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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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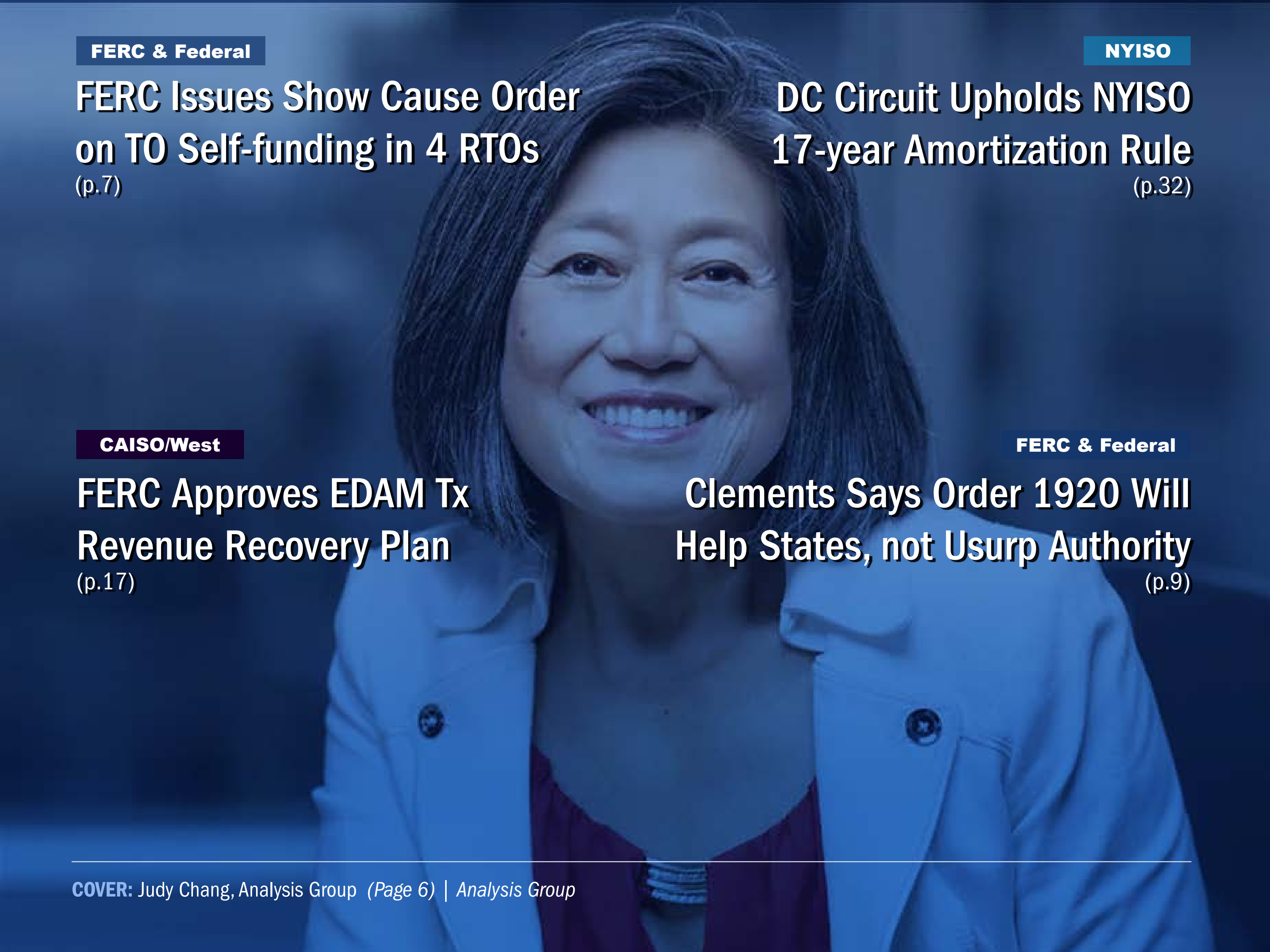

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

Counterflow

By Steve Huntoon

Fusion is Getting Increasing Attention

By Steve Huntoon

2024 is the 35th anniversary of the discovery of *cold fusion*!

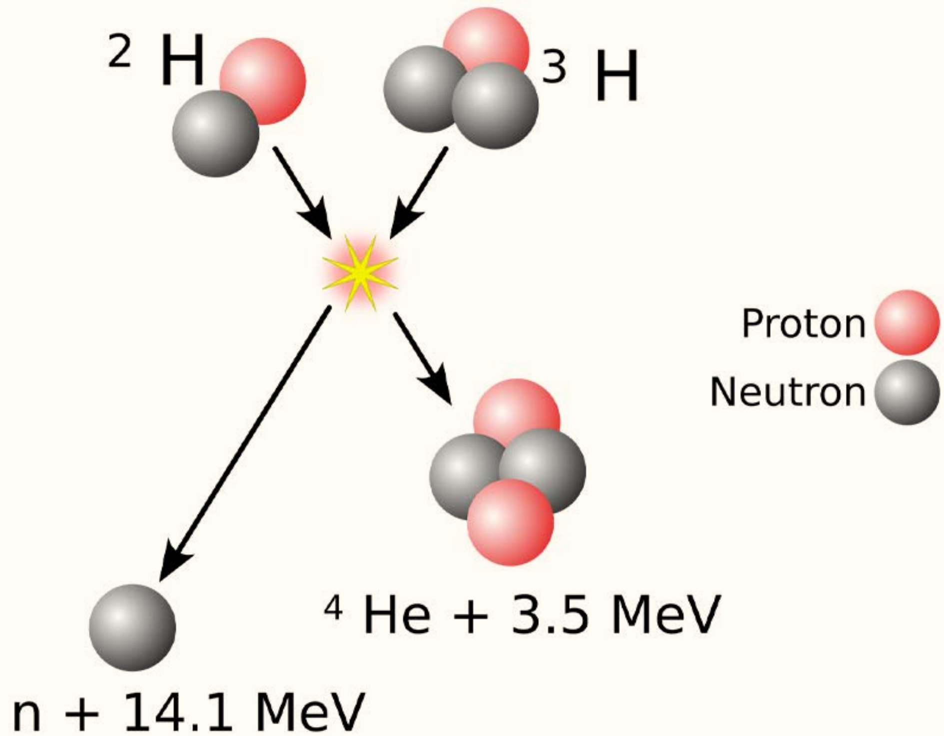
OK, just kidding.

Back to reality: Renewable resources generally are not dispatchable. We are searching high and low for an economic solution to this problem because dispatchable resources like coal and natural gas emit carbon.

Certainly it is wise to maintain existing nuclear plants, as *I urged* long before it became fashionable. But other resources remain highly problematic.

New nuclear fission, such as small modular reactors, has a very high cost. Although *a recent Atlantic article* says we should take a leap of faith because failure is not an option (citing the siting challenges of large wind, solar and transmission), hope is not a plan.

Long-duration battery storage is extremely costly, as I discussed in *my most recent column*. Green hydrogen electricity is a pipe dream (no pun intended), as *I discussed before*.



Fusion of deuterium with tritium | *public domain*

The Fusion Revival

Fusion is getting increasing attention as a possible salvation.

I'm here to tell you that commercial fusion is another fantasy.

The old saying is that commercial fusion is 30 years away and always will be.[1] An Oak Ridge director of fusion energy research said at a conference: "The projected time to realize the ultimate goal of commercial fusion always seems to be *25 or 30 years away*." He said that in 1986 — 38 years ago. So even then it was a cliché.

'Net Energy'

But the hoopla continues, most recently about "net energy" being generated in fusion tests (*for example*).

Two things about such tests that don't get reported in the media: first, that the amount of energy generated is trivial. The most energy generated in a fusion test, at the U.K.'s Joint European Torus (JET), *is 69 megajoules*. That sounds like a lot, but it is the equivalent of 19 kWh. Basically, it could power one American household for about two days. (*The monthly average is 900 kWh*.)

Second, this isn't really net energy. When the JET was running, it consumed 700 to 800 MW *(yes, megawatts)*.

As for the 3.88 megajoules generated at the U.S. National Ignition Facility, the claim is made of "net energy" because 3.88 megajoules generated are more than 2.05 megajoules "*delivered to the target*." The net of 1.83 megajoules would power a 100-W lightbulb for all of five hours.

But more importantly, this formulation ignores the 322 megajoules it took to power the 192 lasers to "deliver" the 2.05 megajoules.[2] It's not "net energy" — it's negative energy. The ratio of energy consumed to energy generated is about 83 to 1.

Reality Check from a Retired Nuclear Fusion Physicist

Part of the problem with fusion is that we've spent $100 billion on it, and thereby created an industry dependent on huge taxpayer subsidies and on hoopla to keep those subsidies coming. Experts not dependent one way or another on the public's money are few and far between.

But I did find this sobering analysis by a nuclear fusion physicist who worked on nuclear fusion experiments for 25 years at the Princeton Plasma Physics Lab in New Jersey, and who is … retired.[3] Here are some of his key points:

- huge parasitic power consumption
- tritium fuel not fully replenished
- radiation damage and radioactie waste
- nuclear weapons proliferation
- outsized operating costs.

His follow-up *article* focused on the colossal International Thermonuclear Experimental Reactor (ITER) in France, originally scheduled to test its "first plasma" in 2020 and achieve full fusion by 2023. However, the schedule was pushed back to test first plasma in 2025 and achieve *full fusion in 2035*, and now the schedule is … *nobody knows*. The ITER has been portrayed repeatedly as using 50 MW *to generate 500 MW*, but the reality is that it will use 300 MW to generate *0 MW of electric energy*.

Counterflow

By Steve Huntoon

If, after reading his analyses, you still think there's a realistic future for commercial fusion, then I admire your optimism. And there are three dozen *fusion startups* that might welcome your investment dollars.

Path Forward

The fact remains we have no realistic, affordable way to maintain resource adequacy in a net-zero future other than to keep a fleet of natural gas plants around that can be dispatched *as needed* — maybe not many hours a year, but enough. This will vary across regions. And they'll have to be compensated to be available and flexible as needed. In the organized markets, they'll have to get meaningful capacity payments to stick around. In the cost-of-service states, they'll have to get regulated compensation. The carbon emissions of the gas plants can be offset/captured as different states deem worthwhile.

This is not rocket science.

Speaking of rocket science, let me repeat from a couple recent columns[4] that regardless of what we might do here and in Europe, humanity as a whole is gonna need Plan B: solar geoengineering. There is no realistic alternative, at least for the near and medium terms (until perhaps those 30 years for commercial fusion to become reality).

"We all have to take a chance. Especially if one is all you have." — Capt. James T. Kirk, "Tomorrow Is Yesterday," 1967. ■

Columnist Steve Huntoon, principal of Energy Counsel LLP, and a former president of the Energy Bar Association, has been practicing energy law for more than 30 years.

[1] A collection of articles about fusion spanning decades as published by the *Bulletin of the Atomic Scientists* is here: https://thebulletin.org/collections/fusion-energy/

[2] https://www.scientificamerican.com/article/nuclear-fusion-lab-achieves-ignition-what-does-it-mean/ ("NIF's 192 lasers consumed 322 megajoules of energy in the process.") https://pubs.aip.org/physicstoday/online/42581/National-Ignition-Facility-earns-its-name-for-a https://www.vice.com/en/article/xgwpkk/jet-reactor-fusion-energy-record-setting-breakthrough

[3] https://thebulletin.org/2017/04/fusion-reactors-not-what-theyre-cracked-up-to-be/#post-heading. An interesting and very readable anonymous posting by an electrical engineer in the industry is here, https://www.reddit.com/r/fusion/comments/10buldl/what_are_the_biggest_hurdles_facing_companies/

[4] https://energy-counsel.com/wp-content/uploads/2023/08/World-of-Hurt.pdf; https://energy-counsel.com/wpcontent/uploads/2022/05/We-are-Going-to-Need-a-Plan-B-RTO-Insider-5-10-22.pdf A recent *Economist* article on the Antarctic ice melt also sounds the alarm, https://www.economist.com/interactive/science-andtechnology/2024/03/27/antarctica-earths-largest-refrigerator-is-defrosting

Stakeholder Soapbox

A New Twist on Capacity Markets in Japan

By Eri Akiyama and Jennifer Fischell

Reliability is a global problem that requires local solutions. For more than 15 years, PJM's solution has been its forward-looking capacity market, the Reliability Pricing Model. Meanwhile, on the other side of the world, Japan recently enacted major reforms to its energy system. Those reforms have included a PJM-inspired capacity auction first held in 2020 for the 2024 delivery year and a related long-term decarbonized power resource auction inaugurated this year.

Japan's energy reforms are of increasing importance globally, including to U.S. companies and investors. A weak yen has spurred investment in Japanese energy projects, and foreign- and U.S.-owned energy companies have *started winning* major capacity contracts in Japan's new system. Recent developments in Japan have revealed, however, that its market differs in significant ways from those in the U.S. — including from the very PJM capacity market on which Japan modeled its own.

A Modified PJM Capacity Market in Japan

When Japan embarked on its energy reforms, it formed a study group to examine foreign capacity markets, including PJM's, and to make a proposal for how best to ensure long- and midterm reliability in its energy markets. Ultimately, the study group concluded a capacity market similar to PJM's model (and the model used in the U.K.) would work best.

The capacity market system Japan ultimately adopted shares the same basic structure as PJM's. It is presided over by a private transmission organization called the Organization for Cross-Regional Coordination of Transmission Operators (OCCTO). Like PJM, OCCTO runs a centralized capacity auction where generation resources offer to sell capacity for a price, and the auction's clearing price is ultimately set at the point where supply and demand curves cross.

There are, however, several key differences between Japan's market and PJM's. For example, unlike PJM's system, participation in OCCTO's capacity market is never required for participation in Japan's wholesale electricity markets. And unlike PJM, OCCTO does not administer the wholesale electricity market itself: Another organization, the Japan Electric Power Exchange, does.

Perhaps most critically, OCCTO's and PJM's systems are different because they are governed by different legal frameworks. OCCTO is authorized and governed by Japan's 2015 amended *Electricity Business Act*, while PJM (like other U.S. RTOs) is governed by the Federal Power Act. Those laws impose materially different restrictions, based on different national policies. The FPA, for example, embraces what U.S. courts have long called the filed-rate doctrine, which forbids retroactive rate changes. That prioritizes pricing predictability, even when doing so may result in higher-than-necessary consumer prices. Japan, by contrast, has not adopted the filed-rate doctrine; it has prioritized lowering consumer prices instead.

A Focus on Reducing Prices

Japan's focus on reducing prices has been especially clear in its management of its new capacity markets. Since the first capacity auction in 2020 yielded prices far higher than expected, Japan's energy regulator — the Electricity and Gas Market Surveillance Commission (EGC) — has been on the lookout for ways to ensure that OCCTO's capacity auction prices remain as low as possible. That has been especially clear in the EGC's handling of the 2022 capacity auction for the 2026 delivery year.

First, after the 2022 auction closed but before results were announced, the EGC discovered that one capacity supplier's offer was too high because of a mistake. In consultation with OCCTO, the commission took the unprecedented step — one that no statute or auction rule permitted — of requiring that the offer be corrected and the resulting capacity price for all participants be changed accordingly.

Second, this year, the EGC discovered another "misbidding" mistake — this time, after the 2022 auction results had been announced and the supplier had been awarded a contract. The commission and OCCTO promptly announced that they would amend the supplier's contract to reduce the contracted capacity price. Recognizing that such a change was also unprecedented, the organizations emphasized that such an adjustment should be made only when the resulting capacity price would be lower, to protect consumers.

Will Japan Adopt Something Like the Filed-rate Doctrine?

Japan's energy and capacity markets are, in many ways, still in their infancy. Japan might still develop or adopt something akin to the filed-rate doctrine, or it might reject the doctrine expressly. Either way, Japan cannot help but recognize that market forces demand some degree of pricing predictability. Even in the recent misbidding investigations, for example, Japanese regulators showed they are sensitive to the same concerns that motivate the filed-rate doctrine. They could have undone the entire 2022 capacity auction this year after they discovered that misbidding affected the clearing price, but they did not. Instead, they amended only the responsible supplier's contract while recognizing that amending such established contracts should be a rare event — one limited to situations where it will protect consumers without destabilizing market expectations.

Even without a formal filed-rate doctrine, in other words, Japan's capacity markets are not the Wild West. Japan cannot make reneging on capacity prices a habit, because participation in the capacity markets there is entirely voluntary. To incentivize participation and ensure reliability for consumers, if nothing else, Japan will need to safeguard the predictability of prices once they are set. Whether it will formally adopt the filed-rate doctrine, or something like it, in the years to come remains to be seen. ■

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Jennifer Fischell is a partner at MoloLamken with a practice focusing on energy and complex civil litigation, administrative law and appeals. She has clerked for judges at all levels of the federal judiciary, most recently for U.S. Supreme Court Justice Elena Kagan.

FERC/Federal News

Senate Confirms Chang as Clements' Replacement on FERC

By James Downing

Judy Chang, Analysis Group | *Analysis Group*

The Senate voted June 13 to confirm Judy Chang to a five-year term at FERC, meaning the commission will be back to a full complement of five members even after Commissioner Allison Clements leaves at the end of the month.

Chang was confirmed in a 66-33 vote, with all the "nays" coming from Republicans. Her confirmation came the day after the Senate approved fellow nominees David Rosner and Lindsay See. (See related story, *Rosner, See Clear Senate to Fill Out FERC*.) Her term will expire June 30, 2029.

Senate Majority Leader Chuck Schumer (D-N.Y.) said he was heartened to see the nominees confirmed with bipartisan support. FERC was in danger of losing a quorum when Clements left.

"This week, the Senate protected access to affordable, reliable and safe energy for all Americans," Schumer said. The confirmations came "in the nick of time."

The three sitting FERC commissioners welcomed all three confirmations in statements June 13.

"As I have said many times, the commission works best when it has five members, so I look forward to welcoming them to the commission so we can work collaboratively to ensure reliable, affordable and sustainable energy for all consumers," said Chair Willie Phillips.

The other two commissioners also welcomed the new members June 12, with Commissioner Mark Christie *posting* on X, and Clements offering congratulations during a talk at a meeting of the Energy Bar Association's Northeast Chapter in D.C.

"I'm pretty excited that they're all coming in together," Clements said. "I think it's a real opportunity for a reset and a new collaboration. Every new commission is that."

The industry and other stakeholders also lauded the confirmations.

Edison Electric Institute President Dan Brouillette thanked the Senate and said all three new commissioners will bring extensive experience in the energy sector to FERC.

"We look forward to continuing to work with FERC on critical regulatory issues to ensure that electricity customers have the energy they need, when and where they need it, reliably and affordably," Brouillette said.

Electric Power Supply Association CEO Todd Snitchler also said a full FERC is important to tackle the issues around growing demand, shifting generation mix and other major issues facing the energy sector.

"We were pleased to see all three of the incoming nominees make commitments to maintain FERC's independence as an economic regulator focused on reliability during their confirmation hearings," Snitchler said. "It will be essential that FERC works to address wholesale power market barriers and opportunities to ensure reliability and drive competitive investment. Support for the proven ability of markets to deliver reliable, cost-effective and innovative grid solutions will be essential."

American Clean Power Association CEO Jason Grumet also commended the Senate for approving the three "talented" new commissioners.

"The strong bipartisan support they received reflects the quality and caliber of these nominees and broad appreciation of the critical role FERC must play in modernizing our nation's energy infrastructure," Grumet said.

The Natural Resources Defense Council's Sustainable FERC Project Senior Attorney Christy Walsh said her group looked forward to working with the new commissioners.

"FERC is at the center of the clean energy transition, and with a full FERC commission, we now can focus on the hard work ahead," Walsh said. "There are tough challenges that must be addressed, chiefly, providing badly needed system upgrades, addressing a scarcity of transmission capacity and implementing long overdue, common-sense guardrails to our natural gas system."

