ISSN 2377-8016 : Volume 2022/Issue 17 ▪ April 26, 2022

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

FERC & Federal

FERC Sets Sights on Tx Planning, Market Changes

CAISO/West

FERC Reverts to Plan B on CAISO Capacity Procurement Mechanism (p.16)

Company News

NextEra Shares Tumble on Solar Supply Woes (p.48)

FERC & Federal

NYISO

New York TOs Again Defend Local Tx Project Rights (p.42)

ERCOT

Overheard at GCPA's 2022 Spring Conference (p.26)

COVER: FERC met in person for the first time in more than two years, though the meeting was not open to the press or public. | *FERC Commissioner Allison Clements via Twitter*

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr.

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Art Director
Mitchell Parizer

New York/New England Bureau Chief
Jennifer Delony

Mid-Atlantic Bureau Chief
K Kaufmann

Midwest Bureau Chief
John Funk

Associate Editor
Shawn McFarland

Copy Editor/Production Editor
Rebecca Santana

CAISO/West Correspondent
Hudson Sangree

ISO-NE Correspondent
Sam Mintz

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Michael Kuser

PJM Correspondent
Michael Yoder

SPP/ERCOT Correspondent
Tom Kleckner

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Chief Operating Officer / Co-Publisher
Merry Eisner

Account Manager
Kathy Henderson

Account Manager
Dan Ingold

Account Manager
Phaedra Welker

Marketing Manager
Eau Rikhotso

Assistant to the Publisher
Tri Bui

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

2022 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,520
Newsletter PDF Plus Web	$2,000

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

FERC Issues 1st Proposal out of Transmission Proceeding

NOPR Focus on Regional Planning, Cost Allocation; More Proposals to Come

By Michael Brooks and Rich Heidorn Jr.

FERC on Thursday proposed changing transmission planning and cost allocation processes in the first in what may be a series of initiatives to help build out the grid in response to electrification and the shift to renewable generation (*RM21-17*).

Meeting in person for the first time after more than two years of telework during the COVID-19 pandemic, the commission voted 4-1 to issue the Notice of Proposed Rulemaking, which would direct transmission providers to revise their planning processes to, among many other things, identify infrastructure needs on a long-term, forward-looking basis and propose a list of benefits on which they would base their selections of proposed projects to meet those needs.

The majority of the commission said the proposal would help planning entities, including RTOs and ISOs, prepare for the growth of renewables, new sources of demand such as electric vehicles and extreme weather events, expected to increase as climate change worsens. In a separate order Thursday, the commission ordered the five jurisdictional RTOs and ISOs to report on how those forces were changing their system needs and what new market rules were required to satisfy them. (See related story, *FERC Asks RTOs for Plans on Changing Market Needs*.)

"If today's proposed rule is finalized, it will facilitate much needed transmission investment, improving the resilience of the grid, enhancing reliability and reducing power costs," Chair Richard Glick said. "It's also going to address our nation's changing resource mix and the changing role of electricity in our society."

FERC Chairman Richard Glick | *FERC*

The NOPR follows an Advance Notice of Proposed Rulemaking issued in July 2021, which covered a wider range of topics. The results of the ANOPR, which drew hundreds of stakeholder comments, has been highly anticipated by not just transmission developers, but the renewable energy industries as well. (See *FERC Tx Inquiry: Consensus on Need for Change, Discord over Solutions*.)

FERC Commissioner Mark Christie | *FERC*

The NOPR would not change planning and cost allocation rules for reliability or market efficiency projects, Commissioner Mark Christie noted. "We don't want to mess with them, and we're not," he said. But it would require planners become more proactive in planning for what Order 1000 called "public policy" projects.

The proposed rule would:

- require transmission providers to conduct regional transmission planning on a long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;
- require transmission providers to identify transmission needs through multiple scenarios that incorporate factors such as federal, state and local laws and regulations that affect the future resource mix and demand; trends in technology and fuel costs; resource retirements; generator interconnection requests and withdrawals; and extreme weather events;
- broaden the benefits that could be considered for project selection and cost allocation;
- require transmission providers to seek the agreement of relevant state entities regarding cost allocation; and
- require an ex-ante cost allocation method or a state agreement process in which states can voluntarily agree to fund a project, or a combination of the two.

FERC met in person for its monthly open meeting for the first time in more than two years, though the meeting was not open to the press or public, only commissioners and staff. | *FERC*

"The clean energy industry is developing thousands of megawatts of clean energy resources — but many projects are stymied by a lack of transmission capacity," the American Clean Power Association said in a statement. "FERC's proposed rule has the potential to accelerate backbone transmission development planning, ensure fair and consistent cost allocation, and provide a substantial role for states in planning transmission for the future."

Many other stakeholder groups issued statements applauding the proposal, though some were more lukewarm. Many called it a "first step," while Sarah Ladin, senior attorney at the Institute for Policy Integrity, said the proposal was "a modest but important step toward more efficient planning that can facilitate decarbonization."

Glick assured stakeholders during the meeting that the commission had not forgotten about the ANOPR's other issues, such as the backlogged generation interconnection queues, interregional transmission planning and incentives. Speaking to reporters after the meeting, Glick advised against taking "the fact that we did a NOPR today on transmission planning and cost allocation to suggest that there wasn't enough support for any of those other issues. Just the contrary. ...

"After all the comments came in on the ANOPR, we realized that there's a lot here; there's a lot of meat on the bone, so to speak. And we thought if we tried to handle to every single issue ... in one big rulemaking, it would take forever. So, we thought we would streamline it into several different rulemakings. ...

"My great hope is that in the very near future,

FERC/Federal News

we'll able to issue a NOPR on interconnection reform, which is very important. ... [But] we didn't think it was wise to do it all in one big rulemaking."

While perhaps not a complete overhaul, the proposal would result in significant changes to transmission planning. RTOs, for example, would be required to create scenarios, with a minimum time horizon of 20 years, that forecast changes in resource mixes and the probability of extreme weather events. Planners would then evaluate project proposals based on FERC-approved criteria that recognize the benefits over the time period for the purposes of cost allocation.

Right of First Refusal

Among the most significant changes would be an exception to Order 1000's elimination of the federal right of first refusal (ROFR).

FERC said regional transmission facilities subject to competitive procurements represent only a small portion of transmission investment in recent years and that Order 1000's removal of the federal ROFR may be "inadvertently discouraging investment" in regional transmission.

Incumbent transmission providers "may be presented with perverse investment incentives" to instead engineer local transmission projects for which they retain development control, the commission said.

It proposed allowing an incumbent to exercise a federal ROFR for a regional project on the condition that it partner with an unaffiliated company with a "meaningful level of participation and investment" in the project.

While that change would be a win for incumbent transmission owners, the commission also proposed new procedures to ensure they don't replace aging transmission infrastructure without evaluating whether they could be "right sized" to provide more cost-effective solutions to regional transmission needs.

Construction Work in Progress

Developers would also not be permitted to take advantage of the commission's construction-work-in-progress (CWIP) incentive for their selected projects. Planners would also be required to seek state approval of their proposed cost allocation methods.

Those requirements were key to Christie's support for the proposal. He said that CWIP puts consumers at risk by allowing developers to be paid "before a single ounce of steel is put into the ground, much less the project is in service." Instead, pre-construction costs would be "booked" as allowance for funds used during construction (AFUDC).

| © RTO Insider LLC

"With AFUDC, the developer gets to book the costs but cannot collect from the consumers until the project is in service," he said.

FERC Commissioner James Danly | *FERC*

The former Virginia State Corporation Commission chairman was also exuberant about the provisions to include state input and approval. In this he disagreed with Commissioner James Danly, who dissented because, he said, "I don't like the purpose of this NOPR.

"It is designed to encourage buildout of transmission specifically for the purpose of encouraging the development of certain types of resources. That is something that I think is not appropriately a concern of the commission. And it does so by socializing costs through putting public policy choices — that is, state and, if you can believe it, even local public policy choices — front and center in the transmission planning process."

FERC Commissioner Allison Clements | *FERC*

Commissioner Allison Clements rejected Danly's criticism.

"It is also not a policy action to advance renewable energy interests. To so frame the proposed long-term transmission planning reforms, or to portray transmission planning as a zero-sum game, misses the point," she said. "Rather, the proposal contains a sensible suite of reforms to shore up cost protections and reliability of the U.S. electricity system based on clear market signals about generation development and demand, the risks of extreme weather and the increasing threat of cyber and physical attack."

Christie said the addition of a state role in cost allocation was "probably the single biggest reason" he voted for the proposal.

"For the first time, it puts states formally at the heart of the planning for these types of projects," he said. "States are going to be at the heart of the planning. States are going to get the opportunity to agree to the criteria, and they're going to get the opportunity to agree to the cost allocation. This has never been a formal requirement in FERC's transmission regulation."

Comments on the NOPR will be due in 75 days from publication in the *Federal Register*. ■

FERC/Federal News

ANALYSIS: FERC Giving up on Transmission Competition?

Tx Planning NOPR Proposes to Reinstate Federal Right of First Refusal

By Rich Heidorn Jr.

FERC's proposed transmission planning and cost allocation rulemaking Thursday was a welcome victory for Chairman Richard Glick (D), coming a month after having to walk back a controversial pipeline ruling, and two months before the end of his current term on the commission.

The Notice of Proposed Rulemaking was approved on a bipartisan 4-1 vote Thursday (*RM21-17*). (See related story, *FERC Issues 1st Proposal out of Transmission Proceeding*.)

"This is a big deal, a great step and one that is moving forward with bipartisan consensus," *tweeted* former Commissioner Neil Chatterjee, a Republican who had frequently clashed with Glick. "Not easy to do on matters that are complex and contentious."

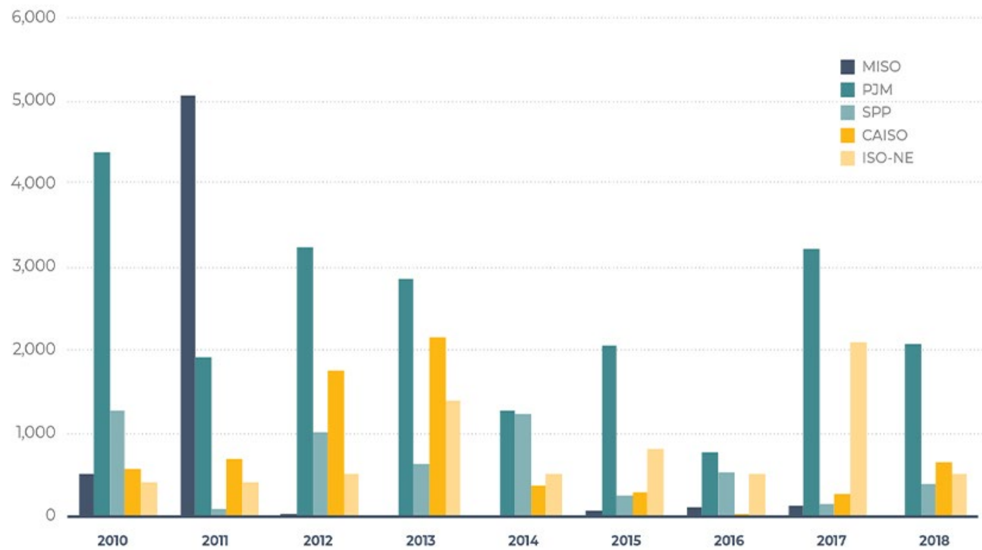
The NOPR also won praise from groups including the American Council on Renewable Energy, Business Council for Sustainable Energy, Natural Resources Defense Council and Edison Electric Institute, which said it would get new wind and solar connected to the grid while adding resilience.

Glick "forged more consensus than people imagined possible on very tough and complex substance," said Seth Kaplan, director of governmental and regulatory affairs at offshore wind developer *Ocean Winds*.

But the proposal also is a retreat from Order 1000's drive to open transmission development to competition: It offers to give incumbent transmission owners a federal right of first refusal (ROFR) on regional projects on the condition that they partner with an unaffiliated company with a "meaningful level of participation and investment" in the project.

The commission said it was changing course because it feared that Order 1000's removal of the federal ROFR may be "inadvertently discouraging investment" in regional transmission. Incumbent transmission providers "may be presented with perverse investment incentives" to instead engineer local transmission projects for which they retain development control, the commission said.

Regional transmission facilities subject to competitive procurements represent only a small portion of transmission investment in recent years, it said.



Annual regionally planned transmission investment in RTOs/ISOs ($ million) | *Americans for a Clean Energy Grid*

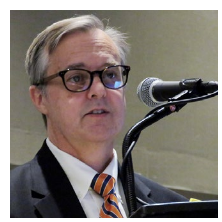
In Order 1000, the commission found that federal ROFRs create "a barrier to entry," discouraging nonincumbent transmission developers from proposing alternative solutions that could be more efficient or cost-effective. But FERC's order could not eliminate ROFRs authorized by state laws, and state legislatures in Iowa, Minnesota, North Dakota, Michigan, South Dakota and Texas have supported such protections for their utilities.

'Practical Reality'

In regions with state ROFRs, "there's not a practical opportunity for third-party transmission," said Rob Gramlich, executive director of *Americans for a Clean Energy Grid* (ACEG) and the *WATT Coalition*. "So, in some sense, I think the commission is just reflecting the practical reality." ACEG supports expansion and modernization of the grid; the WATT Coalition promotes deployment of grid-enhancing technologies.

Rob Gramlich, Grid Strategies | *© RTO Insider LLC*

"Competitive transmission is like a 4.8-degree of difficulty in diving. Generation is way easier," Gramlich continued. "There's been a 40-year consensus on competitive generation. Not that we have it everywhere, but at least the economic policy is agreed to by every economist who looks at it. In transmission, it's just harder and it hasn't worked out well."



Larry Gasteiger, WIRES | *© RTO Insider LLC*

Larry Gasteiger, executive director of *WIRES*, which represents utilities promoting grid investment, said the commission appeared to be prioritizing transmission development over competition.

"The bigger goal was getting the needed infrastructure built and put in place over other processes," he said. "I think it's an acknowledgement by the commission that competition — as it was set forth in Order 1000 and has been implemented for the last 10 years — really hasn't been working in terms of getting needed transmission infrastructure built. … So we were pleased to see that there wasn't a further expansion in that direction and, in essence, a doubling down on what wasn't already working."

Jeff Dennis, general counsel and managing director of *Advanced Energy Economy*, said the commission "is looking to build as many coalitions as possible that can move transmission forward." AEE represents businesses favoring carbon-free energy and electrified transportation.

FERC/Federal News

"Certainly, one could surmise that the commission is sort of offering this renewal of the federal right of first refusal in exchange for incumbents opening the opportunity to invest in transmission to more entities," he added. "The commission … hasn't made this kind of political calculation transparent, but one could imagine that is one thing they are trying to do."

Ed Tatum, vice president of transmission for American Municipal Power (AMP), acknowledged Order 1000 had fallen short, but added, "I'm not sure if elimination of ROFR is the right solution."

