in the higher rates their customers may have to pay as a result.

The IRA provides two potential options here, the report says. The law's *Energy Infrastructure Reinvestment* program provides low-interest loan guarantees to utilities replacing old energy infrastructure with new projects that "avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases," according to the Department of Energy.

The program is administered by DOE's Loan Programs Office which, under Director Jigar Shah, has already set rigorous guidelines for applications. During a recent interview, Shah said the office takes 12 to 18 months to process a typical loan application.

For electric cooperatives, which may be particularly dependent on coal for their electricity supply, the IRA also provides $9.7 billion in loans and grants for the purchase of renewables or other zero-emissions energy systems. The Rural Utilities Service at the Department of Agriculture is administering this program and has recently finished a series of *stakeholder*

FERC/Federal News

roundtables to gather input on its implementation.

Bloodworth's concerns about reliability are a more complex issue that Energy Innovation acknowledges as a major challenge for utilities and grid operators moving from coal to renewables. Delaware's 445.5-MW Indian River Generating Station, owned by NRG Energy, is a case in point, the report says. Though it was scheduled to close in June 2022, PJM requested it stay online through 2026 to ensure system reliability while transmission upgrades were made.

The RTO has "an established 90-day process to review generator retirement requests and their potential effects on the transmission system … to be sure reliability is not impacted," according to Jeffrey Shields, media relations manager for PJM. "This does not have anything to do with what kind of generator it is; it is a matter of how the system will be impacted without the particular generator providing power in a certain area."

In the case of Indian River, continuing to run the plant "was the only real solution to address immediate reliability needs until a long-term solution is built," Shields said in an email. "Longer-term replacement generation could certainly include solar, offshore wind or hybrid renewable units paired with storage."

While the plant is still online, it is run under a reliability-must-run agreement, which means it is run only in situations where system reliability cannot be provided by other sources; for example, in a "capacity emergency when … scheduled reserves are not sufficient," according to Shields.

Delaware ratepayers are paying an estimated $6.45/month extra on their electric bills, according to the *Delaware News Journal*, which called the plant "one of the state's top polluters."

Energy Innovation also said Indian River was "the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs."

"Local replacement of this plant [with wind or solar] could assuage reliability concerns by providing generation and capacity needs at the same location on the grid," the report says. "Our local analysis finds that 246 MW of storage could be funded via savings," which could provide more than half of the plant's capacity.

The Takeaway

Making such diversified portfolios of renewables a core element of regular resource planning is one of Energy Innovation's recommendations for utilities, grid operators and regulators going forward. Both local and "regional" siting is also recommended, as are continuing efforts to improve and streamline interconnection processes.

Specifically, Energy Innovation calls on grid operators to "improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid."

"PJM has already begun this process," Shields said. "We have adopted the effective load-carrying capability rating method to better reflect the reliability capacity value of renewables; and we will be making an additional filing at FERC to make sure that capacity matches up with the existing Capacity Interconnection Rights."

Renewable projects that are able to use a retiring coal plant's interconnection rights also "may reduce or eliminate the amount of network upgrades required for [a] new interconnection" Shields said. Fewer network upgrades could help to move a project up in the queue under PJM's new first-ready, first-served approach to interconnection, he said.

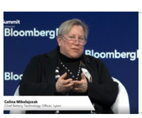
The takeaway here, while hopeful, is that long interconnection queues and the need for transmission upgrades and expansion are systemic problems that will continue to slow the transition to clean energy as the IRA's incentives and regulators' efforts at change work their way through a risk-averse, reliability-focused industry.

But the Energy Innovation report makes clear, among the many challenges an accelerated phaseout of coal could raise, the increasingly lower cost of renewables, combined with local siting could be critical drivers for finding solutions faster. ■

National/Federal news from our other channels

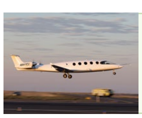
House Energy Panel Talks Permitting in First Hearing

NetZero Insider



Can the US Deliver Competitive Batteries?

NetZero Insider



Low-carbon Propulsion is Changing Aviation

NetZero Insider

Treasury Updates EV Tax Credit Vehicle Classifications

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Duke to Pay $75K in NERC Penalties

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Senate ENR Committee Grills Turk on IIJA Implementation

Manchin and White House at Odds over Law's Purpose, Goals

By K Kaufmann

Sen. Joe Manchin (D-W.Va.) | *Senate Energy and Natural Resources Committee*

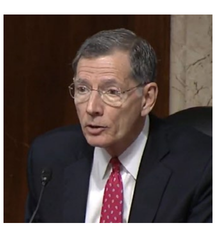
A political war is looming over the interpretation and implementation of both the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, with Sen. Joe Manchin (D-W.Va.), a key architect of both laws, attacking the White House on its efforts to circumvent what he sees as their clearly stated congressional intent.

DOE Deputy Secretary David Turk reports to the Senate Energy and Natural Resources Committee on the agency's rollout of programs funded by the IIJA. | *Senate Energy and Natural Resources Committee*

"The United States has an all-of-the-above energy policy that supports using all of our God-given resources in the cleanest way possible," Manchin said Thursday in his opening remarks at a Senate Energy and Natural Resources Committee hearing on the Department of Energy's implementation of the IIJA. "That's how we shore up energy security, achieve energy independence, while also addressing climate change.

"It is my intention to make sure that these laws are implemented swiftly, effectively and in line with that clear congressional intent, which I can assure you, this administration doesn't seem to want to do, but we're going to make sure they do it," said Manchin, who chairs the committee.

Manchin's opening salvos came as Deputy Energy Secretary David Turk faced the committee's first meeting of the 118th Congress to report on DOE's progress in rolling out the new programs funded by the IIJA. Keeping largely on message throughout the hearing, Turk stressed DOE's commitment to getting the money out "urgently, but right."



Sen. John Barrasso (R-Wyo.) | *Senate Energy and Natural Resources Committee*

Sen. John Barrasso (R-Wyo.), ranking member on the committee, was doubtful from the outset, noting that between the IIJA and IRA, DOE had received a "staggering" amount of money — close to $100 billion — on top of its $40 billion annual appropriation.

"The question is not whether the department is going to waste taxpayer dollars, but how to reduce the amount that it will waste," Barrasso said. He cited a letter from DOE Inspector General Teri Donaldson, noting that her office had received insufficient funds from the two laws relative to the amount of money to be monitored.

Barrasso raised questions about DOE's announcement in November of a $200 million grant to Microvast, an American company that produces battery components and has 80% of its operations in China. In a *January 2022 filing* to the Securities and Exchange Commission, Microvast acknowledged that doing business in China does present substantial risks because of its government's control of the business environment and foreign investment.

But the company is partnering with General Motors on a battery component factory to be located in the U.S., and the two companies are matching the DOE grant with a $300,000 investment.

Turk maintained that while the company had been "selected" for the grant, it has yet to receive any money. DOE is now in award negotiations with Microvast and GM, which will involve extensive due diligence, he said.

In a letter to Barrasso, Kathleen Hogan, DOE deputy undersecretary for infrastructure, stressed that such "thorough post-selection, risk-based due-diligence" was standard practice at the department. She also said that while Microvast's technology was developed in China, the DOE grant would be used for a first-ever U.S. manufacturing facility, "obviating the typical risk of intellectual property."

'Asleep at the Switch'

The current tension between Manchin and the White House is rooted in their very different views of the fundamental goals of the IIJA and IRA. Biden hailed the IRA as an unprecedented investment in climate action. For Manchin, it's about ensuring the energy security of the U.S. and the country's ability to maintain its leadership as a global superpower to help its allies in the face of Russia's invasion of Ukraine and its weaponization of energy.

"That's why we said, let's do a piece of legislation that uses the resources that we have … to be energy independent, using the fossil, horsepower we have, investing $369 billion to create the new technology — less carbon, if you will — but also not replacing what we need now until we have the other that can do the

FERC/Federal News

job. That's all we tried to do. And I don't know why we're in denial," he said Thursday.

Manchin sees such denial in the Internal Revenue Service's late December release of guidelines for the IRA's electric vehicle tax credits, in which the agency announced it was delaying guidelines on the law's domestic content requirements until March.

As originally written, to qualify for the full $7,500 tax credit, an EV's battery must contain a certain percentage of critical minerals sourced in North America or from a country with which the U.S. has a free trade agreement, and a certain percentage of other battery components must be sourced in North America. If one of the domestic content requirements is not met, a consumer may only get half the credit. While delaying the guidelines on domestic content, the IRS is allowing EV buyers to claim the full $7,500 credit.

Manchin has introduced a bill that would require the IRS to implement the domestic content requirements immediately and make them retroactive to Jan. 1, but he has been unsuccessful in bringing it to the Senate floor for a vote. (See *IRA's EV Tax Credits Spark Senate Debate*.)

He also criticized recent guidelines from the White House Council on Environmental Quality directing federal agencies to factor in greenhouse gas emissions when evaluating projects, arguing that they will favor renewable projects over fossil fuels.

Both issues are not under DOE jurisdiction, though Turk said the department was consulting with the IRS on the EV rules.

Responding to Manchin and Barrasso, Turk acknowledged that the U.S. "has fallen asleep at the switch" on building out clean technology supply chains for batteries, as well as solar panels. "China really has a stranglehold now on mineral processing and all these intermediate steps, so we're in a hole right now," he said.

But he defended DOE's grant-making process, which requires applicants to be U.S.-owned and operated, with U.S. headquarters. "The vast majority of our [IIJA] grants are competitive, and these are administered by civil servants. They're done that way for a reason: to ensure integrity in the process; to ensure fairness in the process," he said.

Input from industry experts and intelligence officials are also part of the review process, Turk said.

Turk also promoted DOE's progress on IIJA implementation, reporting that of the $62 billion DOE received in the bill, $37 billion has been made available to communities across the country. Turk's list of specific funding opportunities included $7 billion for regional hydrogen hubs, $750 million for electrolyzer manufacturing, more than $5 billion for "game-changing carbon management programs" and $3.9 billion for grid modernization.

The law's $2.8 billion for battery materials processing and component manufacturing has been paralleled with more than $92 billion in public and private investment in battery manufacturing across the country, he said.

On the IIJA's hydrogen hubs, Turk reported that DOE's solicitation, released in September, drew close to 80 concept papers, 33 of which the agency identified as promising and asked for full applications, setting an April 7 deadline for submissions. Turk expects awards to be announced by the fourth quarter of the year, but he said that Energy Secretary Jennifer Granholm might "try to move that timeline up."

Gas Stoves

While not directly related to either the IIJA and IRA, the political war over gas stoves was also on the agenda, with both Manchin and Barrasso railing against any attempt to ban the stoves in existing or new construction.

The Consumer Product Safety Commission triggered the controversy in January when Commissioner Richard Trumka raised the possibility of a ban because of the health hazards they present. The remark set off a firestorm of opposition and statements from both the CPSC and the White House that no such ban was being considered.

Manchin attacked both the CPSC and DOE, which on Wednesday issued proposed efficiency standards for cooktops, both electric and gas, framing the action as yet another attempt by the Biden administration to "find ways to push out natural gas."

He said he and Sen. Ted Cruz (R-Texas) would be *introducing a bill* to prohibit the banning of gas stoves. "The federal government doesn't have any business telling American families how to cook their dinner," he said.

DOE's *proposed standards* would limit the amount of electricity or gas a stove top can use per year. For electric stoves, those with open-coil cooking elements would be limited to 199 kWh/year and those with smooth element tops to 207 kWh/year. Gas stoves would be limited to 1,204 kBtu/year. DOE will be accepting comments on the proposal through April 3.

Echoing Manchin, Barrasso asked Turk to pledge that no money from the IIJA would be used "to ban or restrict the use of natural gas in new buildings."

Sen. Josh Hawley (R-Mo.) | *Senate Energy and Natural Resources Committee*

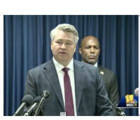
Thursday's hearing also marked the debut of Sen. Josh Hawley (R-Mo.) as the newest Republican member of the committee. A controversial figure — he was the first senator to declare he would object to certifying Biden's election in 2020 — Hawley spent his time browbeating Turk over the closure of an elementary school in his district, where radioactive waste was found in a nearby creek and later in the school itself.

Manchin intervened to explain that DOE has no jurisdiction to take action in the matter, and negotiations are ongoing with the U.S. Army Corps of Engineers, the agency that does. ■

National/Federal news from our other channels

DOE: Physical Attacks, Sabotage Jumped in 2022

ERO Insider



Feds Charge Two in Alleged Conspiracy to Attack BGE Grid

ERO Insider

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CAISO/West News

CAISO Approves Day-ahead Market for Western EIM

By Hudson Sangree

FOLSOM, Calif. — The CAISO Board of Governors and the Western Energy Imbalance Market Governing Body on Wednesday approved a plan to incorporate a day-ahead market into the Western EIM, calling it a milestone in regional grid integration.

"Today holds the promise for a new West, an opportunity for a new beginning in expanded markets and increased regional coordination," WEIM Governing Body Chair Robert Kondziolka said in opening remarks. "The decision items at today's meeting, if approved, are groundbreaking and profound."

The extended day-ahead market (EDAM) proposal passed with unanimous votes from both governing bodies, which met in-person together for the first time since the pandemic began three years ago to exercise their joint authority over the WEIM.

After years of planning and stakeholder meetings, the EDAM promises to greatly expand the amount of electricity traded in the sprawling WEIM, which will cover nearly 80% of load in the Western Interconnection once three new members join this year. The market, which now deals only with real-time transactions, has generated $3.4 billion in benefits for its members since it went live in late 2014.

Real-time trades are only a small part of the electricity market, however. Day-ahead transactions represent a far larger share. Transactions in both timeframes limit curtailment of renewable resources, such as California's abundant midday solar power, and allow for purchases of less expensive electricity during times of tight supply.

A study prepared for CAISO by Energy Strategies found that 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.

From left: WEIM Governing Body member John Prescott, CAISO Board of Governors Chair Mary Leslie, WEIM Governing Body Chair Robert Kondziolka, and CAISO Governor Ashutosh Bhagwat listened to public comments on EDAM. | © *RTO Insider LLC*

The West, with its 39 balancing authorities in states divided by geographic and political differences, is pursuing several major regionalization efforts, any of which could eventually establish the first Western RTO. In addition to EDAM, the Western Power Pool is awaiting FERC approval to launch its Western Resource Adequacy Program, and SPP is planning its own day-ahead market and a Western version of its Eastern RTO.

CAISO must also win FERC approval for the EDAM, which it hopes to start operating in 2024 or 2025.

'Important New Step'

PacifiCorp, a founding member of the WEIM, became the first entity to commit to join the EDAM in December. Others are expected to follow. The WEIM now has 19 *members* in all Western states, except for Colorado, and stretches from the Mexican border into British Columbia.

Key provisions of the EDAM design include a resource sufficiency evaluation intended to ensure participants can meet their internal demand for electricity before engaging in the day-ahead market — a means of preventing members from "leaning" on the market for supply. The final EDAM plan includes a tiered structure of financial penalties for failing to meet the test.

"The day-ahead RSE evaluates, across the next day 24-hour horizon, whether each balancing area's supply offered into the day-ahead market is sufficient to meet its next day forecasted load, imbalance reserve obligation, and self-provisioned ancillary service obligations," a CAISO staff *memo* to the boards said. "This includes functionality to allow each balancing authority to evaluate on an advisory basis its progress toward meeting the final RSE so they may take steps to cure any anticipated insufficiencies prior to the execution of the day-ahead market."

It also includes a provision that market participants make their internal transmission available for EDAM transfers.

"The availability of transmission, both internal to the system and across interfaces between balancing areas in EDAM, is foundational to optimizing unit commitment in the day-ahead market and to identifying robust energy transfers across the EDAM footprint," the memo says.

The CAISO and WEIM boards met together in person for the first time in three years. | © *RTO Insider LLC*

Balancing authorities in the EDAM will retain control of their resource and transmission planning.

A separate *decision* on EDAM governance adopted a plan developed by the WEIM's Governance Review Committee that adopts the WEIM's joint authority model for the EDAM while broadening the scope of that authority as well as the WEIM Governing Body's solo authority over certain matters.

Stakeholder comments were broadly supportive, though some came with caveats about details to be worked out later.

A coalition of 26 entities from across the West — including major utilities, environmental groups and trade organizations — expressed written support for the plan while acknowledging there is more to do.

"The undersigned entities support Board and Governing Body approval of the EDAM Final Proposal," the joint *letter* said. "To be sure, all the work is not yet done, and some entities will still need to conduct their own assessments of whether and when they might expect to join the EDAM, and seek regulatory approvals if applicable.

"There will be significant implementation and market mechanics to be worked through, and the potential EDAM entities will also have to reflect the new market in their own Open Access Transmission Tariffs under which they provide service to their transmission customers," it said. "But the basics on governance, resource sufficiency, transmission access and revenue attribution, and greenhouse gas rules enable the start of an important new step in regional market evolution." ■

CAISO/West News

CAISO CEO Lauds Transmission Planning Agreement

By Hudson Sangree

An agreement signed by California's three electricity planning entities will help coordinate resource and transmission planning in California to better reach the state's clean energy goals while maintaining grid reliability, CAISO CEO Elliot Mainzer told the ISO's Board of Governors on Thursday.

The memorandum of understanding signed by the California Energy Commission, the state Public Utilities Commission's and CAISO is a "new blueprint for our state" that provides for closer links between the planning processes of each party, Mainzer told the board in his monthly CEO briefing.

In California's divided energy planning process, the CEC forecasts demand while the CPUC handles resource planning and CAISO deals with transmission needs.

"All of those are [gears] that need to be synchronized so that we can effectively onboard resources in California," Mainzer said.

Outmoded planning was partly to blame for the state's rolling blackouts in August 2020, CAISO, the CEC and CPUC said in an October 2020 report to the governor. (See *CAISO Says Constrained Tx Contributed to Blackouts*.)

The recent MOU was signed in December and posted by CAISO to its website Jan. 19. It supersedes a 2010 agreement that included only CAISO and the CPUC.

The MOU draws closer links between the CPUC's Integrated Resource Planning (IRP) process, the ISO's transmission planning process, including its conceptual 20-year outlook, the CEC's Integrated Energy Policy Report (IEPR), which identifies the state's energy needs and its activities under Senate Bill 100, which requires all retail customers to be served with 100% clean energy by 2045.

The MOU's provisions include a requirement that the CEC, CPUC and CAISO "implement a joint work plan" on the CEC's IEPR and SB 100 proceedings to align the three parties' planning processes and maintain a flow of information between them. For example, under the new MOU the CPUC must incorporate the CEC's longer-term forecasts into its IRP process, and CAISO has to supply the results of its transmission planning and interconnection studies to the CPUC for resource planning.

CAISO intends to "put that MOU into practice

| © RTO Insider LLC

[this year] and … to transition from what I've characterized as sort of reactive transmission planning to much more leading and proactive transmission planning," Mainzer said.

The ISO expects to release its annually updated transmission plan in May and to "identify the forward-looking zones where we think the next big resource batholiths will be opened up," he said. "Our hope and expectation is that we're going to be using [our] transmission planning … to do a much more effective job of shaping queuing and procurement … because we simply can't be in the place of having to react and then we need 5,7, 10 years to get developed."