"As they take their place on the commission bench, the commissioners must incorporate climate and environmental justice impacts into their decisions, not succumb to the pressure from fossil fuel interests," Sierra Club Executive Director Ben Jealous said. "In doing so, FERC can do its job, working for consumers who simply want to keep the lights on while protecting the health of their families and the planet." ■

FERC/Federal News

FERC Issues Show-cause Order on TO Self-funding in 4 RTOs

Order Covers Practices in MISO, PJM, SPP and ISO-NE

By Amanda Durish Cook

FERC on June 13 initiated show-cause proceedings into the practice by four RTOs of allowing transmission owners to self-fund network upgrades needed to bring generation online, saying the practice may amount to favoring TOs over interconnection customers.

The commission directed MISO, PJM, SPP and ISO-NE to explain within 90 days how their tariff language on the initial funding is fair or, alternatively, to propose changes to make their policies impartial (*EL24-80*). All four grid operators currently allow TOs the first shot at funding and earning a return on the capital cost of network upgrades required for generators to connect to their systems.

FERC said that approach might be biased against interconnection customers, who could see their interconnection service costs rise when compared with having the ability to finance their own upgrades. It said TO self-funding might "increase the costs of interconnection service without corresponding improvements to that service, may unjustifiably increase costs such that it results in barriers to interconnection and may result in undue discrimination among interconnection customers."

The commission added that the grid operators' current practice may amount to barriers to interconnection. It also seeks to "consistently and comprehensively" address the RTOs/ISOs that maintain a TO self-fund option.

Started with MISO

The Order to Show Cause is the latest in a string of seesawing decisions between the commission and the D.C. Circuit Court of Appeals that originated with disputes in MISO.

MISO restored TOs' rights to self-fund in

The Fagen Civil Crew pours the first wind turbine foundation at the at the Palmer's Creek Wind Farm project in Minnesota in 2018. The wind farm's network upgrade agreement was among those filed unexecuted in protest over MISO's reinstating transmission owners' right to self-fund network upgrades. | *Fagen, Inc.*

FERC/Federal News

2019 at FERC's direction. The commission originally issued an order in 2015 preventing TOs from providing initial funding for network upgrades, but that decision was remanded by the D.C. Circuit. At the time, the court said the commission didn't consider complaints from Ameren and five other TOs who claimed the policy forced them to accept "risk-bearing additions to their network with zero return" and essentially act as "nonprofit managers" of network "appendages."

However, the court ruled in late 2022 that FERC did not adequately explain why it reinstated TOs' option to finance network upgrades before the interconnection customers owning generation projects were given the chance to do the same. (See *FERC Must Clarify MISO Tx Funding Decision, DC Circuit Finds*.)

Since 2019, MISO interconnection customers have taken to filing unexecuted network upgrade agreements to protest the RTO reinstating TOs' rights to self-fund. (See *FERC Accepts Unexecuted Agreements Filed in Protest*.)

Other affected grid operators have made filings regarding TOs' right to self-fund upgrades.

PJM in 2021 filed on behalf of its TOs to replace its existing method of generator upfront funding of upgrades with a TO self-funding provision. The RTO also specified that interconnection customers must provide security either to PJM or the transmission owner in question to protect against non-payment. FERC accepted the switch but placed PJM's new rules in a paper hearing and subjected payments to possible refund.

SPP allows either TO initial funding or generator upfront funding. However, FERC last year rejected an SPP proposal regarding its initial funding option, saying its plan to allow TOs a nonbinding decision to elect initial funding could create uncertainties for interconnection customers because a TO could reverse course at the end of interconnection studies, leaving customers with different network upgrade costs.

ISO-NE allows a TO to unilaterally elect initial funding. However, FERC said the practice of initial funding by TOs is rare in ISO-NE, where no TO has ever pursued the option. SPP in 2021 saw its first FERC-approved network upgrade agreement in which the TO elected initial funding.

In 2021, New York TOs filed a complaint against NYISO, which does not have an initial funding option, contending it was unfair the ISO wouldn't allow them to be compensated for "the risks and costs associated with owning, operating, and maintaining system upgrades." FERC denied the complaint reasoning the TOs didn't demonstrate that NYISO's current funding mechanism was inequitable.

'Replacement Rate'

In its show cause order, FERC singled out testimony from RWE Renewables, NextEra Energy and EDF Renewables, who argued that their costs "double or increase exponentially" when TOs take the reins on funding network upgrades. EDF claimed MISO's use of TO initial funding has stymied development of new generation development in MISO and SPP, with larger MISO TOs hiking the cost of network upgrades.

FERC said it was concerned that unilateral TO initial funding might force an interconnection customer to pay a higher financing rate than it otherwise could secure through a lender. The commission also said interconnection customers may incur additional costs through securities to the TOs over a 20-year payback schedule.

"It appears that these increased costs do not provide any additional benefits to the interconnection customer than it would otherwise receive through generator upfront funding. We also are concerned that in some cases, an unjustified increase in costs may be significant enough to result in a barrier to interconnection because the costs are so high that projects that would otherwise be commercially viable cannot proceed," FERC wrote.

Beyond that, FERC said it was troubled by the risk of discrimination to interconnection customers. It said vertically integrated TOs or TOs with affiliates may strategically decide to elect initial funding only for non-affiliate interconnection customers in an attempt to raise costs for competitors.

FERC also said it worried that initial funding may provide TOs the opportunity to double-dip on risk premiums because risks associated with owning, operating and maintaining network upgrades essentially are "baked-in" to TOs' transmission rates, but also noted it might identify that TOs are not being adequately compensated for those risks.

The commission concluded the order saying that if it finds that TO initial funding is prejudiced but also finds that TOs take on uncompensated risks building network upgrades, it could enact a "replacement rate" compensation mechanism. ■

FERC/Federal News

Clements Says Order 1920 Will Help States, not Usurp Authority

By James Downing

FERC Commissioner Allison Clements speaks at the Energy Bar Association's Northeast Chapter in D.C. | © RTO Insider LLC

WASHINGTON — FERC Commissioner Allison Clements said last week that Order 1920 will make it easier for states to address the changes facing the industry.

Rehearing requests have come into FERC, and some states are arguing that the commission cannot impose the new transmission planning and cost allocation rules on them, Clements said at the annual meeting of the Energy Bar Association's Northeast Chapter. The issue of states' rights drove Commissioner Mark Christie to dissent from the order, which Clements and Chair Willie Phillips responded to in a concurrence. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

"Good luck to the states who think they'd be better off going at this alone. Good luck to the economic development opportunities that your state faces. Good luck to the health and safety of your citizens in extreme weather," Clements said. "I mean, I don't know that there's any other way to get there besides all the solution sets, and regional transmission and inter-regional transmission has to be at the top of that list, at least in the FERC-jurisdictional bucket."

The changes are ultimately an incremental step from what FERC did more than a decade ago in Order 1000, and it rests on a firm legal framework, Clements said. It should stand up in court in the face of any appeals.

"The reality is that this money is getting spent every year anyways, $20 [billion] to $40 billion a year on annual spending on transmission," Clements said. "It has to be the commission's responsibility to try and direct that money towards more cost-beneficial outcomes for customers."

Along with Order 1977 implementing the commission's rules on National Interest Electricity Transmission Corridors, and Order 2023 that revised interconnection queue rules, 1920 is meant to help address the rapid changes the industry is facing from new demand to a changing resource mix, Clements said.

"I think the whole time I've been here, I've been focused on what I set out to do in this role, which is to facilitate affordable and reliable electricity as the world around us changes," Clements said. "It's not our job to dictate where the world goes; it's our job to facilitate affordable and reliable electricity service in light of where it's going."

Until this year, load growth in most of the country had been flat, but that has changed with new demand from data centers, reshoring manufacturing and ongoing efforts at electrification. It is unclear how much demand will be growing, even in the near future, she said.

"I don't think we know that it's going to be a 5% increase in U.S. consumption in the next five years," Clements said. "We can estimate that; we can model that; we're sure to be wrong."

The new demand is cropping up in specific areas, and potential shortages are only going to occur part of the year, but investments to bolster the grid are likely to be "low regrets" for the near future, she added.

"I think we're not yet at the point where we need to start worrying about the 'no one's going to show up,'" Clements said. "The top thing I hear from companies, whether it's tech companies or advanced manufacturing companies, is that we are shopping for location, with the No. 1 priority being, 'where is there available capacity on the grid?'"

The low-regrets case is bolstered by the fact that the grid has plenty of room for improvement with advanced grid-enhancing technologies (GETs) that can affordably make the existing system more efficient, she said. The Brattle Group has estimated that such technologies could double the amount of renewables that are online now absent major investment in new transmission, but even if the reality is half that, GETs are a worthy investment, Clements said.

Clements will step down this month after the open meeting June 27, having served three and a half years. Her replacement, Judy Chang, was confirmed by the U.S. Senate the same day she spoke.

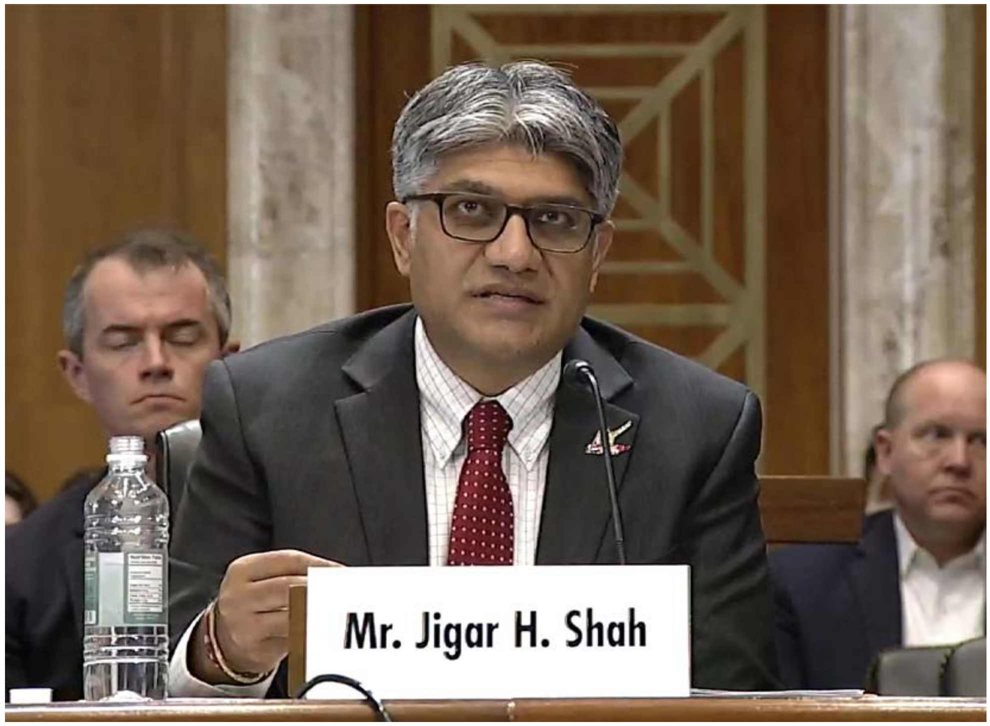
"It has flown by for me personally. I'm not sad for it to be over for my sake and my family's sake," Clements said. "But ... all of the work we're doing is pretty important. You know, I'm really proud of helping to establish our first Office of Public Participation. I think it's a really long road to hoe to think that you're going to actually engage members of the public in our esoteric, technocratic conversations, but we're on our way." ■

FERC/Federal News

Conference Explores AI Solutions to Data Center Power Demand

Shah: Utilities Must Act Like Private-sector Companies, 'Actually Take Risk'

By K Kaufmann



Jigar Shah, director, Loan Programs Office at DOE, at the Senate Energy and Natural Resources Committee in October 2023 | *Senate ENR Committee*

WASHINGTON — The biggest roadblock to the clean energy transition now underway in the U.S. is not technology-related or even the anticipated spike in power demand from data centers, according to speakers at a conference on the energy transition June 12.

It is the engrained, slow and risk-averse culture of U.S. utilities and other private-sector players, they said.

The technologies are ready, said Jigar Shah, director of the Department of Energy's Loan Programs Office, at the Clean Energy Transition Conference, held at the National Press Club by Tech for Climate Action, a UK-based event organizer.

"Now we need to get utilities to act like private-sector companies and actually take risk. You see that in the stock market. … The utilities' stock prices have [gone up] in the anticipation that they're going to turn from dividend companies into growth companies," Shah said during an on-stage conversation with Mary de Wysocki, chief sustainability officer for Cisco. "So, figuring out how that cultural and norm thing occurs is really fascinating to watch."

DOE is providing technical assistance "helping a lot of those folks through that change," Shah said.

Marissa Hummon, chief technology officer of Utilidata, a company developing grid-edge artificial intelligence applications, agreed that a major obstacle for her company is "getting the distribution utilities to act very differently than they have in the past."

The energy transition "is going to happen whether or not utilities decide to step up," Hummon said during a panel on the role of AI in the energy industry. "There will be new energy demands on the system, but the distribution utilities could really be encouraged to take that proactive step to deploy a platform that allows them to actually respond to the changes."

The Biden administration's position has been that the energy transition will be private sector-led and government-enabled with the billions of federal tax credits, loans and other incentives from the Infrastructure Investment and Jobs Act and Inflation Reduction Act. But the message that emerged from the conference is that at least some parts of the private sector have "been caught flat-footed" when asked to lead, Shah said, especially in the face of rising electricity demand from data centers and AI.

While the private sector is supposed to be the most efficient allocator of risk, "that process has been messy," he said. "But I do think it's a little bit unreasonable to believe the entire ecosystem has figured this whole thing out [in] less than two years" since the IRA was passed.

Faced with rising demand from data centers, Shah said, the focus has been on the AI chips and servers, but "much of the rest of the data center actually uses the electricity, so figuring out how we make the system more efficient is the more difficult thing to do. …

"We can't actually decarbonize our processes by thinking the same way we thought about things 10 years ago. This is not just [about] buying carbon credits, figuring out direct air capture and doing everything exactly the same. This is about us reimagining how we actually still live a modern lifestyle but doing things with materials that are more sustainable; doing things with a more thoughtful approach."

The electric power system must be able to "flex" load with the "same level of dexterity that we currently only flex supply," he said.

"When you think about what it's going to take to really meet this moment, it was something we actually needed to do in 2000, but people weren't forced," he said. "When you're a monopoly, obviously, you have a tendency not to deploy innovation as fast as a more vibrant capital system, and so we're doing it now because the pressures are just so great from weather and load growth."

A similar sense of urgency should be used to create new narratives about AI, said Charles Yang, policy adviser at DOE's Office of Critical and Emerging Technologies.

The challenge of load growth from data centers can be converted, not into new natural gas plants, but "into building an order book for the next generation of clean, firm, advanced technologies," Yang said, pointing to Microsoft, Google and Nucor's *recently announced plan* for aggregating their demand and contracting for clean power.

"We need better stories about what AI can do," he said. "How it can help us discover more abundant, affordable batteries; how it can help us coordinate our EV charging and lower costs for ratepayers. These are the stories that we haven't really told; they're not the future we've been told about."

Moving AI to Grid Edge

Since ChatGPT was introduced in November 2022, AI has exploded in the public consciousness, but, Hummon said, "Utilidata has been running AI models to operate the grid for more than 12 years. … We've been using data-driven, real-time methods to create outcomes of a more efficient, powerful grid, very reliably."

What's changed is the emergence of "generative AI" and the creation of large language models (LLMs) that allow users to ask questions or "prompt" the software in plain language.

Utilidata is deploying these advanced technologies to move AI to the grid edge, improving system visibility and opportunities for more efficient operations for distribution system operators, Hummon said. Such systems could not only get "the right information back to a central system to make a better decision, but also … interface with the customer using natural language about their energy use, about their choices, about just what sort of resources they want to purchase," she said.

AI can also support better use of unused capacity on the grid to increase the power that can be sent down distribution lines without having to build new substations or feeders, she said. Optimizing the operation of a substation with traditional, physics-based calculations can take 12 to 18 months, Hummon said.

"If you're using data-driven, machine-learning methods, you can be up and running in two weeks," she said.

Claus Daniel, associate laboratory director at DOE's Argonne National Laboratory, said his researchers and scientists want to push the use of AI in the electric power system further "to figure out how we can use that technology to help us in research and development to find better ways of utilizing energy; better ways of generating energy. …

"Artificial intelligence is particularly well suited to figure out what are the tradeoffs … and what are the connections. It's particularly well suited for handling complexity and recognizing patterns that we currently cannot fully resolve when we just use high-performance computing and physics-based models."

DOE and the National Labs are currently working with their Frontier and Aurora supercomputers — the *largest computers* in the world — to create "reliable and safe large language models," Daniel said, noting that most publicly available LLMs often answer questions with convincing but completely wrong information.

Eelco de Jong, head of AI-enabled utility service at McKinsey & Co., zeroed in on how AI can be used to "more precisely allocate our capital towards the investments that have the highest return for [grid] reliability."

Instead of replacing equipment based on age or zip code, "we're seeing companies using granular data to forecast, for example, which households are most likely to adopt electric vehicles or heat pumps or switch from gas to electric," de Jong said. "And based on that forecast data, we know exactly which neighborhoods or even which feeders are going to first run out of capacity, and we can channel … our capital dollars to that."

Similarly, AI can help with stressed supply chains by routing equipment "to the places where [it has] the biggest impact on customer reliability," he said.

DOE's recent *AI for Energy* report, released in April, focuses on advancing the intelligence of the grid, Daniel said. (See *AI Critical to US Clean Energy, Grid Modernization Goals*.)

"This is something that will fundamentally change how we operate the grid" and help solve the problem of non-dispatchable wind and solar, Daniel said. "If I manage through building controls, through heating and cooling needs … [to understand] what's happening on the edge, I can control my demand in a better way. I can live with a higher percentage of non-dispatchable generation."

AI integrated into thousands of devices on the grid edge could also make the system more resistant to cyberattacks, Hummon said.

"If the edge is intelligent in and of itself, then every individual endpoint can make its own separate decision," she said. "You'd have to hack all those separate decisions in order to create the same type of risk that with pure central decision-making." ■

Rosner, See Clear Senate to Fill out FERC

FERC headquarters in D.C. | © RTO Insider LLC

By James Downing

The U.S. Senate on June 12 confirmed two of President Joe Biden's three nominees, David Rosner and Lindsay See, to FERC.

A day later, it took a final vote to confirm Judy Chang. (See related story, *Senate Confirms Chang as Clements' Replacement on FERC*.)

The votes mean FERC will be back to its full complement of five commissioners when the nominees take office, avoiding the loss of a quorum when Commissioner Allison Clements leaves at the end of the month.

"When it comes to fairly assessing all interests, five heads are better than one," Energy and Natural Resources Committee Chair Joe Manchin (I-W.Va.) said on the Senate floor. "Bringing together five different people, with five different life experiences and perspectives, helps ensure that all affected interests will be heard and fairly considered and assessed."

Rosner, a FERC staffer who has been detailed to Manchin's committee for the last couple of years, was approved 67-27. He fills the seat left open by former Commissioner Richard Glick, who chaired the commission when Biden took office until the end of 2022. His term will end June 30, 2027.

Most of the votes against Rosner came from Republicans, but he also lost support from Sens. Ed Markey (D-Mass.), Bernie Sanders (I-Vt.) and Elizabeth Warren (D-Mass.), with environmental group Friends of the Earth opposing his nomination.

"Lame duck Manchin is being allowed to dictate the future of FERC from beyond his political grave," said Lukas Ross, deputy director of Friends of the Earth's climate program, referring to the senator's decision not to run for re-election. "This dirty deal preserves the status quo by entrenching a pro-fossil gas majority. A paid cheerleader for the LNG boom like David Rosner has no business as a Democratic nominee."

Before his time at FERC, Rosner worked at the Bipartisan Policy Center, whose energy program director, Sasha Mackler, said he was well qualified for the commission.

"David has a tremendously deep knowledge of U.S. energy policy, as well as a keen appreciation for the complexities of the interactions between consumers, households, businesses, energy providers and other key stakeholders, including state governments," Mackler said. "It is hard to imagine a more qualified nominee, or one with a higher level of integrity and dedication to public service."

See, the solicitor general of West Virginia, was approved 83-12. She takes the place of former Commissioner James Danly, who left at the end of last year. Her term ends June 30, 2028.

She received support from every Republican except both of Missouri's senators, Josh Hawley and Eric Schmitt. Hawley, who voted against all three nominees at the ENR Committee, had criticized her response to his questions about the Grain Belt Express transmission project. (See *Senate Energy Committee Advances Biden's FERC Nominees*.)