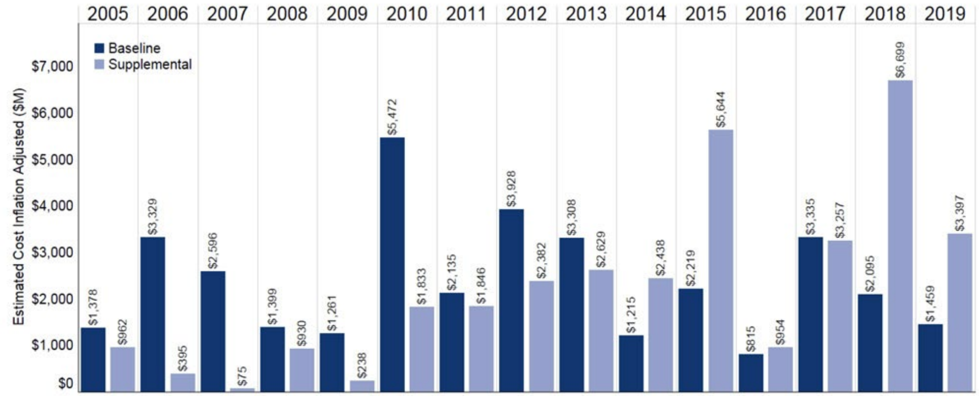

Ed Tatum, American Municipal Power | © RTO Insider LLC

Instead, he said, FERC should adopt the planning process changes that AMP and others proposed in the PJM stakeholder process, which have been rejected by the commission. (See *FERC Rejects Challenges to Decision on EOL Projects in PJM*.)

AMP and its allies are pressing their case before the D.C. Circuit Court of Appeals. "I think we have a better solution," Tatum said. "But it might take the courts to help FERC see that."

Limited Regional Transmission Investments

In the NOPR, the commission indicated dismay that "despite increased investment in transmission facilities overall … recent transmission investment appears to be concentrated in local transmission facility development or regional transmission facilities subject to an exception from competitive transmission development processes, such as immediate-need reliability projects or upgrades to existing transmission facilities, as opposed to investment in regional transmission facilities."



Baseline and supplemental projects by year | *PJM*

Although there has been wide acknowledgement that Order 1000's efforts to open up competition have had only limited success, commenters in the docket were divided on how FERC should respond.

Some, including the California Public Utilities Commission, called for more competition. NRDC, Sierra Club and other public interest organizations said FERC should require transmission providers to plan for local transmission needs as part of the regional planning process. The National Association of Regulatory Utility Commissioners urged FERC to discourage overinvestment in local transmission facilities.

But EEI asked the commission to "remove the complex and costly competitive processes" that it said is delaying transmission development.

FERC noted investment in regionally planned transmission has declined in some regions, including PJM, which averaged $2.76 billion in annual spending on regional transmission from 2005 to 2013 and only $1.65 billion from 2014 to 2020.

Given the experience since the issuance of Order 1000 in 2011 and the comments it received in this docket, FERC said, it concluded that the order's elimination of all federal ROFRs for new regional facilities "was overly broad," resulting in "potentially flawed investment incentives that may be restraining otherwise more efficient or cost-effective regional transmission facility development."

"Order No. 1000 failed to recognize that at least some of the most notable expected benefits from competitive transmission development processes (e.g., new transmission developer market entry, greater innovation in and potentially lower costs of transmission development) could be achieved or at least reasonably approximated through other means."

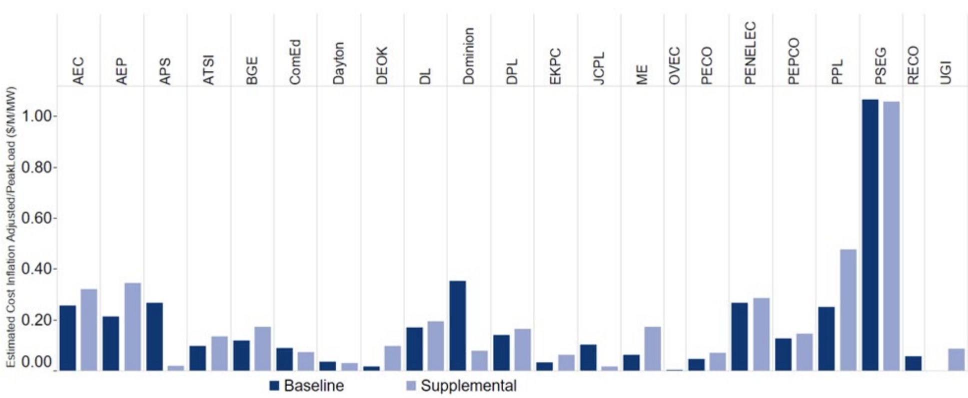
Joint Ownership Proposal

ACEG's Gramlich and others said they were intrigued by the proposal for joint ventures, a model they said has proven successful in MISO's Multi-Value Projects and *CapX2020*, in which 11 transmission-owning utilities in Minnesota and surrounding states built nearly 800 miles of 345-kV and 230-kV transmission. In addition, LS Power Grid New York (formerly North America Transmission) *teamed up* with the New York Power Authority to win state approval for the New York AC project.

"The public power community has always advocated for more joint ownership," Gramlich said.

AEE's Dennis said enlarging the circle of those involved in planning and developing transmission "builds more and more support for determining that those projects are needed, brings in more sources of capital, including low-cost capital from not-for-profit, municipal entities and things like that. That helps move those projects forward."

Dennis said there would likely be opposition, however, to a final rule that allowed "incum-



Baseline and supplemental projects since 2005 (adjusted by peak load) | *PJM*

FERC/Federal News

bent transmission owners being able to essentially ally with each other to exercise a right of first refusal."

'Right-sized' End-of-life Replacements

While the commission's retreat on the federal ROFR would be a win for incumbent TOs, the commission also proposed new procedures to increase transparency on the TOs' local transmission upgrades.

The NOPR would require transmission providers to include in their long-term regional transmission planning an evaluation of TOs' plans to replace aging transmission facilities of 230 kV and above to determine whether they "can be 'right-sized' to more efficiently or cost-effectively address regional transmission needs."

It also expressed concern that local transmission planning processes may lack adequate transparency and stakeholder input, resulting in duplicative spending that increases costs for consumers. The commission noted that local transmission facilities are included in regional plans only as "inputs" for modeling of their reliability impacts, "with minimal opportunity for stakeholder review."

"My initial read of it is it may not be a very dramatic change at all, in terms of how things are currently operating," said WIRES' Gasteiger. "Frankly, I think that's pretty much being done in most regions right now."

But Gramlich said it "could potentially be huge, particularly because we have so many transmission assets around the country that are well over 50 years old that will need to be replaced. And the practical limitations on developing new rights of way are so extreme that one of the best opportunities to expand capacity is to expand capacity over existing rights of way."

Gramlich said there has been poor coordination between local and regional transmission upgrades.

"I've heard the heads of very large transmission owners in some of the RTOs say that it was working a lot better before Order 1000. Because it used to be that any upgrade they would identify on the local system, they would bring to the RTO, and the RTO would consider a more optimal regional solution," he said. "And then Order 1000 came along with the requirement to competitively bid anything in the regional process, and that [coordination] largely shut down."

Dennis said the change could be significant "if the transparency requirements are paired with accountability … meaning ultimately that there is a consequence to building more expensive, less-than-optimal options."

AMP's Tatum questioned the 230-kV cutoff. "There's a whole lot in the [interconnection] queue I believe that is on transmission facilities below 230 kV," he said.

Order 890 required that transmission providers' local transmission planning comply with nine principles, including coordination, openness, transparency and information exchange. "However, implementation of these principles in local transmission planning processes appears to remain uneven," FERC said.

The NOPR would require transmission providers hold at least three stakeholder meetings on each local transmission planning process: one on the criteria, assumptions and models used (Assumptions Meeting); a second on identified reliability criteria violations and other transmission needs (Needs Meeting); and last a review of potential solutions (Solutions Meeting).

Transmission providers would be required to evaluate whether any facilities rated at or above 230 kV that are planned for replacement during the next 10 years can be "right-sized" to more efficiently address regional transmission needs. "Right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (e.g., redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies)," FERC said.

Because the proposed rule would not change existing law allowing the incumbent TO to proceed with developing its planned in-kind replacement transmission facility without right-sizing, the commission said it would establish a ROFR for such facilities located within the utility's retail distribution territory.

Only the incremental costs of right-sizing the transmission facility would be subject to regional cost allocation.

State Role

Dennis said he was pleasantly surprised by the commission's effort to engage states in regional transmission planning and cost allocation. "I think that, paired with the requirements for much longer-term, multiple scenario-based planning, that [effort] really addresses the reality of what's happening on the electric system and the resource mix changes that are occurring," he said.

"By giving them that opportunity to engage up front, they are also giving the states the ability

Jeff Dennis, Advanced Energy Economy | *Advanced Energy Economy*

to really shape what regional transmission plans look like and to really say upfront, 'These are things that we think will benefit our customers' … instead of just having transmission be something that happens to them."

The NOPR's proposed requirement to seek state agreement on cost allocation "was a clear concession to Commissioner [Mark] Christie [R], as part of getting him on board," Gasteiger said.

Gasteiger, who served in senior roles at FERC under Chairs Joseph T. Kelliher and Norman Bay, said it was essential that Glick won bipartisan support for such a sweeping rulemaking.

"On something of such potentially great significance … the commission [must] act on a bipartisan, if not unanimous, basis, and certainly not on a partisan basis, a 3-2 vote," Gasteiger said. "And you don't need to look any further than the pipeline certificate policy statement to see why that's important." (See *FERC Backtracks on Gas Policy Updates*.)

"I was glad to see that the commission made a strong effort to produce a bipartisan decision on this," he continued. "It always involves a lot of compromise, and nobody gets exactly what they want. But it provides a lot more certainty to the industry and a lot more durability to the commission's actions."

After having praised the consensus-building, however, Gasteiger expressed some concern over the state role that helped win Christie's vote.

"Generally speaking, more process doesn't lead to getting more transmission built in a timely basis," he said. "So the devil will be the details and in the implementation of what they've put in place. But I do have a concern with elevating or expanding the role of states in the process, and creating more process. What will that mean for actually getting transmission infrastructure built?" ■

FERC/Federal News

FERC Asks RTOs for Plans on Changing Market Needs

Commission Seeks to Build on Technical Conferences, Staff Paper

By Rich Heidorn Jr.

FERC on Thursday ordered CAISO, ISO-NE, MISO, NYISO, PJM and SPP to report on how their system needs are changing with their shifting resource mixes and how they intend to meet them (*AD21-10*).

The commission said the reports would build on the record developed during four technical conferences last year and provide a foundation for potential market changes.

"At this time, we do not propose a generic solution to address changing system needs across the RTOs/ISOs because of the diversity of those needs and the lack of a compelling record to support any one-size-fits-all solution for meeting those needs," the commission said. "Instead, we believe that it is appropriate to gather additional information from the RTOs/ISOs … to enhance our understanding of the changing system needs in each RTO/ISO and potential mechanisms for addressing those needs as they change over time. We will review the reports and comments to determine whether further action is appropriate."

The grid operators must report on:

- current system needs under changing resource mixes and load profiles;
- how each expects its system needs to change over the next five and 10 years;
- whether and how each plans to change its energy and ancillary services (E&AS) markets to meet expected system needs over the next five and 10 years; and
- information about changes to resource adequacy programs or other market changes, including to capacity markets, that would help each meet changes in system needs.

The commission gave the grid operators 180 days to file reports in response to the order, with public comments due 60 days later.

Democrat Richard Glick called for the proceeding after taking over the commission chairmanship last year.

The commission said the record developed in

Clockwise from top left: FERC Chair Richard Glick; PJM CEO Manu Asthana; ISO-NE CEO Gordon van Welie; and NYISO CEO Richard Dewey at FERC's technical conference in March 2021. | *FERC*

FERC/Federal News

the docket indicated that "RTOs/ISOs currently face changing system needs that vary significantly by RTO/ISO. The time horizon (minutes, hours, days, seasons) of system needs, particularly with respect to net load variability and uncertainty, also appears to vary significantly across RTOs/ISOs."

While the issues have been most acute in regions with the highest penetration of variable resources, such as CAISO and SPP, "other RTOs/ISOs also expect their system needs to change in the future, and the commission and stakeholders would benefit from additional information from all RTOs/ISOs on the subject."

Concurring Statements

Although the commission unanimously supported the order, the panel's two Republicans offered some additional comments in concurring statements.

Commissioner James Danly called for "a sincere effort to take the lessons learned in our markets and re-evaluate whether and how those markets work."

"A single, basic set of questions must be at the heart of our examination: Are price signals providing the proper incentives for the orderly entry and exit of the correct type and quantity of generation to ensure resource adequacy and reliability?" he said. "What we should not do is try to engineer a record by which we might later justify commission action in pursuit of narrow, preordained policy goals."

Commissioner Mark Christie said that although the primary focus of the reports ordered by the commission related to the E&AS markets, MISO's latest capacity auction results "are only the latest evidence that the future of all RTO/ISO market constructs should be considered" in the docket. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

"Specifically, I propose fundamental questions regarding pricing and compensation in the energy, ancillary services and capacity markets that merit discussion due to their potential impact on reliability and fairness to consumers. For example, I think it is time to put the all-important question of the continued use of locational marginal pricing in these market constructs on the table for serious scrutiny and discussion," he said.

Technical Conferences

In March 2021, FERC held its first technical conference in the docket, which focused on capacity markets in PJM, ISO-NE and NYISO and featured broad criticism of the minimum offer price rule. (See *PJM MOPR in the Crosshairs at FERC Tech Conference*.)

That led to PJM's proposal to apply MOPR only to resources connected to the exercise of buyer-side market power or those receiving state subsidies conditioned on clearing the capacity auction. The new rule took effect Sept. 29 "by operation of law" after the commission deadlocked 2-2. The rule change is the subject of a challenge by merchant generators before the 3rd U.S. Circuit Court of Appeals. (See *FERC Declines Rehearing of PJM MOPR; Ball now in 3rd Circuit Court*.)

A second conference on May 25 focused on ISO-NE's markets. ISO-NE CEO Gordon van Welie told the commission markets are "never going to work very well" with inadequate infrastructure supporting them and cited a "misalignment" between the RTO markets and state policies. (See *Regulators, ISO-NE Discuss Market Changes at FERC Tech Conference*.)

A Forward Clean Energy Market, which is under consideration, could relieve some of the tensions, van Welie said. But he said problems will persist "until the region figures out how it wants to socialize some of these costs for reliability that are outside of the market."

After months of debate, ISO-NE earlier this month filed a proposal to eliminate its MOPR after a two-year delay. (See *ISO-NE Sends MOPR Filing to FERC, Teeing up Big Decision* and *Mass. Democrats Take on ISO-NE over MOPR*.)

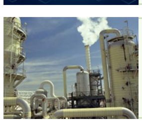
On Sept. 14, the commission held the first of two conferences on E&AS markets, with a focus on the need for flexible ramping products to compensate for shortfalls in forecasted wind and solar output. (See *Flexible Ramping Grows as Ancillary Service*.) FERC staff had teed up some of the issues in a Sept. 7 *white paper*.

The discussions continued at a conference Oct. 12, where speakers agreed that market participation rules should be revised to ease the entry of new and emerging resource types. (See *Stakeholders Ask FERC to Support E&AS Market Changes*.)