"Transmission is a leading indicator of planning rather than a lagging indicator," Mainzer told the board. "I'm hoping to be here by the end of this next year with a significant improvement in establishing those orders of operations."

As an example of the need to improve the process, Mainzer cited CAISO's efforts to deal with its "Cluster 14" queue of interconnection requests, which he detailed in his memo to the board.

"In April 2021, the ISO received 373 interconnection request applications totaling more than 50 gigawatts (GW) of renewable generation and more than 100 GW of energy storage in the Cluster 14 application window," Mainzer said in the memo. "This was more than three times the average of 113 applications over the last decade, and more than double the previous high of 155. Because of the challenge for the transmission owners and the ISO to process that many applications, the ISO extended the phase 1 study process by a full year."

At least 160 of the applications are moving to phase 2, and "that number may yet grow to more than 200 projects representing more than 67 GW, since a number of interconnection customers are still in the final validation process."

The next group of interconnection requests, Cluster 15, could generate 300 new applications by April, putting additional strains on transmission planners, Mainzer wrote.

"The excessive number of applications also provides even more impetus to move forward with overhauling our interconnection process in keeping with the objectives of the recently signed MOU with the CPUC and the CEC to focus on prioritization through alignment of state resource planning, ISO transmission planning, procurement processes, and the interconnection process," he said. ■

Transmission Project Would Span Across Interconnection Divide

By Sam Mintz

A Midwestern utility and an independent transmission company are teaming up to build a first-of-its-kind line that would span across the Western and Eastern interconnections and through three different electric regions.

ALLETE, a Minnesota-based energy company, and Grid United, a competitive transmission developer, *announced* their plans last week to build the North Plains Connector, a roughly 385-mile HVDC transmission line between North Dakota and Montana.

The developers say their project would be the first transmission connection between three "regional U.S. electric energy markets": MISO, SPP and the Western Interconnection. It would create 3,000 MW of transfer capacity between the regions.

SPP spokesperson Meghan Sever said that Grid United has been conducting a feasibility study on several transmission projects with the grid operator's staff and the Transmission Working Group, the scope of which was approved in September.

"Several merchant HVDC developers have approached SPP about projects in various stages of development. As with every project, SPP follows our stakeholder-approved study practices when evaluating the impacts of these projects on the SPP system," Sever said.

The project is still in the development stage, with permitting expected to start this year and a planned in-service date of 2029. Its unique nature has captured attention from the energy world, earning praise for its ambitious goals to connect the regions.

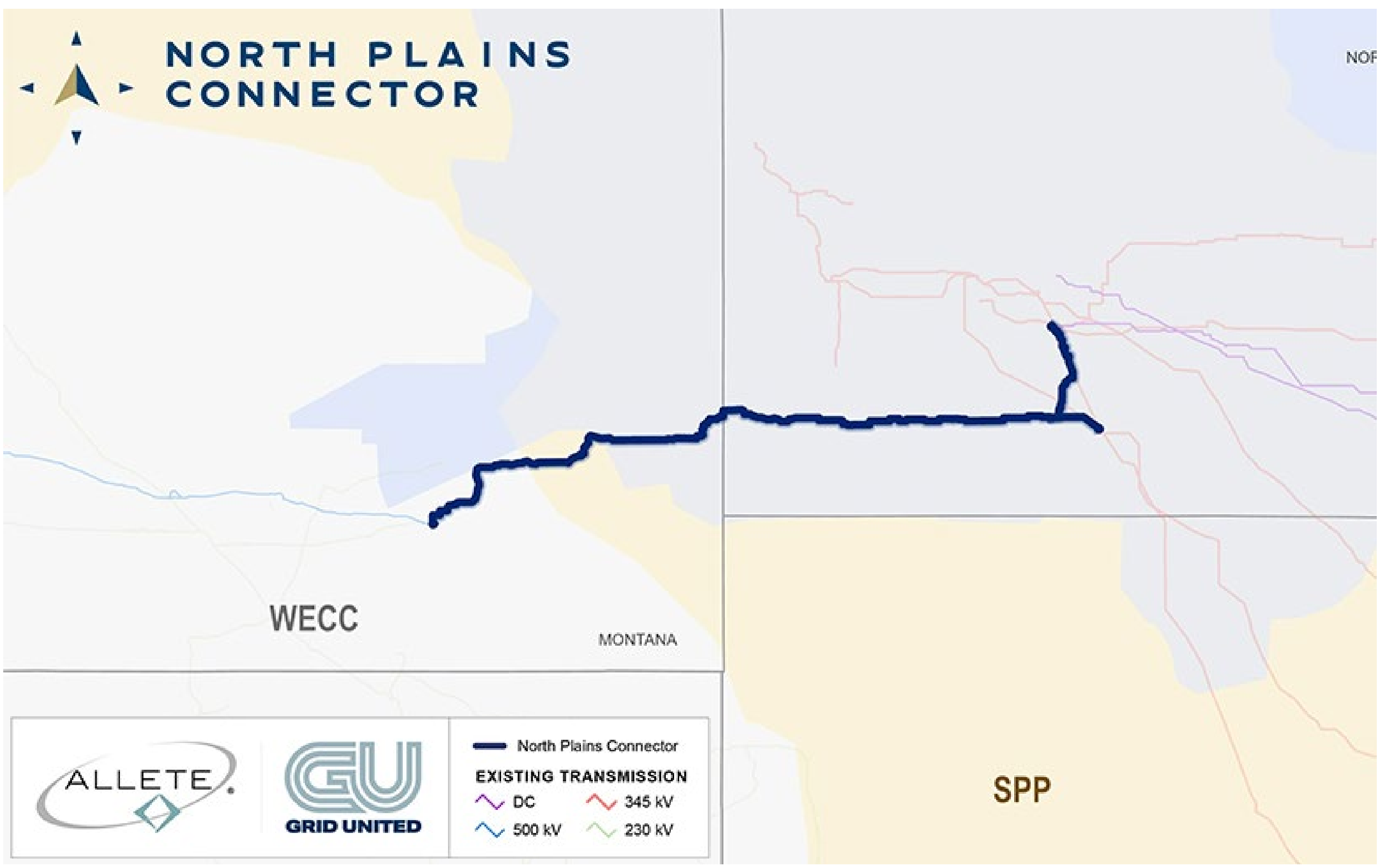
Grid United is run by Michael Skelly, a prominent clean energy executive whose past portfolio includes building transmission and wind projects at Clean Line Energy and Horizon Wind Energy.

"It is no secret that the U.S. is in desperate need of new electric transmission capacity, and the North Plains Connector will provide resiliency and reliability benefits for decades to come," Skelly said in a statement.

ALLETE owns utilities in Minnesota and Wisconsin, as well as energy production subsidiaries in North Dakota, Minnesota and Maryland. Its CEO and president, Bethany Owen, called the project "innovative" and said its an "important step toward a resilient and reliable energy grid across a wide area of the country."

The collaboration between a utility and an independent transmission company is also an innovative part of the project that energy experts have called out.

"It's starting!" tweeted Rob Gramlich, an energy consultant and former FERC official. He predicted that "joint ventures, joint ownership and joint [transmission companies] will join forces to build infrastructure, serve specific utility load and upsize to serve wider market demand." ■



The North Plains Connector would link three regional energy systems. | *ALLETE*

CAISO/West News

Wash. Poised to Become Net Electricity Importer by 2050

By John Stang

OLYMPIA, Wash. — With its abundance of hydroelectric resources, Washington has long been a key exporter of power to other parts of the West.

But the state's Department of Commerce now says Washington is poised to become a net importer of electricity by mid-century as it moves to decarbonize its economy — a development that has alarmed lawmakers.

In 2021, Washington sent more than 18% of its generation to its neighbors in the Western Interconnection. By 2050, the state will have to reverse that pattern and import more supply to reach its goal of weaning itself from fossil fuels, the agency has found.

One reason: a mandate that all new cars sold in Washington by 2035 must be electric vehicles. A lot of additional electricity will be needed to keep those cars running.

In fact, the state's efforts to replace carbon-emitting fossil fuels translates into increased demand for electricity as a substitute, said Glenn Blackmon, manager of the Commerce Department's Energy Policy Office.

"It's replacing fossil fuels in every sector of our economy," Blackmon said in an interview.

"Are we planning for the amount of electricity needed to recharge these [electric] automobiles?" Sen. Lisa Wellman (D) asked during a Jan. 13 hearing of the Senate's Environment, Energy and Technology Committee.

According to data from the U.S. Energy Information Administration, in 2021 Washington generated almost 111 million MWh of electricity, imported slightly more than 5 million MWh, and consumed a bit more than 88 million MWh, translating into roughly 18 million MWh of net exports.

At the Jan. 13 hearing, Blackmon told the Senate committee that the state's power needs will increase by 97% by 2050 — to almost 230 million MWh. That means Washington will have to import a huge amount of power by 2050, he said.

"That's a big thing to say we will begin importing power instead of exporting it," Sen. Shelly Short (R) said.

The Commerce Department predicts that by 2050 36% of Washington's clean energy will likely come from wind farms in Montana and Wyoming.

Industry observers say Washington will need to build much more high-voltage transmission to accommodate the demand stemming from widespread electrification. A new state Senate bill would require utilities to look 20 years into the future to assess tranmission needs. | *© RTO Insider LLC*

"We need more capacity to site and permit clean energy projects in a timely manner, and we need to bolster our transmission infrastructure to reliably deliver clean energy throughout the state," Jaime Smith, spokesman for Gov. Jay Inslee, wrote in an email to *RTO Insider*.

Greater Need for Connection

For almost a decade, Inslee has pushed aggressively to curtail fossil fuel use in Washington, finally achieving major policy victories in the last two legislative sessions. Those included the nation's second cap-and-trade law and a low-carbon fuel standard that went into effect this year. The legislature also set a soft goal of 2030 for reducing sales of gas-powered vehicles, followed by Inslee's mandate last year that no new internal combustion engine cars be sold in the state as of 2035.

Inslee's goals build on a 2008 state law that sets carbon-reduction targets of 45% below 1990 levels by 2030, 70% by 2040 and 95% by 2050. A 2021 Commerce Department *report* put the state's CO_2 emissions at 99.57 million metric tons in 2018. The report shows that from 2016 to 2018, the transportation sector was the largest contributor, at nearly 45% of Washington's emissions.

With the state planning to shift from gas-powered cars to EVs in the 2030s, Washington's power needs will grow, along with a need for more transmission lines, Blackmon said.

An *analysis* published by the Seattle-based Sightline Institute last October put that issue into sharper focus.

"Cascadia, like the United States as a whole, suffers from a woefully underbuilt and aging electric grid," wrote Emily Moore, Sightline's director of climate and energy. "The grid is so inadequate that hundreds of proposed wind and solar projects are ending up at the back of waitlists where they may sit for years. … New transmission lines (the high-voltage lines that often stretch over mountain ranges and along rivers on tall, scaffolded towers) take a decade or more to construct, giving the problem increasing urgency with each passing year."

Moore continued: "Unless Northwest policymakers develop a plan for building out the grid we need, and unless they start erecting it immediately — through the Bonneville Power Administration, state action, utility investment, or some combination of these means — the region's ambitious decarbonization commitments will amount to so much hot air.… That's right. We may fail the climate test because we're missing some wires."

While hard figures are not available, Commerce has determined that massive construction of new power lines between Washington and other states such as Montana, Wyoming and Oregon is needed by 2050.

The state's utilities are legally required to identify and plan for future transmission needs. However, Nicolas Garcia, representing the Washington Public Utility Districts Associations, last month told state senators that many utilities don't have the expertise for transmission planning.

It takes 10 to 20 years to build a power transmission line corridor between Washington and another state, while it takes two to three years to build a solar or wind farm, Kathleen Drew, chair of state's Energy Facility Site Evaluation Council, told the Senate energy committee at a Jan. 18 hearing on a transmission planning bill. Ten years is not long enough to tackle the studies, leasing, permitting, coordinating and construction of a transmission line corridor, she said.

Sen. Joe Nguyen (D), chair of the Environment, Energy and Technology Committee, has introduced Senate Bill 5165 to require utilities to begin using a 20-year planning horizon — instead of the current 10 years — to identify transmission needs.

State agencies, environmental groups and some utilities support the bill. But Avista Utilities and the Association of Washington Business said more details are needed on the processes and targets within the bill.

"It needs clearer standards and deadlines for agency decisions," Avista's John Rothlin said. ■

PG&E Can be Tried Again for Manslaughter

By Hudson Sangree

A California judge ruled Wednesday that there was enough evidence to put Pacific Gas and Electric on trial for four counts of involuntary manslaughter and seven charges of recklessly starting a fire for the September 2020 Zogg Fire in rural Shasta County.

The blaze killed four people, including a mother and her young daughter; burned more than 56,000 acres; and destroyed 204 structures. The California Department of Forestry and Fire Protection (Cal Fire) determined the fire started when a leaning gray pine tree fell onto a PG&E power line.

The Shasta County District Attorney said in its September 2021 criminal complaint that PG&E had failed in its "legal duty to safely operate electrical transmission and distribution lines in a manner that minimizes the risk of catastrophic wildfires" by failing to clear the tree.

The judge dismissed 20 of the original 31 charges, including those related to air pollution from the fire, but the DA's office indicated it intended to press forward with the remaining counts.

"Following a seven-day preliminary hearing, Pacific Gas and Electric was held to answer today for multiple felony and misdemeanor criminal charges for its role in starting the Zogg Fire," the prosecutors office said in a Facebook post. At its next court date on Feb. 15, PG&E "will be arraigned on the information, and a trial date may be set."

The company could seek a negotiated settlement, but in a statement last week, it continued to argue it was not criminally liable for the fire.

"We believe PG&E did not commit any crimes," the utility said, contending that its employees and tree-trimming contractors had exercised "good-faith judgment" in deciding not to cut down the pine tree.

When the charges were filed in September 2021, PG&E CEO Patti Poppe said the utility "accepted Cal Fire's determination … that a tree contacted our electric line and started the Zogg Fire," but "two trained arborists walked this line and, independent of one another, determined the tree in question could stay."

"We trimmed or removed over 5,000 trees on this very circuit alone," Poppe said at the time.

Another Case of Manslaughter?

The Zogg Fire was the second time that the state's largest utility has been charged with manslaughter.

PG&E pleaded guilty in June 2020 to 84 counts of involuntary manslaughter and one count of arson in the 2018 Camp Fire, which, along with a spate of fires in 2017, forced the utility into bankruptcy proceedings and led to a multibillion-dollar settlement with fire victims.

In August 2016, jurors convicted PG&E of six felonies stemming from the San Bruno gas pipeline explosion, which killed eight people and destroyed part of a suburban San Francisco neighborhood. PG&E was not charged in the deaths; it was found guilty of obstructing a federal investigation and violating pipeline safety standards.

A federal judge sentenced the utility to five years' probation starting in January 2017.

In April 2021, Sonoma County prosecutors charged the utility with five felonies and 28 misdemeanors from the October 2019 Kincade Fire, including "recklessly causing a fire with great bodily injury" to firefighters and emitting harmful contaminants, including wildfire smoke and ash into the air, harming children.

Those charges were dropped after PG&E reached a $31 million settlement with the county and four affected cities. ■

Cal Fire determined that a pine tree hitting a PG&E power line started the Zogg Fire in September 2020. | *Cal Fire Shasta-Trinity Unit*

CAISO/West News

WECC Panel Challenges Conventional Views on Grid Reliability

Capacity No Longer 'King,' NERC Official Says

By Robert Mullin

The electric sector must fundamentally reconsider how it measures and manages grid reliability in response to a changing climate and evolving generation mix that increasingly includes variable resources.

That was a key takeaway from an online panel hosted by WECC on Thursday, the first of the regional entity's monthly discussion series this year on resource adequacy.

While the message is not necessarily a new one, panelists offered some fresh perspectives.

"I think [what] we're really coming down to is [that] capacity used to be king; I like to say the king has no clothes," said Mark Lauby, NERC senior vice president and chief engineer.

Lauby was referring to the industry — and NERC — requirement that an electricity network be designed to meet the one-in-10 loss-of-load expectation (LOLE) standard, which calls for utilities to manage their systems in a way that demand doesn't exceed available supply for more than one day in every 10 years. At the heart of LOLE is a focus on carrying enough generating capacity to meet the highest expected loads with a safe reserve margin.

But the makeup of the grid has changed since the advent of the LOLE standard, Lauby noted, and so have the conditions under which it operates. With climate change, weather is becoming more volatile, and weather events such as cold snaps are lasting longer, particularly in areas not accustomed to such events. That change has prompted NERC to alter its approach to producing its reliability assessments.

"Now we're actually laying out different types of scenarios and working with regional entities in the assessment areas to say, 'OK, what about a cold winter?' And let's kind of figure out what that looks like," he said. "What is extreme cold weather for a particular assessment area? And then we work with them to determine what might be the forced outage rates for the plants, because when things get cold, things kind of break a little bit at a higher rate."

Northwest officials speaking on the WECC panel said the region's hydroelectric system is becoming increasingly strained in the face of climate change. | © RTO Insider LLC

CAISO/West News

Instead of focusing on capacity, Lauby said, the industry must shift its lens to measures of energy and essential reliability services, such as frequency and voltage support and ramping capability.

"We were cheating by using capacity because we had firm fuel, and we don't have that anymore in many cases [and conditions] are less certain, and we're actually becoming more and more less certain. So how do we firm that up? What does that look like?" he said.

"We have to develop a whole new set of metrics to understand exactly what are the risks we're dealing with as we transform this grid. And we can do it; we just got to do it in a way in which we can ensure that we can not only deal with the short ramps and the short conditions, but also the long-term widespread conditions," Lauby said.

Small Perturbations, Bigger Impacts

Oregon Public Utility Commissioner Letha Tawney expanded the critique on industry convention, questioning long-held beliefs on what constitutes a reliable resource mix in a warming climate.

"I'm not sure the traditional generation stack is performing particularly well in the face of the stress of climate change," Tawney said. She pointed out that, during a heat wave last summer, a large coal plant in the Northwest tripped offline because of water scarcity and heat stress, pushing two Oregon utilities into emergency alerts.

Oregon PUC Commissioner Letha Tawney | *WCPSC*

Tawney also warned that the changing climate is putting stress on the Northwest hydroelectric system. She said current high natural gas prices in the West are at least partly attributable to relatively low hydro flows.

"I think the variability we may see in the hydro system could really stress us as we get sort of to that outer edge. We're running sort of with less margin in general, and so small perturbations create bigger impacts then maybe they did when we were much longer on [hydro] resources," she said.

George Lynch, legal counsel for the Idaho Governor's Office of Energy and Mineral Resources, echoed Tawney's concerns about the Northwest hydro system. Lynch said that while his state has seen "really rapid development" of renewable resources, his office has "also worked to support dispatchable resources such as nuclear and geothermal, especially as we see our hydropower declining over time, or at least becoming a little less reliable than has historically been."