The same day that it confirmed Rosner and See, the Senate also voted to invoke cloture on the nomination of Judy Chang, former undersecretary of energy and climate solutions in the Massachusetts Executive Office of Energy and Environmental Affairs, 63-31, setting up the final vote for the next day. Chang will replace Clements after the latter leaves, and her term would end June 30, 2029.

"While I may not agree with each of the nominees on all the items all the time, all of them are well qualified," ENR Ranking Member John Barrasso (R-Wyo.) said. ■

FERC/Federal News

Why Gene Rodrigues Came out of Retirement to Lead DOE's Office of Electricity

Assistant Secretary Aims to Get New Grid, Power Tech Adopted at Speed and Scale

By K Kaufmann

WASHINGTON — After 23 years working on demand-side programs at Southern California Edison and another eight as a consultant at ICF International, Gene Rodrigues was four months into retirement in 2022 when he got "the call," to serve as assistant secretary at the Department of Energy's Office of Electricity.

"There were two things that made this irresistible to me," Rodrigues said in a recent interview at DOE headquarters. "I saw this as my opportunity to give back … my opportunity to actually serve all the American people."

Rodrigues felt a more personal pull as well. "I'm the son of a father who was a career military person and a mother who came from her native land and became a U.S. citizen," he said. "So, it was engrained in me since I was a kid growing up around parents with that kind of background that serving the public is not just something you do; it's an obligation that we all have, and this was my opportunity to kind of honor my parents in the same way."

Known for his deep industry knowledge and engaging personality, Rodrigues aced his confirmation hearing before the Senate Energy and Natural Resources Committee and was sworn in as DOE's assistant secretary for electricity delivery and energy reliability on Jan. 9, 2023. In practical terms, his main job is leading the Office of Electricity (OE), which works with DOE's 17 National Laboratories "on solving really big problems, making discoveries and breakthroughs around everything from battery chemistry to materials science … that will help us to advance the grid; to make a truly 21st-century grid," he said. (See *Former NRG CEO Faces Tough Questions at Senate ENR Hearing*.)

Rodrigues sees the OE as part of a continuum running from the labs to DOE's Grid Deployment Office (GDO), which has been awarding billions in funds from the Infrastructure Investment and Jobs Act to help utilities upgrade their distribution and transmission systems. OE does the science — and gets fewer headlines — and GDO does the infrastructure, he said.

"We take basic science discoveries and prove them out through research and demonstration activities that help the market to get confidence in these new technologies [and] new operational approaches," Rodrigues said. The OE focuses on advances in "components and systems, in controls and communications and in grid-scale storage, making them not just accessible but trusted by the folks who are making massive investments, and that helps to accelerate their adoption in the real world."

DOE Assistant Secretary Gene Rodrigues | *© RTO Insider LLC*

In May, for example, the OE awarded $15 million in grant money to *three projects* demonstrating different long-duration storage technologies, including vanadium redox flow batteries providing up to 12 hours of storage and supercapacitors that could provide up to 100 hours of storage.

Rodrigues sat down with ***RTO Insider*** for a wide-ranging conversation on the work that OE is doing and why he spends a lot of his time, not in his D.C. office, but in the field, working with utility representatives, regulators and customers, all looking for new solutions to the core problems of the energy transition. The quotes from the interview here have been edited and condensed.

***RTO Insider*: We know DOE is looking at the role of artificial intelligence in advancing and accelerating the energy transition. What role does the OE have in that? How can it use AI to bridge some of the gaps in technology and policies?**

Rodrigues: "We aren't the shop that specifically works on it, but within science and innovation, we have folks who are 100% focused on what are the potentials of using AI that can help us leapfrog to make the grid even more reliable, resilient and secure. When you look at the grid, you see this incredibly complex network of poles and wires connected to generators, both large central station in faraway places and the solar panels on the roof of my house, connected to a whole bunch of devices in the home. So, it's absolutely clear to me as the assistant secretary for the Office of Electricity that we can't train people to be able to operate a system that complex at the speed of the flow of electrons through wires. But guess what? We can use distributed intelligence to help people make one wise and virtuous choice to participate in a program that helps them financially, helps them with reliability and resilience, but also helps manage this increasingly complex grid. That's the incredible promise of

FERC/Federal News

artificial intelligence."

We can't talk about AI without talking about data centers, the increasing amounts of electricity they will need and how some utilities are reacting, saying they need to build more natural gas plants. What's the way forward here?

"Utilities and the folks who are building these data centers, what they have to do is start working in a way that's more collaborative than in the past because that collaboration allows two things to happen. No. 1, it allows the utilities to plan thoughtfully about where and how to best serve that load using their existing system and whatever expansions are required, [and] how that process can be expedited. The second thing is some of these large data centers are looking at how they can be a constructive participant in the load by using load flexibility. Sometimes these data centers are [built] by firms that have data centers in different parts of the country, and they can move some of that computing load from one place to another to help balance out the energy. And so those are very, very interesting opportunities."

One thing we've been hearing a lot about at industry conferences is the need for new approaches to cost and risk allocation. Do you see any opportunities there?

"I think there's some genius in rethinking cost allocation and risk sharing in our industry, and let me suggest one thing here as an example. In today's world, we have the potential to make suboptimal decisions around transmission planning and investment if we allow ourselves to be boxed into thinking that an individual utility should only look at the costs incurred in its service territory and try to offset them only with the benefits that are accrued in that service territory.

"As we have more interconnections for broader geographies, it allows you to do two things on a reliability and resilience foundation. It allows you to import energy when needed to make up for [when] a storm goes through and you lose some generating capacity locally. But on the other side, it allows you to export energy to a wider area of our nation in ways that might create economic opportunity for the people within a state. So, as we think about how to justify cost and transmission investments, we need to be thinking not just in terms of the artificial boundaries of a service territory in the region, but how interconnections outside of a service territory and even between regions can be truly cost-effective investments in ensuring not just reliability, but resilience."

Covering utilities and conferences, we always hear about pilots and demonstrations but not necessarily how a utility is expanding a pilot across its systems. How does the industry break out of this perennial cycle of pilots and risk-averse utilities and regulators? How are you doing that at OE?

"There's an old joke in our industry, that every utility wants to be the first to be second. And that makes sense when you think about the awesome responsibility of ensuring reliability. It's awfully hard to move away from what's been proven in the past over and over and over again. But I would say this: I think progressive utility leadership and progressive regulators and policymakers are understanding the issue that the energy field is changing in such a way that just relying on the techniques and the tools and the products and the approaches of the past is not the safe approach.

"That is why it's so important for me in this bridge role between basic science of discovery and deployment, to not sit here in the office and just write white papers about how keen and wonderful technologies are but actually to go out and work with utilities and utility associations in partnership to overcome whatever hurdles they have. Some of it is certainty about economics. We have a tool coming out of our office — *Reconductoring Economic and Financial Analysis (REFA)* — and the idea is that because reconductoring is not something that's been done time and time again throughout the industry, we've created a tool to help decision-makers in the utility and in the regulatory bodies to assess the economic benefit of reconfiguring an existing transmission thoroughfare with high quality, highly efficient, advanced technology.

"Our folks here in the Office of Electricity — it's kind of a fun thing we do — I always talk to them about ***impact*** [slams hand on table], and I always slam the table when I talk about impact because that is really what our job is. It's not just to do research, development and demonstration, but it's to ensure it gets adopted in an accelerated fashion and at scale in the real world."

Do you have any success stories you can share?

"When the supply chain issues started being raised by industry and brought to the table here in the Department of Energy, the tip of the spear was distribution transformers. We brought together a convening of manufacturers, the folks who produce electrical steel, the folks from utility associations, all of them came to the table, and we discovered some things. One was there was simply way too much diversity in the design specifications for these transformers, and that slowed down the ability of manufacturers to build [them]. And we discovered that there was too little flexibility in the specification of individual components; so, if you said, 'I want [a certain] component,' and that wasn't available, then it stopped your ability to complete a product instead of using something else.

"So, we added representatives from EEI, APPA, the public power folks and rural electric co-ops — got their engineers around the table with the manufacturers, and we facilitated discussions around how could we put together a matrix of components substitution, so that we would get out of this problem of running into a bottleneck when one component wasn't available. And the other thing they are doing, and they're continuing to work on as we speak, is how can we maybe bring a little more rationality to the diversity in distribution transformer design?"

One of the ongoing challenges of the energy transition is just getting public buy-in on the need for more transmission. Everyone wants clean, reliable, affordable power; they want more of it, and they want it faster, but no one wants wires anywhere near where they can see them. How can the OE address that?

"The answer to that is fairly clear. You can't look at transmission and sell it on its technological features, even though the folks who have engineering degrees in our department love to talk about how high-tech the components and systems are that we work on. I think we really have to get to a conversation in this country that gets people to lose their sense of complacency about the engineering marvel that it is that when you push a switch, the lights come on. We've had over a century of that kind of reliability, and we've just taken for granted all this engineering, economic magic that just happens in the background. You don't need to think about it.

"It is time for policymakers, for regulators for legislators, for people planning and operating and investing in the grid to think about it. So, will transmission ever be sexy? I don't think so. But it should be more in front of mind because we have options available to us today that will help us to ensure reliability, resilience, security and affordability into the future. And if we don't think about, consider and adopt and even embrace those new technologies and new approaches, then we'll be mired in the approaches of the past. And that's not how to lead the world in a giant, clean energy revolution that is being undertaken as we speak." ■

FERC/Federal News

Order 1920 Rehearing Requests from States Seek Bigger Role in Tx Planning

By James Downing

The states that filed for rehearing of FERC Order 1920 on transmission planning and cost allocation either argue the federal regulator is overstepping its authority or want changes to the order to ensure it doesn't upset ongoing regional planning efforts.

Many states, or organizations that represent them, that commented earlier in the rulemaking process did not file for rehearing. But more than a dozen rehearing requests came into FERC from either states or organizations that represent multiple states, such as the National Association of Regulatory Utility Commissioners.

NARUC told FERC it appreciated the outreach to states during the rulemaking process and through task force meetings on transmission policy. But the group filed for rehearing because the final rule rejected some key provisions from the Notice of Proposed Rulemaking and adopted others that could undermine the goal of efficiently expanding the power grid.

"On rehearing, NARUC respectfully requests FERC address the necessary deference to and importance of the state agreement and consensus on planning and cost allocation issues outlined in the NOPR," it said in a rehearing request filed last week. "The suggested changes will necessarily improve outcomes, reduce potential litigation and facilitate subsequent state siting proceedings associated with transmission projects."

The NOPR proposed a stronger role for states in cost allocation, but FERC backed off that and requires only that states in a given region have six months to come up with their preferred cost allocation. The relevant transmission provider could decide to ignore that and file its own proposal.

The state agreement should be binding and subject only to FERC approval, NARUC argued. Transmission providers should have to detail their efforts on state outreach, and if FERC does not require its adoption, transmission providers should have to file details on any state agreement reached.

"Order 1920 creates a process that integrates individual state energy policies and goals into transmission planning, creates extensive procedures for 'consultation' with states and acknowledges how state input will facilitate the planning process," NARUC said. "But then the order establishes conditions that permit the transmission providers to completely ignore and not even report upon state input."

The majority on FERC pointed to a court precedent called Atlantic City in finding that transmission providers ultimately have the final say on whether to file cost allocation methods. The New England States Committee on Electricity argued that was not the case.

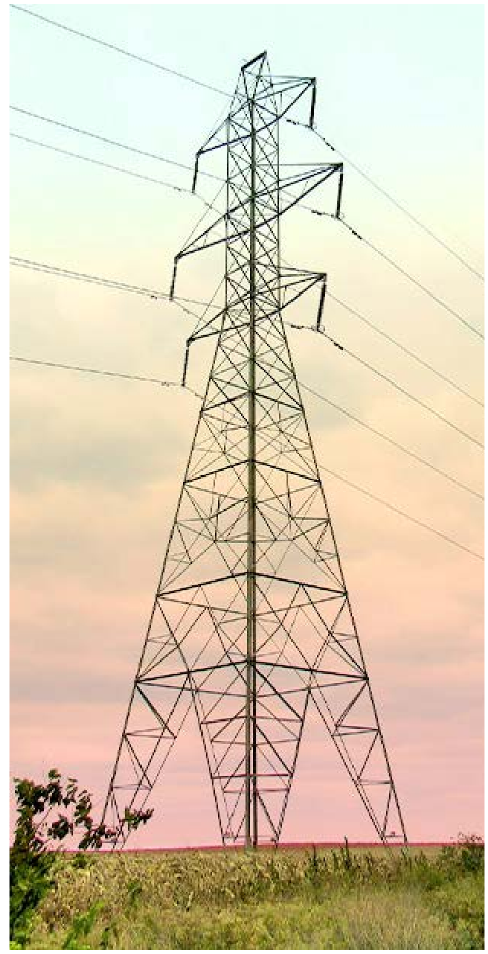
"However, Atlantic City does not prohibit commission action under FPA Section 206, under which authority the commission has promulgated Order No. 1920," NESCOE said. "Rather, Atlantic City simply affirms that transmission-owning utilities have filing rights under Section 205 that FERC may not revoke."

If FERC cannot grant rehearing on that, it should at least encourage transmission providers to voluntarily codify existing or new approaches that would put state alternatives before FERC, which would be consistent with the current practice in NYISO and SPP.

"Including the state-agreed-upon cost allocation method in a transmission provider's Section 205 filing is a lawful and rational means to effectuate in a concrete way the respect for the state role the commission articulates," NESCOE said. "The more the commission is successful in encouraging transmission providers to include such voluntary commitments in their tariffs, the greater the likelihood ... that states in the region will have comfort with moving forward on providing the approvals needed to actually get much-needed new transmission built."

The main thrust of NESCOE's comments was that it did not want Order 1920 to mess with the implementation of recently enacted transmission planning rules where ISO New England has agreed with its state members on transmission plans that enact its members' policies. FERC already has approved rules allowing the ISO to study scenarios developed with the states, but companion rules to competitively solicit actual transmission lines are pending. (See *Stakeholders Support ISO-NE Long-term Tx Planning Filing, with Caveats*.)

"NESCOE shares a commitment to meaningful, long-term regional transmission planning reform and seeks to ensure that FERC-jurisdictional transmission rates remain just and reasonable and not unduly discriminatory or preferential," it said. "In light of the progress in New England, NESCOE especially appreciates the commission's acknowledgment that certain transmission planning regions already conduct regional transmission planning on a forward-looking, proactive basis and its intent not to undermine progress made in these transmission planning regions, and our goal is to set a floor, not a ceiling."



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The Virginia State Corporation Commission and North Carolina Utilities Commission said they support the rule's stated purpose and recognize the potential cost savings and reliability benefits that longer-term, comprehensive planning could provide to consumers. But they took issue with some aspects of the final rule, including its claim that states won't subsidize others' policies.

"Because the same public policies included in planning scenarios, and ultimately embedded in selected transmission projects, are not required to be considered for purposes of cost allocation, it is far from clear how that bedrock principle of just and reasonable rates can be actualized under the final rule," the two said.

State policies like climate laws, which Virginia

FERC/Federal News

and North Carolina have enacted, are included in the long-term plan. But aiding their actual achievement is not among the benefits, so the state may pay too low a share for enacting its policy. The two suggested allowing transmission planners to do "baseline scenarios" that exclude state policies so it can be discerned how much the policies impact the other plans.

North Carolina and Virginia regulators also were skeptical of the proposal requiring utility and corporate "goals" to be included in the long-term transmission plans because they are easily changed, or even abandoned.

"This may 'skew' information submitted in the stakeholder process in favor of utility or corporate interests and result in planning scenarios that give too much weight to 'goals' that are unlikely to be achieved," the SCC and NCUC said.

Other rehearing requests from states were more strident in their opposition to FERC's Order 1920, arguing the commission overstepped its authority in the Federal Power Act and violated the "major questions doctrine."

A group of Republican state attorneys general (from Texas, Alabama, Arkansas, Florida, Georgia, Idaho, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Montana, Nebraska, North Dakota, Oklahoma, South Carolina, South Dakota, Tennessee and Utah) argued FERC is trying to use the planning and cost allocation rule to implement the Biden Administration's green energy policies.

"It shifts transmission costs for those remote renewables to consumers under the guise that those consumers will 'benefit' from those resources, without considering whether less remote resources of any type might be less expensive, more reliable and environmentally beneficial," the attorneys general said.

The filing was coordinated by the Texas Attorney General's office, and it noted that the states aren't opposed to renewable energy, with the Lone Star State leading the country in terms of megawatts of renewables installed.

"The commission's claim that the rule's proposals are necessary to ensure just and reasonable rates stretches the FPA beyond its limits," the attorneys general said. "Indeed, the proposals set forth in the rule will not — and are not designed to — ensure just and reasonable rates; they are blatantly preferential and would harm consumers by shifting costs to load, not protect them."

A group of state regulators used language similar to those attorney generals, with the Louisiana PSC, Mississippi PSC, Arkansas PSC and South Dakota PUC also arguing that while they are not against renewable energy, they are opposed to Order 1920's usurpation of state authority.

"The commission is attempting to do indirectly what it is prohibited from doing directly: usurp the states' exclusive authority over generation choices by instituting planning rules designed to benefit remote generation, and that generation's developers, over local generation and to shift billions or trillions of dollars in transmission costs from those developers onto electric consumers," they said.

The Arizona Corporation Commission said the order violates the major questions doctrine and would preempt its authority, while "unmistakably promoting a 'net zero' policy agenda."

"The final rule seeks to recast FERC as a national integrated resource planner with extraordinary powers to oversee and dictate to all public utility transmission providers in the country, in RTO and non-RTO regions, detailed instructions on planning transmission that fulfills the current presidential administration's stated preferred policies," the ACC said.

The West Virginia PSC was more moderate in its criticism, noting that it supported the NOPR, but FERC's decision to pare back state regulators' input over cost allocation made the longer-term planning horizon and new mandatory benefits no longer just and reasonable.

"That substitute, the engagement period and *de minimis* requirements placed on transmission providers, is so far removed from state cost allocation involvement that was noticed that the cost allocation and state agreement requirements in the final new rules must be re-noticed to give the public an opportunity to comment," the PSC said.

West Virginia is a member of the Organization of PJM States Inc., which filed its own rehearing request, also arguing states should have more of a guaranteed say over cost allocation.

"If states, through the process envisioned and required by the commission, exert the effort and resources to successfully reach agreement on a cost allocation method or methods and transmission providers are not required to file or even acknowledge the relevant state entities' efforts, state engagement in the development of cost allocation methods for long-term regional transmission facilities and any expected development of more efficient or cost-effective facilities may never materialize," OPSI told FERC.

In other words, giving states more authority would make them more likely to actually get steel in the ground.

OPSI was one of several organizations that argued the six months to come up with a state agreement could easily prove too short, given state regulators' other responsibilities. FERC should allow for an extension to 12 months total if states unanimously agree that would help them come up with cost-allocation rules.

The PUC of Ohio's Federal Energy Advocate filed comments noting that while the state has found RTO membership beneficial so far, Order 1920 could change that. RTO membership was based on assuring reliable transmission systems at the least cost.

Order 1920 "puts these principles in the rearview mirror," the Ohio regulator said. "Instead, it attempts to look 20 years into the future to launch a massive program today, not focused on achieving reliability at just and reasonable rates, but rather on building transmission projects to satisfy the ambitions, goals and policies of corporations, developers and governments that are not connected to reliability. Nothing could be further from the principles of Order No. 1000 and the requirement under the FPA for the commission to ensure just and reasonable rates."

The Ohio commission supports the use of the existing State Agreement Approach, which so far has been used only by New Jersey, where PJM planners helped it save money on interconnecting the wind farms called for by its policies. But the rehearing request argued that would no longer be feasible under Order 1920 because the SAA is focused on state policies alone and ignores other benefits the lines produce — limiting cost allocation to the states that agree to it.

The Ohio regulator noted that New Jersey *has decided* to pause on moving forward with another use of the SAA as the Garden State weighs the implications of Order 1920.