"One of the recurring themes we've heard from a number of participants is that increasing reliance on intermittent generation resources and changes in load profiles associated with the growth of behind-the-meter generation requires additional system flexibility," Glick said at Thursday's open meeting. He said the commission seeks feedback from market participants as well as grid operators. "That will help enable the commission to assess whether modifications of the markets we oversee are necessary and to address the changing needs of the system." ■

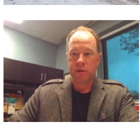
National/Federal news from our other channels

Ohio Hydrogen Study: Blue Now, Green in 2050 — NetZero Insider



DOE Wants 60 GW of Dispatchable Geothermal Power on US Grid — NetZero Insider

CISA Issues Fresh Russia Cyber Warnings — ERO Insider



NERC Standards Committee Moves Projects Forward — ERO Insider

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

FERC/Federal News

Solar Sector Braces for Tariff Probe Impact

Investigation Pits Solar Developers vs. Domestic Manufacturers

By Hugh R. Morley

A U.S. Commerce Department investigation into claims that China circumvented U.S. tariffs on solar components is already having a chilling effect, with developers and industry groups saying they are seeing component price hikes, delivery delays and shortages as manufacturers in the countries under investigation pull back on exports to the U.S.

In an investigation launched March 25, the department is looking into whether crystalline silicon photovoltaic cells imported from Cambodia, Malaysia, Thailand and Vietnam are really made there, or if they are actually made in China and shipped through those four countries to avoid anti-dumping and countervailing duties that would otherwise have to be paid by Chinese manufacturers.

Anti-dumping duties are levied when the *department concludes* that a foreign supplier or manufacturer is selling goods on the U.S. market at below-market prices. The department places countervailing duties on a product when it assesses that a foreign government subsidized the supplier or manufacturer to reduce the price in the U.S. market. Crystalline silicon photovoltaic cells are used in the manufacturing of solar panels.

Even though the Commerce Department has only just started the investigation and made no conclusion, manufacturers and suppliers in the four countries are limiting exports to the U.S. out of fear that further tariff increases will be levied retroactively if the department eventually rules that circumvention took place, industry groups and developers say. The Solar Energy Industries Association (SEIA) has said that more than 80% of solar modular imports come from the four countries, and the probe as a result will affect a wide swath of the solar sector.

"These actions are so detrimental to what we're trying to do," Mike Kruger, CEO of Colorado Solar and Storage Association, said about the department's decision to launch the probe. "My folks doing large-scale projects are already looking at renegotiating [power purchase agreements], potentially pushing out due dates for their projects" by as much as six months, he said. Some developers just won't bid on jobs, because they don't know either how much the panels will cost or when they will be available.

Kruger added that solar developers are faced with trying to work out whether to price jobs at the existing solar panel price or at the price elevated by higher tariffs that will take effect if the Commerce Department concludes that circumvention is taking place.

"It's created a lot of challenges here in the short term," said Jefferson Gerwig, director of procurement for South Bend, Ind.-based Inovateus Solar, which develops solar and energy storage projects for commercial, industrial, municipal and utility customers.

Some manufacturers have raised prices by a "significant" amount, and some have changed the delivery terms on their products, no longer offering to bring them to the buyer's door and instead requiring that the customer pick them up at the factory. That way the buyer would be responsible for any tariff increase levied in the future, he said.

"This is going to have an impact on our pricing," he said. "And it's going to require us to go back and rebid many of our active proposals. So, it is having immediate impacts. We are having to shift numbers and let our customers know that the validity of their quotes needs to be updated, based on these initial price increases that we're seeing."

Tim Powers, development and policy manager for Inovateus, said the uncertainty of getting products has created a "mad rush to get modules as quick as possible. And that just puts a supply-and-demand constraint on the entire industry, and that causes challenges for everybody."

'Existential Crisis'

The investigation, and the reaction of the solar industry, highlights the tension between efforts to create a domestic solar panel manufacturing industry in the U.S. and developers seeking the lowest priced equipment for their projects as the nation seeks to accelerate its solar generation capacity power to meet its zero-emission goals.

The turbulence in the panel supply sector comes as the industry already is facing equipment shortfalls, delays and price hikes because of supply chain problems, mainly caused by the country's emergence from the COVID-19 pandemic.

With the probe underway, the Commerce Department said it will identify the key exporters or producers in each of the four countries and request "quantity and value" data about their shipments of photovoltaic cells and modules. The department will make a preliminary determination in the case in August, and SEIA said it expects the department to make a final determination in January. It could lead to even higher tariffs on solar panels, the organization said.

SEIA said on April 7 that it had *surveyed 412 solar companies* nationwide, of which 78% said that panel deliveries had been canceled or delayed since the Commerce Department announced the investigation. Fifty-six percent said the investigation put at least 70% of the projects in their pipelines at risk this year.

SEIA CEO Abigail Ross Hopper called the department's investigation an "existential crisis" for the solar industry and criticized the fact that the case is based on the "industry killing claims" of only one company.

"The proponents of this case say that harsh tariffs are necessary to grow domestic manufacturing; that this case will have no adverse impact," she said in a SEIA webinar earlier this month. "And if it does cause harm, that's OK: The ends justify the means. They're wrong."

But the Coalition for a Prosperous America (CPA), a trade group that advocates for domestic producers, welcomed the investigation.

"Despite the fear mongering and lobbying by special interest groups that advocate for Chinese solar manufacturers, the Biden administration has chosen to side with American companies and workers," CPA Chairman Zach Mottl said.

Coping With Shortages

In New Jersey, concern at disruption to the flow of solar panels is "freezing … slowing" development and causing "significant price impacts," said Fred DeSanti, executive director of the New Jersey Solar Energy Coalition, which represents 26 state and national solar companies. Price hikes put developers in a bind because they can't adjust their two main sources of revenue — state incentives and the price of energy — to offset the rise in project costs, he said.

In a Feb. 24 letter to Commerce Secretary Gina Raimondo, DeSanti urged the department not to start the investigation, saying that the inquiry could "could threaten existing and

FERC/Federal News

future solar projects that rely on imports, in addition to the well paid solar jobs that these projects create."

New Jersey, like other states, is looking to rapidly expand its solar capacity to help reduce carbon emissions. Gov. Phil Murphy has set a goal of reaching *100% clean energy by 2050*, with a goal of increasing solar capacity from about 3.84 GW at present to 17.2 GW by 2035. The state's strategy for expanding the solar sector includes introducing a community solar program, increasing the number and capacity of grid-scale solar projects, and refocusing the state's solar incentive programs while also reducing the cost to ratepayers. (See *NJ Solar Pipeline Surges While Installations Drop*.)

That kind of dramatic expansion, however, would suffer if, as the developers say, they couldn't get the equipment needed to follow through with projects.

Scott Elias, director of Mid-Atlantic state affairs for SEIA, told the New Jersey Board of Public Utilities (BPU) on April 7 that the investigation "is already needlessly causing serious harm to the industry, including right now and right here in New Jersey." He said that "no importer of record is going to bring solar cells or panels into the U.S. and risk the imposition of a retroactive 50 to 250% duty."

"Solar customers do not have the capacity to absorb these massive costs," he said. "And planned projects are unfortunately not going to be moving forward."

In Colorado, Kruger said that in the longer term, developers that are forced to slow down business because of higher panel prices or delivery delays, as well as lay off workers, could find it difficult to take on new people in the future because of the tight labor market.

"So, this is just really frustrating," Kruger said. "The uncertainty; the unknown: It's immediately impacting the large-scale projects but will impact everybody in the not-too-distant future." That will put in jeopardy the state's efforts to cut emissions with solar energy, he said, predicting that instead of the state seeing the hoped-for double-digit growth in solar capacity over the previous 12 months, it will simply repeat the modest increase of 2021.

Yet the blowback from the investigation is not hurting all sectors of the industry.

Renova Energy, a Palm Desert, Calif., solar installation company, said that it has yet to be affected by the investigation and does not expect to see much impact in the future. One reason is that the company buys all its equipment from SunPower, which has a wide diversity of panel manufacturing sources that are outside the four Asian countries under scrutiny — among them Mexico — and, therefore, is unaffected by the Commerce Department's action, Chief Sales Officer Nate Lewis said.

Renova officials also said the company's focus on rooftop solar installations with higher quality panels, which have a higher energy conversion rate and longer life, means that it does not use the lower-end panels that are made by the manufacturers in the Commerce Department probe.

"We typically don't look for the lowest cost equipment; we're looking for the best value for our customers," Lewis said. "And the cheap Chinese product doesn't work well in our environment."

A Fair Playing Field

The dispute over Chinese solar panel imports stretches back a decade, since the U.S. International Trade Commission concluded that Chinese producers of crystalline silicon photovoltaic cells had dumped and subsidized imports into the U.S., which placed anti-dumping and countervailing trade duties on those products.

Six months ago, the Commerce Department rejected a request by trade group American Solar Manufacturers Against Chinese Circumvention (A-SMACC) seeking an investigation into unlawful circumventing of antidumping and countervailing duties in the solar module market. Announcing the request in an Aug. 16 *release*, A-SMACC said it wanted to "ensure that the playing field for American solar manufacturing is level and ready for the scaled investments necessary to address climate change."

"This targeted enforcement action ensures that the United States' status as an innovation and manufacturing leader will not be endangered by exploitative trade practices that harm the American worker," A-SMACC said.

But the Commerce Department *rejected the request*, saying that it could not conduct an investigation unless A-SMACC identified its members, which the department would need to know to ensure that the complainants were legitimately "interested parties." The organization declined, claiming that that such information was "proprietary."

The Commerce Department, however, launched the current investigation after Auxin Solar, a California-based manufacturer of solar panels, made similar claims.

The department is required to investigate several factors about the products, according to a memo explaining the decision to investigate. One is whether the solar panels are produced in the four countries using merchandise produced in China.

Other factors include how significant the work done in the four countries and whether the merchandise produced is "a significant portion" of the final value of the product that is shipped to the U.S., the memo says.

Shortfall of R&D, Investment

Auxin says that Chinese manufacturers and suppliers responded to the anti-dumping and countervailing duties by changing their tactics. Instead of "fairly pricing" their products, the producers shipped imports from "third-country export platforms," the company told the department in its complaint.

"Their relentless predatory pricing has been fueled by China's non-market subsidization of the upstream solar supply chain, intellectual property theft conducted by China's People's Liberation Army [the country's military] and inhumane forced labor practices," Auxin said.

Auxin provided evidence that producers in Cambodia, Malaysia, Thailand and Vietnam obtained products used in the production of solar panels — such as silicon wafers, silver paste, silane, solar glass, aluminum frames and junction boxes — from China, the department said in the memo. The company also showed that the four countries had experienced "recent surges" in the import of those products, it said.

In addition, China has as much as "99% of the worldwide solar wafer capacity, 95% of the worldwide solar ingot capacity and 64% of solar-grade polysilicon capacity," the memo says. "According to Auxin, this demonstrates that the solar cell producers in Cambodia, Malaysia, Thailand and Vietnam would likely obtain solar-grade silicon wafers from China."

Auxin also argued that the four countries had not made the kind of investment in polysilicon enrichment facilities to support the volume of production it was claiming, especially compared to the extensive Chinese investment in the same thing, according to the memo. And the countries also had made "minimal" investment in R&D related to completing and assembling solar cells into modules and so relied on Chinese knowledge rather than "developing their own technology," the memo said. In addition, the comparatively small size of production facilities compared to Chinese facilities showed that the production facilities in the four countries are "limited," the memo said. ■

FERC/Federal News

Federal Aid Likely Too Late to Save Palisades, Diablo Canyon Nukes

DOE Invites Applications for $6B Civil Nuclear Credit Program

By John Lindstrom and Rich Heidorn Jr.

Palisades Nuclear Plant | *Entergy*

LANSING, Mich. — The U.S. Department of Energy's lifeline to struggling nuclear generators appears unlikely to save the next three units scheduled to retire.

Entergy officials said Wednesday they are unlikely to seek federal aid to prevent the Palisades Nuclear Plant from closing as scheduled on May 31, despite entreaties from Michigan Gov. Gretchen Whitmer (D). And Pacific Gas and Electric said Diablo Canyon 1 and 2 are still scheduled for retirement in 2024 and 2025.

Whitmer sent a *letter* Wednesday to Energy Secretary Jennifer Granholm — her predecessor as governor — urging the department to use $363 million from the Civil Nuclear Credit (CNC) Program created by the Infrastructure Investment and Jobs Act (IIJA) to keep Palisades open. (See *DOE Launches $6B Nuke Credit Program*.) DOE opened *applications* for the $6 billion CNC program April 19.

Whitmer said saving the 800-MW nuclear plant, which employs 600 and is one of the state's largest sources of carbon-free electricity, "is a top priority."

Merchant Power Exit

But Entergy spokesman Nick Culp told *RTO Insider* the company would only reconsider its plans to close Palisades — part of the company's broader exit from the merchant power business — if it received a purchase offer from a "credible formal buyer."

In December, the Nuclear Regulatory Commission approved Entergy's request to transfer Palisades, its nuclear trust fund and its spent fuel to Holtec Decommissioning International.

"Our focus at Palisades power plant remains on the safe and orderly shutdown of the facility in May," the company said in a statement. "We acknowledge having recently been contacted by government officials about the facility potentially operating beyond May 2022. In addition to these conversations, we have and will continue to entertain discussions with qualified nuclear merchant plant owner/operators who may want to purchase and continue operating Palisades. However, it is important to note that no formal proposal to acquire Palisades has been made that provides an opportunity for continued operations and that eliminates the substantial financial and operational risks associated with unwinding the existing contract with Holtec."

Entergy has been preparing to shutter Palisades since 2017 and has not refueled the plant since 2020.

"There are challenges that make continued operation of the facility beyond May 2022 difficult, including the pending transfer of more than 130 employees to other parts of Entergy's business and planned employee retirements post-shutdown," the company added. "Additionally, the plant is unable to operate beyond the target closure date due to the diminished power of its nuclear fuel as it reaches the end of its two-year operating cycle."

Holtec issued a statement saying it was aware of Whitmer's effort to keep Palisades operating. "We remain ready, should these efforts to keep the plant operational not be successful, to transition ownership to Holtec after the plant ceases operations for a safe, efficient decommissioning process," it said.

Keeping Palisades open until at least the end of its current operating license, which expires in 2031, has split the state's environmental community. While a number of environmentalists have called for keeping the plant open to aid decarbonization efforts, others oppose nuclear generation.

During public testimony on developing the MI Healthy Climate Plan — the final version of which was due to Whitmer by Friday, Earth Day — keeping Palisades open drew comments from supporters across the nation. The first version of the plan to make Michigan carbon neutral by 2050 did not discuss the plant.

Expiring PPA

CMS Energy's Consumers Energy, which put Palisades into service in 1971, sold the plant to Entergy in 2015 while purchasing most of its output under a power purchase agreement scheduled to expire this year.

Entergy and Consumers agreed to end the PPA early and close Palisades in 2018, but they canceled those plans under pressure from the Michigan Public Service Commission. Prices under the PPA ranged from $43.50/MWh in 2007 to $61.50/MWh in 2022, with an average of $51/MWh.

A CMS spokesperson said the utility would not oppose continued operation of the plant, located in Covert Township on Lake Michigan.

FERC/Federal News

"If the power from the plant could provide competitively priced and reliable energy for our customers, we would consider working with our partners to keep the plant open," CMS' Katie Carey said.

Whitmer's letter said that "Michigan has already had numerous conversations with the plant owner and leading nuclear operators who may be interested in purchasing the plant and keeping it operational through its 2031 [NRC] licensure date."