Lynch said Idaho has historically enjoyed cheap electricity because of its hydro system, which has attracted businesses that have taken advantage of the low prices.

"We've also had really low natural gas prices, but I think natural gas prices across the region have increased up to threefold this last winter … due to the lower hydro output, so that's something that we've been watching," he said.

More Humility Needed

Tawney turned her attention to the broader West, pointing to the challenges the Western Area Power Administration faces in preventing Arizona's Lake Powell from reaching "dead pool" status amid a record-long drought. That would curtail output from the Glen Canyon Dam and hobble the Southwest's black start capability and ability to maintain a stable grid. "That's a long-term challenge," she said.

Tawney said the power sector hasn't really grappled with the fact that even Oregon is enduring its longest drought in 1,200 years. "I think we don't think ahead to [whether] the coal plants, or any of the thermal plants, [will] have the temperature of water that they need during one of these heat events to cool. Will they be able to access their water rights, or will they be supplanted because it's a particularly bad year?"

Mark Lauby, NERC | © *RTO Insider LLC*

The Oregon commissioner defended California's response to the energy emergencies accompanying last September's scorching heat wave, when CAISO was forced to rely on last-minute conservation measures and a high volume of imports to avoid blackouts in the face of record demand. She called for more "humility" among neighboring states that also would've struggled to meet loads that fell so far outside planning margins. (See *California Runs on Fumes but Avoids Blackouts*.)

Tawney said that while there's "a lot of finger-pointing at California" around its grid issues, the state was actually confronted with "one-in-10" events.

"They've hit their LOLE, and there's still a lot of focus around keeping them moving forward on staying reliable," she said.

"Now, is one-in-10 good enough? I think that's a different question, and it sure doesn't seem like it is. It sure doesn't seem like one-in-10 is actually acceptable any longer, and so that adds a real challenge," Tawney said.

"For all of us in the West, nobody is immune," concluded panel moderator Kristine Raper, WECC vice president of external affairs. "I think this is the lesson that we should have learned over the last handful of years." ■

West news from our other channels

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NetZero Insider

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CAISO/West News

FERC Orders Changes to PacifiCorp and NV Energy Interconnection Rules

James Downing

FERC on Friday ordered show cause proceedings on PacifiCorp's and NV Energy's generator interconnection rules while approving, in part, rules aimed at limiting speculative projects in Nevada.

The first show-cause order (*EL23-26*) found that PacifiCorp's large generator interconnection procedures might be unjust and unreasonable due to rules that trigger restudy of lower-queued customers when an interconnection customer suspends its agreement. The commission also questioned the requirement that the suspending customer pay for the restudies.

FERC Order 2003 requires interconnection customers to pay for their own studies, even if it is a restudy caused by another firm's decision to withdraw its higher-queued project. The order also allows projects to suspend their interconnection agreements for up to three years, which gives developers flexibility to deal with permitting and other delays that are likely to impact large projects.

FERC issued a preliminary finding that PacifiCorp's requirement is unjust and unreasonable because the company can require restudies when a developer only suspends its interconnection agreement, even though a restudy would not be needed if the project ultimately proceeds.

The second show-cause order (*EL23-27*) directs Nevada Power to show why its large generator interconnection procedures are just and reasonable despite not specifying a method for allocating the costs of network upgrades among interconnection customers in a cluster.

FERC has approved serial cluster studies for both ISO/RTOs and independent utilities, including PacifiCorp and NV Energy, subsidiaries of Berkshire Hathaway Energy. NV Energy's 2013 update to its large generator interconnection procedures includes *pro forma* language that said it "may allocate the cost of common upgrades for clustered interconnection requests without regard to queue position," but the procedures do not specify how those costs are allocated.

The specific costs significantly affect rates and should be included in the utility's tariff, FERC said. Without specific rules on file, the commission said, it cannot easily determine whether any cost allocations are consistent with its precedent.

The two utilities must show cause as to why their rules are just and reasonable within 60 days, or they can propose changes under Section 205 of the Federal Power Act to address FERC's concerns. A 205 filing would put the show-cause proceeding in abeyance while the commission considers the proposals.

The third order (*ER22-2933*) approves some changes NV Energy proposed to discourage speculative interconnection projects and allow projects that are ready to move forward with construction to get through the line faster. The utility has seen the number of requests to connect to its grid spike, and recently, 42% of them have either gone into default, been withdrawn, or have interconnection agreements under suspension.

To cut back on the speculative projects, NV Energy proposed increasing deposit requirements; eliminating the use of a "Preliminary Plan of Development" (a document used by the Bureau of Land Management when firms seek to build on federal land) as a form of site control; and setting a withdrawal penalty to hold remaining customers harmless from restudy costs. It also would create a graduated deposit structure based on project size, ranging from $75,000 for up to 50 MW; $150,000 for 50 to 200 MW; and to $250,000 for 200 MW or greater.

FERC approved the stricter site control requirements, including raising the deposit in lieu of site control from $50,000 to $250,000. Those rules will increase the likelihood that only commercially viable projects will have a place in the queue, FERC said.

The commission rejected the withdrawal penalties NV Energy proposed because it found that requiring such customers to cover restudy costs would prove too burdensome. Other utilities have withdrawal penalties, but they are more limited, FERC said.

FERC also rejected NV Energy's proposal to require interconnection customers who suspend their agreements to pay for restudies of lower-queued projects. Because suspended projects still have the option to move forward, FERC ruled it would be "inefficient for [NV Energy] to conduct a restudy based on the assumption that a suspending interconnection customer is going to withdraw from the queue."

The commission also rejected a rule that would have let Nevada Power assign the cost of network upgrades that were only triggered by one project in a cluster to that specific project. FERC found the language was not specific enough.

In discussing that rule, the commission also noted that it launched the second show cause proceeding against Nevada Power because its tariff does not include how the utility allocates the costs of network upgrades among interconnection customers in a cluster. ■

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CAISO/West News

New Coalition Aims for California to be in RTO

By Hudson Sangree

A new coalition of trade and environmental groups says California needs to be part of an RTO to achieve its clean energy goals and maintain reliability, adding its voice to those calling for Western organized markets and for CAISO to grow into a multistate RTO.

Calling itself Lights on California, the coalition's *members* include national trade groups Advanced Energy United and the Solar Energy Industries Association, environmental organizations Natural Resources Defense Council and Environmental Defense Fund, and the California Chamber of Commerce, which wields significant influence in the state capitol.

Lights on California launched Monday with a *news release* and *website*, saying its purpose is to raise awareness about the "state's options for building a more affordable, more reliable clean energy grid through participation" in a Western RTO and to advocate for that goal.

"We simply cannot afford to be left behind as the rest of the West looks for regional solutions that will enhance reliability," Chamber of Commerce Policy Advocate Brady Van Engelen said in the news release. "An RTO is clearly one of the best ways to deliver it, providing a framework for tapping into vast wind, solar and other reliable, low-cost clean energy supplies across the West."

The group's announcement was the latest development in a reinvigorated effort to allow CAISO to become an RTO. Several prior attempts failed, the last in 2018, because lawmakers were unwilling to change the ISO's rules to allow out-of-state members to serve on its Board of Governors.

Circumstances in the West have changed substantially in the years since, fueling a new push and giving advocates more hope of success.

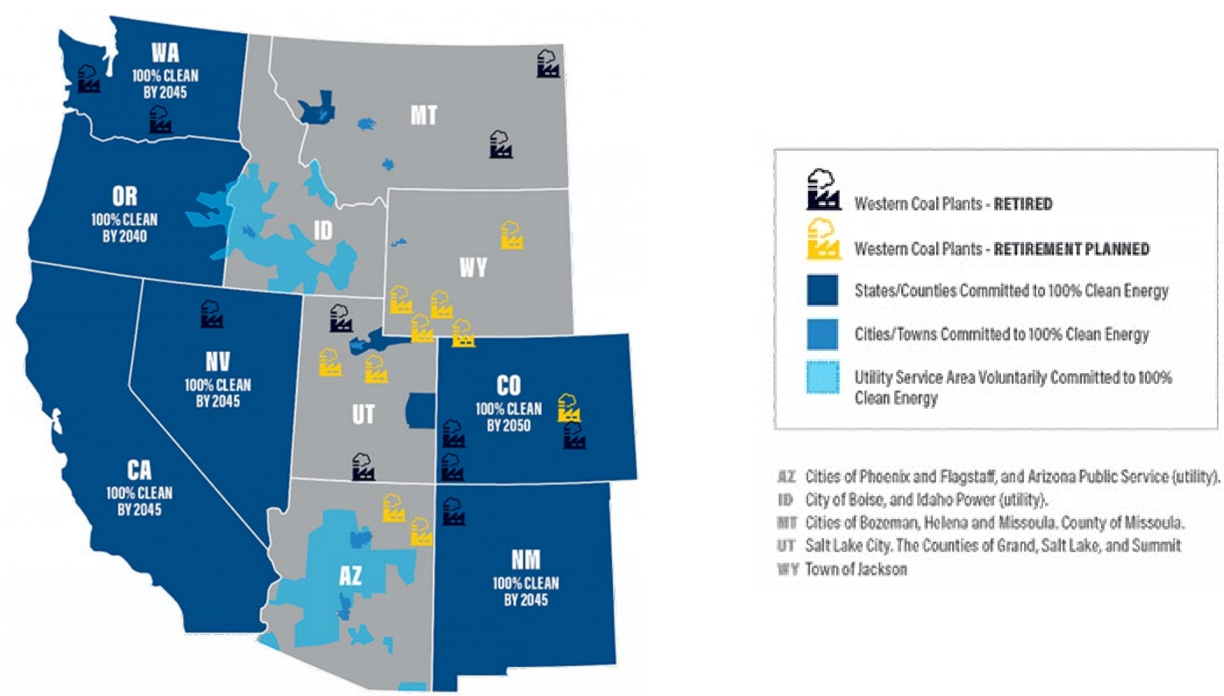
The new conditions include strained supply in CAISO and its neighbors during Western heat waves, the need for new transmission to carry renewable power long distances across the West, and legal mandates for Colorado and Nevada transmission owners to join RTOs by 2030. In addition, more states are adopting clean energy and emissions reduction targets, which advocates say will be much easier to achieve in an RTO.

Potential competition from SPP, which plans to establish its own Western RTO, and from the Western Power Pool, whose Western Resource Adequacy Program could be a springboard to an RTO, are lending urgency to the latest CAISO governance reform effort.

The coalition cited last year's unanimous passage of Assembly Concurrent Resolution 188, which asked CAISO to prepare a report for the state legislature summarizing studies of the benefits of regional market participation. Assemblymember Christopher Holden, who headed the 2017/18 effort to make CAISO a regional organization, authored ACR 188 with the intent of restarting the conversation on CAISO becoming an RTO. (See *Plans Revive to Make CAISO a Western RTO*.)

A draft of the report, performed by the National Renewable Energy Laboratory for CAISO, was published Jan. 13 with a final version due to lawmakers by the end of February. Among the studies it examined was one led by state energy offices in Utah, Colorado, Idaho and Montana that 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. (See *Study Shows RTO Could Save West $2B Yearly by 2030*.)

"As the legislature considers how best to act on the CAISO/NREL findings, the Lights on California coalition will be working together to raise awareness about the benefits of an RTO for consumers, for businesses, for workers and for the environment," the group said in its news release. ■



A map on the coalition's website shows states, cities and utilities committed to 100% clean energy and coal plant retirements. | *Lights on California*

ERCOT Briefs

Ice Storm Hammers Texas; 400K Customer Outages Reported

ERCOT easily met demand last week as icy weather swept through the state and created local distribution outages affecting as many as 400,000 customers at one point.

The grid operator's load never averaged more than the 65.56 GW it did during the early evening hours of Jan. 31, when the storm swept through the northern half of state. Demand peaked at 73.96 GW during the December winter storm, a 16-GW increase from ERCOT's previous high for the month.

Most of the outages were centered on Austin and Northeast Texas, where trees succumbed to the icy accumulation in what locals referred to as an "*oakpocalypse*." *Some observers pointed* to lax vegetation management and opposition to tree-trimming measures as the primary reason for the outages.

Austin Energy crews at work restoring service. | *Austin Energy*

Austin Energy, the city's municipal utility, had more than 163,000 customer outages at one point. By Sunday morning, it had reduced that total to 44,000, meaning some customers had been *without power for 102 hours*, longer than they were during the deadly 2021 winter storm.

Oncor, which serves much of North Texas, said Saturday it had restored power to the *"vast majority"* of its customers. The utility reported more than 140,000 customer outages Thursday morning.

Texas still had more than 65,000 customer outages Sunday morning, according to *poweroutage.us*.

Texas Gov. Greg Abbott *said* ERCOT maintained "ample supply" during the week and reminded his Twitter audience that outages were caused by "local issues." On Saturday, he *declared* disaster conditions for seven counties affected by the storm.

Calpine to Develop Gas Peaker

Calpine said Friday it will begin developing a 425-MW peaking facility at an existing power plant site following the Texas Public Utility Commission's recent adoption of a framework intended to incent new generation.

The PUC last month agreed on the principles necessary to replace ERCOT's energy-only market with a performance credit mechanism (PCM). The design rewards generators with credits based on their performance during a determined number of scarcity hours. Those credits must either be bought by load-serving entities, or exchanged between them and generators in a voluntary forward market. (See *Texas PUC Submits Reliability Plan to Legislature*.)

"The PCM framework adopted last week by the [PUC] sends a strong signal of support for maintaining a reliable grid in [Texas] through market-based mechanisms rather than government mandates," Calpine *tweeted*.

The company is a member of Texas Competitive Power Advocates, which promised to build 4.6 GW of additional capacity if the PCM is adopted.

"We are encouraged that the PUC is acting to ensure Texas maintains a reliable power supply through market-based mechanisms rather than government handouts," Calpine said in a *press release*. "Regulatory certainty on PCM will be critical as Calpine continues to move this project forward."

The peaker will be built next to the *Freestone Energy Center*, a 794-MW combined cycle gas plant between Dallas and Houston. Calpine must secure an air permit from the Texas Commission on Environmental Quality; a spokesman said the project's front-end development will take 12 to 18 months.

61-MW Gas Plant to Retire

Blue Cube Operations, a wholly owned subsidiary of Dow Chemical, *notified* ERCOT on Friday that it plans to decommission and retire a gas-fired plant south of Houston on July 4.

The combined cycle steam turbine has a 61-MW summer seasonal net max sustainable rating and a 58-MW minimum rating. The unit was commissioned in 1982 and is paired with a Dow cogeneration facility.

ERCOT normally conducts a reliability-impact analysis before approving a resource's suspension of operations. It *said* in a market notice last month that it has not designated any generation facility as necessary to avoid an adverse reliability impact in the planning horizon of more than one year.

ERCOT.com Adds 6-day Forecast

ERCOT on Friday unveiled a new six-day forecast on its supply-and-demand dashboard as part of its continued effort to increase transparency into grid operations. The dashboard displays the system's current capacity and demand using real-time data from hourly forecasts and other sources.

The forecasts can be found from the Grid and Market Conditions *page* on ERCOT's *website*.

"While the supply and demand forecasts may change, as weather forecasts do, the dashboard provides a general 'heads-up' on the trends based on currently known information," Dan Woodfin, vice president of system operations, said in a release. ■

— Tom Kleckner

BOEM Continues Planning Process for Gulf of Maine OSW

Series of Public Listening Sessions Concludes

By John Cropley

The concept of floating wind power in the Gulf of Maine continues to take shape.

The U.S. Bureau of Ocean Energy Management last week wrapped up a series of informational sessions online and in person in Maine, Massachusetts and New Hampshire, seeking feedback as it develops a map of potential wind farm sites.

The eight-step process is intended to refine and shrink the initial planning area into individual lease areas, eliminating millions of acres less suited for wind power for reasons as varied as lobsters, pipelines, whales and commercial shipping.

There is more to come: Fisheries data, for example, have not been incorporated into planning yet.

The current "*draft call area*" is only Step 3 along the way and, at 9.9 million acres, is already 27% smaller than the area initially outlined.

"We recognize that this still a large area with significant conflict, and that's really what we're now turning our focus toward, looking toward the fishing effort, marine mammal and avian hotspots and any additional concerns that exist within this area," BOEM project coordinator Zack Jylkka said Jan. 31.

An audience member at the virtual meeting asked if a tract eliminated from the area of consideration could later be added back.

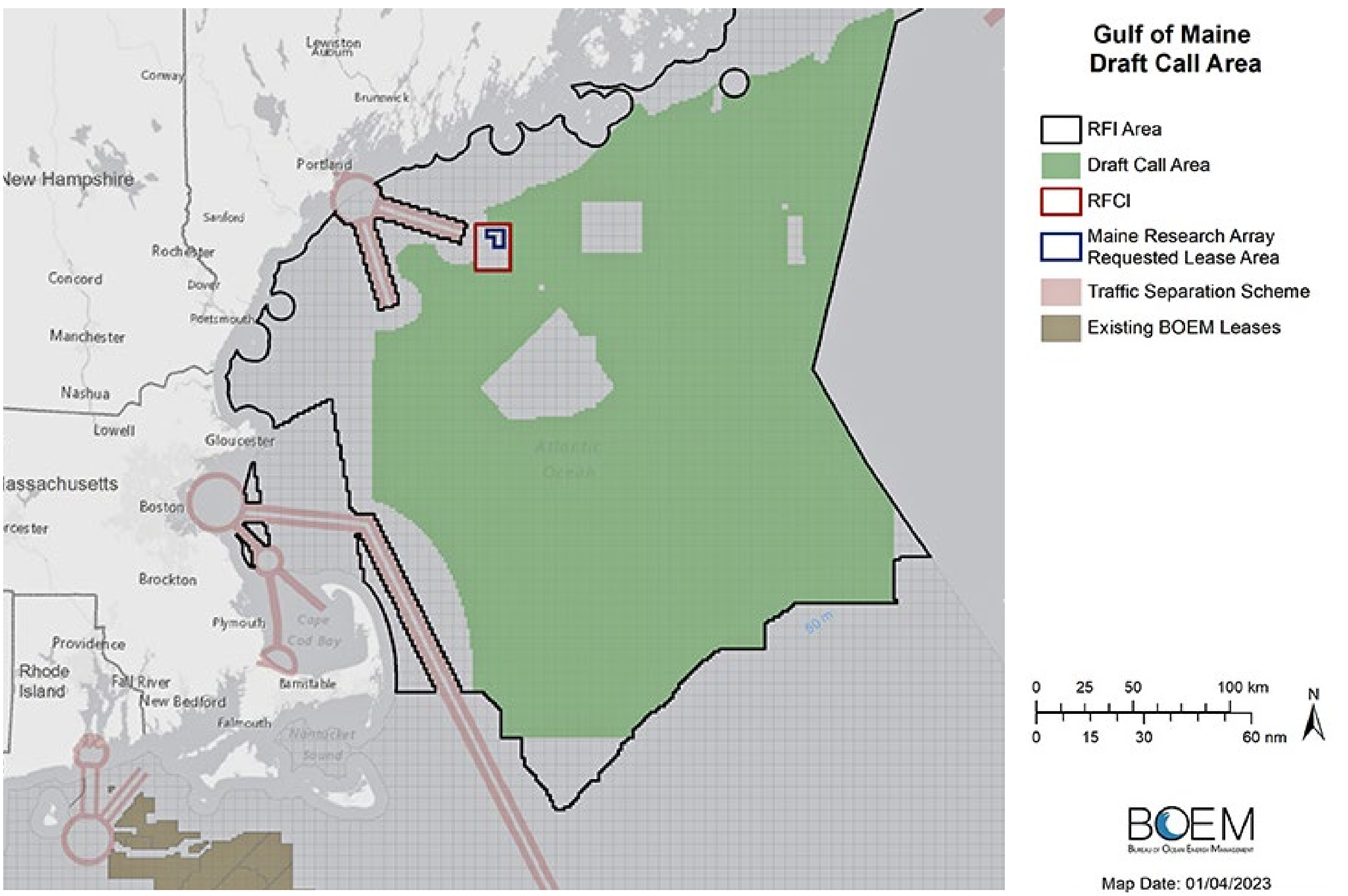
It typically would not be, Jylkka said. The process is slow and deliberative in hopes of avoiding the need for changes. But the ocean is a dynamic environment, so changes are sometimes needed, and BOEM is not precluded from making them, he said.