"FERC must not let RTO membership devolve into an instrument by which states are pitted against one another in a zero-sum game of cross subsidies amongst competing policy interests," the Ohio commission said. "Such a development would undermine the value proposition of RTO membership for states who do not wish to subsidize the policy preferences of others, directly contradicting FERC's goal of encouraging RTO participation as envisioned by FERC Order No. 2000." ■

CAISO/West News

FERC Approves EDAM Tx Revenue Recovery Plan

'Access Charge' was Only Part of EDAM Tariff Rejected by Commission in December

By Robert Mullin

FERC on June 11 approved CAISO tariff revisions that will allow transmission owners to recover transmission revenue shortfalls attributed to transitioning their assets into the ISO's Extended Day-Ahead Market (EDAM) (*ER24-1746*).

CAISO's initial proposal for the "access charge" was the only provision in the EDAM tariff the commission rejected when it approved the market's design and rules in December. (See *CAISO Wins (Nearly) Sweeping FERC Approval for EDAM*.)

In the December order, FERC found the ISO failed to justify the reasons behind the three components constituting the access charge, but Commissioner Allison Clements at the time emphasized that the rejection came "without prejudice" and encouraged the ISO to work with its stakeholders and file a revised proposal.

In the revised filing, CAISO explained that while participation in the EDAM will not alter a transmission owner's transmission revenue requirement, it could cause the owner to lose out on transmission sales it could've made absent that participation, thereby reducing revenues.

"CAISO explains that stakeholders have raised concerns that these changes in transmission owners' revenues due to transmission owner participation in EDAM may result in unexpected downstream cost shifts for ratepayers," the commission said in the June 11 order.

The ISO said those cost shifts could be most pronounced upon launch of the EDAM and each time a new entity joins the market.

3 Components

Like the initial proposal for the access charge, the revised plan consists of three components.

Under the first component, TOs may include revenue shortfalls related to the transition from bilateral market transmission service to day-ahead market service. Those shortfalls could stem from EDAM transfers displacing revenues expected from sales of short-duration non-firm and firm point-to-point transmission service.

"CAISO explains that EDAM transmission owners will first calculate their recoverable transmission service revenue based on the annual average of revenues associated with qualifying eligible short-duration transmission products," the order notes. "The transmission service revenue shortfalls recoverable under the EDAM access charge's first component will consist of the difference between the actual short-term transmission service revenues recovered and the three-year pre-EDAM average short-term transmission service revenues."

Idaho Power has cited implementation of the EDAM access charge as an important factor before it fully commits to the market. | *Idaho Power*

The second component of the EDAM access charge will permit TOs to recover a portion of the costs not reflected in the three-year "lookback" associated with the first component. This will include revenue shortfalls "from foregone sales of non-firm and short-term firm transmission service over certain new network upgrades and associated with the release of transmission capacity resulting from the expiration of EDAM legacy contracts," the order noted.

Under this component, a TO's access charge can include only lost revenues associated with new network upgrades that have been approved by FERC or a local regulatory authority and that function as available transmission in EDAM.

"CAISO explains that eligible new network upgrades are those that increase transfer capability between EDAM BAAs or between the CAISO BAA and an EDAM BAA, are in service and are energized after the EDAM Entity begins participation in the day-ahead market," the commission wrote. The ISO also clarified that a TO cannot roll all its eligible new network upgrade costs or expiring legacy transmission contract costs into the EDAM access charge, but only an applicable percentage.

The third component of the access charge allows an EDAM TO to recover shortfalls "associated with wheeling through an EDAM BAA or the CAISO BAA in excess of the total net EDAM transfer of the BAA," with costs based on the transmission used to wheel energy completely through a TO's system.

"CAISO further states that in periods where this excess occurs, the EDAM Entity, on behalf of the EDAM transmission owner, will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner's non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate," the commission said.

'Effective Indefinitely'

Under the rules, CAISO will calculate an access charge rate for each EDAM entity based on the entity's gross load.

"CAISO proposes to calculate the rate using the aggregate projected annual transmission revenue shortfalls for each of the three EDAM access charge components of all other EDAM transmission owners, pro-rated to each EDAM BAA by its gross load ratio. As such, CAISO states no EDAM entity will be assessed its own projected recoverable revenue shortfalls," the order said.

The order notes that while CAISO views the EDAM access charge as a temporary measure, it expects the mechanism to "be a necessity for the foreseeable future" and remain "effective indefinitely" as more participants integrate into the market over time.

Coming little more than a week after NV Energy confirmed its intent to join EDAM over SPP's Markets+, FERC's approval of the access charge marks another accomplishment for the CAISO market — and one that could draw additional commitments.

In a March 21 *letter* to CAISO COO Mark Rothleder signaling its intent to join EDAM, Idaho Power cited the need for a "transmission revenue recovery mechanism" as a key concern the ISO needed to address before the utility could formally commit to the market.

In addition to NV Energy and Idaho Power, the EDAM has won solid commitments from Balancing Authority of Northern California, Los Angeles Department of Water and Power, and Portland General Electric, while PacifiCorp in April became the first entity to fully commit to signing an implementation agreement with the market. ■

WAPA Tariff Falls Short of Reciprocity Status, FERC Finds

Federal Power Agency's OATT Still Must Comply with Orders 1000, 2023 to Qualify

By Robert Mullin

The Western Area Power Administration's non-jurisdictional Open Access Transmission Tariff does not meet the standard of an "acceptable reciprocity tariff," despite recent revisions the federal power agency incorporated into the tariff, FERC ruled June 12.

The commission's ruling came in response to WAPA's April 2023 request for a declaratory order affirming that tariff revisions the agency submitted to meet the requirements of FERC orders *676-I*, *676-J* and *881* conform with or are superior to FERC's *pro forma* OATT and that the revised tariff satisfied the requirements for reciprocity status (*EF23-5*).

The 676 orders, issued in 2020 and 2021, require transmission providers to incorporate certain North American Energy Standards Board standards into their tariffs, while 2021's Order 881 requires providers to begin using ambient-adjusted ratings for their lines by July 12, 2025.

While the commission determined WAPA's tariff revisions complied with those three orders, it stopped short of granting reciprocity status because the agency said it would continue to defer implementing FERC *Order 1000*, the 2011 directive that intended to encourage development of interregional transmission projects by eliminating the right of first refusal for incumbent utilities.

WAPA said it would need to continue delaying Order 1000 compliance until: 1) It can ensure final changes to the WestConnect transmission planning group's regional planning documents do not conflict with the federal statutes governing WAPA and 2) it determines whether its Desert Southwest, Rocky Mountain and Sierra Nevada regions can continue to participate in that group.

The power agency said it will consider altering its tariff to accommodate Order 1000 once FERC approves the changes to the WestConnect planning documents and after it completes a review of the needed tariff revisions and obtains input from its stakeholders.

In denying WAPA reciprocity status, FERC also pointed out that WAPA has not yet complied with last year's *Order 2023*, which directs RTOs/ISOs and other transmission operators to streamline their generator interconnection processes.

"We find that WAPA's proposed revisions to its tariff, including its ministerial changes, substantially conform with or are superior to the commission's *pro forma* OATT," FERC wrote. "However, for the commission to find that WAPA has an acceptable reciprocity tariff, WAPA must submit revisions to its tariff to incorporate changes the commission made to the *pro forma* OATT associated with Order Nos. 1000 and 2023.

"Because WAPA has determined to defer implementation of Order No. 1000 to a later date, and because WAPA has not submitted revisions associated with Order No. 2023, we cannot find that WAPA's tariff, as revised here, is an acceptable reciprocity tariff." ■

Transmission lines in WAPA's Desert Southwest Region | *Western Area Power Administration*

Critics Call out Ariz. Commission for 'Troubling' Precedent

State Regulators Under Fire for Decisions on Gas Plant Expansion, IRP Audits

By Elaine Goodman

Arizona regulators voted to allow UNS Electric to expand its gas-fired Black Mountain Generating Station without a certificate of environmental compatibility — a decision critics said sets a "troubling" precedent.

The Arizona Corporation Commission voted 4-1 on June 11 to grant a "disclaimer of jurisdiction" to the 200-MW expansion. UNS successfully argued that the project's four natural gas-powered units, each with a nameplate capacity of 50 MW, individually fall under the 100-MW threshold at which a certificate of environmental compatibility is required.

The commission's vote overturned a decision from the Arizona Power Plant and Transmission Line Siting Committee, which viewed the expansion as a 200-MW project that needed an environmental certificate.

In another decision from the June 11 meeting that's facing criticism, the commission voted 4-1 to remove the requirement for an independent, third-party review of utilities' integrated resource plans. The decision came after ACC staff said they couldn't find a consultant to do the work within budget after issuing two requests for proposals.

The decision applies to IRPs filed in November by Arizona Public Service, Tucson Electric Power and UNS, as well as future integrated resource plans.

1st Time in 50 Years

UNS' application for the Black Mountain expansion is the first time any company has sought a disclaimer of jurisdiction for a power plant since the state legislature enacted line siting statutes in 1971, according to the Line Siting Committee.

The process for obtaining a certificate of environmental compatibility includes public outreach and hearings before the Line Siting Committee and the ACC.

Western Resource Advocates said the commission's decision "creates a troubling new precedent for gas and electric utilities seeking to build new generation facilities."

"This is a disappointing decision that overturns decades of commission practice to essentially exempt most gas plants from commonsense environmental review, depriving Arizonans of a voice in siting these large, polluting industrial facilities," WRA attorney Emily Doerfler said in a statement.

In a statement after the vote, ACC Executive Director Doug Clark said that "the law as written left the commission no choice but to disclaim jurisdiction." It's up to lawmakers to change the wording, he said in a release.

The Black Mountain expansion still must obtain permits from state and local agencies, including the Arizona Department of Environmental Quality, Clark said. And UNS will need a certificate of environmental compatibility for interconnection with related transmission lines.

UNS said an expansion of the Black Mountain Generating Station is needed for reliability in its service territory. The power plant, near Kingman in Mohave County, now has two 61-MW units that started operating in 2007.

The expansion is expected to cost $218 million and to begin operations in 2027.

IRP Review

The requirement for third-party review of utilities' integrated resource plans came from a commission decision in 2018 aimed at improving the IRP process.

The decision ordered an independent review of scenarios and resource portfolios in each IRP and projected costs and benefits. The review could include the development of alternative scenarios and portfolios that the third-party analyst thinks should be considered.

"Their specialized experience … allows them to provide an unbiased and critical assessment to validate or challenge the assumptions and conclusions presented by the utilities in their IRP filings," WRA said in a letter to the commission.

Alex Routhier, WRA's senior policy adviser in Arizona, said the third-party review is even more important because ACC is short-staffed and lacks the expertise to run complex modeling on its own. The third-party analysts are familiar with what's happening industry-wide and best practices that are in use, he said.

Commissioner Anna Tovar said the requirement for third-party review is needed to counter inaccurate data and modeling the commission receives.

An Arizona Corporation Commission vote has cleared the way for an expansion of UNS Electric gas-fired Black Mountain Generating Station. | *UniSource Energy*

"You're assuming that all that data and modeling is correct, and you don't have the skill set to deviate and prove that it's not," said Tovar, who cast the lone vote against removing the requirement. "I would say that is my biggest issue in regard to that."

Commissioners who voted in favor of removing the requirement for third-party analysis said staff could still hire a consultant to review IRPs, but the step would no longer be required.

Commissioner Nick Myers said some stakeholders had been given access to the modeling platform the utilities use and could run their own analysis or hire someone to do so.

And Chair Jim O'Connor noted that the commission only "acknowledges" IRPs rather than voting to approve them. ■

CAISO/West News

CAISO Board Approves Interconnection Enhancements Proposal

Despite Widespread Support, Strong Opposition to Plan Lingers

By Ayla Burnett

CAISO's Board of Governors on June 12 unanimously approved the ISO's Interconnection Process Enhancements proposal, the product of more than a year of stakeholder engagement and rigorous troubleshooting.

Intended to complement — but not replace — CAISO's FERC Order 2023 compliance filing, the final proposal is designed to streamline the interconnection process in response to the "unprecedented volume" of requests the ISO received last year by reducing the amount the number of projects it will have to study. (See *Stakeholders Seek Clarity on CAISO Interconnection Process Plan*.)

During the June 12 board meeting, Danielle Osborn Mills, CAISO principal of infrastructure policy development, presented slides showing that Cluster 15 in April 2023 vastly exceeded expectations and the interconnection queue now contains roughly three times the capacity needed to achieve California's 2045 requirements.

"I cannot overstate the importance of this initiative and the challenges our team and stakeholders faced in developing these transformative changes to our interconnection process," Neil Millar, CAISO vice president of transmission planning and infrastructure development, said at the meeting.

"The fundamental transformation we are seeking to implement is to shift more meaningful project development and procurement engagement to earlier stages in the interconnection study process," Millar said. "While these changes will be disruptive and uncomfortable, they are necessary so that the ISO can deliver meaningful study results more quickly and phase out the habit of using the ISO interconnection process to simply screen potential sites."

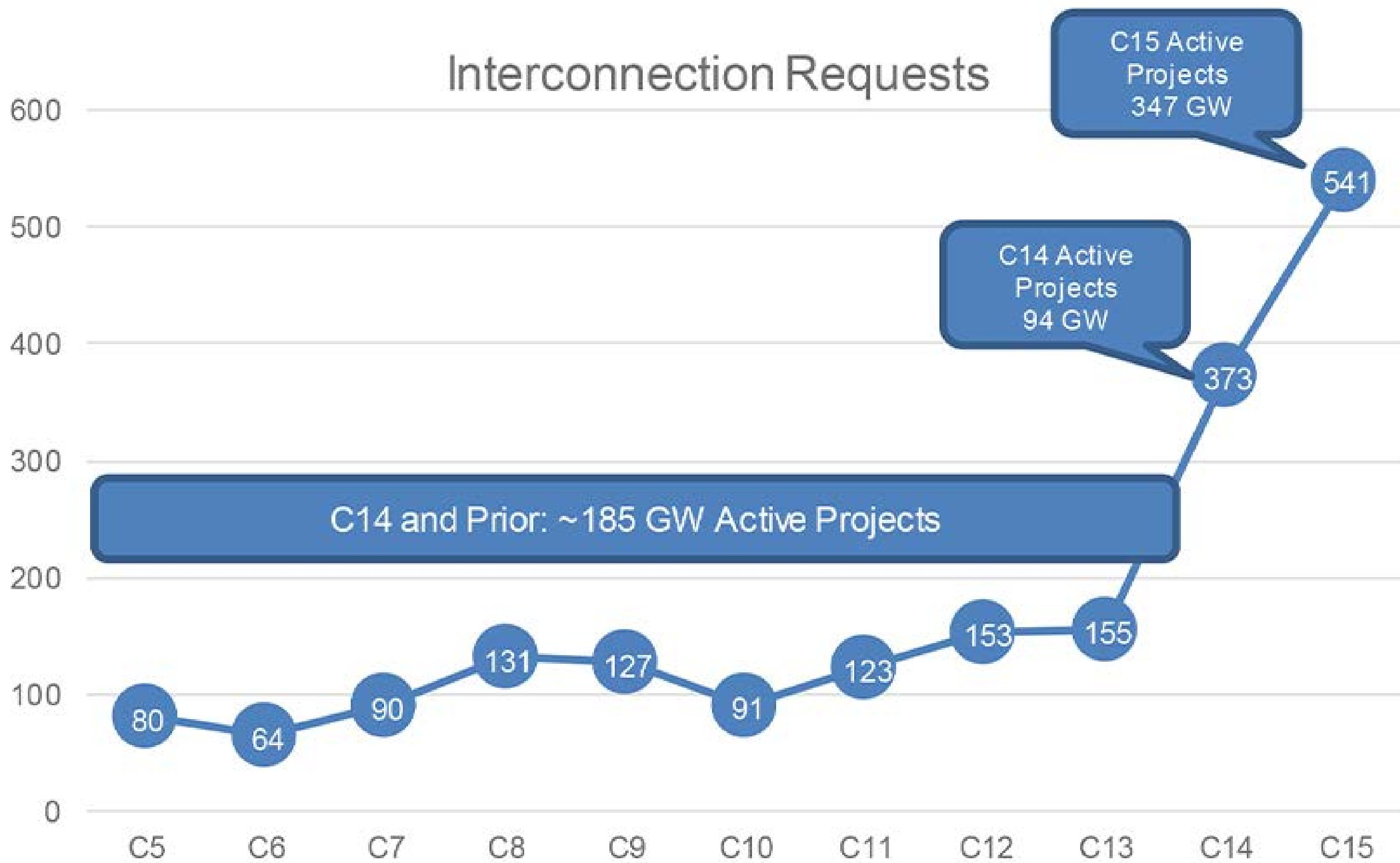
Responding to stakeholder feedback, CAISO staff made one key change to the final proposal not included in prior drafts: a requirement for load-serving entities to opt in to the point allocation process and publicly post both contact information for the department or individual responsible for the process and selection criteria for allocating capacity.

The change is intended to "increase the transparency and rigor of the load-serving entity allocation process," Mills said. The prioritization of LSE interest in the scoring and point allocation process has been a significant area of concern for stakeholders.

Scoring Criteria Concerns

While the proposal received broad support during the board meeting, many stakeholders expressed concern about moving forward with the final proposal.

"One of the biggest concerns is the lack of



The ISO Board of Governors approved staff's proposed Interconnection Process Enhancements on June 12. | *CAISO*

CAISO/West News

allocation to the non-load-serving entities," said Melissa Alfano, senior director of energy markets and counsel at the Solar Energy Industries Association. "There is the ability for the LSEs to withhold some things and strategically push forward less efficient projects."

Other stakeholders echoed Alfano's concerns.

"The scoring criteria are rooted in significant potential for a lack of transparency, unjust discrimination against non-LSE developers with viable projects and infringement upon principles of open access," said Ryan Millard, senior director of West region regulatory and political affairs at NextEra Energy Resources. Other stakeholders "also highlighted instances of LSEs seeking concessions from developers in exchange for early points allocation which demonstrates a clear risk of exploitation."

He gave an example of a recent instance in which an LSE indicated to NextEra that it issues a request for proposals that includes Cluster 15 projects and would require developers to grant the LSE a right of first offer and submit a $5/kW deposit to secure LSE point allocation.

"To put that into context for you, if you were to apply this to a 300-MW storage project, that's a $1.5 million deposit that we would need to post 10 years before expected [commercial operation date] just to enter the queue. That's untenable, even for some of the largest Western developers," Millard said. "While we appreciate CAISO's desire not to propose a prescriptive [request for information] process for LSEs, the absence of minimum standards introduces too much potential inequity."

Mills responded that the setting of standards falls under the jurisdiction of the California Public Utilities Commission and individual local regulatory authorities, not the ISO. Additionally, she emphasized that the ISO would continue to monitor the LSE allocation process after implementation and that the CPUC will exercise oversight over the procurement process, "scrutinizing utility-owned contracts against other contracts" to make sure they were selected fairly and transparently.

"We did not want to do anything that was going to open the floodgates to only utility-owned generation, but at the same time, [we] didn't want to do anything that was going to discourage or prevent it either," Mills said.

CAISO CEO Elliot Mainzer also weighed in.

"We all know that any system of rules that you set up, including the existing system, can be subject to untoward behavior," he said. "We know that there are risks here, and we have taken steps both within our tariff and in direct consultation with the leadership of the state and other local regulatory authorities to make sure that their processes are monitored carefully to make sure that we do not see untoward behavior or manipulation of the rules."

The ISO said it intends to file the changes with FERC in July and plans to begin study of Cluster 15 projects in October. ■

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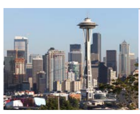

NERC: ITCS to Become 'Road map' for Grid Studies — ERO Insider

NERC Committee Seeks Focus in Busy Standards Projects — ERO Insider

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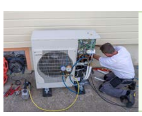

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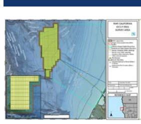

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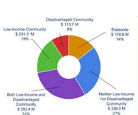

Calif. Clean Transportation Program Needs Equity Emphasis — NetZero Insider

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CAISO/West News

Bill Gates' TerraPower Breaks Ground on Advanced Nuclear Plant

Constellation Energy CEO Discusses Future of Nuclear Industry

By James Downing

TerraPower on June 11 broke ground on its Natrium reactor demonstration project in Wyoming, making it the first advanced reactor to enter construction.