"If another buyer does not materialize and Entergy maintains its stance, Gov. Whitmer might look to other sources of leverage to keep the plant in service, and Secretary Granholm could prove a valuable ally in this respect," ClearView Energy Partners said Wednesday, citing two options: invoking the Defense Production Act to prevent plant closures, or seeking relief from the NRC.

The commission's December 2021 press release announcing its license transfer approval said it was "subject to [the NRC's] authority to rescind, modify or condition the transfer based on the outcome of any subsequent hearing on the application."

In February 2021, Michigan Attorney General Dana Nessel requested a hearing on whether Holtec has sufficient financial strength to decommission Palisades. "If the NRC were to grant that request, it could delay the transfer (and perhaps even 'rescind, modify or condition' it)," ClearView said.

No Takers for First Round of CNC Program?

DOE says 12 commercial reactors have closed early since 2013 because of economic pressures. Illinois, New Jersey, Connecticut, Ohio and New York have approved *subsidies* to keep plants operating within their borders.

DOE's CNC program will allow owners of commercial nuclear reactors at risk of closure to competitively bid on credits to keep them in operation. The IIJA requires applicants to prove their reactor will close for economic reasons and that the closure will result in increased air pollution. Credits would be allocated over a four-year period.

The department will accept applications for its first round of CNC funding through May 19. While the first cycle will be open to reactors that have already announced their intention to cease operations, future cycles — beginning with the second cycle in the first quarter in FY2023 — will "not be limited to nuclear reactors that have publicly announced their intentions to retire," DOE said.

According to the Nuclear Energy Institute, Palisades and PG&E's Diablo Canyon 1 and 2 are the only operating nuclear units that have announced retirement plans.

"PG&E is committed to California's clean energy future, and as a regulated utility, we are required to follow the energy policies of the state," PG&E spokesperson Suzanne Hosn told *RTO Insider*. "At this time, the state has not changed its position regarding the future of nuclear energy in California. The plan to retire Diablo Canyon Power Plant was introduced in 2016 and approved by the California Public Utilities Commission, the State Legislature and Gov. [Jerry] Brown in 2018."

Matt Crozat, executive director of policy development at NEI, said his group "will work with our members to ensure this program [CNC] is as effective as possible and continue to advocate for a production tax credit, which will offer greater certainty for owners to make long-term investments in their carbon-free nuclear plants." ■

FERC/Federal News

Higher Prices, Longer Queues Highlight FERC Market Report

By Michael Yoder

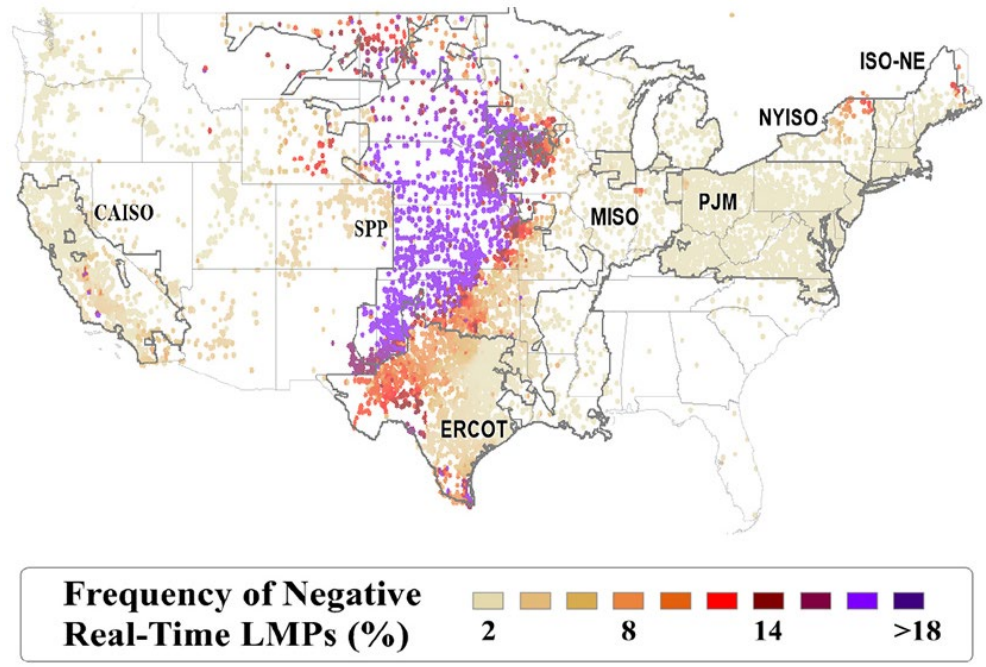
Rising natural gas prices and extreme weather pushed wholesale electricity prices higher in 2021, FERC said Thursday in its *State of the Markets* report.

Commission staff said changes in fossil fuel markets "drove price increases" across the board, including for natural gas, oil, propane and electricity, reversing trends of flat to declining prices for several years.

Henry Hub spot gas prices averaged $3.82/MMBtu in 2021, compared with $1.99/MMBtu in 2020. And gas prices have continued to increase in 2022, averaging $4.54/MMBtu through March 14.

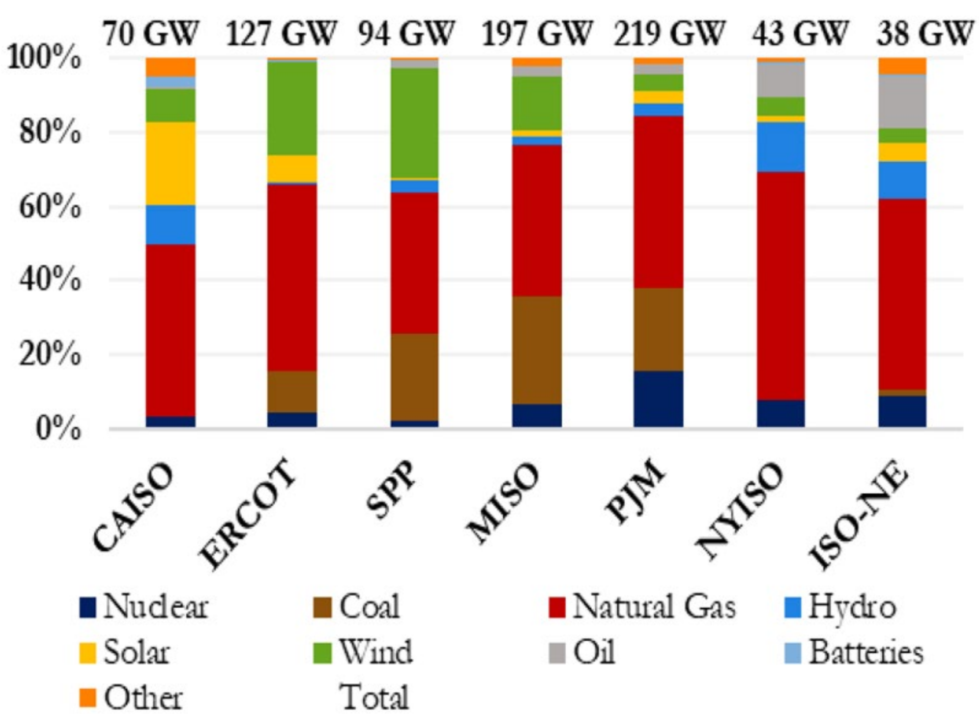
Average day-ahead peak prices increased last year at pricing hubs in each RTO and ISO, FERC said, up more than 45% on average and more than 100% in ISO-NE and NYISO. Commission staff said "stressed market conditions" during the February 2021 winter storm in ERCOT, MISO and SPP led to high prices that raised the average for the year.

Despite rising prices, FERC said, instances of negative prices in real-time markets continued to increase across various regions. In 2021, negative average hourly real-time LMPs occurred in about 3.5% of all hours across all RTO/ISO pricing points, compared with 3.1% in 2020.



Frequency of negative real-time LMPs in 2021 | *ABB Power Grids Velocity Suite*

SPP's negative prices averaged -$15/MWh over the year, and the RTO accounted for 41% of negative LMPs across all markets, the result of high wind output and low demand, as wind's share of total output jumped to 34% from 27% a year earlier. ERCOT accounted for 29% of negative prices at an average of -$12/MWh, while CAISO's share was 21% at an average of $-15/MWh.



Generation capacity by fuel type as of December 2021 in RTOs/ISOs | *FERC*

Generation Sources

Commission staff said higher natural gas prices also "increased the relative competitiveness" of coal-fired generation, with coal output rising 20% despite continued unit retirements. Across the RTOs/ISOs, the share of coal-fired output increased from 21% to 24%, while gas-fired generation decreased from 38% to 35%.

Generating capacity continued recent trends, as aggregate nameplate generating capacity grew from 768 GW in 2020 to 789 GW across all RTOs/ISOs. As of December, natural gas represented 46% of the capacity mix, followed by coal at 18%, wind at 14%, and nuclear at 8%.

FERC said some RTOs/ISOs experienced "relatively large changes" in capacity mixes, including an increase in battery storage capacity in CAISO from 0.7% to 3.2% of its capacity mix, an increase in wind capacity in SPP from 26.8% to 29.5% and solar capacity in ERCOT rising

FERC/Federal News

from 4.1% to 7%.

The largest portion of capacity retirements came from coal, the commission said, although the 6.5 GW of retirements in 2021 was the lowest number since 2014. FERC said the decline was partly driven by increased electricity demand and the higher natural gas prices.

Electric Transmission

About $15 billion of transmission projects came online in 2021, FERC said, with more than 1,000 line-related transmission projects entering service in the Eastern and Western interconnections. The commission said about one-fifth of the projects included new lines, and about a quarter of those projects were at or above 230 kV.

Market Hub	Average 2021	Median 2021	Difference	Median Price as a Percentage of Average Price
Socal-Citygate	$6.99	$5.05	$1.95	72%
PG&E-Citygate	$4.96	$4.78	$0.18	96%
NWP-Rockies	$5.21	$3.45	$1.76	66%
NGPL-Midcon	$6.79	$3.38	$3.41	50%
Waha	$5.80	$3.35	$2.45	58%
Henry	$3.82	$3.62	$0.21	95%
Chicago	$5.06	$3.48	$1.58	69%
Eastern Gas-South	$3.06	$2.81	$0.25	92%
Transco-Z6 NY	$3.48	$3.16	$0.33	91%
Algonquin	$4.51	$3.88	$0.64	86%

Average and median natural gas prices in 2021 | *Platts Gas Daily*

FERC highlighted the Western Spirit project, a 155-mile 345 kV line in New Mexico, costing $360 million and connecting more than 1,000 MW of generation in the state to the electricity grid operated by Public Service Company of New Mexico. The line was the largest new high-voltage transmission project and the only merchant transmission line to enter service in 2021.

The commission said Order 1000 transmission planning in each region "worked towards or completed a regional transmission plan" in 2021. CAISO's 2020-21 transmission plan identified three reliability-driven transmission projects estimated at less than $5 million, and two other transmission projects that could be replaced with battery storage. SPP identified 28 new projects with a total of 397 miles of new lines and 48 miles of rebuilt lines, costing $1 billion.

MISO identified 335 new transmission projects totaling 1,188 miles of new lines and 3,137 miles of upgraded lines, costing $3 billion.

PJM added to its Regional Transmission Expansion Plan with 118 new baseline transmission projects at an estimated cost of $920 million and 34 new network transmission projects at an estimated $48 million. Of the new baseline transmission projects, 52% were driven by transmission violations, 23% by generator deactivations and 25% by other NERC and PJM reliability criteria.

Electric Interconnection Queues

The commission said a changing resource mix with increasing renewables has made delays in generation interconnection queues a "persistent, growing feature" of the markets.

"There has been an unprecedented volume of requests to interconnect new generating facilities, which, in turn, has led to backlogs and delays in interconnection queues nationwide," FERC said in its report.

The RTOs/ISOs had 716,783 MW in interconnection queues at the end of 2021. Solar accounted for the largest portion (282,978 MW), followed by batteries (216,426 MW), wind (114,634 MW), hybrid resources (41,873 MW), DC transmission (19,620 MW), natural gas (9,972 MW), thermal (6,034 MW), combined cycle (4,804 MW), hydro (2,958 MW) and steam turbines (1,119 MW).

Of all the regions, CAISO had the largest amount of capacity by megawatts in its interconnection queue, with solar and batteries as the most common resource types. PJM had the second largest queue by capacity volume, with solar and batteries also comprising the largest shares. ■

CAISO/West News

FERC Reverts to Plan B on CAISO Capacity Mechanism

By Robert Mullin

FERC on Thursday reversed a previous decision allowing CAISO to include a 20% adder in the compensation formula for energy resource offers that exceed the soft offer cap for the ISO's capacity procurement mechanism (CPM) (*ER20-1075*).

The commission instead defaulted to approving an alternative proposal that omits the adder from the formula.

The D.C. Circuit Court of Appeals last December remanded the original May 2020 order approving the adder back to FERC after determining the commission's decision "was not the product of reasoned decision-making" (*20-1388*). (See *Court Overturns FERC on CAISO CPM Rates*.)


CAISO headquarters in Folsom, Calif. | *© RTO Insider LLC*

The CPM acts as an out-of-market "voluntary backstop" that enables CAISO to purchase backup resources to maintain reliability ahead of potential energy shortfalls, such as those caused by extreme weather or generation and transmission outages.

The ISO's tariff permits resources that do not already have a resource adequacy contract to submit bids into a competitive CPM solicitation to receive compensation up to the $6.31/kW-month soft offer cap. The soft cap is based on the going-forward costs of a reference unit, which include fixed operations and maintenance costs, *ad valorem* taxes, and insurance costs.

At issue in Thursday's order was a February 2020 filing in which CAISO proposed two separate plans for compensating resources that bid above the soft cap. In the ISO's "preferred" proposal, later accepted by the commission, a resource bidding above the cap could file an offer with FERC that includes its going-forward costs plus a 20% adder.

In arguing for the proposal, FERC noted, CAISO said the methodology: "aligns with how the existing CPM soft offer cap is derived; is consistent with prior commission guidance that CPM compensation should allow for some meaningful contribution to fixed cost recovery and provide incentives for resources to undertake necessary upgrades and long-term maintenance; and reflects the voluntary nature of CPM designations."

In the ISO's alternative proposal, a resource bidding above the cap would submit a FERC filing based on the same going forward costs but would not include the 20% adder.

"To date, no resource has ever sought to justify compensation above the CPM soft offer cap," FERC noted in Thursday's order.

In approving CAISO's preferred proposal in May 2020, FERC said "the inclusion of a 20% adder on top of demonstrated going-forward fixed costs is consistent with commission precedent on CPM compensation." The commission was specifically referring to its 2015 CAISO CPM decision, which found that the soft cap, which itself includes a 20% adder, would allow a resource sufficient recovery of fixed costs plus a return on capital to fund incremental upgrades and improvements.

The commission did not address the alternative proposal in that order.

'Substantial Differences'

But the California Public Utilities Commission (CPUC) sought rehearing of the May 2020 decision (*CPUC v. FERC*), contending that FERC erred by relying on its 2015 CPM order in accepting the adder. The CPUC argued that FERC should instead accept the alternative proposal.

The D.C. Circuit agreed with the CPUC in its ruling last year, finding that FERC's reliance on the 2015 CPM order "was not the product of reasoned decision-making," the commission said.