Has there been coordination with grid operators on the best interconnection points for electricity from offshore wind?

"One of the variables there is distance to shore, distance to interconnection points," Jylkka said. "So, we're certainly looking at that to inform some of the suitability of potential areas. But ultimately, we're still asking a lot of questions ourselves."

Is impact on endangered species weighted more than impact on nonendangered species?

The methodology has evolved in the last couple of years, said James Morris, a marine ecologist with the National Oceanic and Atmospheric Administration's National Centers for Coastal Ocean Science. "We'll essentially assign a score to each one of those species, based on its status and trend."



This area in the Gulf of Maine is being studied for potential offshore wind development. | *BOEM*

ISO-NE News

A species with small and declining numbers would get a very low score for compatibility with a wind project, for example. All the scores for all the species are combined to produce a single data layer, to be added to the map with layers for the various other potential impacts.

The U.S. Department of the Interior in 2021 said it hoped to hold a lease sale in the Gulf of Maine by 2025. Jylkka said last week that the auction is currently projected to be in the third quarter of 2024.

The offshore wind industry is still in its very early stages in the U.S., and the projects now being built and planned on the East Coast entail towers on seabed foundations. But the areas targeted for development in the Gulf of Maine, like those off the California coast, are deep enough to require anchored floating wind turbines, a technology still being developed and refined.

Five companies so far have expressed interest in potentially developing wind power in the gulf, Jylkka said: Avangrid Renewables, Hexicon USA, Pine Tree Offshore Wind (RWE Renewables and Diamond Offshore Wind), Total Energies SBE US (Total Energies and Simply Blue) and US Mainstream Renewable Power.

As large-scale commercial wind power is considered in the Gulf of Maine, the state of Maine is pressing forward on a related track: It has applied to BOEM for a *research lease* on 9,700 acres about 45 dozen miles southwest of Portland for up to a dozen floating turbines with a combined capacity of up to 144 MW.

The University of Maine has been designing and developing a floating concrete hull technology for offshore wind for more than a decade. A research array would advance that technology and give insight to the interaction floating wind turbines would have with fishing, shipping and other maritime activities and ecosystems.

On Jan. 19, BOEM *announced* a "determination of no competitive interest," moving the state's application to an environmental review of potential impacts from such a project.

The university, in a partnership that includes RWE and Diamond, is planning to anchor a single 10-MW floating turbine close to Monhegan Island in 2024. It is an up-scaled version of a *turbine* that was tested off the coast at Castine a decade ago.

Kelt Wilska, energy justice manager for Maine Conservation Voters and Maine's lead representative in *New England for Offshore Wind*, told *RTO Insider* last week that he likes the progress being made.

"I view this through the lens of urgency," he said. "We need to move very quickly to meet our climate goals both at the state and federal level."

But there is value to a deliberative process, Wilska added.

BOEM was not required to hold the series of public meetings, he said. The fact that it did so indicates the agency is committed to a just and inclusive process, which is important to him and those he works with.

"I am pleased with the amount of care they are putting into winnowing down this area," Wilska said.

The draft version of Maine's own offshore wind *roadmap* shows the results of extensive outreach and collaboration, he added. "We want to really build on that." ■

ISO-NE News

FERC Resolves NextEra-Avangrid Dispute over Seabrook Circuit Breaker

By Sam Mintz


The Seabrook Station nuclear plant in New Hampshire | *Jim Richmond, CC BY-SA 2.0, via Wikimedia Commons*

FERC on Wednesday settled a dispute between NextEra Energy and Avangrid over whether the former should be responsible for upgrading a circuit breaker at the Seabrook nuclear plant in New Hampshire (*EL21-3, EL21-6*).

The two have been going back and forth on the project, which ISO-NE says is necessary to help support Avangrid's New England Clean Energy Connect transmission line, since 2020.

NextEra, which owns and operates Seabrook, initially asked FERC to find that the plant should not have to take a financial loss in order to upgrade the breaker. Avangrid then filed a complaint arguing that Seabrook has been "unlawfully attempting to delay and unreasonably increase the costs of the breaker replacement."

FERC essentially found that Avangrid's reasoning for why Seabrook should replace the breaker was faulty, but that the nuclear plant can't refuse to replace it because the breaker is a component of the generating facility and upgrading it is required by "*Good Utility Practice*."

The nuclear plant's interconnection agreement "does not permit Seabrook to refuse to replace the breaker when replacement is needed for reliable operation of the Seabrook Station and given the concerns in the record related to the impact of any unreliable Station operation on the reliable operation of the system," FERC wrote.

And the principles of Good Utility Practice require Seabrook to replace the breaker before NECEC interconnects because the breaker will be "overdutied" once it does, the commission said.

An ISO-NE system impact study found that the breaker is operating at 99.6% of its capability now, but it would be at 101.2% once NECEC is in service.

While FERC has been considering the complaint, the two parties have been hashing out an agreement: The filing says that the breaker replacement is now scheduled for a fall 2024 refueling outage, with the commercial operation date for NECEC being December 2024.

According to FERC, both agree that Avangrid should pay for the direct costs of the breaker placement, but they disagree over whether the company should pay opportunity and legal costs.

FERC sided with Avangrid, saying that Seabrook can't recover those additional costs.

"The commission typically allows opportunity cost recovery so that the resource will be revenue-neutral and therefore indifferent towards the system operator's decision as to which service the resource will provide," FERC wrote. "That is not the case here." ■

MISO News

Solar Trade Group Challenges MISO Ban on Renewable Ancillary Services

By Amanda Durish Cook

The Solar Energy Industries Association last week lodged a complaint at FERC against MISO's practice of blocking intermittent resources from its ancillary services market.

SEIA, represented by Earthjustice, *asked* that the commission find as unjust and unreasonable MISO's tariff provisions and business practice procedures restricting wind, solar and battery hybrid resources from providing regulation service, spinning reserves and supplemental reserves.

The organization said the RTO prevents its dispatchable intermittent resources (DIRs) from ancillary services participation "despite the fact that [they] have the operational capability to provide such services."

"No other FERC-jurisdictional RTO or ISO codifies this explicit discriminatory prohibition," SEIA said in its filing, noting that PJM and CAISO explicitly state wind and solar resources' eligibility.

SEIA also pointed out that MISO never meant for its ban on renewable ancillary services to be permanent. In a 2010 filing with FERC, the grid operator said it needed "to gain experience with this new method of modeling and dispatching" before allowing renewable energy to supply operating reserves. SEIA said FERC's ultimate agreement with MISO's prohibition hinged on its temporary nature. To date, MISO has never provided a "technical justification" for its ban, the organization said.

It argued MISO's market rules discriminate against some resources because they're tailored to the large, centralized power plants of the past.

"MISO's discriminatory and unjustified tariff provisions that prohibit DIRs from providing ancillary services in MISO's wholesale market is a prototypical example of how outdated tariff provisions can result in unnecessary and deleterious market barriers," the organization said.

SEIA said lifting the ban would increase competition and allow new resources to "provide the critical grid-stabilizing services that MISO will need." It said that though MISO "fundamentally agrees" that renewable resources should be able to provide all the services they're capable of, the grid operator hasn't acted on a longstanding suggestion that it extend its ancillary service market to renewable energy. According to SEIA, the issue was raised as part of MISO's 2018 market roadmap improvement ideas; staff last year *recommended* putting the idea to rest without action.

The complaint comes as MISO has announced plans to ban dispatchable intermittent resources from providing ramping needs, saying they're historically unhelpful. (See *MISO Plans to Bar Intermittent Resources from Ramp Capability*.)

"Rather than doubling down on nonmarket-based blanket prohibitions, MISO ought to be focused on facilitating technology-neutral, operations-focused solutions that properly establish criteria for when a resource is called upon to provide ancillary services," SEIA said.

In a *press release* accompanying the complaint, Earthjustice attorney Aaron Stemplewicz said his organization is prepared to challenge

| SEIA

MISO's "attempts to strip wind, solar and battery hybrid resources from providing ramp capability."

"Any backsliding will be rigorously challenged with regard to the eligibility of renewable resources to provide all the services they are capable of providing," he said.

SEIA Energy Markets Director Melissa Alfano added that energy markets must keep pace with a changing grid.

"Renewable assets like solar, storage and wind have more than proven themselves as reliable, and we need to recognize the full scope of their benefits if we want to rapidly decarbonize in the next 10 years," she said. ■

MISO News

FERC Ends MISO Compensation for Reactive Power Supply

$220 Million Annual Revenue Requirement Eliminated

By Amanda Durish Cook

FERC last month approved MISO Transmission Owners' request to eliminate reactive power compensation for generators, rejecting multiple protests.

The commission's Jan. 27 order cited *Order 2003*, which said generators do not have to be compensated for providing a standard range of reactive power because they're simply meeting a condition of interconnection (*ER23-523*).

MISO Transmission Owners in December filed to eliminate reactive power and voltage control charges from their own and unaffiliated generation resources. TOs said the revisions will result in a rate decrease for transmission customers. They argued that the number of unaffiliated generators collecting reactive power compensation has grown to a $220 million annual revenue requirement and climbing. (See *MISO TOs File to End Reactive Supply Compensation*.)

Under Schedule 2 of MISO's tariff, most generation owners can apply to receive separate compensation for their reactive supply. The TOs asked FERC to eliminate separate charges to pay for reactive service supplied within the standard power factor range of 0.95 leading to 0.95 lagging.

Several clean energy generation owners accused the TOs of using their agreement with MISO in an "abusive" manner. Groups including the Coalition of Midwest Power Producers, American Clean Power Association and Clean Grid Alliance said MISO TOs lacked the authority to make the change, gave stakeholders just 19 days' notice that it intended to make the change and failed to vet the proposal in the stakeholder process.

EDF Renewables and Vistra Energy argued many independent power producers in the footprint will suffer harsh financial effects. The Solar Energy Industries Association and Wolverine Power Supply Cooperative contended that eliminating reactive supply compensation could lead to generation developers installing reactive power capabilities only to the bare minimum standard power factor range, setting off a possible shortfall that could keep MISO from returning to reliable operations during an emergency.

The protestors also said the removal of Schedule 2 wasn't fair because generation-based

Alliant Energy's new Wood County Solar Project in Wisconsin | *Alliant Energy*

reactive power won't be eligible for compensation while MISO TOs will continue to be paid for their transmission-installed reactive devices in their rate bases. They noted that MISO's 2022 Transmission Expansion Plan includes $146 million of new reactive support and voltage control devices on which the MISO TOs will earn cost recovery plus a rate of return.

But FERC said a reliance on reactive supply compensation isn't a good enough argument to continue its practice. It said new interconnecting generators must provide standard reactive service as a condition of interconnection and aren't entitled to payment for doing what's mandatory.

The commission waved away concerns that MISO's system reliability could suffer without the compensation. It said other wording in MISO's tariff allows MISO to compensate a resource if it has to direct it to provide reactive power outside of the standard power factor range.

FERC also said it found no discrimination against independent power producers in the proposal. It said the IPPs are free to try to recover lost reactive power revenue through increased power sales rates, just as TOs' generating units can through retail rates.

Finally, the commission rejected arguments that TOs can unfairly continue to collect reactive power payments through transmission-installed reactive devices. The commission said the issue at hand related to generation-based reactive power payments, not transmission. It said TOs proposed to treat affiliated and unaffiliated generation alike.

Commissioner James Danly disagreed with the commission's decision, writing that MISO TOs did not meet their burden of proof that the current rate was unreasonable, given the "substantial unrebutted evidence of the negative rate impacts that this will have on generators not affiliated with the MISO TOs."

Danly said it was unsatisfactory for MISO TOs to simply cite Order 2003 and previous orders where the commission decided that generators don't have to be paid for reactive power within the standard range.

Danly argued that in prior cases, FERC "eliminated reactive power compensation when only a handful of unaffiliated generators were receiving — or still seeking — it."

"The situation in MISO clearly is distinguishable where scores of generators are recovering reactive power compensation and it has been a part of the MISO tariff for years," Danly wrote.

Commissioner Allison Clements concurred in a separate statement, writing that she would have preferred the MISO TOs use a "different procedural approach" that incorporated more stakeholder input.

She said MISO TOs' filing is evidence that FERC's current cost-based methodology for reactive power compensation "is poorly suited for newer technologies and non-synchronous generation like wind, solar, and storage." She said FERC should act on its Notice of Inquiry opened in 2021 to examine the current regulations associated with reactive power compensation (*RM22-2*). The commission has not acted in response to comments filed in the docket early last year. (See *FERC Seeks Comments on Reactive Power Compensation*.)

"Whether or not generators located in MISO were justified in relying on continued reactive power compensation, parties have stated in the record that this decision will cause financial disruption," she said.

Clements encouraged MISO stakeholders to "consider more effective alternatives to cost-based reactive power compensation."

"Services should be appropriately compensated for the benefits they provide, and reactive power plays an important reliability function… [S]takeholders may wish to consider market solutions and/or compensation models that are based on the performance of the generators in providing reactive power when called upon, or that incentivize reactive power generation to be located where additional reactive supply is most needed from a reliability perspective," Clements wrote. ■

MISO News

MISO Says 2nd LRTP Portfolio Still in Flux

By Amanda Durish Cook

CARMEL, Ind. — System planners last month emphasized that MISO won't analyze its second portfolio of long-range transmission projects (LRTP) with any preconceived notions.

Matt Tackett, principal adviser of expansion planning, told stakeholders during a Jan. 27 workshop that MISO's current project map is not a final proposal. He said it's a "starting point for analysis," repeating that phrase for emphasis.

Tackett said the concept map was based on "qualitative future considerations" and that a final second portfolio could morph into something entirely different.

"This is a work in progress. It could change before we even begin the analysis," he said. "Please don't interpret this as a final proposal or even speculation at what a final proposal could look like.

"We must consider the fact that we're under a new operating scenario in the future," Tackett said, adding that the RTO's resource mix and load profile will be different in future years and generation dispatch will be more volatile.

MISO late last year debuted a conceptual map of a second Midwestern LRTP portfolio that planners said could cost up to $30 billion. (See *MISO Staff Preview New LRTP Projects with Board*.)

"It goes without saying that this is a major effort … to further our reliability imperative and effectuate our ongoing fleet change," said Jarred Miland, senior manager of transmission planning coordination.

He said any projects staff eventually recommend will have "benefits that far exceed costs." He promised more information in the coming months on reliability and economic modeling that will inform future decisions.

Clean Grid Alliance's Natalie McIntire said the first LRTP portfolio's projects are likely already spoken for, given the amount of renewable generation coming online. She urged that MISO "cast a wide net" for its second effort.

Staff said they haven't foreclosed the possibility of a 765-kV or an HVDC line in the second portfolio. They also said they are currently drafting benefit definitions for the portfolio's possible cost allocation. MISO will share the definitions for stakeholder review this spring when the analysis is complete. (See *MISO to Test Long-range Tx Allocation Benefits*.)

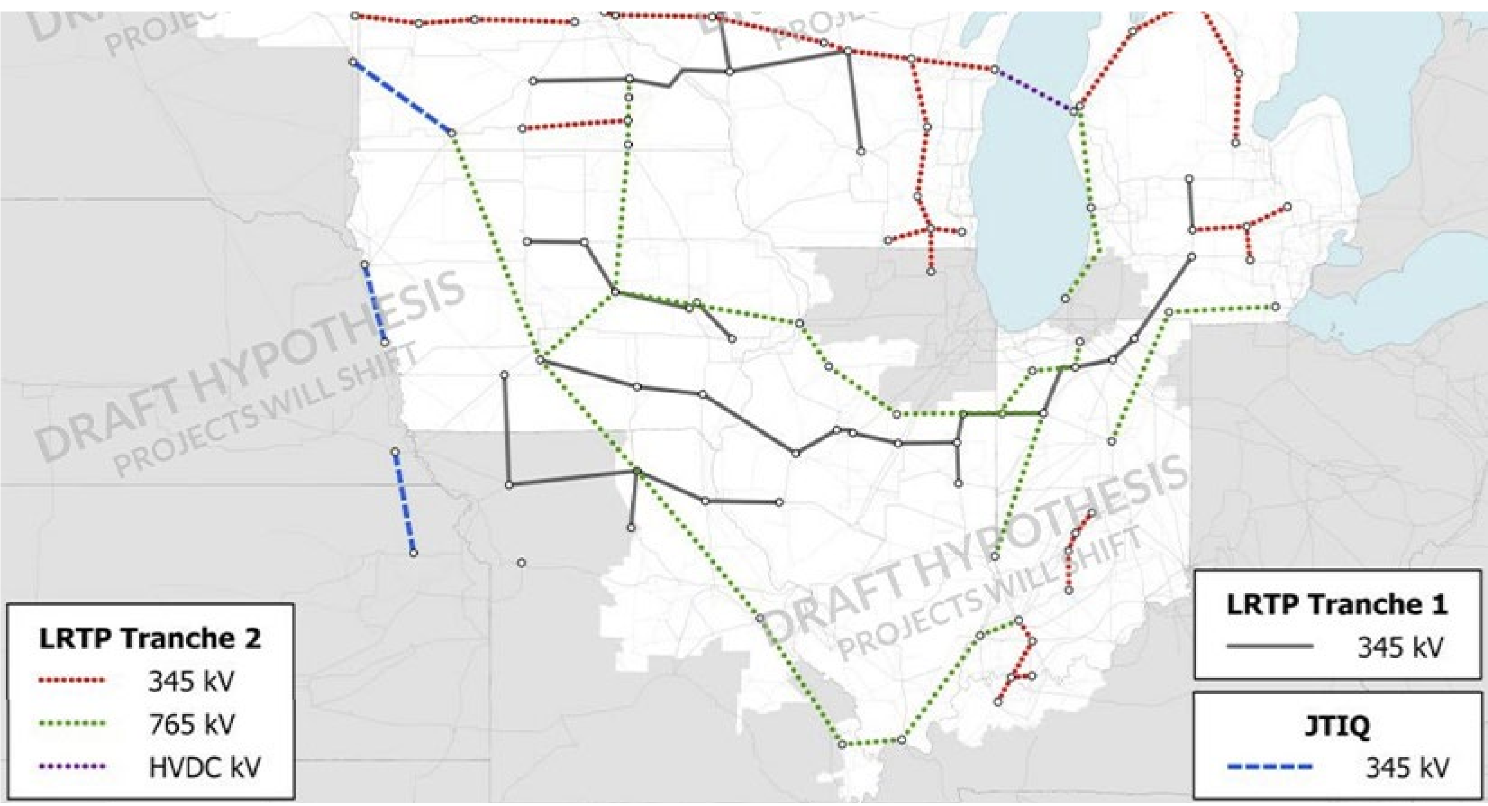
During a Jan. 24 Regional Expansion Criteria and Benefits Working Group meeting, Sustainable FERC Project attorney Lauren Azar said the grid operator is running out of time to finalize and file a cost-allocation approach for the third cycle of LRTP projects, which will focus on MISO South.