TerraPower was founded by billionaire Bill Gates and the project is supported by a long-term contract with PacifiCorp, which is part of fellow billionaire Warren Buffett's Berkshire Hathaway business empire.

"I'm proud of all the partners and people who helped get the most advanced nuclear project in the world built in Kemmerer, Wyo.," Gates said in a statement. "I believe that TerraPower's next-generation nuclear energy will power the future of our nation — and the world."

Construction is expected to take five years and at its peak will employ 1,600 workers. Once the plant is operational, TerraPower expects it will support 250 permanent employees.

The Natrium reactor will be a fully functioning commercial power plant, which is being built at the site of a retiring coal-fired power plant in Kemmerer.

The 345-MW reactor uses sodium-cooling technology with a molten salt-based energy storage system that can boost its overall output to 500 MW when needed, which is enough to power 400,000 homes. The energy storage capability allows the project to help balance with renewable power, which has long been an issue with conventional nuclear plants that that lack ramping flexibility.

The company's construction permit application is still pending at the Nuclear Regulatory Commission, but it was able to start construction on non-nuclear facilities while nuclear construction awaits regulatory approval.

The NRC *announced* last week that it was advancing its consideration of the project and noted that if it approves construction, TerraPower would have to submit another application to actually operate the power plant.

"This is a challenging yet exciting time in the energy industry," PacifiCorp CEO Cindy Crane said in a statement. "In an era of rapid change, the need for reliable, affordable and dispatchable energy will remain a constant. Innovative technologies like the Natrium project will enhance our ability to serve our customers, meet growing demand and ensure a reliable and resilient energy future."

The ceremonial groundbreaking for TerraPower's advanced reactor in Wyoming on Monday. | *TerraPower*

Engineering firm Bechtel is building the facility, and company President Craig Albert said in a statement that the project will launch a new approach to nuclear construction that is meant to be safer, cleaner and faster. The company has built 150 nuclear plants around the world over the past 70 years.

"Working together, the combination of advanced technology and streamlined constructability has the potential to diversify the U.S. power generation industry," Albert said. "The option of deploying smaller advanced nuclear plants that can work in concert with other clean energy sources will help speed our progress toward net-zero emissions."

Constellation's Dominguez Comments on State of the Industry

Speaking on a Reuters webinar June 10, Joseph Dominguez, CEO of Constellation Energy, which owns and operates one of the largest nuclear fleets in the country, said it's still an open question which technology will dominate the future of the industry. Dominguez said the existing fleet of reactors could run until 2060 or beyond, but that would require major investments and Constellation is also focused on expanding nuclear production.

"We are expanding the output of our plants," Dominguez said. "As we change over equipment, we tend to get better materials, better efficiencies and all sorts of things, generators, pumps, everything that allows us to increase the output of the machines and put on the grid almost immediately, at least in power terms — over a handful of years, new firm, clean energy. And then we're also investigating the next generation of small modular reactors or large-scale nuclear plants."

Some firm clean power is going to be necessary to reach net-zero goals, and nuclear faces competition from other technologies, including natural gas-fired generation with carbon capture and storage, which Constellation is also looking into, he added.

While the company recently bought NRG's share of the South Texas Project, Dominguez said other opportunities to buy existing nuclear plants are not on the table because their owners recognize the value of those assets, focusing Constellation on organic growth through capacity uprates, the possibility of restarting its Three Mile Island plant in Pennsylvania, and eventually the potential for building new plants.

"Over the last 10 years, [the industry] only brought on two nuclear units," Dominguez said, referring to Southern Co.'s Plant Vogtle expansion. "And some reports indicate that those have been as much as $20 billion apiece to build. So, the ability to restart a unit at a fraction of those costs, to create an environment where you can do all the state-of-the-art upgrades to the unit to allow it to be able to run for decades more — that's an incredibly valuable opportunity for America."

The theory with small modular reactors is that much of the equipment would be manufactured at a central facility and then transported to the power plant's location, which is how the industry builds gas-fired and renewable power plants, Dominguez said.

"The way we think about it right now is we've got to see these technologies evolve, we've got to see folks prove out the competency," he added. "I think they'll do that in the next five or six years. And then we'll select the technologies that best suit our needs, and our customers' needs." ■

ERCOT News

Texas Supreme Court Rules for ERCOT, PUC During Uri

Appeals Court Reversed; Laws Allow Emergency Pricing

By Tom Kleckner

The Texas Supreme Court has ruled ERCOT and the Public Utility Commission were within the law when they raised wholesale prices to more than 300 times above normal during the deadly February 2021 winter storm that came within minutes of bringing down the grid.

The high court on June 14 *reversed* a state appeals court's ruling that the PUC's order to raise wholesale prices to their $9,000/MWh cap during Winter Storm Uri violated state law.

The Supreme Court said the commission met the requirements of the Public Utility Regulatory Act's (PURA) Chapter 39 — added when ERCOT was opened to retail competition — when it issued the emergency orders in a desperate effort to bring generation back online to meet demand. It also found that the commission "substantially complied" with the Administrative Procedure Act's procedural rulemaking requirements (*23-0231*).

"The [PUC] has the expertise to manage the electric utility industry; the courts do not," Chief Justice Nathan Hecht said, writing for the 7-0 majority. (Two justices recused themselves.) "The Court of Appeals thus strayed from its lane by inquiring whether the orders could have used 'competitive rather than regulatory methods' to any greater extent than they did."

The Texas 3rd Court of Appeals in March 2023 reversed the PUC's emergency orders and raised the issue of repricing the market transactions during the storm. The court found the commission's actions "entirely" eliminated competition and were contrary to state law. (See *Texas Court Reverses PUC's Uri Market Orders*.)

Luminant initiated the proceeding after it incurred $1.6 billion in losses when forced to buy backup power at the system cap and gas supplies at equally exorbitant prices. (See *Vistra's Winter Storm Loss Deepens to $1.6B*.)

The PUC argued that Luminant's ability to recoup its losses in the administrative proceeding was speculative because ERCOT does not maintain a fund of money.

The Texas Supreme Court has ruled in favor of ERCOT's emergency price increase during Winter Storm Uri. | *Xcel Energy*

ERCOT "just facilitates market transactions — and any payment would come out of the pocket of other market participants," the high court said. "Essentially, the commission's argument is that the egg cannot be unscrambled."

The court noted that Chapter 39 directs the PUC to establish protections entitling customers "to safe, reliable and reasonably priced electricity, including protection against service disconnections in an extreme weather emergency."

It said the law also "expressly" directs ERCOT to "ensure the reliability and adequacy of the regional electrical network" and gives the commission "complete authority" to ensure that ERCOT adequately performs that duty, including rulemaking related to the grid's reliability.

The Supreme Court heard oral arguments in January. (See *Texas Supremes Hear Arguments Over Uri's Prices*.)

When the PUC issued its directive to ERCOT on Feb. 15, 2021, the grid operator's algorithm was setting prices as low as $1,200/MWh, even though generation was dropping offline. Under ERCOT's market construct, prices are designed to increase during scarce conditions to incentivize more generation to come online.

The problem was there wasn't enough generation during the first two days of the storm because of frozen equipment or lack of fuel supplies. ERCOT kept prices at the $9,000 cap — since reduced to $5,000 — until Feb. 19, resorting to rolling blackouts to keep the grid stabilized.

The emergency order resulted in $16 billion of market transactions that ERCOT's Independent Market Monitor said were incorrectly priced during the 33 hours that followed the end of firm load shed. The PUC declined to reprice the transactions. (See "Monitor: $16B ERCOT Overcharge," *ERCOT Board Cuts Ties with Magness*.)

Some of the $16 billion balance has since been securitized. Other transactions have been settled outside ERCOT and can't be undone, according to legal experts.

The court also *dismissed* a lawsuit by RWE Renewables Americans and an RWE wind farm, finding that the 3rd Court of Appeals did not have jurisdiction over the proceeding (*23-0555*). ■

ERCOT News

Renewable Developers Oppose Proposed ERCOT IBR Rule

Change Would Impose Voltage Ride-through Requirements on Inverter-based Resources

By Tom Kleckner

Goff Consulting's Eric Goff has represented the joint commenters' interest during the NOGRR245 conversation. | © *RTO Insider LLC*

Several renewable energy developers have indicated they will oppose ERCOT stakeholders' approval of a controversial rule change for inverter-based resources (IBRs) when the issue goes to a vote before the Board of Directors later this month.

Invenergy Energy Management, NextEra Energy Resources, Southern Power, Avangrid Renewables and Clearway Renew — the *ad hoc* "joint commenters" who have argued against the change — on June 10 filed a *recommendation to oppose*, urging the board to reject the revision to the Nodal Operating Guide (*NOGRR245*) during its June 17-18 meetings.

ERCOT's Technical Advisory Committee endorsed the rule change June 7 after months of trading and reviewing comments with staff. It would impose voltage ride-through requirements on IBRs, aligning ERCOT's protocols with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers' *standard* for IBRs interconnecting with the grid. (See *ERCOT TAC Endorses Rule for Inverter-based Resources*.)

The committee inserted gray-box language with potential modifications that wouldn't become effective until March 2025. The language would enable entities to meet the applicable ride-through requirements when they have not yet added a "technically feasible" change. The revisions are aimed at those entities for which upgrade costs are less than 40% of the full, in-kind replacement cost of a plant's inverters or turbines and converters.

The joint commenters agreed there is a sense of urgency to impose the standards and make them effective for IBRs. However, they urged the board to ensure that the ride-through standards "do not have the unintended consequences of harming reliability by eliminating existing generation and harming future investment in infrastructure in the ERCOT market."

The commenters said TAC attempted to defer issues around hardware changes by placing them in the gray-box language, but that the action did not accomplish anything.

"The gray box simply indicates that hardware changes contemplated by ERCOT would be required unless a new NOGRR modifies such requirement before the gray box becomes effective," the commenters wrote. They asked that the language be deleted and that required hardware modifications for existing IBRs be bifurcated from the NOGRR and addressed after further study of the reliability need for the requirements.

NOGRR245's TAC-approved version has "fatal flaws," they said. "It imposes arbitrary costs on existing generation [IBRs] and unlawfully gives ERCOT ... authority to indefinitely shutter existing operational IBRs."

'Unresolved Issues'

"While I appreciate that both the joint commenters and TAC wanted to decouple hardware changes from everything else, there are still a lot of unresolved issues," Eric Goff, representing the commenters, said in an email to *RTO Insider*.

During the June 7 conference call, Goff recommended that TAC members vote against the motion. He said that while the main intention is in "good spirit," the six to nine months allowed to work on hardware issues won't solve any problems.

"That's due to the [Public Utility Commission of Texas'] procedural rules," he told TAC. "If the joint commenters believe that the proposals here are not lawful or bad policy, we have 35 days to appeal an ERCOT action. We would be forced to appeal this or lose the right to appeal it, so it would result in this issue not getting six to nine months of time in the ERCOT stakeholder process, but rather in a contested case with the commission."

Goff also said the NOGRR includes "inappropriate" changes to technical requirements that have yet to be approved.

The joint commenters face long odds in seeing the board reject NOGRR245. ENGIE's Bob Helton pointed out during the TAC call that striking the gray-box language would lose ERCOT's support for the change.

"I would assume that means [ERCOT] is going to challenge that at the board. I've got a pretty good idea of where we would end up. ... The board would likely go with ERCOT on the appeal," Helton said.

The ERCOT board remanded the NOGRR back to TAC in April, directing that the language — approved by the committee over staff's objections — be modified to address staff's reliability concerns. (See *ERCOT Board of Directors Briefs: April 22-23, 2024*.)

A pair of IBR-related voltage disturbances in West Texas in 2021 and 2022, dubbed the "Odessa disturbances," added urgency to eventually passing the measures. (See *NERC Repeats IBR Warnings After Second Odessa Event*.) ■

ISO-NE News

NE Generators Propose Financial Assurance Changes

By Jon Lamson

Representatives of the New England Power Generators Association (NEPGA) and Competitive Power Ventures (CPV) offered amendments to ISO-NE's proposed changes to the financial assurance provisions for the Forward Capacity Market at a joint meeting of the NEPOOL Markets Committee and Budget and Finance Subcommittee on June 11.

ISO-NE has *raised concerns* that its financial assurance policy — intended to ensure that generators can pay penalties associated with failing to meet their capacity supply obligations (CSOs) — does not adequately protect against the risks of generators defaulting.

To address these concerns, the RTO has proposed to rely on a "*corporate liquidity assessment*" to evaluate whether generators will be required to provide additional financial assurance.

The proposed amendments presented at the meeting focused on ways to reduce pool-wide default risks, with the hope that reducing the overall risks would enable ISO-NE to ease the financial assurance requirements for generators.


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

NEPGA's Bruce Anderson *said* allowing generators to sell monthly CSOs closer to each period would help mitigate the risk of equipment failures leading to unmet obligations. He noted that the last opportunity to sell CSOs is more than a month in advance of each monthly period.

"Allowing for bilateral trading closer in time to the relevant month will decrease the risk of default for a market participant that may not be able to perform," Anderson said.

NEPGA has also proposed to increase the payback period for Pay-for-Performance penalties, saying this would similarly reduce the overall risk of defaults. He highlighted recently approved tariff changes at PJM "allowing for longer payoff periods of up to nine months."

CPV's Joel Gordon *echoed* the potential of increasing the opportunities for generators to sell their obligations. He said ISO-NE could consider a rule to enable it to terminate a CSO if a generator defaults on a penalty, or it could create a special status for defaulting generators.

"There are market design solutions that would significantly reduce the potential exposure that should be explored," Gordon said, emphasizing the need to "address the underlying cause first."

ISO-NE said it plans to respond to the proposals in July and is targeting an initial vote on the finance assurance changes in August. ■

ISO-NE News

New England Stakeholders Talk Community Engagement at Roundtable

By Jon Lamson

From left: Penni Conner, Eversource; Larry Susskind, MIT; Gretchen Kershaw, DOE; Rev. Mariama White-Hammond, New Roots AME Church, and Moderator Janet Gail Besser | *© RTO Insider LLC*

BOSTON — Early and meaningful engagement with host communities will be an essential component of expediting energy permitting and siting processes, panelists said at Raab Associates' New England Electricity Restructuring Roundtable on June 14.

"We are in a change-or-die moment," said the Rev. Mariama White-Hammond, former chief of energy, environment and open space for the city of Boston, adding that the pace of clean energy deployment must accelerate rapidly to meet the need to decarbonize.

To meet the moment, utilities and project developers will need to collaborate with many of the communities and organizations they fought in the past, she said.

"There is a question of who will hold the power," White-Hammond said. "Will it be the technocrats, investors and government officials, or will it be all of us?"

Ultimately, developers will face significant backlash if they try to force through projects without incorporating community input in the decision-making process, White-Hammond added.

Penni McLean-Conner of Eversource Energy echoed the need to work with communities in the early stages of project development and consider community input when weighing the tradeoffs of project alternatives.

"Eversource is committed to an enhanced community-centric approach," McLean-Conner said, adding that the company hopes new energy facilities can be seen as opportunities rather than burdens by residents.

One key to changing this conversation is understanding and respecting the historical inequities faced by these communities, McLean-Conner added.

"We can't assume we know or have all the answers," she said. "We need to incorporate their shared experiences and unique perspectives into our thinking going forward."

Larry Susskind, professor of urban and environmental planning at MIT, said project developers should work with a range of stakeholder representatives and organizations to reach "informed consensus" within a "confidential space for joint fact-finding and collaborative problem-solving."

Once developers identify the unique needs and concerns of a host community, they should negotiate and sign binding community benefit agreements they submit to the state during the permitting process, Susskind said.

Getting community benefit agreements right is "as much about compensation as it is about mitigation," Susskind said, adding that "we need to think in terms of bartering to create benefits, not just minimizing costs."

Permitting and siting has been a major topic of conversation for Massachusetts lawmakers over the past few months, with key legislators indicating it's a top priority for a potential climate bill they hope to pass by the end of the current session in July.

Legislative leaders of the House and Senate have been working with the Healey administration to develop a compromise bill that likely will revolve around the recent recommendations of the state's Commission on Energy Infrastructure Siting and Permitting. (See *Mass. Commission Issues Recs on Energy Project Siting, Permitting*.)

The Massachusetts Senate plans to take up a climate bill centered around permitting and siting reform this week.

The state commission recommended consolidating state and local permitting and siting processes and requiring authorities to issue permits within 15 months of verifying that an application is complete.

Michael Judge, undersecretary of energy at the Massachusetts Office of Energy and Environmental Affairs, said the state's Energy Facilities Siting Board (EFSB) historically has taken between one and four years to approve a project, "after which the project still needs to get all other permits."

"This isn't working for anyone," Judge said, adding the state is unlikely to meet its climate mandates without permitting reform.

Adam Chapdelaine, CEO of the Massachusetts Municipal Association, which represents the state's 351 cities and towns, expressed his "concern about getting consolidated permitting right" while preserving the rights and role of municipalities.

He recommended initially adopting an opt-in consolidated local permitting program to inform the consideration of statewide reforms to local permitting.

In response, Judge emphasized that, under the commission's proposal, local permitting would remain under local control but would need to be expedited and consolidated under one permit parallel to the EFSB approval process.

He said making the local permitting reforms optional could lead to an "inconsistent framework" for smaller projects that are subject only to local permitting, potentially creating longer timelines for some smaller projects. ■

MISO News

MARC 2024 Displays Mixed Feelings on Transition Feasibility

By Amanda Durish Cook

MINNEAPOLIS — The 2024 Mid-America Regulatory Conference (MARC) June 9-12 showcased a tug-of-war of positivity and cynicism over meeting growing demand with a fleet that should evolve faster to meet clean energy goals.

'Kitchen Renovations'

"You know how it feels when you're renovating your kitchen, and you have to live there at the same time? It's uncomfortable. … And that's how it's going to feel in the clean energy transition," Smart Electric Power Alliance's Yok Potts said in opening a panel on virtual power plants.

Much like the reward of a new kitchen after the inconvenient remodeling, the grid will emerge modernized and smarter, Potts said.

Illinois Commerce Commissioner Conrad Reddick said it's challenging to enter a new territory of unpredictable load growth after years of expected patterns.

"The years of, 'the grid isn't growing so we don't need to replace things' are gone," he said.

Sen. Tina Smith (D-Minn.) also said the messaging around the clean energy transition has changed in recent years.

"The old story of the energy transition is 'we have to do this, or we're all going to die,'" she said. Now, she said it's "a story of opportunity" that can result in economic booms, good jobs, a cleaner environment and a more equitable supply of energy.

Smith said she will never forget during her time as Minnesota's lieutenant governor when a teenage climate activist asked, "What are you going to do with your power?" She asked commissioners and regulatory staff to reflect on that question themselves.

The Data Center Question

Minnesota Public Utilities Commissioner Joe Sullivan said load growth from data centers could expedite the move to clean sources of energy. However, he said the rising growth carries risks of moving backward in the clean energy transition, or over-forecasting demand and then overbuilding generation that ratepayers get stuck with.

"Data centers are giving us a lot of bad news and good news," Minnesota PUC Commissioner Hwikwon Ham said.

Commissioners take the stage at MARC 2024 at the Renaissance Downtown Minneapolis June 12 | *© RTO Insider LLC*

Scott Wright, MISO | *© RTO Insider LLC*

Xcel Energy's Ryan Long said the rise of data centers comes at an opportune time, with Xcel switching off its remaining coal plants. He said he sees an opportunity for data centers to facilitate the "last firm clean energy" sources needed to get utilities to 100% carbon-free electricity.

But Long said utilities should craft contracts carefully so data centers pay a fair rate for energy and so utilities can "spread fixed costs among more sold kilowatt hours."

Long said in the past, developers behind data centers were more likely to ask for discounts while insisting on 100% clean energy, whereas now they're more willing to "ride out the rest of our energy journey with us." He emphasized that utilities should keep commitments to existing customers and environmental goals at the forefront. He said data centers shouldn't be subsidized by the existing customer base.