"In particular, the D.C. Circuit stated that the commission failed to grapple with the distinction between bids submitted below the soft offer cap, which were the subject of the 2015 CPM order, and bids above the soft offer cap," the commission wrote. "Thus, the court held that the commission erred by relying on precedent 'without recognition of the substantial differences between the two cases.'"

In reversing its decision Thursday, the commission acknowledged the D.C. Circuit's finding that the 2015 CPM order dealt with the derivation of the soft offer cap, "which is a resource-agnostic fixed rate based on the costs of a reference unit."

"Here, in contrast, we are evaluating resource-specific compensation for a resource with going-forward costs above the soft offer cap," the commission continued. "We find that the record contains no evidence regarding the actual cost recovery needs of specific resources with going-forward costs above the soft offer cap that demonstrates that an adder is warranted to ensure sufficient cost recovery and conclude that the findings in the 2015 CPM order need not govern here."

The commission further determined there was no evidence establishing why a 20% was appropriate, even if an adder was "otherwise justified."

The commission additionally found that the alternative proposal was consistent with FERC precedent, "indicating that compensation for voluntary backstop procurement mechanisms should, at a minimum, provide for recovery of a resource's going-forward costs." ■

BPA Set to Go Live in Western EIM in May

By Robert Mullin

The Bonneville Power Administration is on target to enter the Western Energy Imbalance Market (WEIM) in early May after agency executives met April 18 to make a final determination on its market readiness.

"BPA is on track to start participating in the Western EIM on May 3. Barring any unforeseen setbacks, we are a go," agency spokesperson Doug Johnson told *RTO Insider*.

The federal power marketing administration was initially scheduled to begin transacting in the WEIM on March 2, along with Pacific Northwest utilities Avista and Tacoma Power, but in January it decided to delay entry by two months because of customer training and technology issues. (See *BPA Postpones Western EIM Entry by 2 Months*.)

During a stakeholder meeting in late March, BPA officials said the agency was on course for the May 3 entry despite remaining issues related to market technology. But they noted that they would still meet privately April 18 to make a final decision, citing the need for a smooth integration to best serve stakeholders. (See *BPA 'Full Speed Ahead' on May EIM Entry, but Issues Remain*.)

The decision came without fanfare or notice on the agency's website. Johnson called it a "procedural, but important, step in our march to participation."

That march began in 2018 with a long series of stakeholder meetings leading to a September 2019 signing of an EIM implementation agreement, followed by last September's official decision to commit to joining the market. Over the course of those developments, BPA was already engaged in an exhaustive process to prepare its customer base of publicly owned utilities for the complexity of market integration.

BPA will be bringing its enormous volume of generating and transmission assets into the Western EIM when it goes live in the market on May 3. | © *RTO Insider LLC*

BPA will be the most significant entrant into the WEIM since the market commenced operation in November 2014 with PacifiCorp, and its two utilities' six-state territory, as its pioneering member.

With 15,000 miles of high-voltage transmission and 31 hydroelectric projects under its control, BPA will be the largest transmission and hydro provider in a market that now includes 16 members with territories spanning most of the Western Interconnection.

The agency controls about three-quarters of the transmission in the Northwest, making its system a vital link between the Northwest's massive network of hydroelectric dams and WEIM areas in California and the Southwest that are becoming increasingly reliant on solar energy. The flexibility of hydro generation is particularly well suited to firming up the variable output of intermittent renewable resources.

BPA also owns more than 50% of the capacity on the California-Oregon Intertie, which links the Northwest into the CAISO system in Northern California, and — along with the Los Angeles Department of Water and Power — is half-owner of the Pacific DC Intertie, a 500-kV line that delivers energy into Southern California. LADWP began participating in the EIM last year. ■

CAISO/West News

Sellers Urge FERC to Raise WECC Soft Price Cap

Commission Orders More Refunds of Premiums Earned in Summer 2020 Crisis

By Hudson Sangree

FERC on Thursday ordered five more entities to refund the premiums they earned from sales into CAISO during the severe heat wave of August 2020, which strained the Western grid to the breaking point and caused rolling blackouts in California for the first time in two decades.

In its decisions, the commission rejected pleas from three of the five sellers to raise WECC's soft price cap from $1,000/MWh to $2,000/MWh — the same as CAISO's soft offer cap for external transfers — to avoid repeating the situation in the future.

Mercuria Energy America, Tenaska Power Services and Shell Energy North America argued in their filings that the difference between the WECC cap in the non-CAISO West and the CAISO cap for external transfers is unreasonable. The difference puts sellers in the position of having to justify prices of more than $1,000/MWh for bilateral spot trades that occur outside CAISO, while the same trades internally into the ISO would not require justification to FERC, they argued.

FERC, however, said the issue was outside the scope of the proceedings.

"The issue in the instant proceeding is limited to Tenaska's [and other parties'] justification for [their] sales above the existing WECC soft price cap during which time a $1,000/MWh price cap was in place," FERC said. "The issue of the value of the WECC soft price cap is not before the commission."

FERC has been deciding, case-by-case, 21 instances in which sellers exceeded WECC's soft price cap for sales into CAISO on Aug. 18-19, 2020, as the ISO tried to head off more outages like those that occurred Aug. 14-15, when supply fell short of demand on hot evenings after solar went offline.

On April 18, it told PacifiCorp to refund an unspecified amount that exceeded index prices at the Palo Verde trading hub in Arizona on Aug. 18-19. (See related story, *FERC Tells PacifiCorp to Refund Premiums*.)

It did the same Thursday to Tenaska, Mercuria, Shell, Tucson Electric Power and, in a single decision, BP Energy and Mesquite Power (*ER21-42*, *ER21-46*, *ER21-47*, *ER21-51* and *ER21-57*). As it did with PacifiCorp, the commission found that the index prices at Palo Verde already reflected scarcity conditions and said the companies had failed to justify higher prices.

Palo Verde wholesale prices on the Intercontinental Exchange (ICE) peaked at a record $1,515/MWh on Aug. 18 and $1,750 on Aug. 19, according to data posted by the U.S. Energy Information Administration. Palo Verde's average index price for delivery during peak hours was $1,400.50 on Aug. 18 and $1,639.60 on Aug. 19, the EIA *reported*.

In contrast, the average price at Palo Verde from June to August 2020, excluding the high prices of Aug. 18-19, was $52/MWh, Southern California Edison and Pacific Gas and Electric said in FERC filings protesting the high prices.

"We find that Mercuria has justified making the identified August 2020 spot market sales at the relevant average index price, but it has not justified the amounts charged above the average index price," FERC said in a sentence similar to one in its PacifiCorp order and the four other decisions Thursday. "Accordingly, we direct Mercuria to refund the amounts charged above the average index price for the sales at issue within 30 days of the date of this order and file a refund report within 30 days of the refunds being issued."

As he did in the PacifiCorp decision, Commissioner James Danly dissented, questioning FERC's authority to negate bilateral contracts reached between buyers and sellers in a time of short supply.

"The legal question in this case is whether the commission can abrogate a contract to sell electricity pursuant to market-based rate authority when the contract price is above a commission-imposed 'soft' price cap absent a finding that the public interest so demands," Danly wrote. "The answer is 'no.'"

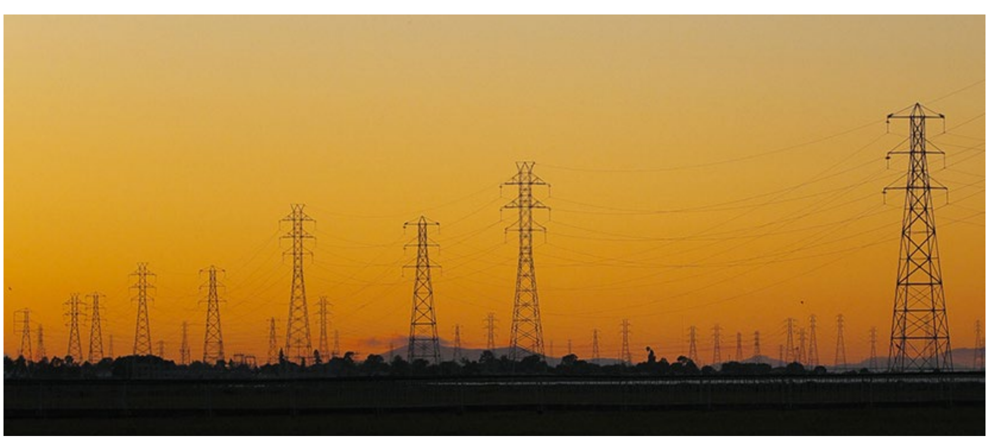
Instead, Danly said he would apply the presumptions of the 1956 cases *United Gas Pipeline v. Mobile Gas Service* and *FPC v. Sierra Pacific Power* (*Mobile-Sierra*) — which PacifiCorp and all five sellers involved in Thursday's decisions contended should govern the sales to CAISO on Aug. 18-19, 2020.

"I would apply the *Mobile-Sierra* presumption to the contract sale at issue and not require [the sellers] to pay refunds for the 'premium' amount above the price index that [the sellers] and the willing buyers freely negotiated because no showing has been made that the public interest is seriously harmed by the contract rate," he said.

The four other FERC commissioners found the *Mobile-Sierra* doctrine applied to sales in the proceedings but did not "prevent the commission from enforcing the requirement that sales in excess of the WECC soft price cap must be justified and are subject to refund."

"While the *Mobile-Sierra* presumption applies to these contract sales, this fact is not dispositive as to the question of whether [the] sales that exceeded the WECC soft price cap were justified or whether the commission can order refunds if it finds the prices for those sales are not justified," the majority said.

FERC was not "modifying the contracts, as would trigger application of the *Mobile-Sierra* presumption," it wrote. "Instead, the commission is enforcing requirements incorporated into the contracts" through orders establishing the WECC soft price cap and provisions in the sellers' market-based rate tariffs. ■



| *Shutterstock*

CAISO/West News

Extra Large PG&E Battery Project Goes Live

By Hudson Sangree

A major battery storage project built by Pacific Gas and Electric and Tesla is ready to help California deal with the reliability problems it encountered in the past two summers, PG&E said last week.

The utility said its 182.5-MW Elkhorn Battery facility had been "fully energized and certified for market participation by" CAISO earlier this month. The project's 256 Tesla Megapack battery units sit on 33 concrete slabs on Monterey Bay and can discharge 730 MWh of electricity for up to four hours, providing energy and ancillary services to the grid.

"We are ushering in a new era of electric system reliability and delivering a vision into the future for our customers with the commissioning of the Tesla Megapack system in Moss Landing," PG&E CEO Patti Poppe said in a news release. The utility owns and will continue to operate the units, it said.

The Elkhorn facility now ranks among the world's largest battery energy storage systems (BESS), and it sits beside the No. 1 largest, Vistra's 400-MW Moss Landing facility, along with Vistra's gas-fired Moss Landing Power Plant.

Moss Landing's racks of non-Tesla batteries were shut down after overheating incidents in September and February triggered fire alarms, set off sprinklers and melted equipment.

"Vistra is in the process of conducting repairs, commissioning facility systems and implementing enhancements to improve the original design of the facility," the company said in its initial findings on the September incident, released in late January about two weeks before the second incident occurred.

PG&E purchases Moss Landing's output, along with energy from four other large BESSes: the 200-MW Diablo Storage System in Contra Costa County, the 60-MW Coso Battery Storage in Inyo County, the 63-MW NextEra Blythe system in Riverside County and the 50-MW Gateway system in San Diego County. All went online in the last two years.

Batteries for Reliability

In June 2021, the California Public Utilities Commission ordered PG&E and the state's two other large investor-owned utilities, Southern California Edison and San Diego Gas & Electric, to procure 11.5 GW of new resources in the next three years to head off

PG&E's 182.5-MW Elkhorn Battery project was built next to Vistra's 400-MW Moss Landing battery system on Monterey Bay in California. | *EKM Metering*

shortfalls.

It ordered the IOUs and other load-serving entities to purchase another 3 GW of additional capacity through supply- and demand-side programs to prevent shortages during potentially extreme heat waves in the summers of 2022 and 2023. (See *CPUC Orders Procuring 3 GW of Capacity*.)

The transition from fossil fuels to clean energy in California and other Western states has increased wind and solar generation while coal and gas plants have retired.

Reliability problems arose during Western heat waves in 2020 and 2021, as solar power waned on hot summer evenings but demand remained high. CAISO ordered rolling blackouts in August 2020 and declared energy emergencies both years.

Responding to the CPUC orders, PG&E said it hopes to have 3,300 MW of in-state battery storage under contract by 2024. More than 955 MW of that is already connected, and about 1,400 MW of storage capacity is scheduled to come online in 2022 and 2023, it said. PG&E won approval Thursday from the commission to contract with nine more proposed battery storage *projects*, totaling 1,600 MW, that could start operating between 2024 and 2026.

CAISO said it has added more than 2,400 MW of battery storage since the 2020 blackouts and expects to add 2,100 more by June.

The ISO posted a *video* in March on "California's historic embrace of battery storage to support the grid as we transition to a carbon-free system."

"Last summer was a pivotal moment for battery storage, and we felt it was important to document the story and to share our experiences and the lessons we learned," CEO Elliot Mainzer said in a *statement* on the video.

"The potential of lithium-ion batteries had been talked about and anticipated for a long time," he said. "Now they are a central part of our toolbox to make sure that supply and demand are balanced, and the system remains reliable even during the most challenging conditions." ■

CAISO/West News

Siting Official Raises Habitat Concern over Wash. Solar Growth

By John Stang

A Washington Energy Facility Site Evaluation Council (EFSEC) member is requesting a look at the cumulative effect of solar farms on the state's Yakima River Valley after the agency recently received applications for two new projects in the area.

Yakima County in Central Washington is split west-to-east by the valley, with a U.S. Army training ground covering its north side and the Hanford Nuclear Reservation bumping against the northern half of the county's east border.

The area is predominantly shrub-steppe, a treeless, sagebrush-filled semi-desert that is home to unique vegetation and animals, including greater sage grouse, which are listed as endangered by the state. Yakima and the surrounding counties are host to many solar proposals.

Shrub-steppe still covers a good chunk of Eastern Washington, but farms and towns have been gobbling up land for more than a century. The shrub-steppe has shrunk from an estimated 10.4 million acres filled with unique birds and critters in the 19th century to 40% of that today.

North Carolina-based Cypress Creek Renewables submitted applications to the EFSEC on April 7 to develop two 80-MW solar farms — High Top and Ostrea — near the county's eastern border, just south of the Army training center.

At least two other solar farms are under consideration. EFSEC is considering whether it will approve the 80-MW Goose Prairie Solar project in the western part of the valley, while the Yakima County government is considering approval of the Black Rock solar farm near Goose Prairie.

Washington has a patchwork approach to approving wind and solar projects, giving renewable energy developers the choice of seeking permits from either the state or host county governments. If a developer chooses the state option, the EFSEC reviews the application and makes recommendations to the governor for a final decision.

During a briefing on the High Top and Ostrea projects April 19, EFSEC member Mike Livingston noted that the two projects are on a chunk of land that connects the Army's Yakima training center and the Hanford reservation, both of which protect shrub-steppe lands within their borders. Livingstone said the four projects are strung along the training center's southern boundary.

Livingston said solar farms might block unique species such as sage grouse from traveling from one area to the next. "We need a cumulative impact study [on the environmental effects]," he said. "We're going to lose the connectivity we have in this area."