Azar said a continuation of the postage stamp rate allocation would be acceptable if MISO and stakeholders fail to propose another, more specific allocation.

"I'm fine if we don't end up with a new cost allocation, but I know other stakeholders aren't," she said. "I would strongly urge them to present proposals."

Southern Renewable Energy Association's Andy Kowalczyk asked whether MISO will be able to devise an allocation by June.

Milica Geissler, the RTO's cost allocation specialist, said the answer was a "Yes, and." She said an allocation design is contingent on compelling suggestions from stakeholders and ideas proposed in upcoming meetings. ■



MISO's concept map of the second LRTP portfolio | *MISO*

MISO News

FERC Approves Incentives for Great River Energy's MVP Lines

Commissioner Christie Uses Concurrence to Argue for Changes to Incentive Policy

By James Downing

FERC last week approved Great River Energy's request for transmission rate incentives for two MISO Multi-Value Projects (MVPs) it is working on: the Iron Range-Benton County-Cassie's Crossing project and the Big Stone South-Alexandria-Cassie's Crossing project (*ER23-513*).

The incentives for the two transmission projects include construction work in progress (CWIP) for the Iron Range project and the recovery of 100% of prudently incurred costs in the event they are abandoned.

GRE is an electric generation and transmission cooperative in Minnesota that provides wholesale electric service to 28 co-ops there and in Wisconsin. The Iron Range and Big Stone projects are both part of the MVPs that MISO approved in its 2021 Transmission Expansion Plan.

Iron Range involves the construction of a new 150 mile, double-circuit, 345-kV line from Minnesota Power's existing Iron Range Substation to GRE's existing Benton County Substation, replacing some existing lines and upgrading substations. GRE owns 52.3% of it, with the rest belonging to Minnesota Power, and its total cost is $969.9 million.

The Big Stone project involves the installation of a new 128-mile, single-circuit, 345-kV line between the Big Stone substation in South Dakota and the Alexandria substation in Minnesota, and a second 345-kV line being added between Alexandria and Monticello substations. The total cost of the project is $573.5 million, but GRE is only responsible for $27.5 million, as multiple firms are building the line.

Both lines should relieve potential reliability issues, while the Iron Range line is expected to help connect renewable power to market as well.

In an order issued Jan. 31, FERC said that because the two projects cleared MISO's planning process, which evaluated whether they would improve reliability, they are entitled to a rebuttable presumption that they meet commission requirements for incentives. Firms also have to prove that the incentives sought are connected to the investments being made, meaning they address demonstrated risks or challenges the transmission developer faces.

| *Great River Energy*

The Iron Range project is the largest transmission dollar investment ever made by GRE, and with multiple permits and owners, it created a more complex negotiating, decision-making and implementation process. Both the capital structure of 50% debt and 50% equity for both lines and the CWIP for Iron Range should ensure GRE can make the needed investments without lowering its credit rating.

FERC agreed that the incentives were tailored to meet the project's risks, with the CWIP helping GRE avoid higher costs on the project itself and other investments.

GRE also won approval for the abandoned plant incentive to deal with regulatory and siting risks that are outside of its control. FERC found the incentive would protect GRE and its member co-ops if the projects are canceled for reasons beyond its control.

Christie's Concurrence

Commissioner Mark Christie concurred with his colleagues, saying that while the order complies with FERC's current transmission incentives policy, those should be revisited. The CWIP incentive effectively makes consumers the bank for transmission development, while the abandoned plant incentive makes them the insurer of last resort, he said.

"Just as consumers receive no interest for the money they effectively loan transmission developers through CWIP, they receive no premiums for the insurance they provide through the abandoned plant incentive if the project is never built," Christie said.

FERC has a pending proposal to limit the adder for RTO membership to just three years after utilities join, and another one to eliminate the CWIP incentive altogether. Christie also wants the procedures and criteria for the abandoned plant incentive to be reconsidered.

"Revisiting all these incentives is imperative at a time of rapidly rising customer power bills," Christie said. ■

MISO News

MISO Broaches Inverter-based Performance Requirements

By Amanda Durish Cook

MISO said last week it will begin discussions next month on inverter-based resource performance requirements as the industry inches toward standardization.

Patrick Dalton, a power studies engineer, said during an Interconnection Process Working Group meeting Jan. 31 that the RTO has an imperative to get ahead of potential IBR performance issues noted in recent NERC disturbance reports. Dalton told stakeholders that by June, MISO hopes to have detailed performance requirements that can be drafted for the tariff.

"We are seeing this as part of how reliability attributes work," Dalton said, referencing the grid operator's ongoing discussion on attracting generation with certain system reliability attributes. Staff have defined six attributes as essential: availability, delivering long-duration energy at a high output, rapid start-up times, voltage stability, ramp-up capability and fuel assurance. (See *MISO Considers Resource Attributes as Thermal Output Falls*.)

Dalton said MISO will begin its work by looking into recent grid reliability disturbances. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

"The level of alarm continues to increase here," he said, noting that *one of two disturbances* near Odessa, Texas, caused about 1 GW of solar resources to trip offline in ERCOT. "If there is any silver lining of these NERC reports, it's that these events can be prevented if we were to implement standardized functions."

MISO has time to avert issues, Dalton said, because most IBRs have yet to come online. He said the time to act is a "luxury" that other regions don't have.

The RTO said standard IBR requirements are likely to benefit voltage stability, small-signal stability, voltage control and detection of short-circuit faults.

The discussions coincide with and are inspired by FERC's notice of proposed rulemaking issued last year to implement IBR reliability standards (*RM22-12*). The grid operator said it will draw on the Institute of Electrical and Electronics Engineers' recent standard for the resources' interconnection and performance (*IEEE 2800-2022*) to form its requirements. ■

The 198 MW Pomeroy Wind Project in Iowa | *EDF Renewables*

NYISO News

Hochul Proposes Expanded Clean Energy Role for NYPA

By John Cropley

New York Gov. Kathy Hochul is proposing a significant expansion of the role of the nation's largest state-owned utility.

In her budget presentation Wednesday, Hochul called for legislative authorization for the New York Power Authority to develop, own and operate renewable energy projects, and to provide bill credits from those projects to residents of disadvantaged communities.

The governor's *proposal* would also require NYPA to propose a plan to phase out its small-scale gas-fired peaker plants by 2035, except when needed to support emergency services or reliability. And NYPA would also be able to fund training programs for prospective workers in the renewable energy field.

The proposal would not, however, compel NYPA to plan, design, develop, finance, construct, own, operate, maintain or improve renewable generation. It would merely allow NYPA to do so, alone or in partnership.

The concept Hochul is proposing is not new: A similar *measure*, the New York State Build Public Renewables Act (BPRA), was approved by the New York State Senate in 2022 but never advanced to a vote in the State Assembly.

Initial reaction to her proposal was underwhelming Wednesday, with some dubbing it "BPRA Lite."

Public Power NY criticized it for omitting some of the more progressive aspects of the BPRA, such as its provisions for union labor and a just transition, and for pushing back the 2030 peaker retirement it stipulated.

"Furthermore, the governor's proposal omits nearly all of the democratization elements found in BPRA," Public Power NY said in a *news release*. "NYPA's resources must be used to build as much renewable energy as it takes to protect our climate and safeguard our future, especially for disadvantaged communities on the frontlines of pollution and the climate crisis. This means ensuring a true mandate for NYPA to actually build renewables when the state is falling behind, not just reviewing our lack of progress."

Gavin Donohue, president of the Independent Power Producers of New York, said he needs to further analyze the proposal, but on its face, it seems unnecessary.

The New York Power Authority's St. Lawrence Power Project is shown in Massena, N.Y. Gov. Kathy Hochul is proposing an expansion of NYPA's role in the state's clean energy transition. | *The New York Power Authority*

The private sector is capable and willing to develop renewable power in New York, he said. "NYPA is not in a position to be more effective in building these projects."

The Alliance for Clean Energy New York, which advocates for rapid adoption of renewables and represents companies in that sector, *said* it is opposed to the plan for several reasons, most of them boiling down to its focus. Executive Director Anne Reynolds said would do nothing to address the transmission constraints, onerous permitting process, non-standardized taxation and slow, expensive interconnection process that slow down renewable energy construction in New York.

"A better approach," she said, "would be to harness NYPA's resources and expertise to invest in the transmission system to unbottle opportunities to site wind and solar energy projects and open up new areas for projects, in addition to making other improvements to the investment landscape in New York."

But as Public Power NY noted in its news release, Hochul's proposal may be only an initial draft.

The executive budget proposed early in the year by the governor is one of the opening moves in New York's budget process. Private negotiations between the governor and top legislative leaders; backroom lobbying by stakeholders; and campaigns to public popular support for (or opposition to) various provisions follow.

At the end of closed-door negotiations, near the April 1 start of the state's fiscal year, the budget that emerges is different from the governor's executive proposal, sometimes significantly. It is rushed through a vote in the two houses by the two leaders who negotiated it with the governor. Policy matters and other non-spending measures are sometimes wrapped into the budget measure to ensure quick passage.

In her *memorandum* of support for the NYPA proposal, Hochul said it is a necessary part of her budget plan because it will assist the state in meeting its goals under the Climate Leadership and Community Protection Act, the roadmap for the state's clean energy transition.

Also in Hochul's executive budget is an extension of NYPA's authority to procure and sell power. It would extend the sunset date of Public Authorities Law from June 30, 2024, to June 30, 2044. Again, she writes, doing this will help the state meet its climate goals.

With 16 generating facilities and more than 1,400 circuit miles of transmission lines, NYPA *calls itself* the nation's largest state power organization. The American Public Power Association *ranks* NYPA as the nation's largest public power system by net generation as of 2020, narrowly higher than Arizona's *Salt River Project*, and second-highest behind SRP by megawatt-hour sales. ■

NYISO News

NY DPS Decreases ZEC Prices by 14%

By John Norris

The cost of New York zero-emissions credits is set to fall 14% for the next two years after the Department of Public Service issued its biennial adjustment on Jan. 31.

The department laid out the change in a *letter* to the Public Service Commission. The letter explains that ZEC prices for Tranche 4 (April 1, 2023 – March 31, 2025), will be set at $18.27/MWh, down from $21.38/MWh for *Tranche 3* (April 2021 to March 2023) (*Case-15-E-0302)*.

Tranche 2 (April 2019 to March 2021) ZECs were priced at $19.59/MWh.

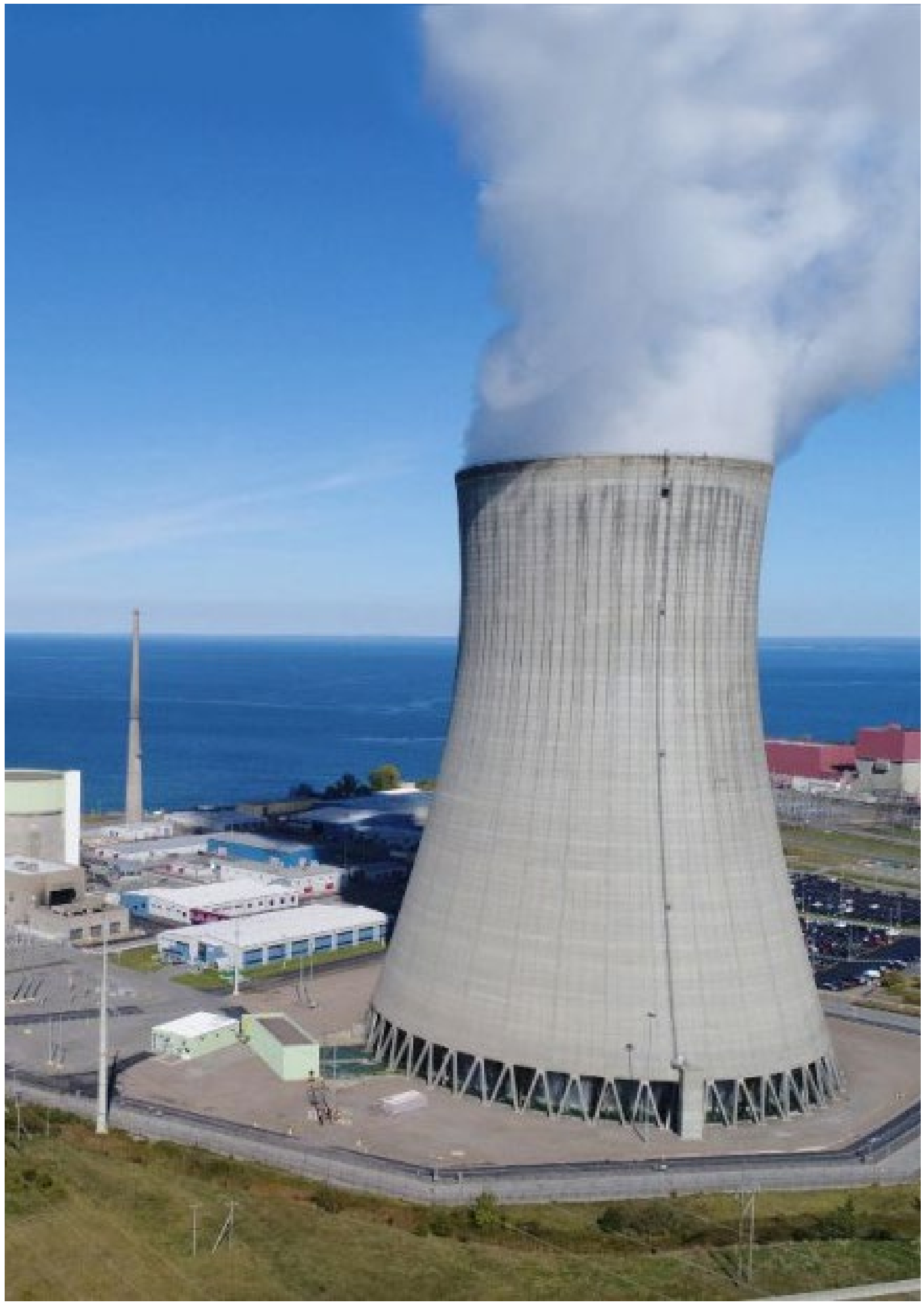
ZECs are subsidies for nuclear facilities that load-serving entities purchase monthly from the New York State Energy Research and Development Authority to prevent those facilities from retiring. They play an integral role in the PSC's *Clean Energy Standard* because they keep economically distressed nuclear plants, such as Nine Mile Point, James A. FitzPatrick and R.E. Ginna, online and use the collected funds to help build more renewable generation, which will replace the load generated by these nuclear plants.

Adjusted every two years, the ZEC is *calculated* by subtracting an adjustable reference price (currently $37.78) from the Zone A forecast energy price and rest-of-state forecast capacity price (currently $43.34/MWh). The difference between those is then subtracted from the social cost of carbon, which is currently set at $23.83/MWh.

The PSC has capped the number of ZECs that can be purchased, and that cap will be reduced should any facility close. Should any facility fall below the mandated production level of 85% of historical production for any two-year period, the PSC will further reduce the ZEC cap.

The program is intended to keep nuclear plants open until March 31, 2029, at which point New York expects to have installed enough additional renewable capacity to compensate for anticipated nuclear retirements.

ZEC prices will be adjusted again in 2025. ■



Nine Mile Point Nuclear Facility | *Constellation*

PJM CIR Cap Unlikely to End Accreditation Dispute

By Devin Leith-Yessian

PJM members' vote last month to limit resources' capacity interconnection rights is not likely to end the dispute over how the RTO accredits intermittent resources.

Roy Shanker | © RTO Insider LLC

Economist Roy Shanker, who filed a FERC complaint on Nov. 30, said last week that members' vote to change the rules was insufficient (EL23-13). (See PJM Stakeholders Endorse Accreditation Changes for Renewables.)

Shanker's complaint alleged that PJM has been improperly permitting energy above renewable resources' capacity interconnection rights (CIRs) to be entered into the Reliability Pricing Model (RPM) auctions as capacity, a practice he says is in violation of the RTO's Reliability Assurance Agreement (RAA) and the interconnection service agreement (ISA) for each generator.

| Michael Surran, CC BY-SA 2.0, via Wikimedia Commons

The result of the alleged over-accreditation, Shanker said, is 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.

In response, PJM on Jan. 17 argued that the complaint stems from a mischaracterization of its standard ISA, which states that "to the extent that any portion of the customer facility described in section 1.0 is not a capacity resource with capacity interconnection rights, such portion of the customer facility shall be an energy resource."

PJM said Shanker attempted to link this language to its accreditation of unforced capacity (UCAP), where no connection exists. Instead, it says the section is "a simple acknowledgement that a device is physically capable of providing energy above its CIR value, up to its maximum facility output level."

Pointing to FERC's 2021 approval of its effective load-carrying capability (ELCC) construct, PJM argued that the protest constitutes a "collateral attack" on the commission's past ruling and called it to be rejected as an "attempt to revive arguments rejected in prior proceedings." (See FERC Accepts PJM ELCC Tariff Revisions.)

PJM also said Shanker did not demonstrate that the complaint is in response to an injury and that, as such, he lacks standing.

Shanker argued that FERC's order accepting the ELCC methodology was partly based on testimony in which PJM presented "incomplete and misleading" information about ISA provisions, as well as the difference between test conditions and normal transmission relating to accreditation. He also said FERC's approval of the accreditation methodology was never codified into PJM's governing documents.

He noted that in its order accepting the ELCC construct, FERC wrote that PJM had stated that it will account for "historically binding transmission constraints by considering each variable resource's historic performance, including instances of curtailment due to transmission constraints." This has not been the case, he argued, writing that when defining CIR levels and deliverability requirements, PJM does not look at dispatch, system operation and the relative price of resources.

"PJM previously presented incomplete information to the commission in terms of the underlying facts related to this issue in material ways. When this is recognized, the entire prior conclusions of the commission become 'flipped,' and it becomes clear that output from an energy resource (defined as effectively 'not capacity') should be excluded in accreditation of variable resources with respect to the amount of AUCAP [accredited UCAP] they can sell (or should even be considered in any ELCC calculations)," Shanker wrote.