Aaron Tinjum, of the Data Center Coalition, said data centers generally are "highly efficient facilities" and his member companies' "North Star" is clean, reliable electricity that decarbonizes the existing grid.

MISO Executive Director of Resource Adequacy Scott Wright said spot load growth from data centers is new to MISO, whose load growth has been "lackluster" for years.

"We haven't seen anything like this on the load side in a couple decades, before MISO's formation," Wright said.

However, Wright said MISO's load-serving entities cannot account for some of the growth in their forecasts because the projects are speculative. Wright said MISO likely will introduce probabilistic load forecasting to capture a plausible level of growth.

Wright said MISO has so far accumulated about 10 GW of demand from data center announcements in the footprint, with a new announcement occurring every few weeks. But he said aside from the data centers, the Midwest is entering a manufacturing renaissance.

"This is really an economic development opportunity for the Midcontinent," Wright said. "A year from now, let's talk about how we innovated, instead of being at the same place, talking about this tsunami of economic development at MISO's doorstep."

Wright said if load growth takes hold like some believe, it makes MISO's long-range transmission planning (LRTP) even more essential. But he warned that MISO is still waiting for 50 GW of approved and unbuilt generation to emerge. Developers within MISO remain encumbered by supply chain challenges, he warned.

Sullivan said MISO's switch from a deterministic forecast to probabilistic load forecast gives him pause. He said utilities are naturally incentivized to overbuild and he's concerned a probabilistic approach could put "a thumb on the scale" toward construction.

Wright said its resource adequacy survey with the Organization of MISO States, due out publicly next week, is returning an uptick in demand.

"We've got to know how big this thing could be. We've got to scope it out," Wright said. "The risk of not being prepared is bad for reliability and perhaps a huge, missed opportunity for economic growth."

Pilot Project Effectiveness

CenterPoint Energy's Muss Akram said it's incumbent on utilities and regulators to share the results of pilot projects so others in the industry get a heads-up on which technologies on the cusp are practicable.

"I see the industry moving more and more in that direction, and it's exciting," Akram said.

"Everybody wants to pilot, right?" Heimdall Power CEO Jørgen Festervoll said, adding that regulators don't always need a demonstration via a pilot because some technology has been in use and proven in other parts of the country for years.

Festervoll jokingly said he's learned not to bring up what Europe is doing on its grid during his presentations. But he said the U.S. grid, which took 120 years to build, is set to see a doubling in demand soon. He said regulators and utilities must develop a willingness to deploy technologies that haven't been in widespread use on the grid.

From left: Illinois Commissioner Stacey Paradis, Beth Soholt of Clean Grid Alliance, Eric Watson of Energy Dome and Gabe Murtaugh of the Long Duration Energy Storage Council | *© RTO Insider LLC*

"There's no way we're going to be able to build ourselves out of this problem," he said while pitching his company's sensors that are mounted on power lines and use real-time conditions to flow more power.

"We're in a phase right now where we're not synchronizing very well," said Iowa Utilities Board Commissioner Josh Byrnes. He said utilities are powering down old baseload plants as developers simultaneously "break ground" on data centers that will introduce new load. All this while breakthrough technology seems years away, he said. Complicating matters, the industry is struggling to attract new talent and secure supplies, Byrnes said.

"It's a problem right now," he summed up. "The grid is so tight. It makes me nervous. We really need to be squeezing out every electron."

VPPs

Sparkfund founder Pier LaFarge said though the virtual power plants of today are too unsophisticated and slow to respond to influence utility planning, they will become "core" to generation and system planning in time. Virtual power plants eventually will reach gigawatt-scale with utility management, he said, and urged regulators to make participation free and give underserved customers the first opportunity to join.

"There's been decades of antagonism between [distributed energy resources] and the utility," LaFarge said. But he added that tension will dissipate as utilities "take DERs for what they should be" and develop tools and programs.

Midcontinent Considerations for Energy Storage

Clean Grid Alliance Executive Director Beth Soholt said several gigawatts of storage are lined up in MISO's interconnection queue at a time when the RTO needs to overhaul its studies. She said MISO currently rigidly assumes storage charges at shoulder times and discharges on peak and imposes limits on charging that are in place for the life of the storage asset. Soholt said a "cookie-cutter" approach to every project is obscuring some of the benefits that storage can provide and returning expensive network upgrades.

"It's a bit of a square peg in a round hole. … We're focused on getting the model right," Soholt said. "I just feel we need more storage online so utilities figure out exactly how they want to use it. We need to kick the tires and show exactly what it can do."

Illinois Commerce Commissioner Stacey

MISO News

Paradis predicted there will be "sticky issues" around RTOs' interconnection of storage that will need to be figured out in the next few years. She said even though the industry is "crawling toward" storage penetration at present, it will become a game-changer.

Energy Dome's Eric Watson said any storage company would be happy to turn over extensive data to show they are the "technology of choice" and secure a place in utilities' integrated resource plans.

Watson said his company uses modular domes to house turbines and compressors to store energy in the form of liquid CO_2 under pressure. He said the domes use "off-the-shelf" components that don't need special design.

"We're effectively making large fire extinguishers," Waston explained of the technology's closed-loop, zero-emissions process.

Watson said the first U.S.-based dome will be at Alliant Energy's retiring Columbia Energy Center in Wisconsin and will use the plant's existing interconnection rights with MISO to come online sometime in 2026. He said he hopes the facility can return "good data" to show that Energy Dome technology is viable elsewhere.

Order 1920, Interregional Tx Planning

MARC secured a FERC commissioner to speak on last month's Order 1920.

Commissioner Allison Clements said the order "is in a lot of ways modeled after what MISO is already doing" and said regulators of MISO states should feel good about that.

FERC even contemplated "not messing up" the planning MISO already engages in when drafting the rule, she said.

Clements said the rule requires players in the planning realm to consider needs years down the road and consider both intensive and lower-cost solutions. She said there's an opening now to reassess what's no longer working on the grid and deploy "emerging technologies that are in fact as old as the Walkman." She said it's time to innovate in the electricity sector, which historically hasn't been a hot spot for technological advancements.

"If we can get past that color of molecule or that source of electron, if we all want to be grownups sitting around the table, there's a lot of progress to be made," she said.

MISO's Jennifer Curran said MISO already is largely conducting the long-term, scenario-based transmission planning that Order 1920 prescribes.

FERC Commissioner Allison Clements | © *RTO Insider LLC*

However, a panelist from ITC said the same can't be said of the RTO's interregional transmission planning.

"There's interregional coordination going on. Not so much planning," ITC's Krista Tanner said. "The current process isn't producing projects."

Tanner said planning between the RTOs only seems to work when they step outside their existing processes, like MISO and SPP's Joint Targeted Interconnection Queue (JTIQ) portfolio of transmission projects. Tanner said MISO and PJM's recently announced transfer capability study seems promising also because it's a departure from the RTOs' usual coordinated system plan studies. (See *MISO, PJM Agree to Perform New Type of Joint Transmission Study*.)

"Thinking out of the box is key," Curran said of her experience working on the JTIQ with SPP.

Curran said a study dedicated to MISO and PJM's seams is timely, with NERC and FERC focusing on transfers between grid operators. PJM's Sami Abdulsalam said the RTOs have begun scoping the study and are focusing on avoiding complex, greenfield development. Abdulsalam also said PJM "isn't quite there yet" on undertaking a JTIQ-like study with MISO.

Curran said MISO's job is easier when the RTOs' state regulatory committees come forward and articulate which issues they want MISO and its neighbors to address. The Organization of MISO States and the Organization of PJM States wrote a letter to the RTOs at the beginning of the year to call for more extensive joint planning.

Tanner asked RTO planners, regulators and utilities to contrast the costs of backbone, interregional projects with the more destructive outcomes of extreme weather events without the transmission. She said four days like with Winter Storm Uri in early 2021 can inflict as much cost in damages and fuel as the whole of MISO's first, $10 billion LRTP portfolio.

Cooperation in Permitting

Energy consultant Charles Sutton said landowner fatigue with permitting has grown recently and will continue to increase as MISO's LRTP projects enter the construction phase.

He said developers can blunt the negativity by awarding construction to local companies to show they support the local economy. Sutton added that developers should anticipate totally different reactions in different communities and that developers should be flexible and not rely on a single playbook to convince communities.

Robert Larsen, president of the Lower Sioux Indian Community, urged regulators to open honest communication at the very beginning stages of development "before things are too late, before things get disturbed." He said groups should consult with tribal nations during scoping steps, not when they're ready to begin construction.

"We've always said that progress is great, but we cannot have progress that destroys," Larsen said. He urged utilities, developers and regulators to "do their homework" and research who historically lived in the areas they've designated for projects.

Larsen said for instance, wind developers have sited projects near Buffalo Ridge in Southwestern Minnesota, a high point in the geography where the native community comes to pray and fast. The "blinking red lights" of the turbines are a distraction, he said.

But Larsen said he was taken aback and touched when the Minnesota PUC last year voluntarily asked to be included in a state law that requires consultation with tribal nations.

Larsen urged young people in the crowd to remember their relationship with the land. He applauded Minnesota's 2040 clean energy deadline and called for a restoration of land after "we've stripped it, mined it, polluted it."

"We want to keep everything clean and useful," he said.

Sen. Smith said utilities and regulators must regard tribal nations as sovereign entities, not special interest groups, with authority that is "inherent instead of bequeathed."

NextGen Highways' Randy Satterfield, whose company attempts to bundle infrastructure

MISO News

Sioux President Robert Larsen and Senator Tina Smith | © *RTO Insider LLC*

rights of way along roadways, said initiatives such as "co-locating infrastructure where there's already infrastructure" is common sense.

Satterfield said Wisconsin for 20 years has allowed stackable rights of way for transmission in highway corridors, but many states ban combination permitting along interstates. Last month, Minnesota Gov. Tim Walz (D) ended the Department of Transportation's ban on co-location of transmission along highways when he signed an omnibus transportation bill. NextGen Highways led the push for the language in the legislation.

Unions Make Appearance

In a MARC first, the annual conference featured a panel devoted to union labor.

ICC Commissioner Michael Carrigan, himself a member of the International Brotherhood of Electrical Workers Local 146, said it's going to be an undertaking to recruit a workforce that can grow to meet demand.

Kurt Zimmerman, of the IBEW Local 160, said utilities must stay competitive when negotiating contracts, enough to ensure laborers have good careers. He asked commissioners reviewing projects to make sure the labor is from an indentured program to ensure a "solid, safe, reliable" workforce.

"Who builds projects is not something in the last 20 years that people have necessarily cared about," said Jason George, of the International Union of Operating Engineers Local 49. "As a commissioner or developer, you should really care who's building your projects."

George said high schoolers these days don't select their career field from a table at a career fair and want to know their work will be meaningful. He said aspiring apprentices now can take high school courses introducing them to engineering and take hands-on trade tours. George also said he's on the lookout to recruit kids for training who don't have experience with machinery, as well as the kids who grew up on a farm.

"People come in and change the course of their whole generational history with one job and a union card. It's life-changing," George said.

Richard Kolodziejski, of the North Central States Regional Council of Carpenters, said it's important to seek out union labor so untrained people aren't building the energy infrastructure of the future.

Kolodziejski said the construction trades culture needs to change to be more welcoming to women and people of color. He also said there should be more attention on the mental health of construction tradespeople, who experience some of the highest rates of suicide by vocation. ■

MISO News

Xcel Wins FERC Waiver of MISO Interconnection Rules on Coal-to-Solar Plan

By Amanda Durish Cook

FERC has authorized an exception to MISO's interconnection rights transfer process, allowing two Xcel Energy subsidiaries to cooperate on a replacement of a coal-fired plant with a solar farm.

FERC said Xcel's Northern States Wisconsin is free to substitute about 650 MW of new solar and potential storage facilities for Northern States Minnesota's 591-MW Allen S. King Power Plant, which is scheduled to be powered down in 2028. The project would use the King plant's point of interconnection (*ER24-1719*).

Xcel requested the waiver of MISO's ordinary interconnection rules because it plans to hand over MISO interconnection permissions from one Northern States Power affiliate to another. The King plant is near the Minnesota-Wisconsin state line.

Ordinarily, MISO's generating facility replacement rules prevent owners of retiring generator from transferring their facilities and interconnection rights to someone else from a year before they submit a replacement request up until the replacement generation reached commercial operation.

Xcel plans to be coal-free no later than 2034 and said this transfer is a piece of the puzzle. It said pursuing an expedited process using a different interconnection customer under MISO's generator replacement process is preferable to submitting the project for study in the interconnection queue, which takes years to complete.

Xcel said it investigated alternatives to Northern States Wisconsin developing the solar facilities, including having Northern States Minnesota lead the project. However, it said Northern States Minnesota would be considered an out-of-state developer on the project, which requires approval from the Public Service Commission of Wisconsin.

FERC said its approval was based in part on the fact that Xcel first explored alternatives and concluded they would "present tariff obstacles or other significant complexities and challenges."

King Power Plant | *Xcel Energy*

The commission said the transfer doesn't introduce queue-jumping concerns because the waiver encompasses "two wholly owned subsidiaries that operate a single integrated system" and doesn't involve "unaffiliated entities outside of the interconnection queue."

The waiver, however, elicited a caution from Commissioner Allison Clements, who said the order exemplifies the "increasingly strained reasoning underpinning the transferability restrictions in MISO's (and other transmission providers') generator replacement rules." She called for a "fulsome evaluation" of generator replacement rules because of their "piecemeal proliferation" across the country.

"I concur because the effect of granting this waiver is that a brownfield site of existing generation on the transmission system can be expeditiously reused. I believe that outcome is consistent with the purpose of MISO's generator replacement rules, and I acknowledge that fast-tracking the interconnection of new generation at previously studied sites may yield efficiencies and cost savings," Clements nevertheless wrote in a concurrence to the order.

But Clements suggested MISO's transfer restrictions today may show undue preference to owners of existing generation. She said at this point, it appears MISO's transfer rules require only the party assuming interconnection rights to be an affiliate of the original owner to bypass the queue and the cost responsibility of the original network upgrades.

MISO's generator replacement requests are poised to increase as members turn off the lights at their aging, baseload plants.

Clements ended by urging the commission to take a fresh look at generator replacement processes and their "nonsensical transferability restrictions" that FERC "must contort around to permit rational commercial arrangements." ■

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NYISO News

DC Circuit Upholds NYISO 17-year Amortization Rule

NY PSC had Appealed; Court Faults Regulator for not Clarifying Environmental Mandate

By John Cropley

The D.C. Circuit Court of Appeals has *upheld FERC's approval* of a key NYISO capacity market price determinant that New York's utility regulator says could raise costs by hundreds of millions of dollars per year.

At issue is the amortization period for a hypothetical new peaker plant in its installed capacity market.

NYISO in late 2020 had proposed reducing the amortization from 20 to 17 years due to New York's decision to require a zero-emissions grid by 2040.

The period in question is the 2021/25 demand-curve reset, the middle of which was 2023, which was 17 years from 2040, when fossil-fired plants might have to shut down to meet the mandate.

FERC repeatedly rejected that proposal as "speculative," prompting appeals by the Independent Power Producers of New York that ultimately led FERC to reverse itself and approve the 17-year time frame.

This prompted protests by consumer advocates and the New York Public Service Commission over the costs likely to result, but FERC reaffirmed its decision in early October 2023.

The PSC in mid-October appealed to the D.C. Circuit, saying the policy likely would increase capacity costs by more than $225 million per year.

The court on June 14 rejected that argument.

In a prepared statement, the PSC said:

"We are disappointed in the court's decision. The fact of the matter is that the effect of changing the amortization period for setting capacity prices is resulting in windfall profits to the existing fossil fuel power generators and does nothing to add the resources we need to meet the state's climate and reliability objectives. We will continue to advocate for just and reasonable rates. PSC is reviewing its options to protect New York customers both at FERC and in the courts."

In the 2-1 ruling, the court noted that the metric in question is a key part of the capacity market pricing. It said the relevant question in the PSC petition was whether FERC's decision "fell within the zone of reasonableness."

The ruling says: "To be sure, FERC's change of heart a mere five months after its initial decision on remand is eyebrow-raising, and we usually view such 'flip-flops' in an agency's position with some skepticism."

But it added: "FERC appropriately concluded that the proposal fell within the zone of reasonableness."

The ruling noted that New York's 2019 Climate Leadership and Community Protection Act mandated a zero-emissions grid by 2040 but gave no indication how to reach that goal, or whether all fossil-fired plants in the state would have to shut down as a result.

So, it makes sense, the ruling said, that a reasonable investor could conclude a new fossil-fueled plant would not be viable after 2039, and it was reasonable for NYISO to design its rates accordingly.

The court previously highlighted the PSC's failure to clarify the 2040 mandate, calling it "regulatory inaction."

"It is ironic that the Public Service Commission objects so strenuously to the system operator's interpretation of the New York climate act. That act vests in the commission alone the power to 'establish a program' to achieve the zero-emissions target, yet the commission has not issued so much as a proposed rule implementing the act."

The court notes that the PSC was required to enact such a program by mid-2021 but only began the process in May 2023 and has only gathered comments since then.

Judge J. Michelle Childs dissented on the ruling, saying the majority's attempt to justify FERC's decision failed. She wrote:

"The distinction between what is required by the act and what may be required by its future implementing regulations is crucial: No one disputes that the system operator may justify its proposed amortization period based on what the act requires, but an amortization period based on what future implementing regulations may require is difficult to square with FERC's anti-speculation precedent."

NYISO had reduced the amortization period from 30 years to 20 years in 2014 beacuse of increasing risks to investing in the hypothetical new plant. ■

D.C. Circuit Court of Appeals | *D.C. Circuit Court of Appeals*

NYISO Board of Directors/MC Briefs

FERC Briefs NYISO on Transmission Rules

Emily Chen, an analyst with FERC's Office of Energy Market Regulation, gave a briefing on Orders 1920 and 1977 to members of the NYISO Management Committee on June 11 during a joint meeting with the ISO's Board of Directors.

"We've had a busy year, and a busy May with two commission meetings, as I'm sure you're well aware of," Chen said. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

Order 1920 requires transmission planners to use a 20-year horizon to identify long-term needs and the facilities to meet them. Long-term planning must occur at least once every five years using at least three plausible scenarios with the best available data and incorporating factors such as retirements, policy goals and corporate commitments.

"We also require that you consider at least seven benefits to evaluate these regional proposals, including production, cost savings, or mitigation of extreme weather and unexpected system conditions," Chen said.

She noted that the order had been published in the *Federal Register* just that day, and it will go into effect Aug. 12.

The rule also requires transmission providers to propose a default method of cost allocation to pay for long-term regional facilities and to hold a six-month engagement period before submitting their compliance filings.

Order 1977 updates the process FERC uses when it is called upon to exercise its siting authority to include a Landowner Bill of Rights and a codified Applicant Code of Conduct for applicants to demonstrate good faith effort to engage with landowners in the permitting process. It also directs applicants to develop engagement plans to environmental justice communities and federally recognized tribes. The order was published May 29 and is effective July 29.

Project Prioritization Process

Kevin Pytel, director of product and project management for NYISO, presented the proposed internal project prioritization for 2025 and outlined changes to the process since last year.

"This process is not perfect, we know that, and we try to make it better every year," Pytel said.

NYISO had 53 proposed market projects this year; of those, eight were continuing projects. They include implementing five-minute transaction scheduling and ancillary service shortage pricing.

The primary changes were to how NYISO handles "continuing" projects, which are those that were approved in a prior year that have progressed to the functional requirements specification, software design, development completion or deployment stages.

Stakeholders had requested that the ISO revise the timeline for stakeholders to decide whether to continue with a project; they now have until June, pushed back from March.

"The hope is that by moving this back three months, we will have a more healthy discussion and be able to come to a resolution quicker on which projects should be considered 'continuing,'" Pytel said.

The ISO also shifted the stakeholder scoring survey from June to July, which it said will allow it to develop a project set for budgeting purposes by early August.

The Budget and Priorities Working Group will decide on the continuing projects at its meeting June 24; NYISO will also provide its own project scores at the meeting. The survey will be distributed July 3, with a deadline of July 14. The ISO will present the results to the working group July 31.

NYISO's internally facing enterprise projects that do not involve market rule changes are not subject to stakeholder approval.