Livingston is not the first Washington official to raise a red flag on the potential impact of solar on the state's shrub-steppe areas. Last September, Department of Fish and Wildlife staff and members of the state's Habitat Committee expressed concern that solar developers were neglecting to investigate sensitive species and habitat impacts before locking into project development sites. (See *Eastern Wash. Solar Projects Endanger Sensitive Habitat*.)

Cypress Creek expects construction of the two solar farms to take nine to 18 months. The company has requested an expedited approval process from EFSEC, meaning a public hearing must be conducted by June 6.

Cypress Creek has built roughly 8 GW of solar projects and owns and operates about 1.6 GW of solar across the country, the company's director of development, Tai Wallace, told the EFSEC. "We've developed quite a few projects of this scale." ■

Washington's shrub-steppe habitat has been reduced by more than half over the years in the face of farming and other development. | *The Nature Conservancy*

CAISO/West News

In Passing Bill to Kill Competition, Ariz. Lawmakers Rekindle Idea

By Elaine Goodman

The Arizona legislature passed a bill last week that would close the door to electric retail competition, but lawmakers indicated the conversation on deregulation is not over.

The state Senate on April 19 passed *House Bill 2101* on a 17-11 vote, with two senators not voting. The bill was transmitted Wednesday to Gov. Doug Ducey, who has five business days to take action.

Arizona Senate President Karen Fann | *Elect Karen Fann*

The same day as the Senate vote, House Speaker Rusty Bowers and Senate President Karen Fann announced the formation of a joint Ad Hoc Study Committee on Energy. The nine-member committee will meet after the close of the current legislative session, with a report due by Dec. 31.

Arizona House Speaker Rusty Bowers | *Bowers for AZ*

"The interim work of the committee will enable future discussion of the state's energy policies and the benefits and risks of energy 'deregulation' by providing a robust base of knowledge for policymakers and regulators," Bowers and Fann said in a joint statement.

The committee will discuss the reliability and affordability of diverse power generation, transmission and distribution resources. Arizona's governance over electric generation and transmission will be another topic.

Customer Choice

HB 2021 would repeal a 1998 law that was intended to give customers a choice of electricity service providers in the service territories of both investor-owned utilities and consumer-owned "public power entities" (PPE).

But rules that the Arizona Corporation Commission (ACC) adopted to allow competition were shot down by a 2004 appellate court ruling. And proponents of HB 2101 say competition should be rejected to maintain reliable electric service.

The bill, sponsored by Rep. Gail Griffin (R), comes as an application from Green Mountain Energy is pending before the ACC. Green Mountain, a renewable energy company, applied in August to provide competitive electric generation services within the territories of the state's largest investor-owned electric utilities, Arizona Public Service and Tucson Electric Power.

HB 2101 had its ups and downs in the legislature, as proponents scrambled to gather enough votes.

The House passed the bill in February on a 37-21 vote — after rejecting the bill earlier that month but passing a motion to allow reconsideration. (See *Retail Anti-competition Bill Hits Snag in Ariz.*)

Similarly, the Senate shot down HB 2101 in March, but passed a motion to allow reconsideration.

During last week's floor session, several senators commented on why they switched their vote or stuck with their previous decision.

Sen. J.D. Mesnard (R) said HB 2101 would remove a statute that was not working, and his vote in favor of the bill had not changed. Mesnard said he generally supports free-market policies and would have preferred to have a replacement for the deleted statute. He said he's hopeful that the interim committee will make progress in that regard.

"I'm going to be ... very interested in a replacement and be an advocate for creating more competition, more choices for our ratepayers and our consumers," Mesnard said.

But Sen. Lisa Otondo (D) questioned the timing of the interim committee. She remained opposed to HB 2101.

"Since when do we do an ad hoc committee and stakeholder meetings after the bill has passed?" Otondo said. "What a slap in the face. I vote 'no.'"

Sen. Tyler Pace (R), who voted against the bill last month but in favor of it last week, said he had spent dozens of hours studying the issue. Electric retail competition is different from competition in other retail markets, he said.

"This idea that somebody in the middle can just buy energy from whoever they want and then sell it to whoever they want without ever producing and without ever actually laying the wire is not, in my personal or business opinion, a reliable market," Pace said. "Because when something does go bad, there are some issues with that business model."

Transparency Concerns

Pace and Otondo both noted a lack of transparency around the bill.

"It was sold as a simple fix to remove defunct statutes from the books, so that the [Arizona] Corporation Commission couldn't deregulate the energy market and cause a catastrophe, like what we saw in Texas last winter," Otondo said.

Otondo said she later learned that the utility pushing the bill was involved in antitrust litigation. The utility had been sued by customers with rooftop solar, who were being charged up to 65% more than customers without it, she said.

Otondo didn't name the utility in the case but seemed to be referring to *Ellis v. Salt River Project*. HB 2101 would repeal a section of statute that says the Uniform State Antitrust Act applies to a PPE's competitive electric generation service and other services.

Outside of the legislature, the business group Advanced Energy Economy called "phony" claims that HB 2101 was needed to increase energy system reliability. The group opposes the bill.

The bill does "next to nothing to strengthen the power grid," AEE Principal Shelby Stults said. "It's just a way for utilities to reinforce their control over Arizonans' energy choices."

If Arizona wants to improve reliability, it should look into joining a Western RTO, Stults told *RTO Insider*. That would allow more renewable energy to be incorporated in a reliable manner, she added.

Mark Parsons, Green Mountain's vice president and general manager, said Arizona residents have indicated they want a choice of energy providers. The state has avoided aggressive governmental mandates for clean energy, he said.

Parsons urged Gov. Ducey to reject the bill.

"We are disappointed that HB 2101 repeals the statutory basis for us to receive a license to operate in the state," Parsons said in a statement following lasy week's Senate vote. "That is a legal prerequisite for us to be able to do business." ■

CAISO/West News

FERC Tells PacifiCorp to Refund Premiums

Prices in WECC Soared in Strained Grid Conditions of August 2020

By Hudson Sangree

FERC told PacifiCorp last week that it must repay premiums it earned on wholesale electricity sales during the August 2020 Western heat wave that forced CAISO to order rolling blackouts and pushed prices sky-high in other parts of the West (*ER21-60*).

PacifiCorp received premiums on top of the spot market's average index prices at Arizona's Palo Verde trading hub on Aug. 18-19, 2020, when CAISO was struggling to prevent more blackouts like those it ordered Aug. 14-15, and the Western grid was strained by record triple-digit temperatures. (See *CAISO Blames Blackouts on Inadequate Resources, CPUC*.)

Palo Verde wholesale prices on the Intercontinental Exchange (ICE) reached a record $1,515/MWh on Aug. 18 and $1,750 on Aug. 19, according to data posted by the U.S. Energy Information Administration. (The average price at Palo Verde from June to August 2020, excluding the high prices of Aug. 18-19, was $52/MWh, Southern California Edison and Pacific Gas & Electric said in FERC filings.)

Prices outside CAISO in the West fall under the Western Electricity Coordinating Council's (WECC) soft price cap of $1,000/MWh, which requires sellers to justify prices above the cap to FERC or to issue refunds. The process, instituted in response to the California energy crisis of 2000-01, is meant to avoid the exercise of market power.

Prices above the cap can be justified based on three frameworks — a production cost-based framework, an opportunity cost-based framework or an index-based framework — FERC said in guidance it issued in June 2021. (See *FERC Offers Guidance on Exceeding Western Price Caps*.)

FERC found that PacifiCorp had justified its prices on Aug. 18-19 using the index-based framework, in which a seller cites an index at a specific trading hub to justify prices that exceed WECC's soft cap. But FERC said the utility had failed to justify premiums it received above the index prices.

PacifiCorp defended the premiums by arguing it had seven bilateral spot market sales in August 2020 that exceeded the $1,000/MWh price cap. Four were brokered day-ahead transactions, with the price set by the buyer based on the Palo Verde day-ahead ICE index, and three were "direct transactions with counterparties that contacted PacifiCorp," the commission said.

"PacifiCorp [contended] that, to the extent the prices reflect a premium over the prevailing index price, the premium was set by the customer, and PacifiCorp had no visibility into the prevailing index price for these transactions until after the ICE day-ahead market closed," FERC wrote. "PacifiCorp notes that it served as a price-taker, which it argues the commission has recognized addresses any concern about the legitimacy of price formation."

Triple-digit heat strained the Western grid in August 2020, pushing electricity prices to new highs. | *Shutterstock*

The premiums, which raise the cost of wholesale electricity marginally above the index price, usually are added by customers to "secure energy during times of scarcity," the utility said.

FERC rejected the argument that the adders were justified.

"The Palo Verde price index already reflects scarcity conditions," it said. "PacifiCorp's attempt to justify prices above the soft cap by arguing it was a price-taker is insufficient."

"In these circumstances, the index-based framework only justifies prices up to the index price and … any premiums above the index must be justified in other ways, which PacifiCorp failed to do," FERC said. "Accordingly, we find that PacifiCorp has not provided adequate justification for the premiums above the index price."

The commission directed the utility to refund the premiums to buyers within 30 days and report back to the commission in another 30 days. The decision did not cite specific amounts of the premiums or the total amount that could be at stake.

Four of the five FERC commissioners approved the order.

Commissioner James Danly issued a dissent in which he said FERC was meddling with contracts to sell electricity at market-based rates.

"I would … not require PacifiCorp to pay refunds for the 'premium' amount above the price index that PacifiCorp and the willing buyers freely negotiated because no showing has been made that the public interest is seriously harmed by the contract rate," Danly wrote.

With its decision, FERC was putting sellers in an unworkable position, he said. The commission requires wholesalers to sell electricity, or it will investigate them for withholding and market manipulation, but then it negates market-based prices, he said.

"The *de facto* result is that we require PacifiCorp to sell, and then we require them to sell at our preferred price," Danly said. "No wonder there seems to be no end in sight to the supply shortage in California and, increasingly, the Western United States." ■

CAISO/West News

FERC Opens Probes on Western Tx Rate Protocols

Fail to Meet Standards of 2012 MISO Order, FERC Says

By Rich Heidorn Jr.

Lineworkers on PacifiCorp transmission line | *PacifiCorp*

FERC on Thursday ordered show cause proceedings on the transmission formula rate protocols of five Western utilities, saying they do not appear to provide customers and regulators the ability to challenge rates resulting from the formulas.

The commission opened proceedings under Section 206 of the Federal Power Act on the formula rate protocols of PacifiCorp (*EL22-38*), Idaho Power (*EL22-37*), Puget Sound Energy (*EL22-41*), Public Service Company of New Mexico (*EL22-40*) and Public Service Company of Colorado (*EL22-39*).

The commission said the companies' rate protocols did not meet the standards it has required since a 2012 order regarding MISO's transmission owners.

Under formula rates, the commission does not require transmission owners to make FPA Section 205 filings to update their annual transmission revenue requirements. Instead the utilities update the input data in the formulas.

"Safeguards need to be in place to ensure that the input data is correct, that calculations are performed consistent with the formula, that the costs to be recovered in the formula rate are reasonable and were prudently incurred, and that the resulting rates are just and reasonable," FERC said.

"Formula rate protocols provide the parties paying for transmission service specific procedures for notice of, review of, and challenges to the rates that they will be charged. In order to fulfill this purpose, formula rate protocols must afford adequate transparency to affected customers, state regulators or other interested parties, as well as provide mechanisms for resolving potential disputes."

The commission's orders Thursday found that each of the five utilities' protocols fell short on one or more of the following: "(1) the scope of participation (i.e., who can participate in the information exchange); (2) the transparency of the information exchange (i.e., what information is exchanged); and (3) the ability of customers to challenge transmission owners' implementation of the formula rate as a result of the information exchange (i.e., how the parties may resolve their potential disputes)."

In the 2012 MISO order, the commission ruled that the MISO's protocols inappropriately limited who could participate in the review processes and directed MISO and the transmission owners to revise them to include all interested parties, including customers under the MISO tariff, state utility regulatory commissions, consumer advocacy agencies and state attorneys general.

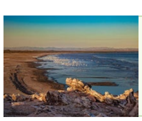
Similarly, the commission said Thursday that PacifiCorp's protocols do not define the term "interested party" to identify who is eligible to participate. "Without such a definition, PacifiCorp's formula rate protocols may not provide sufficient clarity and may provide PacifiCorp with the discretion to determine who is an interested party, and therefore appear to be unjust and unreasonable," the commission said.

In the Puget Sound order, the commission said the utility's protocols regarding challenge procedures lacked "straightforward and defined procedures" or "the level of specificity required" in the MISO standard.

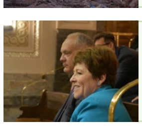
It ordered each of the utilities to respond within 60 days to either show cause as to why its protocols remain just and reasonable or explain what changes it will make to remedy the commission's concerns. ■

West news from our other channels

HECO Cancels Oahu Battery Storage Project — NetZero Insider



54 GWh EV Battery Plant Proposed for Lithium Valley — NetZero Insider



Wash. Looks to Boost Prospects for Winning Hydrogen Hub — NetZero Insider

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

CAISO/West News

NV Energy Issues Solicitation for New Renewables

By Elaine Goodman

NV Energy is seeking proposals for renewable energy projects to add to its portfolio, including solar, hydroelectric, geothermal, wind, biomass or biogas resources.

The projects must be at least 20 MW and be in operation by Dec. 31, 2025. The utility is also considering proposals for renewable energy resources coupled with energy storage systems.

The application deadline is May 18.

NV Energy will consider buying existing renewable energy resources, including solar and wind projects, through an asset purchase agreement (APA). The utility is also open to build-transfer agreements (BTAs) for new solar and wind.

The utility said it's not interested in APAs or BTAs for geothermal, hydroelectric, biomass or biogas projects. But proposals for power purchase agreements will be accepted for any of the renewable energy technologies.

NV Energy said it would evaluate proposals based on factors including the economic benefit to Nevada, job opportunities in the state and value to its customers. The utility noted that projects chosen through the RFP will still need approval from the Public Utilities Commission of Nevada.

The projects will help NV Energy meet the renewable portfolio standard set by the state. Under Senate Bill 358 of 2019, the percentage of electricity sold that must come from renewable resources is 29% this year, increasing to 50% in 2030.

More information on the request for proposals is *here*.

Tax Breaks Offered

NV Energy's solicitation comes as the Nevada Governor's Office of Energy continues to offer tax breaks to encourage renewable energy projects in the state. GOE administers the Renewable Energy Tax Abatement (RETA) program, which was launched in 2009.

GOE announced on Friday that five renewable energy projects approved for tax abatements last year will boost the state's renewable energy capacity by 1,166 MW. The state's existing capacity is just under 5,000 MW.

In addition, the projects are expected to pump about $1.5 billion into Nevada's economy.

"Our RETA program creates jobs, brings large economic investments into the state, and maximizes use of Nevada's abundant renewable energy resources to help reach our renewable portfolio standard of 50% of power generation from renewable sources by 2030," GOE Director David Bobzien said in a statement.

The five projects approved for tax breaks last year are Dry Lake Solar, Gemini Solar and Boulder Flats Solar in Clark County; Citadel Solar in Storey County; and Ormat's North Valley Geothermal Development Project in Washoe County.

So far this year, one project — Arrow Canyon Solar in Clark County — has been approved for abatements. GOE received an application this year for one additional project, Iron Point Solar in Humboldt County.