In comments defending PJM's practice, a group of environmentalist and clean energy organizations jointly argued that Shanker's complaint is based on a misreading of PJM's tariff that each megawatt of capacity must equal 1 MW of deliverable power. With this interpretation, they write that FERC's findings in the 2021 ELCC filing were well-informed and correct.

"The commission was not misinformed, but instead reached a well considered decision that it agreed with PJM on a disputed issue — a determination for which Dr. Shanker's client in that matter did not seek rehearing," said the Sierra Club, Natural Resources Defense Council, American Clean Power Association and Solar Energy Industries Association.

They also argued that the current practice does not introduce any reliability risks, as repeat PJM analysis has not identified any transmission upgrades required for existing intermittent resources. Citing information from PJM's Data Miner portal, they also noted that wind resources delivered energy 350%

times their CIR level during the December winter storm.

Stakeholders' Accreditation Proposal may not Address all Issues

The Markets and Reliability and Members Committee endorsed a proposal on Jan. 25 addressing some of the same issues in Shanker's complaint, including language that would cap the hourly output of resources to their CIR rating when using the ELCC analysis to set their accreditation. Shanker told *RTO Insider* Jan. 30 that the proposal would not, however, resolve the issue of hourly input above CIRs being entered into the accreditation for resource classes, leading to resource types being allocated inflated capacity payments to be divvied between generators in that category.

The proposal would limit the slice of the pie that an individual generator can receive but would continue to allow intermittent resources to have an overly large portion reserved for them, Shanker said. He also noted that the endorsed language remains a proposal and still requires the approval of the PJM Board of Managers and FERC.

"It never goes away once it gets into the database," Shanker said of energy output above CIRs being included in resource class accreditation. "The pie increases, and it will always get allocated to someone."

The complaint also asks that FERC order PJM to change its accreditation methodology immediately and potentially provide a form of retroactive relief. This would effectively eliminate the transition methodology included in the endorsed proposal, which would create a system for generation owners to submit uprate requests and seek access to available headroom on the transmission system until PJM processes their request for higher CIRs in the interconnection queue. Without the formal execution of an ISA recognizing the higher CIRs, Shanker argued that PJM does not have the power to grant a resource a claim on any available transmission headroom.

In comments on the complaint, the Independent Market Monitor agreed that PJM's tariff dictates that the ELCC methodology must cap the hourly output for a generator at its CIRs when determining accreditation for both individual units and resource classes. The impact of PJM's current practice has been overstated intermittent capacity suppressing the final clearing price in recent Base Residual Auctions (BRAs).

"PJM has, to date, based on a mistaken interpretation of the market rules, based on an initial oversight, included energy deliveries above the level of CIRs obtained for intermittent resources in defining the ELCC values for those resources, affecting both the capacity value of individual resources and the capacity value of the total ELCC resources and therefore capacity auction clearing prices," the Monitor wrote.

Had the correct accreditation been used for solar resources in the 2022/23 BRA, the IMM estimated the resource class average derated MW would have been 20% lower, while for wind resources it would have been 48.9% lower. Ultimately the IMM estimates that generator revenue would have been 4.4% higher with the proper ratings.

The Monitor called on FERC to require that PJM correct its definition of the capacity available from intermittent resources for the 2025/26 BRA and to not permit that auction to go forward until the issue has been resolved. The auction is currently scheduled for June 14, 2023. ■

NJ Bills Push Rooftop Solar, EV Chargers, Grid Upgrades

By Hugh R. Morley

New Jersey state house in Trenton, N.J. | *Shutterstock*

The New Jersey Senate Environment and Energy Committee advanced bills last week that would variously require new state buildings to facilitate distributed energy resources, provide business tax credits for the retrofit of warehouses to take solar panels and clarify the space needed for electric vehicle chargers at multiunit dwellings.

The spate of climate change-related legislation also included a bill that would set increasing targets for food recycling in an effort to reduce the methane produced when organic food is dumped in landfills. And a fifth bill would require the New Jersey Board of Public Utilities (BPU) to study how to upgrade the state's transmission and distribution systems to interconnect more DERs.

Sen. Bob Smith, the committee chairman and a sponsor of four of the bills, said the BPU is "generally in favor" of the grid study.

"We all agree this is a really good bill. So, I think we should get it moving," Smith said shortly before the committee approved the bill. "Just by way of background, our grid really stinks," adding that addressing the issues is "really the key to ... renewables."

The bill, *S3489*, would require the BPU to "study means of allowing grid segments to host more distributed energy sources and improving the reliability of the grid."

The areas of research suggested in the bill include: using substations to transmit electricity from the distribution system to the grid; the use of solar inverters to "to autonomously control the reactive power passing through the inverter"; and the impact of requiring the use of storage systems that can allow the input and output to vary depending on the power demand on the grid.

The BPU would be required to file a report on the study within a year. It would have another year to draft rules and regulations that would implement the findings of the report, which would be the basis for a pilot program and eventually perhaps a statewide program.

Doug O'Malley, director of Environment New Jersey, said the key elements of the bill are those that plan for pilot testing of the solutions unearthed in the study, and the adoption of rules and regulations needed to implement the solutions.

"The reason why this bill is so critical is because our energy grid obviously needs to be modernized and updated," he said.

S1533 would require any new building used solely for state government that is larger than 15,000 square feet to include a DER that could be switched on "when the normal source of electricity is disrupted due to a power outage."

The bill defines a DER as "one or more electric power generation, management or storage technologies, excluding diesel fuel technologies, located at or near the point of energy consumption, which are capable of providing the standard energy needs of a building or structure, or group of buildings or structures."

Smith said the bill should be called "do what you are asking everybody else to do."

"We're the ones who are trying to make our state more sustainable, more renewable; all that kind of stuff," he said. "We should be setting the standard and the example."

EV Charging and Warehouse Solar

Smith said he drafted the EV charger bill, *S3490*, to amend a *law* that mandated the allocation of spaces set aside for EV charging stations in certain buildings. The law, enacted in July 2021, had left some confusion as to what was required, he said.

The bill would exempt multiunit low- or moderate- income housing dwellings from the law's requirements to install "make-ready" parking spaces: those with the cables and support equipment ready to hook up to EV charging equipment. It would also clarify how many make-ready spaces are required by, for example, exempting off-street spaces that are incapable of supporting chargers from the total number.

PJM News

Jeff Kolakowski, CEO at New Jersey Builders Association, said the bill still needs refinement to clarify how many spaces are needed in the multitude of different scenarios faced by builders.

"There's a lot of different parking situations in residential communities out there," he said.

S427 follows a *law* enacted in June 2021 that required new warehouses of more than 100,000 square feet to be ready to install rooftop solar in the future. (See *NJ Bill Would Require Warehouses to be Solar Ready*.) It would provide a tax credit for a warehouse that installs solar panels on a building with a "solar ready" zone. The credit would pay for 50% of the cost of the retrofit or $250,000, whichever is smaller. And the total amount of tax credits allocated to pay for the retrofits would be no more than $25 million.

The bill drew support from the Chamber of Commerce of Southern New Jersey, the New Jersey Conservation Foundation and Environment New Jersey. Alison McLeod, policy director of the New Jersey League of Conservation Voters, urged legislators not to overlook the rapid pace of warehouse development in New Jersey. The state is seeing a dramatic expansion of the warehouse sector, often on farmland, driven by the need for e-commerce companies and logistics providers serving the Port of New York and New Jersey.

"As warehouses continue to sprawl across the state, anything that we can do to help minimize their environmental impact is helpful," she said.

Cutting Organic Waste Emissions

Turning to the bill designed to reduce the volume of organic waste disposed in landfills, *S421*, Smith said, "It's looking like it might have as much or more of an impact on global climate change than carbon dioxide and fossil fuels, which is huge."

Several speakers took issue with elements of the bill, however.

The bill would require the state by Jan. 1, 2027, to reduce by 50% the level of organic waste disposed in the state from 2016 levels, and by 75% by Jan. 1, 2032. The *statement* explaining the bill defines organic waste as "biodegradable waste that derives from organic material, and includes food, paper and cardboard, yard trimmings, animal waste, bio-solids, and sludge.'"

"The vast majority of organic waste that is generated in New Jersey is deposited into landfills, where it breaks down and releases methane, a potent greenhouse gas," according to the statement. "While a percentage of this methane is collected by landfills and used to provide energy, much of it escapes into the atmosphere, contributing significantly to climate change."

The bill would also require, within 18 months, the Department of Environmental Protection (DEP) to adopt rules and regulations for the program. Among them would be rules on how local governments direct the behavior of organic waste generators and suggestions for potential penalties for noncompliance.

The rules also would set out how the state by 2030 can recycle 20% of the "excess, unused and edible food that is currently disposed of" for human consumption, the bill states. It would also require the DEP by July 2027 to submit a report for the governor documenting the state's progress toward the targets.

Gary Sondermeyer, vice president of operations at Keasbey-based Bayshore Recycling, told the committee that he generally supports the bill but does not believe that New Jersey could reach the 75% target.

"The real problem is we have woefully inadequate composting infrastructure in the state," said Sondermeyer, who also represented the Association of New Jersey Recyclers. "Municipalities and counties are very eager to set up and develop composting programs to drive material away from landfills, and from resource recovery plants. But, to use the old cliche, we're all dressed up and nowhere to go. We need infrastructure."

Mary Ellen Peppard, vice president with the New Jersey Food Council, echoed the sentiment, adding that the council is committed to food waste reduction.

"A really big concern is the lack of food waste recycling facilities," she said. "We actually have a couple of members at the moment who have been trying for several years to build some food waste recycling facilities, and they're running into a lot of challenges."

Ray Cantor, a lobbyist for New Jersey Business and Industry Association, said his group agreed with the goal of cutting food waste disposal but was concerned that the bill gives too much power to the DEP.

"Our major concern is there's just an awful lot of delegation to DEP as to how to implement those goals," he said. "We don't necessarily have a tremendous amount of faith that DEP is going to do the right thing or will not come up with regulations that may be too onerous or too burdensome." ■

PJM News

Berkeley Study Finds Rising PJM Interconnection Costs

RTO Questions Results

By Devin Leith-Yessian

A study *released* by the Lawrence Berkeley National Laboratory last month found that interconnection costs have been steadily rising for decades in the PJM region and are disproportionately high for renewable resources.

"The core finding that we've had for PJM is overall interconnection costs have increased both for projects that have completed all the required interconnection studies, as well as for those projects still moving through the interconnection process," said Jo Seel, principal scientific engineering associate with the lab. The study is part of a series looking at interconnection costs for each RTO in the U.S.

Drawing off available interconnection studies released by PJM, the study found that costs for generators that have successfully connected to the grid have doubled from 2000 through 2019. The average for completed projects has grown even more sharply over recent years, rising from $29/kW between 2017 and 2019, to $240/kW between 2020 and 2022.

Costs are highest for projects that ultimately dropped out of the interconnection process, at $563/kW, which Seel said could point to network upgrades being a driving factor behind projects leaving the queue.

"It seems to me pretty likely that high interconnection costs make a certain set of projects infeasible and they cannot move forward," Seel said. "We see that especially well for solar projects, where the upgrade requirements for some of these solar projects is up to nearly 40% of the overall project [capital expenditures] ... that just breaks project economics, so I think that's a pretty good explainer of why some of these solar projects then do not move forward and ultimately withdraw."

The study also found a wide gap in network upgrades for different resource types. Natural gas carries some of the lowest costs, with an average of $24/kW, while offshore wind was the highest at $385/kW. Onshore wind saw average interconnection costs of $136/kW, while solar projects had costs around $253/kW.

Scale of Rising Costs Questioned by PJM

PJM Senior Director of Interconnection Planning Jason Connell said he believes the study overrepresents the extent that network upgrade costs have grown because of the inclusion of feasibility studies in the data. Because the studies identify the upgrades that an individual project would require to interconnect prior to cost allocation between projects, he said it could result in double counting of costs if multiple projects needed the same upgrade.

"The issue is that those projects for which they're scraping the data are in various stages of completion: some very early on in the feasibility stage, and some have signed and executed an interconnection service agreement. It doesn't make sense to compare them as an aggregate, because those study costs get refined the further along a project is in the study process," he said.

Seel said that wherever possible, the Berkeley team looked for the most recent and accurate data available, and only a small number of feasibility studies were included in their data. In those cases, they sought to correct for the possibility of double counting and, he believes, were able to formulate accurate findings.

The Lawrence Berkeley National Laboratory has released a study finding transmission costs in PJM are rising. | *Shutterstock*

"We used the best available data to categorize these costs," he said.

Independent Market Monitor Joe Bowring said data accessibility at PJM has long been a challenge, making it difficult for studies to be conducted.

"If PJM wants more accurate studies done, they should provide more accurate data," he said.

As the grid becomes increasingly complex and built up, Connell said costs are bound to rise to a degree. While the first few projects in a region may require replacing equipment at a substation, subsequent installations may necessitate the reconducting of lines or substation rebuilds. Despite the growing investments needed, there's been no slowdown in the number of new requests for interconnection studies across resource types, including developers looking to install renewables.

"Each upgrade is an order of magnitude of difference for each of the newer projects," he said.

The new approach for studying interconnection requests approved by FERC last year could provide more clarity on the costs developers could face, Connell said. The new methodology clusters projects together both for identifying network upgrades and allocating costs. It also requires that deposits be made throughout the process to discourage speculative filings. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

Seel pointed to the medium-term transmission plans conducted by MISO as another approach for lowering network upgrade costs. The RTO's plans identify larger network upgrades, and it makes the necessary investments itself, rather than allocating the expense between individual generators based on interconnection requests. A more holistic and forward-looking approach to evaluating grid upgrades can create efficiencies that outweigh the investments, he said.

Bowring said he's hopeful PJM's new interconnection process will decrease costs by making the interconnection process more efficient and reducing speculative filings, but he believes that retaining competition and accurate costs in the buildout of transmission is important to ensuring that generation is sited in the most economical locations. Upgrade costs rising are appropriate so long as they reflect the reality of the cost to interconnect, he said. ■

PJM News

PJM Stakeholders Discuss Capacity Market Changes After Winter Storm

By Devin Leith-Yessian

PJM's Independent Market Monitor has proposed a plan to eliminate performance assessment intervals (PAIs) and related penalties from the RTO's capacity market, saying the non-performance charges stemming from the late-December cold snap have threatened the functioning of the market.

"Winter Storm Elliott provided the first real test of the [capacity performance] design. Elliott showed that the CP design does not provide effective incentives," Monitor Joe Bowring said during the Jan. 31 meeting of PJM's Resource Adequacy Senior Task Force.

Under the Monitor's *design concept*, capacity resources would only be paid the capacity price when they are available in a given hour and would be required to have firm fuel, which entails access to dual fuel, multiple pipelines or a defined amount of onsite fuel storage, plus weekly testing to ensure that the resources can produce when called upon.

Capacity resources would also be subject to a must-offer requirement. When energy is valuable, resources that provide energy will be paid the high market prices for energy and reserves, as the energy market provides the correct energy pricing, Bowring said.

"If we can't handle two days of cold weather without having a massive dislocation, we need to rethink how this market is designed," Bowring said. "The penalties create potential threats to the incentives to invest in existing resources and to invest in the new resources that will be needed in the next three to five years."

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

Bowring also said his design would replace the effective load carrying capability (ELCC) accreditation model for intermittent resources. By only paying such resources when they are delivering energy, he said the change would recognize that intermittent resources are not always available while still allowing them to be compensated for when they are online.

"ELCC is very quickly going to end up with a marginal value of zero for standalone solar and wind while continuing to have a performance obligation equal to its full capability. ... What I'm proposing is something very different, which is paying capacity only when it's available," he said.

That tension between the reduced megawatts that qualify as capacity and the obligation to perform at the full megawatt value of the resource will make offering intermittent resources as capacity increasingly untenable under the ELCC approach.

The Monitor's proposal would build on FERC's 2021 rejection of the CP market seller offer cap (MSOC) and "would recognize that the capacity performance model was a failed experiment," Bowring said. (See *FERC Backs PJM IMM on Market Power Claim*.)

"The only purpose of the capacity market is to make the energy market work. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market," Bowring said. "The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market."

Bowring noted that the CP design focuses on a small number of critical performance assessment hours, imposing large penalties on generators that fail to produce energy only during those hours. He said the use of capacity market penalties rather than energy market incentives created risk.

"While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in concept, to provide an incentive to produce energy during high demand hours that was even higher than the energy market incentive," he said.

PJM has said that generators may be facing total penalties between $1 billion and $2 billion for as much as 46,000 MW in capacity

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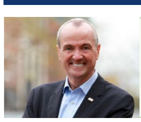

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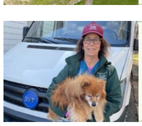


Electric MHD Truck Incentives Promoted in NJ NetZero Insider

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

PJM News

being offline during the storm, including over a third of gas resources. That has raised concern about significant amounts of generation leaving the market, either through default or determinations that there is too much risk in the exchange. (See *PJM Gas Generator Failures Eyed in Elliott Storm Re view.*)

"Everybody knew what the potential penalties were. Nonetheless, the behavior did not match … that expectation. ... Massive penalties are not the answer here," Bowring said.

David "Scarp" Scarpignato, of Calpine, suggested that a third product may be needed alongside energy and capacity resources, noting the impact the fuel requirements would have on certain gas generators.

Combustion turbine plants connected to only one pipeline would no longer be able to participate as capacity resources and therefore lose their capacity interconnection rights. Without the guaranteed access to the transmission grid when shortage pricing is in effect, those units may no longer be economical, he said.

Steve Lieberman, of American Municipal Power, said the majority of generator conversations around the MSOC come down to properly defining their units' capacity performance quantified risk (CPQR) — the risk that they will face non-performance penalties. AMP has proposed one of six design concepts currently being discussed by the RASTF, along with the IMM.

"I believe what Winter Storm Elliott has taught us is we need to put the scalpel away and it might be time for the chainsaw. … We do agree CP is a failure; it was an experiment that we implemented after the polar vortex," he said.

AMP's proposed *design* includes a higher degree of fuel availability for capacity resources, namely dual fuel or onsite inventory, and would expand the use of ELCC accreditation to thermal resources.

"An approach that's similar for thermals and non-thermals alike is our preference," Lieberman said, adding that he has reservations about ELCC, but feels that having one accreditation approach for all resources is best.

Stakeholders Seek More Clarity on Offer Caps

With deadlines approaching for June's 2025/26 Base Residual Auction, Jeff Whitehead, of GT Power Group, said that generation owners will soon have to make decisions about their CPQR and unit-specific offer caps. He said guidance from PJM and the IMM on what will be allowable would aid in the drafting of those figures.

He noted that without changes to the current auction schedule, there are few parameters that can be changed in time, primarily the performance assessment hour assumption.

"I think we need to come to a common agreement on what is a reasonable basis for including Winter Storm Elliott, or I'll say more broadly the changes in the penalty risk view that comes out of that event," he said.