Rate Schedule 1 Allocation of the NYISO Budget

Chris Russell, senior manager of customer settlements for NYISO, reminded the committee of an upcoming vote to determine whether a new cost-of-service study should be conducted to evaluate the Rate Schedule 1 allocation between withdrawals and injections.

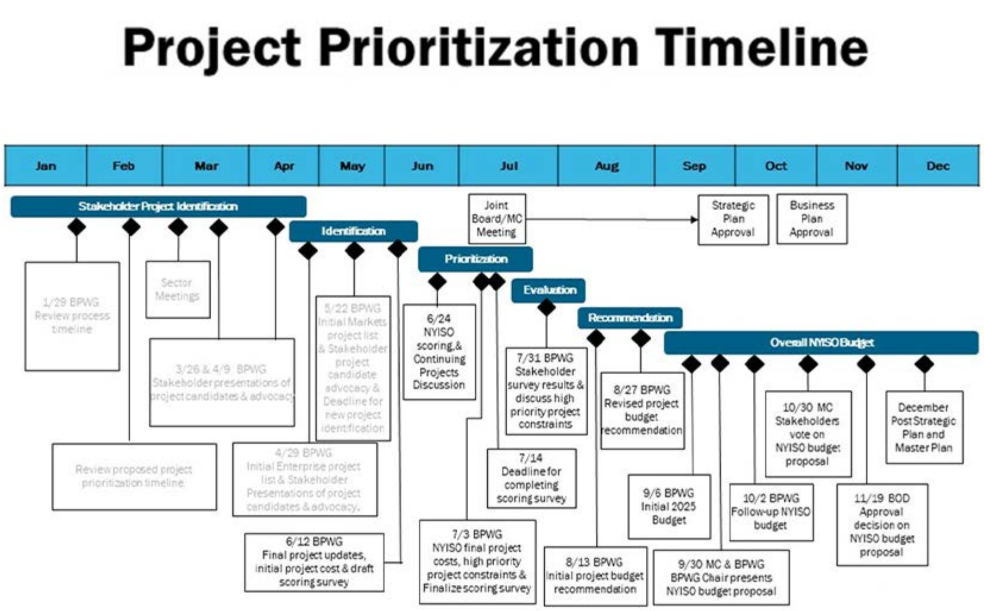
Rate Schedule 1 is used by the ISO to collect its operating costs from members. The 2024 rate is $1.281/MWh, with 72% from withdrawals and 28% from injections.

The current allocation was set by the committee in July 2011. It was originally scheduled to be effective for January 2012 to December 2016, but in 2016, the committee voted to decline conducting a study and has done so annually every third quarter through 2023.

Russell said market participants have indicated that a study is necessary in the future because of the evolving market. Last year, the committee voted to waive the study by an overwhelming majority of 91.22%. (See *NYISO Management Committee Briefs: July 26, 2023*.)

The vote will take place at the committee's July 31 meeting. ■

— Vincent Gabrielle



| NYISO

PJM News

TOs Approve Transferring Transmission Plan Filing Rights to PJM

By Devin Leith-Yessian

Mark Takahashi, PJM Board of Managers | © RTO Insider LLC

PJM transmission owners June 13 approved transferring filing rights over the RTO's transmission plan to the grid operator itself through a package of amendments to the Consolidated Transmission Owners Agreement (CTOA).

The vote by the Transmission Owners Agreement-Administrative Committee (TOA-AC) greenlights the revisions to be filed at FERC, following a May 31 *letter* from the PJM Board of Managers announcing it had agreed to the proposed amendments.

The proposal would move Schedule 6, which details the Regional Transmission Expansion Plan (RTEP), from the Operating Agreement to a new Schedule 19 in the tariff. It would also move the RTEP dispute resolution processes to the tariff and clean up references and definitions to point to the tariff instead of the OA. During the May 6 meeting of the Members Committee, PJM Associate General Counsel Jessica Lynch said the substance of the RTEP would remain unchanged by the shift.

Shifting the RTEP process to the tariff would allow PJM to revise its planning processes through a Federal Power Act Section 205 filing, which would not require the endorsement of RTO membership and a finding that the existing governing documents are unjust and unreasonable, as would be the case with a Section 206 complaint. The PJM board also said the 60-day timeline for FERC to respond to a 205 filing would allow faster action when prompt action is needed.

"It has become very clear that PJM will need to be more proactive and nimble in its planning efforts. As has been referenced in prior discussions, most all other ISOs/RTOs (and indeed virtually all other transmission planning public utilities in the United States) have Federal Power Act Section 205 filing rights over transmission planning, which allows these entities to independently propose rules to FERC and, perhaps most importantly, receive a reaction from FERC, whether positive or negative, within 60 days," the board wrote. "The board views this ability to receive feedback from FERC in a timely manner as strategically important in determining how best to plan the PJM system for the energy transition in the coming years."

The MC voted against endorsing the revisions during its May 6 meeting, where the changes received 25% sector-weighted support. Several stakeholders argued that empowering PJM with unilateral filing rights over regional transmission planning would allow it to bypass the stakeholder process and that the proposed dispute resolution process included would create an inappropriate barrier to MC-endorsed OA amendments being filed at FERC. (See *Members Vote Against Granting PJM Filing Rights over Planning*.)

During the Public Interest and Environmental Organization User Group's meeting May 8, Ari Peskoe, director of the Electricity Law Initiative at Harvard University, said the language would allow "shadow governance," where CTOA signatories could challenge PJM's prospective Section 205 filings, regional plans or other actions through a confidential mediation process. Also, he argued that it would allow utilities to pre-empt PJM planning by submitting similar, but more expensive, projects of their own. (See *Consumer Advocates, Environmentalists Urge Holistic Thinking at PJM*.)

Peskoe told *RTO Insider* he believes the CTOA amendments would violate the FPA and should be rejected by FERC. He said it's unfortunate the PJM board accepted the agreement.

The board wrote that the RTO continues to value the stakeholder process, but there may be times that changes are needed in the face of deadlocked membership.

"As PJM has stated many times, having FPA Section 205 rights will not curtail stakeholder discussion of planning matters; never has it been more important to have stakeholders weigh in on the issues before us," the board said. "But should member consensus be unattainable, having FPA Section 205 rights will allow for PJM to still move forward with an FPA Section 205 filing with FERC and, in turn, receive a timely reaction from the commission on a given planning rule change. This will better position PJM to continue to fulfill the reliability needs of consumers as we advance through this energy transition."

Exelon Director of RTO Relations Alex Stern told *RTO Insider* the proposal would reinforce PJM's independence and ensure it has the authority to act when it determines that changes are needed to maintain reliability. He said authority would mirror the RTO's ability to move swiftly when issues are identified with market designs.

"These revisions are a big step that those who own transmission don't take lightly," he said.

Lacking support for the revisions at the MC underscored the need for PJM's planning to have independence from its membership, Stern said, adding that comments stakeholders made prior to the vote showed a belief that membership, rather than PJM, should have control over planning. He said that is not the case under the status quo and would create a dynamic where PJM would be responsible for planning a reliable grid without having control over how it conducts that planning.

Stern said there have been several efforts to expand PJM's planning processes in the past that have been stymied by deadlocks in the stakeholder process, including establishing a paradigm for storage-as-transmission assets and facilitating offshore wind generation. (See *Vote Delayed on PJM SATA Proposal*.) ■

EIA: Dispatch of Coal Generation Falls in PJM

High Fuel, Start-up Costs Cited as Reasons

By Devin Leith-Yessian

Analysis from the U.S. Energy Information Administration finds that the average runtime for PJM coal-fired generators has declined sharply over the past decade because of increasing fuel and start-up costs.

The agency's June 17 "Today in Energy" *report* said the RTO's coal-fired power plants ran at an average of 34% of their maximum output in 2023, down from 56% in 2013.

That resource class made up 14% of generation available to PJM and 18% of capacity last year, compared with 44% and 38% a year earlier. About 34 GW of coal generation retired over that period, and an additional 2 GW was shifted to other fuel sources. EIA attributed much of the change to competition from the growth of efficient combined cycle gas generation.

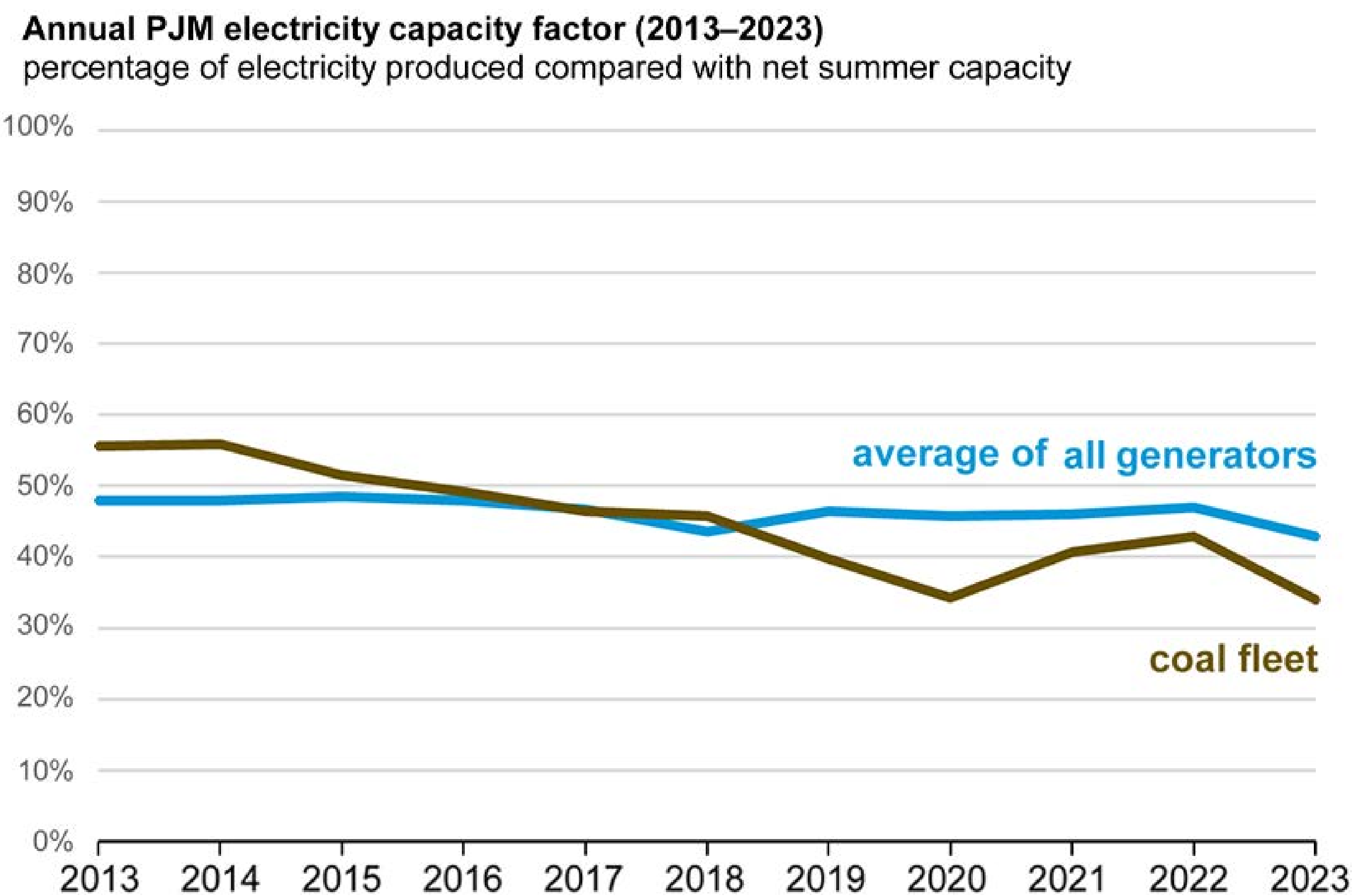
The strain of repeat starts and stops can increase maintenance costs for thermal generators designed to operate at a constant rate, meaning that when PJM is selecting the lowest-cost resources for dispatch in the energy market, it's often uneconomic to start an offline coal plant.

"Coal-fired generating units are generally designed for steady-state operation, and they operate with the fewest problems when they run all the time," EIA wrote. "Restarts can be costly because large thermal plants can experience problems caused by repeated start-ups and shutdowns, increasing maintenance costs. The restart cost can be a key factor in determining plant operating strategy. … Because those restart costs increase their market offer, coal plants, when competing against other sources, may not be selected to operate."

The changing economics hit independent power producers particularly hard, with 24 GW of IPP-owned coal generation deactivating over the past decade, leaving 17.6 GW on the grid. IPPs lack the cost recovery mechanisms that allow regulated utilities to mitigate financial risk for their generators, EIA said.

In an email to *RTO Insider*, PJM's Dan Lockwood said the findings appear to be in line with a *white paper* the RTO published last year, which found that retirements of thermal generators could outpace the development of new resources through 2030. (See *PJM Chief: Retirements Need to Slow Down*.)

"As PJM pointed out in its 'Energy Transition in PJM: Resource Retirements, Replacements & Risks' study issued early last year, a confluence of conditions — including state and federal policy requirements; industry and corporate goals requiring clean energy; reduced costs and/or subsidies for clean resources; stringent environmental standards; age-related maintenance costs; and diminished energy revenues — are leading to an overall decline in the use of thermal resources, including an increase in coal unit retirements," Lockwood wrote. ■



| PJM

SPP News

FERC Requests Briefings on SEEM After DC Circuit Order

Clements Calls Commission's Filing a 'Dead End'

By Holden Mann

FERC on June 14 called for stakeholder briefings on the Southeast Energy Exchange Market (SEEM) as a step toward satisfying a D.C. Circuit Court of Appeals order last year remanding the commission's approval of the market (*ER21-1111*, et al.).

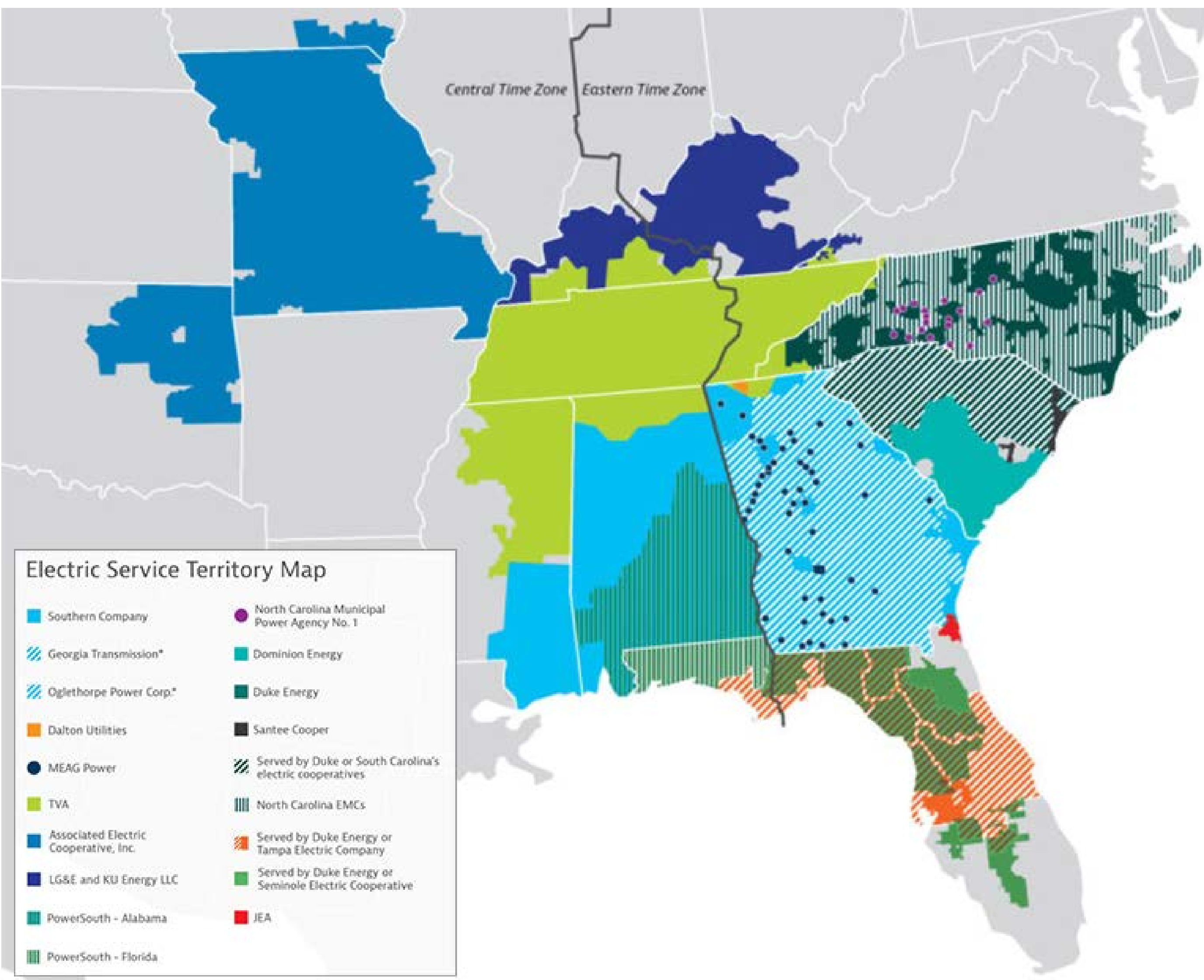
The vote was 2-1, with outgoing Commissioner Allison Clements filing a dissent calling the commission's briefing request "a dead end" that "ignores the court's explicit conclusion" on SEEM's fairness.

SEEM has been controversial since it was first proposed in 2021. Its founding utilities, which included Duke Energy, Southern Co., Dominion Energy, and LG&E and KU Energy, contended that the market would reduce trading friction and promote the integration of renewable resources through automated trading, elimination of transmission rate-pancaking and allowing 15-minute energy transactions.

However, some opponents argued the market would favor transmission-owning utilities and promote monopolistic behavior, while others pushed for alternative structures like an RTO.

FERC's latest order arises out of legal wrangling that began with the commission's original approval of the SEEM agreement in 2021. At the time the commission had only four members, who split 2-2 when the deadline for approval arrived. Under the Federal Power Act, in such a situation the measure under consideration is automatically considered approved.

As a result, the SEEM agreement became effective by operation of law. FERC later approved — by majority vote — revisions to the agreement along with the market's non-firm energy exchange transmission service (NFEETS) and tariff revisions by the founding



SEEM covers all or parts of 12 states following the addition of territories in Florida last year. | *SEEM*

SPP News

utilities. (See *FERC Accepts Key Tariff Revisions to SEEM*.)

A consortium of environmental groups including Advanced Energy United, the Clean Energy Buyers Association and the Southern Alliance for Clean Energy, which had opposed SEEM since its original proposal, filed a request for rehearing in 2021. FERC denied the request, claiming it was submitted after the 30-day deadline for rehearing motions expired.

The opponents then appealed the denial to the D.C. Circuit, which agreed that their request was filed within the deadline and remanded the approval back to FERC. (See *DC Circuit Sends SEEM Back to FERC*.) The court also found that FERC failed to adequately explain why SEEM should not be considered a loose power pool under Order 888. Opponents had argued that NFEETS made the market a loose power pool, which under FERC's rules must be open to nonmembers.

FERC's order last week stopped short of addressing the court's directives. Instead, the commission's majority called for "supplementing the record" with briefings from stakeholders on whether SEEM qualifies as a loose power pool and whether the market's requirements that entities transacting in it have a source and sink inside its footprint violates Order 888.

The commission provided a series of questions that respondents should answer, including:

- whether SEEM is a loose power pool;
- if so, whether and how SEEM "is consistent with or superior to the open-access requirements for loose power pools" in Order 888;
- if SEEM is not a loose power pool, whether and how it is superior to or consistent with the pro forma open access transmission tariff;
- whether NFEETS should be considered a non-pancaked rate;
- whether NFEETS is "comparable to traditional transmission arrangements in bilateral markets"; and
- whether entities with a source or sink outside of SEEM's territory could conform with the technical requirements of the market's matching platform.

Stakeholders must submit their responses within 60 days of the commission's order; reply briefs are due 30 days thereafter.