The RETA program reduces sales and use tax and property tax for renewable energy facilities approved for the abatement.

In exchange for the tax breaks, companies must agree to operate in the state for at least 10 years with a production capacity of 10 MW or more. At least half of their employees must be Nevada residents.

And hourly wages must be higher than the statewide average: at least 110% of average for operational jobs and at least 175% of average for construction jobs. ■

Ormat geothermal plant in eastern Nevada | *Ormat*

CAISO/West News

Western EIM Tops $2B in Benefits

More Participants Join as CAISO Plans Extended Day-ahead Market

By Hudson Sangree

CAISO's Western Energy Imbalance Market surpassed $2 billion in total member benefits in the first quarter of 2022, hitting the new milestone 20 months after it reached $1 billion in benefits.

The *WEIM* has grown substantially since it began in 2014 with only CAISO and PacifiCorp as members. It now has 17 participants, including most of the West's largest utilities.

CAISO attributed the rapid growth in benefits to the entry of new participants.

"This remarkable milestone is further evidence of the value of West-wide market coordination," CAISO CEO Elliot Mainzer said in a news release. "We are very appreciative of the partnerships established through the WEIM and look forward to working together to bring even greater value to the people we serve."

More than $172 million in economic benefits in the first quarter of 2022 pushed total benefits to $2.1 billion by February, the ISO said in results announced Thursday. It was the third best quarter on record for the EIM, falling only below the previous two quarters.

The WEIM saw unprecedented quarterly benefits of $301 million in the third quarter of 2021 — more than in all of 2019 and almost as much as in calendar year 2020.

Summer heat waves in California, the Desert Southwest and the Pacific Northwest triggered high demand amid tight supply, pushing electricity prices higher. Participants were able to access less-expensive supply through the WEIM.

As a result, the WEIM realized a record $739 million in benefits in 2022.

In the first quarter of 2022, "WEIM benefits accrued from having additional WEIM areas participating in the market and economical transfers displacing more expensive generation," CAISO said in its Q1 *benefits report*.

The Los Angeles Department of Water and Power, Public Service Company of New Mexico, NorthWestern Energy and the Turlock Irrigation District joined the WEIM in 2021.

Washington's Avista Utilities and Tacoma Power joined in April, and the federal Bonneville Power Administration is scheduled to go live in May. (See *BPA 'Full Speed Ahead' on May WEIM Entry, but Issues Remain*.)

CAISO was by far the biggest winner in Q1, realizing more than $63.5 billion in benefits. PacifiCorp came second with $26.4 billion in benefits, and the Balancing Authority of Northern California was third with $18.6 billion in benefits.

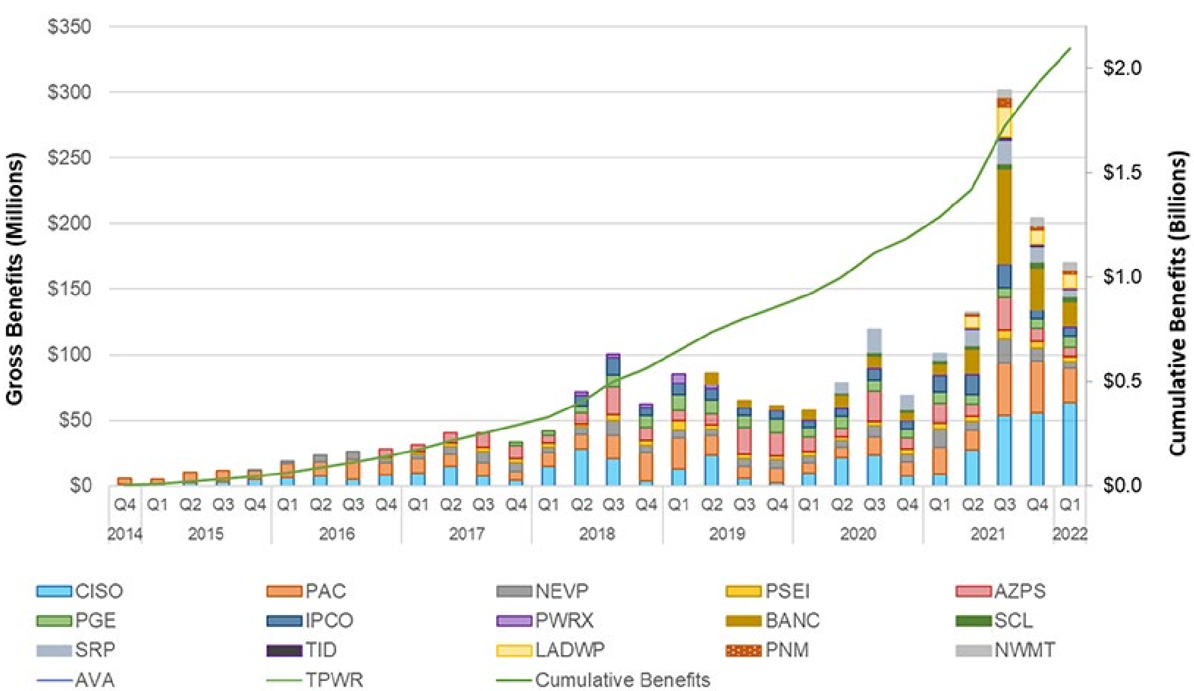
"The measured benefits of participation in the WEIM include cost savings, increased integration of renewable energy and improved operational efficiencies including the reduction of the need for real-time flexible reserves," CAISO said in its Q1 report.

By 2023, the WEIM is expected to have 22 participants serving nearly 80% of the electricity demand in the Western U.S. Its footprint already includes portions of Arizona, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming and British Columbia.

In a major effort, CAISO is seeking to expand the WEIM's real-time trading market with an extended day-ahead market (EDAM). Stakeholders have been meeting since January to hammer out key design elements of the EDAM, and CAISO plans to release a *straw proposal* on April 28.

The ISO is planning to finalize the market's design this year and to on-board its first participants in early 2024.

"The day-ahead timeframe is where the majority of energy transactions occur," CAISO said in its Q1 news release. "By optimizing diverse generation resources and transmission connectivity on a day-ahead basis across the WEIM's wide geographic footprint, market participants and consumers could realize even greater reliability, economic and environmental benefits." ■



A graph shows cumulative economic benefits for balancing authority areas in the Western Energy Imbalance Market from its inception in 2014 through the first quarter of 2022. | *CAISO*

ERCOT News

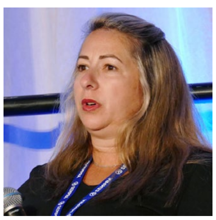
Overheard at GCPA's 2022 Spring Conference

The Gulf Coast Power Organization gathers for its 35th annual Spring Conference. | *© RTO Insider LLC*

Market Participants Frustrated with ERCOT's Market Redesign

HOUSTON — The Gulf Coast Power Association drew more than 400 attendees to its first in-person Spring Conference, and 35th overall, since 2019 and "that thing," as GCPA President Mark Dreyfus referred to the COVID-19 pandemic.

A pair of panels discussing regulatory and market changes since the February 2021 winter storm brought the ERCOT grid within minutes of a total collapse kicked things off. Panelists expressed frustration with the pace of change and the uncertainties of future market designs.



Michele Richmond, Texas Competitive Power Advocates | *© RTO Insider LLC*

Michele Richmond, executive director of lobbying group Texas Competitive Power Advocates (TCPA), said her members want to be compensated for the weatherization requirements and other obligations that have been placed on them.

"We focused on reliability, which was good early on for many years, but what we've seen is a shift to command and control," she said. "There's an unwillingness to let the market commit resources. We've seen a lot of mandates placed on generators, which we understand in terms of winterization and resiliency, but that is largely uncompensated so far."

Richmond called for a reliability standard, saying ERCOT's conservative approach to operations and heavy use of reliability unit commitments "have not done anything to incentivize new investment in ERCOT's dispatchable fleet."

"That hasn't done anything to incentivize existing resources, many of which are marginal," she said. "When the wind's not blowing and the sun not's shining, you definitely want my members to turn on. The economics for gas plants don't work. No one wants to lend you money to do that. Until we have a market that allows full recovery on dispatchable generation costs, we'll continue to see problems."

Bryan Sams, Calpine's executive vice president of governmental regulations, said the Texas Public Utility Commission's lowering of the operating reserve demand curve's system cap from $9,000/kWh to $5,000/kWh has been among several changes that have sent a dampening signal to the market and is taking money out of it.

Bryan Sams, Calpine | *© RTO Insider LLC*

WattBridge's Tina Lee agreed, saying, "We haven't seen the price impacts ripple through the market. For generators, we think the market signals have been muted, not only by ERCOT's conservative operations approach, but the other revenue channels' dispatchable generation needs. You want to incent new generation, not keep older generation around."

"Historically, in an energy-only market, all revenue comes from the market itself and a small portion from ancillary services," AB Power Advisors' Matthew Berend said. "Now, we've gone to an approach where there's more value in a smaller part of the market. That doesn't necessarily translate into more thermal generation being built."

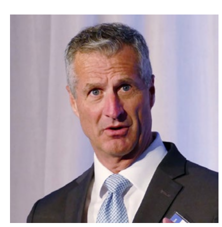
Last December, the PUC suggested several market designs to be evaluated for the ERCOT market's second phase of restructuring. Commission Chair Peter Lake asked staff to focus on a backstop reliability service proposal first and then a load-side reliability mechanism that some have likened to a capacity market — a four-letter word in Texas. (See *PUC Forges Ahead with ERCOT Market Redesign*.)

Bob Helton, ENGIE | *© RTO Insider LLC*

"All of them have their challenges, and there's no silver bullet," Berend said.

"If you're going to use the 'c' word ['capacity'], you may as well belly up to the bar and say we need a capacity market," ENGIE's Bob Helton said.

Jones: Will Stay as Interim CEO



Interim ERCOT CEO Brad Jone. | *© RTO Insider LLC*

Interim ERCOT CEO Brad Jones declined to use prepared remarks in addressing attendees, opening himself up to questions, but with a catch: only two-word questions.

"Retirement plans?" he was asked.

"Soon. Soon. Very soon," Jones said. "I have

ERCOT News

committed to the state, to the PUC, to politicians and others that I will be here as long as they need me, but only as interim CEO. I want to ensure they get that right person into this role."

Since Jones was chosen to lead ERCOT last April, his retirement plans have slipped from the fall to April, and now to June. According to industry insiders, the grid operator's Board of Directors has been looking at five to 18 candidates but is having trouble finding someone to fill what has become a political position. (See *ERCOT Board Chooses Jones as Interim CEO*.)

Responding to the one single-word question he received ("Cryptos?"), Jones said cryptocurrency and Bitcoin miners present a "fantastic" resource to the grid operator. He said the large, energy-intensive data farms used to solve the complex calculations that yield Bitcoin are "very price-responsive" and have the ability to quickly shut down operations, making them effective in balancing supply and demand.

Jones said one crypto load near ERCOT's control center in Taylor has about 700 MW of load, about half of Austin's average load. He said when he asked one legislator to imagine half of Austin — one of the deep-blue urban areas in an otherwise red state — disappearing from the grid, the lawmaker cracked, "Wow! That would be pretty cool."

"We need to work with these folks to bring them in," said Jones, who is expecting ERCOT's current crypto load of 1.5 GW to reach 5 GW in two years. "I see that as a positive, but we've got to think about some policy issues."

Jones was unable to provide an answer to "2032 peak?" But he offered a 2022 number: 80 GW. That would shatter ERCOT's record peak demand of 74.7 GW, set in 2019.

"I believe we have the resources to meet that kind of load. I'm excited about that," Jones said. He cited the "extraordinary growth" in renewables — 15 to 18 GW in a year — in pushing ERCOT's renewable capacity to 44 GW.

"As we speak, we expect to have about 28 GW of production from our wind generation," he said. "California bragged about 18 GW of wind the other day. … Let's show them our numbers."

MPs Ask for Continued Stakeholder Involvement

Several panelists brought up their concerns with ERCOT's stakeholder process, in which the Technical Advisory Committee endorses system changes and market rules before they go to the board.

The new board, completely changed since last year's storm, has created a Reliability and Markets Committee that some market participants worry will take them out of the governance process.

"The stakeholder process forces collaboration and improves outcomes," TCPA's Richmond said. "Our members are experts in running power plants, but not transmission and distribution utilities. Something is missed if you don't have expertise from other [market] segments. It's sometimes a messy process, and sometimes we argue … but the outcomes tend to be better. It's more thought out when you conduct it that way."

Pedernales Electric Cooperative CEO Julie Parsley, noting she served on the board for all of five months before it was essentially disbanded after the winter storm — "A little coincidental, isn't it?" she remarked — said market participants need to be involved at the board level.

"There's a non-electric industry view that market participants being a part of the market process is the fox guarding the henhouse," she said. "Nothing could be farther from the truth. It's checks and balances. No one's going to let anybody rob the henhouse, because we'll see that. I hope we can maintain that stakeholder interest. When you're working in the market, you see the functionality of the market."

"The stakeholder process has always been key. It's made this market," ENGIE's Helton said. "You're not going to invest if you don't have a voice and your access. I hope we keep going down a path of strong stakeholder involvement."

"That puts us all in a tough environment. I can't tell you where the board will be, but there's a strong belief in the value of the stakeholder process," Jones said. "That's my prediction. It's just a matter of getting that board into a place of comfort."

Jones also addressed outage scheduling, "the hot issue of today." He said the outage windows have become shorter, and with the increase of renewables in the market, the spring and fall shoulder months are also having trouble. On April 18, TAC unanimously rejected an ERCOT-drafted rule that would have complied with 2021 legislation to give the grid operator total control over approving or denying maintenance outages. (See *ERCOT Technical Advisory Committee Briefs: April 13, 2022*.)

"The discussion in the last several weeks, months in fact, is how many outages can we accept. How many megawatts can we take offline," he said. "The legislature gave us the ability to approve or deny all generation outages, which leaves all generators in a concerning spot.

Julie Parsley, Pedernales Electric Cooperative | © RTO Insider LLC

"That discussion leaves us at odds on some issues," Jones said. "ERCOT wants to hold as much control as possible over that, while generators want to control as much as possible, but I believe we'll get there."

Brouillette Stresses Energy Balance

Former U.S. Energy Secretary Dan Brouillette, now president of Sempra Infrastructure, said the world is seeing a rebalancing of the energy equation, not just in Europe with Russia's invasion of Ukraine, but across the globe.

He said he spent much of his time in Europe during the Trump administration warning Germany and other countries that they were too dependent on Russian gas.

"We could see what the ultimate goal was on the part of Russia. We recognize now that those admonitions of three to four years ago were correct," Brouillette said. "Environmental security is very important, but also important is economic security and financial security. You have to balance all three, or else you'll be in the position Germany is today."

Asked why the U.S. and its allies haven't been able to replace the gas coming from Russia, Brouillette said, "We can't simply snap our fingers and create the enormous facilities to produce natural gas. … We're going to be somewhat dependent on Russian gas. I just don't see how we replace that amount of gas in such a short time."

He said energy transition's historical arc has always been from less energy to more energy; from less dense energy like wood and biomass, to more dense sources like nuclear power.

"As it gets more dense, it gets cheaper and meets more needs. To grow economies, you need more energy," Brouillette said. "Whale oil is the only source we've taken out of the energy stack over the last 1,000 years. Everything else has been additive. [I've] always promoted an all-of-the-above strategy. You need to produce all these sources to keep the economies rolling."