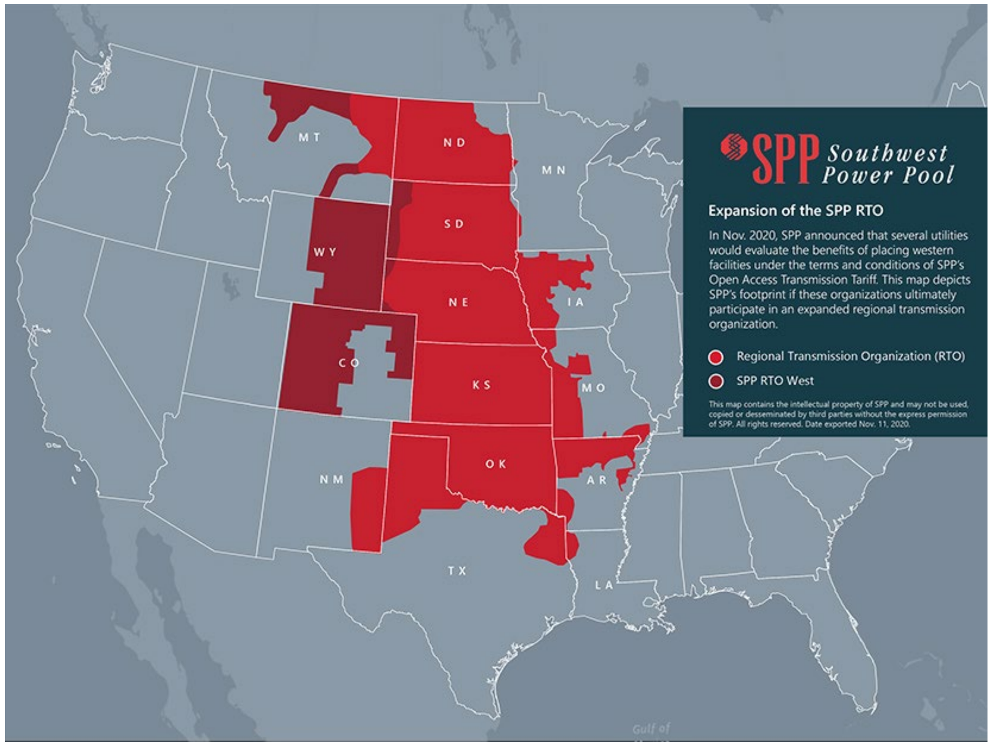
Bowring said he believes the current MSOC construct is correct and the best way to incorporate the winter storm data into offer caps is by rerunning the simulations the Monitor conducts with the data from Elliott added in. Part of his consideration of the storm's impact is that to an extent the emergency conditions were the result of generators being unavailable.

"We have to operate in a rational defined space, and that space is going to be calculating what we think the impact on CPQR is of the actual facts of Elliott," he said. "Given that this is the first significant PAI event since the introduction of the CP model, it is unlikely to have a large effect on CPQR." ■

SPP News

SPP Board/Members Committee Briefs

Directors, Members Approve Resource Adequacy Revisions



SPP RTO West and its current RTO footprint | *SPP*

SPP's Board of Directors and Members Committee last week approved two revision requests related to resource adequacy requirements, ending a last-minute dash to gain stakeholder approval.

The tariff changes, *RR536* and *RR537*, would provide load-responsible entities with a short-term, nonpunitive alternative approach to deficiency payments for the summer resource adequacy requirement (RAR). They breezed through a gauntlet of stakeholder groups the week before and were then approved by the Regional State Committee on Jan. 30. (See *SPP MOPC Approves Late Resource Adequacy Revisions*.)

Staff have been working on the mitigation strategy since July, when SPP increased the planning reserve margin (PRM) from 12% to 15%, effective this year. That left some members complaining they would not have enough time to meet the requirements. (See *SPP Board of Directors Briefs: Dec. 6, 2022*.)

"There is no doubt that we've had some fairly lively discussions on some probably critically important issues over the last three quarters," board Chair Larry Altenbaumer said during the Jan. 31 meeting. "I believe that despite some of the concerns that had been raised, we did end up with a balanced and a constructive outcome. I think it does legitimately help us fulfill our overall planning reserve requirement for SPP's footprint, and because it is limited to a two-year window, it is responsive to the original desires that were laid out by our stakeholders … to their planning."

Stakeholders modified RR536 to clarify that LREs can make a sufficiency payment only when the PRM is increased within the previous two years and the entity demonstrates it had adequate capacity to meet the PRM before it was changed. A deficiency cannot result from selling accredited capacity to another region after the PRM's increase is approved.

Under the change, capacity could only be claimed for accreditation by one asset owner in the SPP footprint. Capacity used to resolve deficiencies could not be sold to another region for the applicable RAR season.

The measure includes the Market Monitoring Unit's sufficiency valuation curve for the market's capacity. The curve would start at twice the cost of new entry (CONE) at or below the sum of noncoincident peak loads, then slope downward to a net CONE value when regional accreditation reaches the PRM. When the region has sufficient accredited capacity, the net CONE would drop down to zero at 115% of the PRM.

RR537 emerged from the stakeholder process with revised language that removes a tariff violation when LREs fail to make a resource adequacy payment. As modified, LREs would be deemed sufficient for the adequacy requirement with a deficiency payment.

The change was also modified to clarify that only capacity resolving deficiency is obligated to stay in SPP; the obligation would only apply to a specific RAR season; and that a deficiency payment is based on a kilowatt-year.

Staff hope to gain FERC's approval in time to accredit resources for the summer season (June 1-Aug. 31).

The Advanced Power Alliance's Steve Gaw abstained from the Members Committee vote on the two measures, warning of unintended consequence from a permanent tariff change. American Electric Power's Antonio Smyth also abstained but did not explain his decision.

"We accommodated the fact that the [PRM] increase was pretty steep in a fairly short time frame," said Gaw, who supported the RRs' approach to the increase. "However, I am very concerned about this going into the tariff as a permanent fix. This is a significant lessening of the consequences of not increasing individual LREs' accredited capacity under the resource-adequacy obligation when the PRM increases. The tariff language change allows this to kick in on any increase to the PRM in the future without really having a longer look and understanding of all the consequences."

"The increase was fairly quick. … Steve makes a good point that you're setting yourself up potentially for some unintended consequences," Basin Electric Power Cooperative's Tom Christensen said. "There are some safeguards so that it appears it won't be abused. If there are some unintended consequences that come about, I think we'll just need to make sure that we deal with those as they come."

COO Lanny Nickell agreed. "The language that we have arguably allows this to be used time and time again. My sense is that there is appropriate focus and discipline … to make sure that nothing happens that will abuse what's provided here," he said.

The RSC's members had brought up a similar issue during its discussion the day before. The committee's president, Kansas Corporation Commissioner Andrew French, resisted an

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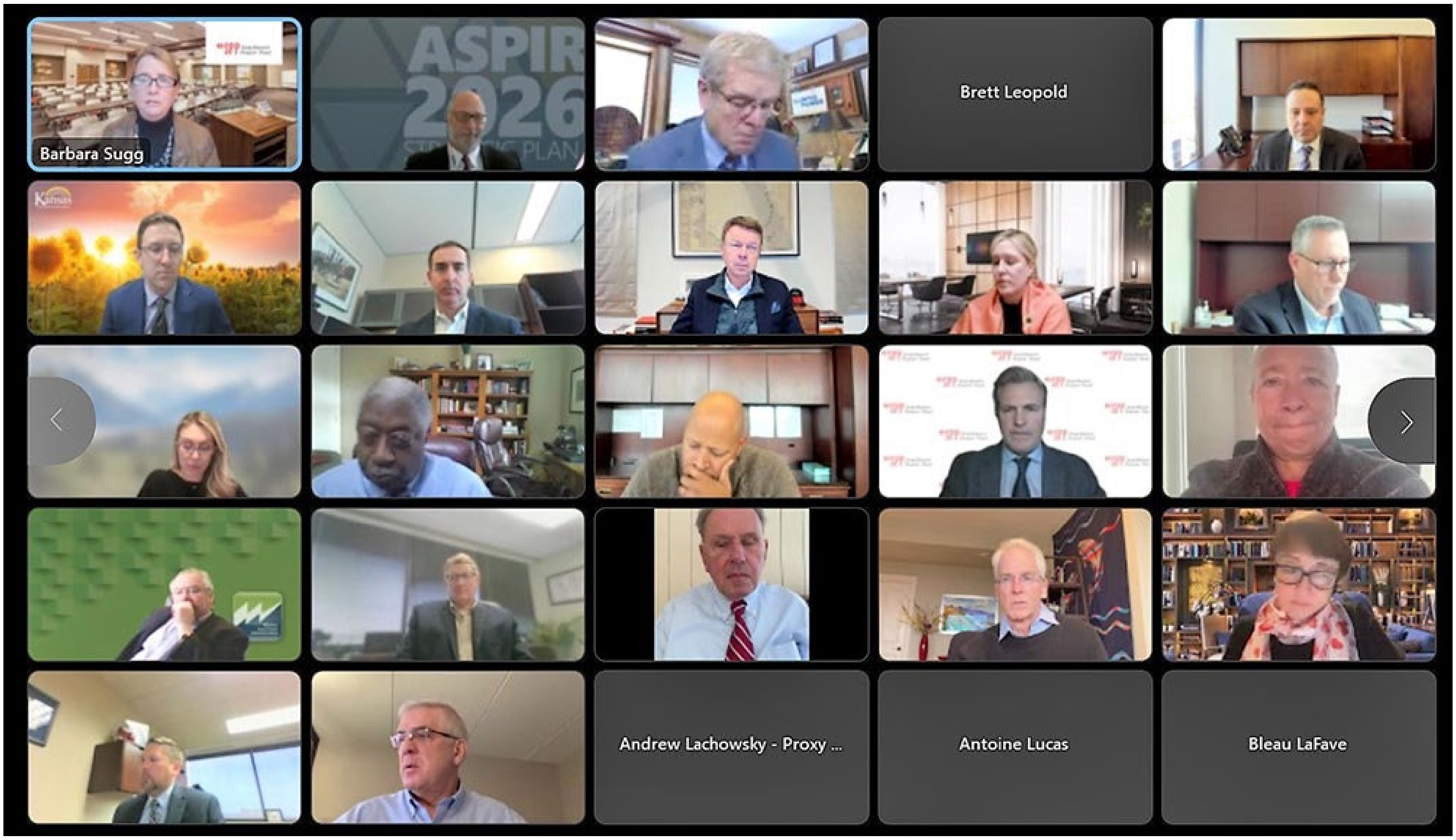


SPP CEO Barbara Sugg kicks off the Board of Directors/Members Committee's virtual January meeting. | *SPP*

attempt to table RR536 over concerns FERC could reject a previously approved tariff change (*RR515*) that would allow LREs to qualify for and receive exemptions from deficiency payments.

SPP General Counsel Paul Suskie assured the regulatory group that all three revision requests are designed to stand on their own.

French said 536 and 537 are "acceptable responses to the current situation" but "perhaps another planning reserve margin increase" is necessary if a more "holistic" design is not put in place.

"I would only support [the RRs] as an interim approach. They are not a good long-term resource adequacy construct to support long-term resource planning," he said.

French joined with the other members in rejecting the motion to table and then in approving RR536. The measure passed 8-3, with Nebraska, North Dakota and South Dakota regulators in opposition.

The RSC passed RR537 9-2, with North Dakota Public Service Commissioner Randy Christmann and South Dakota Public Utilities Commissioner Kristie Fiegen dissenting.

"I get the point of it. [LREs] are making a deficiency payment, but you're either compliant, or you're not compliant. You're either deficient, or you're not deficient," Christmann said. "Paying the penalty doesn't change that. It's just the penalty that's associated with being deficient."

Board Grants CRSP More Time

The directors and members both approved new terms and conditions for RTO West membership that make allowances for Western Area Power Administration's Colorado River Storage Project (CRSP) to potentially join the market, granting a four-month extension for the acceptance period.

The federal power marketing administration now has until July 1 to accept the new membership terms and conditions. The extension is contingent on CRSP publishing its intent to purse SPP RTO membership in the *Federal Register* by Feb. 28.

The new terms include crediting CRSP's point-to-point (PTP) transmission service and a federal service exemption (FSE) of replacement energy to satisfy its statutory load obligations. The Strategic Planning Committee endorsed the recommendation during its January meeting. (See "CRSP Faces Tx Rate Issues," *SPP MOPC Approves Late Resource Adequacy Revisions*.)

CRSP was built to move federal hydropower, but low water levels are increasingly risking the utility's ability to meet its service obligations. In addition, about 88% of CRSP's transmission obligations sink outside its zone, leaving the remaining 12% exposed to rate increases because of SPP's treatment of PTP revenues.

Working with eight other Western parties interested in RTO West membership, staff were able to modify the conditions to allow CRSP's PTP revenue from using its facilities to meet contractual or statutory obligations be distributed back to the agency.

Because SPP's tariff won't allow replacement power that CRSP may need to meet its obligations be classified as an FSE, the parties agreed that replacement energy delivered from the utility's zone be eligible for the exemption. Replacement energy delivered to CRSP's zone would be subject to tariff provisions and charges.

Director John Cupparo, who led a $6 billion transmission investment program in the West while with Berkshire Hathaway Energy and also served as PacifiCorp's CIO, said adding

SPP News

Western members and strengthening the seam between the two interconnections is "going to pay huge benefits."

"I think it's clear that something's going to happen in the West for the first time in decades," he said. "Market development is going to occur in some form, and as those lines get drawn, they don't typically get redrawn.

"So, I've encouraged the [SPC] and this group to keep an open mind and be supportive as we look to advance these initiatives," Cupparo added.

Sugg Lays out 2023 Goals

CEO Barbara Sugg said resource adequacy and resilience will continue to top SPP's list of corporate goals for the year, saying that while the RTO will dedicate "significant attention" to completing its strategic plan, "none of it matters if we don't get resource adequacy right."

She said clearing the generation interconnection queue is also one of SPP's top goals. Staff are on track to clear the 2018 and 2019 clusters this year and to work through the 2020 and 2021 clusters next year, Sugg said.

Other priorities for 2023 include process improvements to the queue and the consolidated planning process; maturing the enterprise risk management program; and making "significant and measurable progress" on the strategic plan's goals.

"We know that standing still is not a good option for SPP, and it's only through our collaborative stakeholder process that we will achieve what we've set forth in that strategic plan," Sugg said.

Altenbaumer, Martin to Leave Board

Joshua W. Martin III | *SPP*

The meeting marked Altenbaumer's last as the board's chair. He and Joshua W. Martin III are both leaving the board at the end of the year, taking a combined 38 years of service with them. Martin has served as a director since 2003 and Altenbaumer since 2005.

Vice Chair Susan Certoma, now the board's most senior member with three years of experience, will succeed Altenbaumer as chair. Liz Moore will become vice chair.

"I want everyone to know that it has been and continues to be a cherished honor to serve on this board," said Altenbaumer, who took over the chairmanship in 2018. "At the time that I became board chair, I felt that it was appropriate to only do so for about five years. I believe there is value in rotation for an organizational leadership, and I think that this is a good time to make that change."

CEO Barbara Sugg and Board Chair Larry Altenbaumer | © *RTO Insider LLC*

"You have brought a lot of collaboration. You listen and you have listened as chair to our variety of different interests. Your patience is incredible," Gaw told Altenbaumer. "This organization is far better today for your service, especially from how you are able to listen to the concerns of all of those stakeholders and still find a way to bridge the gaps and move things forward."

The Corporate Governance Committee will begin the process of filling the vacancies during the second quarter before, as Sugg said, "Larry and Josh ride off into the sunset listening to Jimmy Buffett."

The committee will use the search firm that is already under contract from last year. Sugg said the committee has the "full expectation" of bringing recommendations to annual members meeting in October. (See "Membership Elects 2 New Directors," *SPP Board/Members Committee Briefs: Oct. 25, 2022*.)

Moore has announced her intention to serve another three-year term when her current term expires at the end of the year. "I have no doubt that we will be very happy to renominate her," Sugg said.

The CGC also has two vacancies to fill on the Members Committee and another on the Human Resources Committee, following Sunflower Electric Power CEO Stuart Lowry's retirement last year. The committee plans to bring nominations for the vacancies to the board's April meeting.

Consent Agenda Flies

The board consented to approval of the SPP Transmission Expansion Plan (STEP); a sponsored upgrade study of NextEra Energy's proposal to add a 345/138-kV transformer at Oklahoma Gas & Electric's Cimarron substation; and two revision requests, all previously approved by the Markets and Operations Policy Committee:

- *RR505*: streamlines the approval of remedial action schemes with more defined criteria and clarifies RASes' appropriate uses.
- *RR519*: formalizes the SPP operating criteria's requirement to perform an annual resource real-time availability evaluation and report findings and recommendations to the appropriate stakeholder group.

It also consented to withdrawing notifications to construct for a Sunflower 115-kV capacitor bank and a 69-kV Western Farmers Electric project; removing the suspension of Basin Electric's Kummer Ridge-Roundup project in North Dakota, comprising a new 33-mile, 345-kV line and substation upgrade; and modifying the NTC's approval date for NextEra Energy Transmission Southwest's 345-kV Wolf Creek-Blackberry project in Missouri and Kansas, from Jan. 1 to May 17. ■

— Tom Kleckner

SPP Regional State Committee Briefs

Commissioners Approve 90-10 Split on JTIQ Cost Allocation

SPP's state regulators last week approved staff's proposed cost allocation for the five projects in the RTO's Joint Targeted Interconnection Queue (JTIQ) study portfolio.

The Regional State Committee, which has specific authority over cost allocation, accepted several recommendations from the Cost Allocation Working Group during a virtual quarterly meeting Jan. 30.

The JTIQ study with MISO was designed to find potential projects on the RTOs' northern seam that could reduce congestion and allow additional resources, primarily wind farms, to interconnect with the two systems. The RTOs' staff have *proposed a cost allocation* that assigns most of the portfolio's $1.06 billion in costs to generation. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

The RSC unanimously approved the CAWG's recommendations that:

- generators bear 90% of the portfolio's capital costs and that load cover the remaining 10%;
- load's portion of the JTIQ's annual transmission revenue requirement (ATRR) be based upon adjusted production costs, as outlined by the RTOs' joint operating agreement; and
- allow each building transmission owner to recover the non-capital construction costs allocable to generator interconnection customers through the TOs' formula rate template in their respective regions.

The commissioners also unanimously approved the CAWG's recommendation that SPP staff ensure the portfolio is implemented in a "reasonable manner" to improve its chances of securing U.S. Department of Energy funding to improve the benefit-cost ratio for all SPP load. SPP and MISO have joined forces with the state of Minnesota and the Great Plains Institute to apply for DOE grants from the latter's $10.5 billion *Grid Resilience and Innovation Partnerships (GRIP)* program. (See "SPP, MISO Applying for DOE Funds to Help with JTIQ Portfolio," *SPP MOPC Briefs: Jan. 17-18, 2023*.)

The committee revised the CAWG's motion by adding the word "reasonable" before "manner" to address a complaint from North Dakota Public Service Commissioner Randy Christmann.