Clements Says Briefings Only Delay the Inevitable

In her dissent, Clements argued that the commission was only delaying an inevitable recognition that its "previous decision-making [on SEEM] was arbitrary and capricious." She cast the court's decision as a vindication of those who have questioned SEEM's usefulness and fairness.

"Commissioners supporting SEEM have constructed a straw man, attempting to dismiss my and petitioner's concerns as stemming from a desire for a full Southeastern RTO, of which SEEM falls short," Clements wrote. "But my concerns have been and remain focused only on … whether SEEM as proposed is legal under the requirements of the Federal Power Act, Order No. 888 and Order No. 888-A."

Clements insisted that the court's "clear conclusions and directives obviate further record development" that would only serve to further waste "the valuable time of stakeholders we ask to engage in these proceedings." Concerning FERC's question about whether SEEM's geographic requirements are necessary for it to be technically feasible, Clements asserted the court had already determined that such necessity "does not render the construct permissible."

Clements concluded by pointing out that the court last year ordered FERC to consider both the Order 888 questions as well as the requests for rehearing. She emphasized that "the majority's order fails to accomplish either task." ■

SPP News

SPP's REAL Team Approves Base PRMs, Sufficiency Value Curve

By Tom Kleckner

SPP's Resource and Energy Adequacy Leadership (REAL) Team approved a proposed tariff change June 13 that would codify its work and some votes over the past six months.

The revision request (*RR622*) would set separate base planning reserve margins (PRM) at 36% and 16% for the winter and summer seasons, respectively, effective with the 2026 summer. It would also clarify that the sufficiency valuation curve is effective for three years, beginning at the same time.

"I think it dawned on us, and probably a number of you in the room, that it wasn't exactly clear," Casey Cathey, SPP vice president of engineering, told the REAL Team.

The tariff change would also implement the 2023 loss-of-load expectation study that determined the appropriate PRMs for both seasons.

The Market Monitoring Unit (MMU) offered cautious support for the change, saying it supported the 36% and 16% PRMs and the sufficiency valuation curve's extension. However, it also recommended that SPP continue to monitor generation's performance during the next winter storm "and the one after that."

"We see those as a minimum that should be approved," the MMU's John Luallen said, referring to the PRMs. "But with that said, I want to point out that in the last three winter storms, SPP found [itself] in a situation where they could not serve their load with accredited capacity. They had to rely on non-accredited capacity and on imports."

The Monitor's concern is what's not in RR622, Luallen said. He said the sufficiency valuation curve lowers the deficiency payment, which, combined with a cost-of-new-entry value that the MMU believes is not quite accurate, could be sending the wrong market signals.

"If [the CONE]'s not updated for another four years, it will be even further from accurate," Luallen said. "In our mind, it discounts an already discounted number, which is fine except that if the deficiency penalty gets low enough, then it could not have the signal that it needs for [load-responsible] entities to get the capacity. They could choose to just pay the penalty instead. So, we're concerned about the signal this could be sending."

The REAL Team approved the package 9-4. American Electric Power, Arkansas Electric Cooperative Corp., the Oklahoma Corporation Commission and the Oklahoma Municipal Power Authority provided the opposing votes, mirroring their votes on the related policies.

Looking ahead, the team's workload includes ramping resource adequacy, an issue heightened by the increasing addition of intermittent renewable resources.

"What is ramping capacity?" SPP's Charles Hendrix asked by way of explanation. "As load is increasing or decreasing, can your resources follow that load?"

"There's a lot of data out there, but here's what's happening in real time," Cathey said, using a graph of forecasted wind and solar resources to make his point. "We're trying to figure out ways to incent and better value ramp.

"It should not be alarming to LREs in terms of what the system needs today. We have enough rampable capacity today. The question is, how long can we sustain it? Does it send a strong signal around dispatchable resources?" Cathey added. "That's part of the reason we're trying to add this requirement." ■

Real-time graph of forecasted renewable energy vs. load | *SPP*

SPP News

FERC ALJ Lambastes Basin Electric's Business Practices

'Co-op Way' Does not Exempt from Federal Power Act, Judge Writes

By James Downing

Basin Electric Power Cooperative headquarters in Bismark, N.D. | *Basin Electric Power Cooperative*

A FERC administrative law judge on June 11 found that Basin Electric Power Cooperative improperly included the costs of a for-profit gasification business in its wholesale electricity rates, admonishing the co-op for its business practices and for apparently not understanding "some fundamental facts about what it means to be subject to independent regulation" (*ER20-2441-002, et al.*).

In his 905-page initial decision, ALJ Scott Hempling opened with some of the basics of FERC's regulations under the Federal Power Act. This, he wrote, was because Basin only came under FERC jurisdiction in 2019, after providing wholesale services since 1962.

"This half-century absence of independent regulatory constraint explains the breadth, depth and intensity of the disputes over Basin's rates for 2020 and 2021," Hempling wrote. "Perhaps recognizing how remote are Basin's practices from normal, customer-focused regulatory principles, Basin's able counsel and witnesses have repeatedly sought refuge in such phrases as 'the cooperative way,' 'the customers are the owners' and the 'democratic process.' ...

"But the cooperative movement's venerable principles, and its honorable history, provide no logical or legal justification for the managerial mistakes, financial errors and discriminatory practices revealed by the record in this proceeding. The cooperative way shouldn't create divisions among the cooperative's members. A democratic process doesn't always produce prudent decisions. And in a democracy, the majority shouldn't discriminate against a minority."

'Thousands of Unnecessary Hours'

Basin is the largest rural electric cooperative in the country, based in North Dakota, and serves 3 million customers and 140 member co-ops in nine states in both the Eastern and Western Interconnections. When it filed its wholesale rates with FERC in 2020, having readmitted the jurisdictional Tri-State Generation and Transmission Association, several of its members and the Sierra Club protested, and the commission initiated an investigation under FPA Section 206. (See *FERC to Investigate Basin Electric Rates; Danly Dissents*.)

Basin also owns for-profit subsidiary Dakota Gasification Co. (DGC), which produces natural gas from coal and urea that is used for fertilizer, among other products. The company bought the Great Plains Synfuel Plant from the Department of Energy in 1988, which is located next to Basin's Antelope Valley Station coal generator in North Dakota.

The co-op has set its electricity revenue requirement since 2016 at a level it says is needed to provide the financial health of the entire consolidated corporate family, taking into account all of its businesses' losses — including DGC's.

"Because Basin's consolidated corporate family includes nonutility businesses, most prominently DGC, the annual electricity revenue requirement reflects not only the costs of providing electricity, it also reflects DGC's financial experience, positive or negative," Hempling wrote. DGC's losses added hundreds of millions of dollars to Basin's electricity revenue requirement, he said.

One of Basin's members, McKenzie Electric Cooperative, argued that other than the products that it needs to provide power, none of DGC's costs should be reflected in rates, and it should update its revenue requirements to reflect that.

Hempling not only agreed; he castigated Basin for wasting his and intervenors' time by ignoring FERC precedent.

"Basin made no change in its pre-jurisdictional practice — the practice of basing rates on its consolidated income statement. Basin thus ignored commission precedent that protects a utility's jurisdictional customers from the costs and risks of non-jurisdictional affiliates," he wrote. "Basin also ignored commission precedent prohibiting the collection of amounts for unspecified, merely possible future events.

"Insisting that 'the cooperative way' justifies its disregard for commission precedent, Basin has caused intervenors, and this tribunal, thousands of unnecessary hours — hours spent seeking, reading, interpreting and critiquing thousands of internal document — all to do what Basin should have done on its own: Take seriously the rule of law, as Congress enacted it in the Federal Power Act and as this commission has applied it in interpreting that act. Taking seriously the rule of law means presenting a revenue requirement that reflects the cost of electric service and only the cost of electric service."

Hempling also addressed the prudence of Basin and DGC's business decisions. Though he ruled that this ultimately did not matter as to Basin's electricity rates, "McKenzie and Basin have litigated the question of prudence, [so] they and the commission deserve my conclusions on that question."

The ALJ ruled that Basin failed to assess cheaper alternatives compared to investing in existing coal plants. He outlined numerous flaws in the companies' decision-making process, from the overlapping structure of their boards to lacking a culture that encouraged internal debate.

"Basin's board failed Basin's members — the ultimate consumers — by making them involuntary risk-takers in DGC's business prospects, he wrote. "Worse, the board did so without any knowledge of, or any concern for, their members' risk appetites."

Hempling also found that Basin treats some of its members who had contracts with it through 2050 differently from those who had contracts through 2075, charging the latter more favorable depreciation rates and providing them relief from pancaked transmission rates.

"This dissimilar treatment of similarly situated customers violates the statutory prohibition against undue preference or advantage," he wrote.

Precedential?

"In the absence of competitive pressure or regulatory oversight, Basin has spent its members' money on costly and polluting generation resources without ever assessing whether cleaner alternatives would better serve customers' interests," Sierra Club Managing Attorney Kristin Henry said in a statement. "Instead, Basin blindly spent tens of millions of dollars on aging coal plants that were already uncompetitive in the energy market. This initial decision makes significant strides forward in holding Basin accountable for its egregious disregard of customers' interests."

Initial decisions still have to be voted on by the entire commission before any of its findings actually go into effect. Sierra will continue to participate in the case as it is considered by the full commission, so any final order, or future rate case, provides relief from the imprudent spending, Henry said.

If FERC adopts the initial decision's findings, it would be precedential in finding cooperatives are not exempt from accountability under the FPA, nor from the general regulatory principle that monopoly utilities must minimize costs, Sierra said.

"This decision sends a clear signal: Instead of doubling down on these expensive and outdated coal plants — without even considering alternatives — Basin should commit to replacing coal plants with readily available, low-cost renewable sources of energy," said Sierra Club Chief Energy Officer Holly Bender.

The initial decision did not recommend disallowances, or ratepayer refunds, associated with the coal plant spending, but it could be liable for some monetary remedy if Sierra Club can present enough evidence on transmission infrastructure and other alleged deficiencies in future dockets, it said.

Basin said in a statement that it was still evaluating the initial decision.

"But there are a number of findings that are contrary to the positions we made in the case," the co-op said. "Discussing an active proceeding in front of FERC is a delicate matter, but we will continue to aggressively defend our collective interests in the proceeding as this moves to the full FERC commission. This is one step in a long process, and Basin Electric Power Cooperative remains committed to the cooperative principles and serving our members." ■

SPP Board Adds Final OK to JTIQ Cost Framework

By Tom Kleckner

SPP's Board of Directors added its approval June 12 to a proposed tariff revision that establishes a *cost-allocation framework* for projects in the Joint Targeted Interconnection Queue (JTIQ) with MISO.

The revision request (*RR620*) addresses chronic transmission issues on the RTO's seam with MISO related to generator interconnection requests and implements cost-allocation policies already approved by SPP's state regulators. It also memorializes and defines how the JTIQ process will be implemented and applied once executed.

Combined with earlier endorsements from stakeholders June 7 and state regulators June 10, RR620's approval ends a process that began nearly four years ago after repeated fruitless attempts to find interregional projects both RTOs could agree on.

SPP CFO David Kelley, who has assumed new responsibilities since the work began, told the board, "This feels like we are near the end of a really long marathon. It's been a good journey."

The trek began with a thawing of relations between the two RTOs and their CEOs and, Kelley said, "a challenge to both SPP and MISO staff to go and work out a solution to problems that were shared by both RTOs."

The grid operators have identified five projects along their seam that can help unlock new generation and resolve congestion issues in the absence of interregional projects.

After being awarded a $464 million grant from the U.S. Department of Energy, the RTOs revised their original direct-billing approach for JTIQ projects to one that assigns 100% of the portfolio's engineering and construction costs for interconnection requests that meet certain criteria. Those costs are estimated at between $1.6 billion and $1.8 billion before applying the DOE funds.

(See *MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant*.)

"The more complicated piece of this would be associated with the funding and the handling of money from interconnection customers in both RTOs, as well as the transmission owners in both RTOs," Kelley said. "That's something that has never been done before, and it took a significant amount of time to figure those things out."

The Members Committee's advisory vote passed 17-2, with two abstentions. EDP Renewables and the Advanced Power Alliance (APA) both voted against the measure.

EDP's David Mindham said that while his independent power producer sector supports transmission buildout and the JTIQ projects, the process itself represents a failure of planning in the two regions. He said a lack of coordinated assumptions and models has led to a "dysfunctional planning system that is broken."

"Generators want this transmission to be built ... and we're willing to pay for it," Mindham said. "But in order to do that, the entities paying for this transmission are being asked to compromise on a lot of other issues and a lot of additional things that have bad precedent nationally for us, and we just can't support that today."

Kelley reassured Mindham and the APA's Steve Gaw that the framework's structure is specific to the projects in the current portfolio and that their objections could be considered for the next round.

"We fully understand that should there be another round of [JTIQ projects], we're going to have these conversations and justify either something different or something else that is viable going forward," Kelley said.

The Regional State Committee unanimously approved the tariff revision June 10, and the Markets and Operations Policy Committee endorsed it June 7 with 89% approval.

SPP will coordinate the FERC filing with MISO once its neighbor gains approval of its tariff revision. It will seek board approval of the JTIQ portfolio if the commission accepts the tariff change and updates to its joint operating agreement with MISO. ■

The five projects in the MISO-SPP JTIQ portfolio, extending from the Dakotas and Minnesota down to Kansas and Missouri. | *SPP*

Company Briefs

GOW24: Offshore Wind 'Reaches 75-GW Milestone'

Global offshore wind capacity has increased by more than a fifth over the last year, reaching a 75-GW milestone, according to a new RenewableUK report.

The report also stated that global operational offshore wind capacity could reach 277 GW by the end of 2030, according to the analysis. The global pipeline of projects at all stages of development has increased slightly to 1,231 GW, up from 1,228 GW a year ago, with more than 1,500 projects across 41 countries.

China has the largest pipeline of offshore projects at 227 GW, with the UK second at 96 GW. The U.S. (94 GW), Sweden (68 GW) and Brazil (61 GW) round out the top five.

More: *Renews*

Google, NV Energy Partner on Geothermal to Power Data Centers

Google last week announced it has entered into an agreement with NV Energy to power its Nevada data centers with advanced geothermal electricity.

The deal, which still needs regulatory approval, would increase the amount of geothermal electricity injected into the local grid for Google's operations to 115 MW in about six years, Google said. The partnership advances Google toward its goal of running on 100% clean energy by 2030.

More: *Reuters*

Residential Installer Titan Solar Power Closes its Doors

Residential solar dealer Titan Solar Power has closed, according to an email shared across social media.

The email stated that Titan was negotiating with a potential buyer to acquire the company, but the deal fell through. The company closed June 13.

Titan began its construction business in 2013 in Arizona and installed solar in over 20 states.

More: *Solar Power World*

Federal Briefs

Democrats Call on Financial Regulators to do More on Climate

Nineteen Democrats and one independent last week called on U.S. financial regulators to do more to address financial risks posed by the changing climate.

The lawmakers, led by Sen. Elizabeth Warren (D-Mass.) and Rep. Sean Casten (D-Ill.), wrote to the Federal Reserve, Office of the Comptroller of the Currency and Federal Deposit Insurance Corp. to call for more action. The letter particularly raises concern about a Bloomberg report that said American regulators upended an effort to make climate risk more of a focus in international financial rules.

"The United States' lack of progress and innovation in establishing robust measures to address the financial and economic risks from climate change places us behind our international peers and is counterproductive to American interests," the letter read in part.

More: *The Hill*

MVP Pipeline is 'Mechanically Complete,' FERC OKs Operation

Mountain Valley last week announced that its 303-mile natural gas pipeline is "mechanically complete."

A day later, FERC gave the go-ahead for the pipeline to begin operations. The Pipeline and Hazardous Materials Safety Administration said it had no objections to FERC authorizing the pipeline to begin service.

Testing has also been completed on all segments. The company is still waiting for results from metallurgical testing of the pipe section that ruptured under high-pressure water testing. What caused the pipe to fail has not been determined.

More: *The Roanoke Times*, *The Associated Press*

State Briefs

CALIFORNIA

City Council Rejects Power San Diego Proposal

San Diego City Council last week unanimously rejected a proposal to cut ties with San Diego Gas & Electric and start the city's own municipal utility.

The initiative garnered enough signatures to go before the council, but after hearing arguments from both sides, the council decided to stick with SDG&E.

More: *KUSI*

FLORIDA

GRU Board Fires Manager, Appoints Resigning Member to Interim Position

The Gainesville Regional Utilities Authority board last week fired General Manager Tony Cunningham, with authority Chair Ed Bielarski subsequently resigning from the board and being named interim general manager.

Bielarski is the sixth GRU member to resign in the past year, as four previous members left their positions over a lawsuit filed by a local citizens group that questioned if the members met residency requirements outlined in the bill that created the authority. Another resigned before being sworn in because she was not a GRU electric customer.

Bielarski previously served as GRU general manager and was fired in 2022 by the Gainesville City Commission before launching a failed bid for mayor.

More: *Gainesville Sun*

MAINE

PUC Approves CMP Rate Hike

The Public Utilities Commission last week approved a $220 million rate increase for Central Maine Power that will cover the costs the utility racked up while restoring power and cleaning up after destructive storms in 2022 and 2023.

The hike will increase customers' bill by about $10 (8%) a month.

CMP said it faced costs of $120.4 million in three "Tier 3" storms at more than $15 million each. The utility also said it faced costs of $41.3 million for five Tier 2 storms that each cost between $3.5 million and $15 million.

More: *Portland Press Herald*

MARYLAND

PSC Denies Much of Pepco's Rate Increase Request

The Public Service Commission last week authorized a rate increase of $44.6 million for Potomac Electric Power Co. (Pepco).

The amount is far less than the $213.6 million Pepco originally requested. The average customer bill will increase by $5.72 per month (3.5%).

More: *T&D World*

MICHIGAN

Whitmer Says Restarting Palisades Nuclear Plant Only Way to Climate Goals

Gov. Gretchen Whitmer last week said restarting the Palisades Nuclear Generating Station will be necessary if the state wants to meet its climate goals.

Whitmer and Energy Secretary Jennifer Granholm announced that the federal government will offer a $1.5 billion loan to help the plant's new owner, Holtec International, restart Palisades. Also, the Legislature has approved a $150 million subsidy to help reopen the plant, while Whitmer has requested another $150 million in her new budget proposal.

Palisades has been closed since 2022. Holtec bought the plant with an eye toward decommissioning it but is now open to restarting the facility. It would be the first nuclear plant in the U.S. to be restarted after being shuttered.

More: *Michigan Public Radio*

MISSOURI

Ameren Seeks to Build 800-MW Natural Gas Backup

Ameren Missouri last week filed an application with the Public Service Commission to build the 800-MW natural gas-fueled Castle Bluff Energy Center as a flexible backup source.

Ameren said the $900 million plant is necessary due to rising energy demands and the increasing threat of extreme weather.

The company said it already has existing infrastructure in the area and transmission line access, which could reduce overall construction time and costs.

More: *Daily Energy Insider*

NEW YORK

State Breaks Ground on South Brooklyn Marine Terminal

New York last week had an honorary groundbreaking for construction of the South Brooklyn Marine Terminal.

The $861 million site will build, maintain and ship wind turbines that will be a part of the Empire Wind project. The project will start with 54 turbines.

More: *Spectrum News*

NORTH CAROLINA

Gunfire Attack on Duke Equipment Causes Durham County Fire, Outage

The Durham Police Department last week said Duke Energy power equipment was struck by gunfire, causing a slow oil leak and a fire.

Duke said it received reports of a fire and equipment failure June 10 along its grid, resulting in 730 customers losing power for two hours. Power poles in the area were burned, while a nearby stop sign was littered with bullet holes.

The FBI is assisting in the investigation.

More: *WRAL*, *WNCN*

NORTH DAKOTA

Fedorchak Wins GOP Primary for House Seat

Julie Fedorchak has won the Republican nomination to represent the state in the House in its at-large seat, according to a projection from Decision Desk HQ.

Fedorchak, a member of the Public Service Commission, defeated several candidates for the seat, including former state Rep. Rick Becker and Cara Mund, an attorney and former Miss America who ran as an independent for the seat in 2022.

More: *The Hill*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