"What I'm reading here is that we are willing to implement this in whatever manner the DOE comes up with in order to get them to pay for our desires," he said. "That just basically commits us to agreeing to anything they come up with. I'm fine with pursuing the DOE funding, as long as we're not committed to doing whatever they want."

Three of the committee's 11 members — representing Louisiana, North Dakota and Oklahoma — voted against the CAWG's recommendation that SPP's 10% load share in the current portfolio and the next study of the southern party of the MISO-SPP seam be regionally allocated on a load-ratio share basis consistent with previous RSC policies.

"I don't think we should be making our allocation decisions based on balancing our regions," Christmann said. "I don't like the idea of passing something based on its pluses and minuses and saying we're going to do this one regionwide, and in exchange, we'll do whatever the southern end comes up with regionwide to whether it meets the criteria or not."

David Kelley, SPP vice president of engineering, said the recommendation was consistent with other policies the RSC has reviewed and approved. He said the grid operator's experience with importing and exporting power during winter storms proves additional transmission interconnections between regions provides "greater reliability and resiliency … going forward."

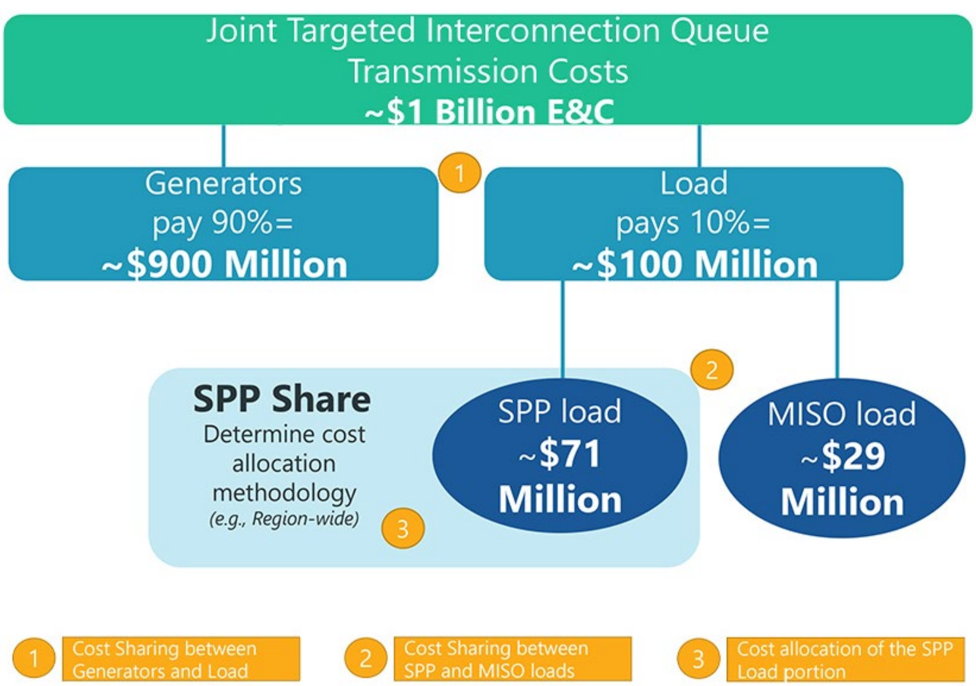
Texas Public Utility Commissioner Will McAdams said he views the JTIQ portfolio as a "building block of a greater reliability framework" where everybody chips in.

"If you have a need on a seam, you're going to build transmission just like road planners build highways. If you build a highway, everybody gets to use that," he said. "We're going to need to replace new generation, and the guiding principle for me is I would rather that new generation settle in our SPP footprint to where our RTO can control those resources … and then if they have excess, sell into MISO during scarcity periods at a profit to help reduce the cost on their loads.

"To me that makes sense, and if we see that occur in both the SPP northern area as well as the South, then that benefits everybody," McAdams added.

Christmann proposed a separate motion that the JTIQ portfolio only receive construction notifications when the executed generator interconnection agreements can pay for 50% of the eligible engineering and construction costs.

"We're preparing to do an approval to construct based on the fact that GI customers are going to pay 90%. That can be our plan, but if



Proposed cost allocation for the MISO-SPP JTIQ portfolio | *SPP*

SPP News

they don't come through, somebody is going to pay the costs of that project or these projects," he said.

Minnesota Public Utilities Commissioner John Tuma acknowledged Christmann's concerns but pointed out that no one is forcing companies to invest in generation and that they're capable of making their own judgments.

"I'm hoping they make the right judgment because they got to come in front of me for recovery," Tuma said.

"If you're a generator interconnection customer going through the process, you don't have any certainty that the transmission will be there," Kelley said. "Signing up to pay for transmission that may or may not be there is not something that they could get financing for."

"My concern is that this unravels the way we normally get these people signed up for projects. … This solves a lot of the problems," Tuma said. "I think it also jeopardizes the DOE funding because a condition like this could put a lot of the projects and ability for these projects to go forward in jeopardy. We are messing with some financial situations that I think are going to unravel what we're doing with JTIQ and the ability to get this paid at a reasonable rate."

Christmann's motion failed, receiving only supporting approval from members representing Louisiana, Nebraska and Oklahoma.

Saying she valued the conversations during the discussion, SPP CEO Barbara Sugg expressed a "high degree of confidence that the generators will be there."

"We still have a lot of work to do in the partnership with MISO that is already proving to be beneficial for both SPP and MISO and our states and our end-use customers," Sugg said. "We've got to keep this moving forward."

Missouri's Rupp Opposes RCAR III

The RSC approved the Regional Allocation Review Task Force's third Regional Cost Allocation Review (RCAR III) of SPP's highway/byway transmission cost-allocation methodology.

The mechanism assigns 100% of all 300-kV or above transmission upgrades' ATRR to all 17 transmission zones on a regional basis using a load-ratio share. One-third of upgrades with voltage ratings between 100 and 300 kV are allocated regionally and two-thirds to the host zone's transmission customers.

RCAR III, the first such review since 2016, indicated every zone exceeded the RARTF's 0.80 benefit-cost threshold and was above 1 when analyzing projects approved for construction since June 2010 and in service prior to 2020.

The review was conducted using the Integrated Marketplace's daily results paired with analysis on transmission planning models, limited to those projects in service before 2020. The task force said the methodology is expected to provide more reasonable results and avoid technical issues from past RCAR studies.

Still, RCAR III drew the ire of Scott Rupp, chair of the Missouri Public Service Commission, who cast the only vote against its approval, saying he couldn't in "good conscience" attach his name to something "that's just so bad."

"I feel like I'm Pontius Pilate. I'm just washing my hands with this," Rupp said. "We're being told that, 'Hey, this is the one that's the best. This is the one that's going to fix everything and look, everybody's great.' I can tell you personally, that things are not great."

Utilities in southern Missouri have long complained about the RCAR process, saying system congestion has limited their ability to move energy. The City Utilities of Springfield transmission zone was the only one found deficient in the 2016 study; it was also among six zones, mostly in the Midwest, that was deficient in the 2013 review. (See "Cost Allocation Review Cycle Could Extend to 6 Years," *SPP Markets and Operations Policy Committee Briefs*.)

In December, the southern Missouri region experienced extremely low voltages caused by resource trips, lack of deliverability and parallel system flows. Empire Electric District had to shed about 25 MW of load for 15 minutes on Dec. 22.

"Basically, what SPP has done is they've just taken the formula and they've tinkered with the methodology again until they got a result that they wanted, that would just quiet everybody that's been having concerns," Rupp said. "Southern Missouri has been saying, 'Hey, we need help down here' for 10 years. Every year, we do a lessons learned after one of these things, but the lesson we've learned is [we're] going to get hosed."

Saying she felt compelled to defend SPP's honor, Sugg said she is very aware of the region's problems and that she respected Rupp's position.

"This is not the place for me … or anybody else to try to unpack all of the things that you said," she told Rupp. "I will say … I am committed to us working to … alleviate some of the challenges that we face in that area. You've not seen the last of this, and please don't think that I'm dismissing anything that you've said."

The previous RCARs were completed every three years. FERC in 2017 approved SPP's request to conduct the review every six years; the grid operator said that would save staff time and consulting costs. (See *FERC Approves 6-Year Cycle for SPP RCAR Review*.)

Safe Harbor Criteria Unchanged

The RSC also approved the CAWG's recommendation to keep the current $180,000/MW safe harbor criteria for a network study's directly assigned upgrade costs (DAUC) after customers request transmission service.

To qualify for safe harbor treatment from some or all DAUC, transmission customers must meet three base-plan funding criteria: a five-year minimum commitment term; 125% or less of load in all designated resources; and, if the designated resource is wind, that 20% or less of the designated resources come from wind.

Customer can request a waiver of the criteria, and the RSC and SPP's Board of Directors have approved the requests under certain circumstances.

The CAWG reviews the safe harbor limit and criteria each year and conducts a more in-depth analysis every five years. The group has also opened an action item to continue studying performance-based accreditation's effects on the 20% wind rule and the 125%-of-load resource limit.

John Krajewski, who consults for the Nebraska Power Review Board, told the committee the safe harbor criteria keeps transmission customers from being charged the full rate for service and the cost of any upgrades.

This policy "basically keep customers with these long-term requests from paying twice for the same facilities," he said.

Krajewski shared the CAWG's recent analysis of the safe harbor requirements. It indicated 18 of 49 load-serving entities are over the 20% limit, but that a vast majority of requests qualified under the safe harbor limit.

Ex-KCC's Albrecht Chairs CAWG

Former Kansas regulator and past RSC President Shari Feist Albrecht has returned to SPP as the CAWG's chair.

Albrecht chaired the Kansas Corporation Commission during much of her eight-year tenure as a commissioner. She was succeeded by Andrew French in June 2020 after her second term expired.

She has rejoined the commission as a part-time consultant. As a member of the Utilities Division's SPP Workgroup, her responsibilities include representing Kansas on the CAWG. ■

— Tom Kleckner

Company Briefs

Rivian to Cut 6% of Jobs

Electric vehicle maker Rivian Automotive last week said it is laying off 6% of its workforce to cut costs.

In a letter to employees, CEO R.J. Scaringe said the company is focusing resources on ramping up vehicle production and reaching profitability.

More: *Reuters*

Exxon Posts $56B Profit in 2022

Exxon Mobil last week posted a $56 billion net profit for 2022.

The results far exceed the then-record of $45.2 billion net profit it reported in 2008.

Excluding charges, profit for the full year was $59.1 billion, while production was up by about 100,000 barrels of oil and gas per day over a year ago.

More: *Reuters*

GM Forecasts Strong 2023

General Motors last week reported higher net income for the fourth quarter, forecasted stronger-than-expected earnings for 2023, and said it would cut $2 billion in costs.

The automaker released a forecast that said it could hold its pre-tax margins steady between 8% and 10% through 2025 despite a "price war with Tesla."

The news caused company shares to jump 7.1% upon release on Jan. 31.

More: *Reuters*

Denault Steps Down as Entergy CEO, Chairman

Leo Denault last week stepped down from his role as CEO and chairman of Entergy.

Entergy announced in August that Denault would step down on Nov. 1; however, he stayed on as the utility's executive chairman until the leadership transition officially took place. Andrew Marsh, Entergy's former CFO, took over as CEO in November and recently assumed the title of board chairman.

Denault, 62, joined Entergy in 1999.

More: *Nola.com*

AEP Names Burbure VP of FERC, RTO Strategy Policy

American Electric Power last week named Stacey Burbure as vice president of FERC and RTO Strategy and Policy, effective Feb. 4.

Burbure most recently served as senior counsel for transmission policy and rates. She will be responsible for leading AEP's regulatory and policy efforts at FERC and RTOs.

Burbure will replace Amanda Conner, who now serves as chief of staff to President and CEO Julie Sloat.

More: *AEP*

Vistra Appoints Lagacy to Board of Directors

Vistra last week announced the appointment of Julie Lagacy to the Board of Directors as an independent director.

Lagacy will serve on the board's Sustainability & Risk Committee and the Social Responsibility & Compensation Committee.

Lagacy most recently was first chief sustainability and strategy officer with Caterpillar where she had served since 1988.

More: *Vistra*

Federal Briefs

Biden Pumping Breaks on Gulf OSW Development

The Biden Administration last week said it will delay the first auction of wind energy lease areas in the Gulf of Mexico by at least six months.

Biden's signing of the Inflation Reduction Act put those plans on hold, as it requires the government offer new drilling opportunities across the Gulf and mandates that wind projects take a back seat to oil and gas projects on public lands and waters. The provision was included to secure the support of Sen. Joe Manchin.

BOEM's most recent timeline for the Gulf includes a multi year process involving site assessments, surveys and environmental review. Barring any more slowdowns, wind developers could begin installing turbines in 2030.

More: *Nola.com*

Republican Govs Ask Biden to Delay Clean Water Rule

The Republican Governors Association (RGA) last week wrote a letter to the Biden administration asking it to delay the implementation of the revised Waters of the United States rule until the Supreme Court rules on a case pertaining to the Clean Water Act (CWA) this summer.

RGA members argued implementing the revision would create new bureaucratic hurdles at the state level when a June court decision could potentially render them moot. The upcoming decision, *Sackett v. EPA*, will determine whether most wetlands and streams can be considered waters of the U.S. under the CWA.

The Sackett case was brought by two Idaho homeowners after they were told a wetlands permit was required for construction on their property.

More: *The Hill*

More Than Half of New US Capacity will be Solar in 2023

Developers plan to add 54.5 GW of new utility-scale capacity to the U.S. grid in 2023, according to the EIA's Preliminary Monthly Electric Generator Inventory, more than half of which will be solar power (54%).

U.S. utility-scale solar capacity has been rising rapidly since 2010. Despite its upward trend, additions declined by 23% in 2022 compared to 2021 because of supply chain disruptions and other pandemic-related challenges. The EIA expects some of those delayed projects to begin operating this year, when developers plan to install 29.1 GW of solar. If all the capacity comes online as planned, 2023 will boast the most utility-scale solar capacity added in a single year, more than doubling the current record (13.4 GW in 2021).

Battery storage (17%, 9.4 GW), natural gas (14%, 7.5 GW) and wind (11%, 6 GW) round out the new capacity top four.

More: EIA

State Briefs

CALIFORNIA

Ex-Solar Firm Executive Sentenced for $1B Fraud

Ryan Guidry, the former vice president of operations for DC Solar, was sentenced to 6.5 years in prison last week and ordered to pay nearly $620 million in restitution for his role in a $1 billion fraud scheme.

Guidry pleaded guilty in 2020 to conspiracy and money laundering charges, the U.S. Attorney's Office said.

More: *The Associated Press*

COLORADO

Xcel Energy Outlines Plan to Lower Gas Bills

Xcel Energy customers could see their monthly gas bills drop by as much as 15% in February and March, according to a new cost adjustment plan approved by the Public Utilities Commission.

Under the plan, the average homeowner's bill should decrease by about $18 a month, mainly because of falling natural gas prices. The temporary adjustment comes after several months of sky-high bills for which Xcel blamed market forces beyond its control.

More: *CPR News*

MINNESOTA

Court of Appeals Upholds 'Clean Car Rule' on Emission Standards

The Court of Appeals last week upheld the state's "Clean Car Rule," which ties the state's vehicle emission standards to California regulations. The ruling came after judges accepted assurances that California's planned phaseout of gasoline-powered cars won't automatically apply in Minnesota.

The panel rejected arguments from auto dealers, who claimed that the Pollution Control Agency exceeded its authority and unconstitutionally delegated its rulemaking authority to California. The court ruled that the agency within its statutory authority and that the rule is therefore valid.

PCA officials said they have no immediate plans to ban gas-powered vehicles but did not rule it out.

More: *The Associated Press*

NORTH CAROLINA

Duke Energy Proposes New Programs to Encourage Renewable Energy Use

Duke Energy last week asked the Utilities Commission to approve expansion of a program that lets large customers contract renewable energy. The utility also wants to offer renewable energy credits to customers who support the shift to clean energy.

The new program would let customers contract up to 4,000 MW of renewable energy over the next 10 years.

The proposed program is required by the state's 2021 energy reform law and would build on a pilot program that began in 2019. It would also allow customers to contract with developers for up to 100% of their energy use while adding an option for battery storage.

More: *WFAE*

TEXAS

El Paso-area Electric Bills Going Down to Reflect Lower Fuel Costs

El Paso Electric last week said it will reduce electric bills by about 62% for at least a few months to reflect expected lower costs of natural gas.

Residential bills will go down an average of $12.90 per month beginning in February; the reduction would last until at least June 1.

More: *El Paso Times*

EPA Investigating Complaints Against Commission on Environmental Quality

The EPA said in a letter that it is looking into allegations that the Commission on Environmental Quality allows developers to skirt environmental rules, cuts the public out of permitting processes, and is not doing enough to safeguard against water and air pollution.

The inquiry comes after dozens of environmental groups filed separate petitions asking the agency to step in and take over permitting in the state. A Sunset Advisory Commission review last year deemed the CEQ to be "reluctant regulators" and recommended lawmakers increase fines on polluters, add time for the public to weigh in on proposed permits and improve online transparency, among other things.

The CEQ did not comment.

More: *Houston Chronicle*

VIRGINIA

DEQ Proposes Easing Emission Limits for Data Centers

The Department of Environmental Quality last week proposed easing certain air emissions rules for facilities in a "danger zone" to allow them to get extra power from generators.

The variance, which would be in effect between March and July 31, would suspend certain short-term emissions limits for data centers if they sit in an area for which PJM has issued a warning about acute strains on the transmission system. The data centers would then be allowed to operate their emergency generators.

Approximately 150 data centers in Prince William, Fairfax and Loudoun counties could be eligible.

More: *Virginia Mercury*

WISCONSIN

Edgewater Generating Station to Become Battery Project

Alliant Energy last week announced plans to build the Edgewater Battery Project on the same property as the soon-to-be-retired Edgewater Generating Station.

The retirement of Unit 5 is slated for 2025. Pending approval, the battery project is expected to begin construction next year and be completed by June 2025.

The new facility will be built on 7 acres of land. The remainder of the 265-acre campus occupied by the power plant is being evaluated for future use.

More: *WHBL*

Wheatland Town Board Approves Solar Farm

The Wheatland Town Board last week approved a conditional use permit for the Salix Solar Project.

Proposed by OneEnergy Renewables, the 7.5-MW system would sit on 34 acres and consist of 16,380 solar panels.

The proposal now goes go to the Kenosha County Planning, Development and Extension Education Committee for action on Feb. 8.

More: *Kenosha News*

WYOMING

Lawmakers Propose EV Charging Tax

A bill is waiting to be introduced in the House of Representatives that would more than double the price of electricity used to charge electric vehicles.

The legislation would impose a tax of $0.15 per kWh on commercial and residential chargers and on vehicle self-charging features beginning in 2024. According to the EIA, the average November price for a kilowatt-hour in the state was about $0.11 for households and $0.10 for businesses.

The bill would also raise the state's annual EV registration fee to $350 and introduce a $175 fee for hybrids. However, drivers would be able to choose between paying the registration fee or the charging tax.

More: *Casper Star Tribune*