Nuclear energy should remain a part of that mix, Brouillette said. One of the projects he is proudest of as energy secretary was enriching

ERCOT News

nuclear fuels.

"This specialized fuel allows the creation of these smaller reactors they're talking about," Brouillette said. "It allows for walk-away safe nuclear reactors. If the cooling system goes away, nothing happens. There's no [radiation] release. The reactor just shuts down."

Analytics Important to Glotfelty

Saying he never wanted to be a regulator, Jimmy Glotfelty, the newest member of the first four-person PUC, has embraced his role as overseer of the ERCOT market.

"We used to be brother and sister, and now the legislature has given us full regulatory oversight over ERCOT," Glotfelty said, referring to legislation passed in the wake of the February 2021 winter storm. "We can't let them be the entire analytical process for the commission. We have to have our own view. We have to be able to build out our own processes and our own thoughts."

Analytics are important to Glotfelty, who had a previous career as a wind developer. He hit the ground running when confirmed to the PUC, meeting with lawmakers after he had already been sworn in and participating in an ERCOT market redesign workshop.

"The cornerstone of [the market redesign's second phase] is analytical. We have to have the analytics," Glotfelty said. "I believe the market had some challenges in February [2021], but I don't believe the market failed. Components of the market failed. Components of winterization failed. Components of the gas system failed. If analytics prove that we don't know, we're going to have to understand a little more of it.

Pat Wood lauds Vicki Oswalt before handing her his namesake Power Star Award. | © *RTO Insider LLC*

"I'm eager to get into these analytics," he said. "I've been saying this since I got to the commission; it needs to be the cornerstone of how we analyze policies at the PUC."

Storage Key to ERCOT 'Pummeling' the Future

During an afternoon workshop on energy storage and its integration into the market, ERCOT staffer Kenneth Ragsdale remembered the first battery that connected to the system 10 years ago.

"It was 36 MW with about 15 minutes of discharge," he said. "We registered it as controllable load and generation storage. Unfortunately, we're still using that workaround, but we are trying to get to a single-model aspect."

Fast forward a decade and the grid operator has about 1.5 GW of storage capacity either installed or synchronized to the grid. Ragsdale thinks the number could approach 5 GW by year-end.

Sempra Infrastructure's Dan Brouillette (left) and Brian Lloyd enjoy a laugh during a "fireside chat." | © *RTO Insider LLC*

"We're pummeling the future here with the rapid integration of wind and solar energy. When you walk into an office and tell people you're in the storage business, they lean forward," said Pat Wood, former FERC and PUC chair and now CEO of Hunt Energy Network. "This particular piece of energy storage will absolutely be critical to that. The lack of storage requires us to do a much more complex market design."

Industry Vet Oswalt Wins Star Award

Vicki Oswalt, a 33-year veteran of the Texas electric industry, was honored by the GCPA's board as its 2022 recipient of the Pat Wood Power Star Award, given annually for the honoree's significant contributions toward advancing Texas' competitive energy markets.

"This award is as much about all the people I've worked with than it is about me," Oswalt said. "I don't want to name names, or we would be here all day. I really feel I share this award with all of you."

The award is named for Wood, who presented the award to Oswalt and recalled meeting her when he joined the PUC in 1995. The commission wasted no time in installing Oswalt as the first chief of the newly formed Office of Policy Development.

Oswalt joined the PUC in 1989 as a regulatory analyst. After joining Reliant Energy in 1997, she helped implement Senate Bill 7, which opened ERCOT's competitive retail market. Oswalt also spent time at Energy Future Holdings and its TXU Energy and Luminant subsidiaries before retiring earlier this year as senior vice president of regulatory affairs for Sharyland Utilities.

The GCPA board also took advantage of the opportunity to present ExxonMobil's Alexandra Williams with its 2021 emPOWERing Young Professionals Award. The award is presented annually to an individual under the age of 40 who has achieved excellence in the electric power industry. Williams actually won the award last year, but she had laryngitis during GCPA's 2021 virtual Fall Conference, so she could not verbally accept the award. (See "Industry Leaders Honored," *Overheard at the 2021 GCPA Fall Conference*.)

A NERC-certified reliability coordinator, Williams has contracted more than 800 MW of renewable power purchases, and managed the two largest demand response portfolios and more than 15 GW of power generation. ■

— Tom Kleckner

ERCOT News

Overheard at RE+ Texas Conference

Solar providers line one of RE+ Texas' several exhibit halls. | © RTO Insider LLC

Texas at Center of the Renewable Industry's Growth

SAN ANTONIO — The newly rebranded RE+ Texas conference last week attracted hundreds of renewable energy professionals out to gain information on the latest trends and policies affecting the Texas market.

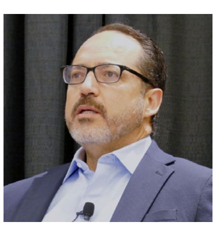
The event couldn't have been hosted in a more appropriate state. According to the event's presenters, the Solar Energy Industries Association and Smart Electric Power Alliance, Texas:

- produces more electricity than any other state, generating almost twice as much as Florida, the second-highest producing state;
- ranks sixth nationally for solar installations with 2.5 GW and expects to install another 4 GW of capacity over the next five years, which would make it the nationwide leader in solar energy; and
- leads the nation in wind-powered generation and produced one-fourth of all the U.S. wind-powered electricity in 2017.

Milwaukee-based Sunrun has been involved in the Texas market since 2017, with its main footprints in Dallas, Fort Worth, Houston, Austin and San Antonio.

Amy Heart, Sunrun | © RTO Insider LLC

"Texas is well positioned," said Amy Heart, Sunrun's vice president of public policy. "It's an interesting market, because you can actually have conversations about the value of solar and you can work in that competitive market space."



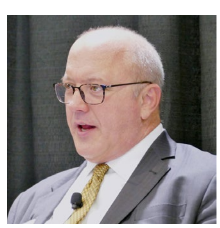
Texas State Sen. José Menéndez | © RTO Insider LLC

Texas Sen. José Menéndez (D), who has represented San Antonio for 25 years either in Austin or on the City Council, said he was relieved that last year's legislation in the wake of the devastating winter storm left renewable resources somewhat unscathed.

"I was really worried there was going to be a greater attack on the industry than thermal [generation]. I don't believe we had anything that came out of [legislation] that would hurt renewables," he said. "There was a desire for renewables to play a greater role in paying for reliability ... 'because they're not reliable, they should pay more into the grid for reliability.'"

Menéndez — whom Lynnae Willette, EDF Renewables' director of regulatory and legislative affairs, referred to as "solar champion" — said he found it "laughable" that renewable resources taking advantage of federal tax credits have been criticized for putting traditional energy sources at a disadvantage.

"We've been giving tax breaks to the oil industry for years in this state," he said. "It's been the investment that the renewable industry has been making in the desolate places of West Texas and all across the state that has produced economic benefits for Texans. Typically, renewable energy is seen as the space of the center-left or left. It shouldn't be a partisan issue."



Michael Jewell, Jewell & Associates | © RTO Insider LLC

Consultant Michael Jewell, a former Republican government staffer and now a board member for Conservative Texans for Energy Innovation, agreed. He said forming the organization took a lot of "cajoling," but that the end justifies the means.

"We need that conservative voice. We need a conservative voice that has the credentials, but also gets it," Jewell said. "The true conservative that supports the innovation in the energy space is talking about why clean energy matters from a conservative perspective. More and more conservatives are recognizing that rooftop solar is not only about a clean environment; it's about resiliency. It's about having self-control over your energy."

Panelists Debate New Market Designs

ERCOT market experts engaged in an entertaining discussion on the market redesign proposals being considered at the state's Public Utility Commission.

Beth Garza, R Street | © RTO Insider LLC

Beth Garza, the grid operator's former market monitor and a senior fellow at R Street Institute, stressed the need for resource adequacy requirements paired with load-serving entities' obligations to

ERCOT News

meet reliability requirements. She was part of a team funded by NRG Energy and Exelon that filed *one of several proposals* last fall that are being considered by the PUC. (See *Study Suggests Texas LSEs Can Provide Reliability*.)

"In a world we're heading toward — in a world where variable energy resources, zero-marginal-cost resources are becoming even more prevalent — the market will not provide enough revenue for all that capacity that needs to be recovered," Garza said. "Generators need to get paid, but what they're getting paid today are through energy prices with no scarcity and energy prices with scarcity, which can be a handful of hours a day. Historically, the newest units added to the system were the most efficient, and so that provided a gap to fund the less efficient stuff. That's no longer the case with zero-marginal-cost resources."

Jay Zarnikau, a research fellow at the University of Texas' economic department and one of the authors of a *report* for the PUC on the storm's enduring blackouts, said he agreed with Garza's analysis, but not the focus on capacity.

"One of the things we found out with [Winter Storm] Uri was we had a lot of capacity, but that capacity didn't work. There was snow on the panels, wind turbines that couldn't turn," he said, although the report indicates every source of generation failed. "I don't like to measure reliability with a goal of capacity. I like to use the existing assets more efficiently. I don't think the answer is building more power plants; there are a lot of things we can do with existing production, better things we can do with pricing, things we can do with reserve margins and capacity. I like to do things to get more efficiencies out of the market."

Alison Silverstein, former FERC and PUC staffer and consultant with an eponymous practice, offered a "sobering dash of realism."

"Our legislature, our political governing class in the state and the PUC is enamored of the concept of dispatchable resources and of command and control," she said, "because by God, if you can turn the knobs, maybe those plants won't freeze up."

Silverstein said their plan to increase reliability by building more dispatchable gas plants won't work well because there is a lack of planned gas generation.

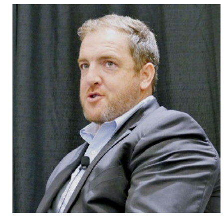
"There's so few gas plants in the interconnection queue today that you could raise the level of payment of prices for gas plants and you wouldn't get a lot more gas plants online anytime real soon," she said. "So, great concept. Let's raise prices really high so that those prices go to the people who are already running inefficient gas and oil and coal plants today. That's not a solution that makes me happy because it won't improve day-to-day reliability, nor will it save costs or will it achieve any efficiencies. All it will do is fatten up the existing fleet."

University of Texas' Jay Zernicke (left) and Alison Silverstein share a light moment. | *© RTO Insider LLC*

Integrated DERs Pose a Challenge

Panelists discussing distributed energy resources' opportunities and challenges in the state were bullish on the customer-site solar batteries and electrification's ability to meet grid and resilience needs.

Sterling Clifford, Sunnova's manager of government affairs, said policy changes are either a result of "a cool thing to do" or a solution to a huge problem.



Sterling Clifford, Sunnova | *© RTO Insider LLC*

The grid "is not going to be able to keep pace with demand as we electrify our homes, our vehicles and our businesses. The system can't keep up, and the problem is only going to get bigger," he said. "If we don't take advantage of every solution to that problem, we're not going to be delivering benefits to homes and businesses."

"The system as a whole needs more flexibility. It needs more resources that can participate in just ensuring the grid is reliable," said 17-year ERCOT executive Warren Lasher, who struck out on his own with Lasher Energy Consulting last summer.

PUC Commissioner Will McAdams on Wednesday *filed a memo* calling for integrating more DERs into the market. ERCOT currently has nearly 3 GW of distributed generation resources, adding more than 740 MW last year alone.

"Participating in that process is going to be critical for us as an industry," Clifford said. "It will create a pathway where we do all the things we do now, but we can make sure there are channels for growth as the technology improves as well."

"We have an incredible market here. It's incredibly vibrant; it's incredibly strong; it's incredibly competitive," Lasher said. "But it's dealing with changing technologies. … The way the market works, it puts us in a position where the commission doesn't have a whole lot of knobs and dials to kind of adjust things. In the end, to the extent you're relying on the competitiveness of the market and wholesale deregulated investment, it doesn't give you a lot of opportunities to have incentives for some of these new technologies.

"We've got these new resources, and we want to put these new resources into the system that we have in place, but where we are is this system is changing at an incredibly rapid pace," he said. "The problem that we have is we need to be thinking about how these resources fit into where we're going to be five years from now, 10 years from now. Storage is going to fundamentally transform how we think about energy. Getting everything to fit together is just an amazing challenge at this point." ■

— Tom Kleckner

ISO-NE News

ISO-NE Defends Order 2222 Filing

By Sam Mintz

Environmental advocates and renewable industry groups continue to battle ISO-NE over its Order 2222 filing. | *Shutterstock*

ISO-NE defended its Order 2222 compliance filing on Wednesday, providing FERC its response to protests from environmental groups, renewable energy industry organizations and Massachusetts' attorney general.

ISO-NE's response to the federal order requiring RTOs to allow distributed energy resources to participate in wholesale markets has frustrated advocates, who say it fails to meet the goals laid out by FERC and would limit the availability of behind-the-meter resources to engage the market. (See *'Beautiful Symphony' or Bust on Order 2222, Advocates Say*.)

That frustration led to a number of protests arguing, among other things, that the order doesn't allow sub-metering, gives utilities too much time to review aggregated DER proposals and that its seven participation models for DERs proposed by ISO-NE aren't in compliance with Order 2222. Among those protests was a *combined filing from environmental groups* and another from *several industry organizations*.

FERC's rules technically don't allow ISO-NE to file an answer to protests, but the grid operator is asking for an exception.

In its *filing*, ISO-NE argues that it has fully met the requirements of the FERC order.

Metering

Order 2222 gave RTOs flexibility in how they can establish market rules for metering DERs, ISO-NE said in its response.

And the alternatives that advocates proposed in their protests could lead to double counting of services, shift costs to customers without DERs and require new metering infrastructure, the RTO argues.

The filing also cites a previous FERC order in saying that metering at the retail delivery point (as proposed in the compliance filing) is appropriate for demand response resources, rather than the device-level sub-metering proposed in the protests.

And finally, it says FERC should reject the intervenors proposal to allow third-party metering because of double counting and data validation issues.

Utility Review

The protestors also challenged ISO-NE's rule giving utilities 60 days to review DERs seeking to participate as part of an aggregation.

FERC's order specifically allowed a 60-day review period, ISO-NE wrote, so the environmental groups' request to shorten it should not be granted.

It gave a similar response to the industry groups' proposal that the period for utilities to review the modification of DERAs be shortened.

Participation Models

Perhaps most significantly, ISO-NE defended its seven participation models for DERAs wishing to take part in the models.

"The standards and requirements associated with each participation model in the Compliance Proposal are tailored to the products and services offered in the New England Markets," ISO-NE argued, and they meet the requirements of Order 2222.

Specifically, the response provides defenses of ISO-NE's continuous storage facility model, its settlement-only DERA model and changes to the existing Alternative Technology Regulation Resource. ■

ISO-NE News

Mass. Breaks from New England States on ISO-NE MOPR

By Sam Mintz

Massachusetts Energy and Environmental Affairs Secretary Kathleen Theoharides is leading the state in breaking from the rest of New England over ISO-NE's MOPR plan. | *Office of Governor Charlie Baker*

Amid a flood of comments last week on ISO-NE's proposal to delay elimination of its contentious minimum offer price rule, the most significant came from Massachusetts' top energy official (ER22-1528).

In a *letter* to FERC, Massachusetts Energy and Environmental Affairs Secretary Kathleen Theoharides expanded on the state's position, separating it from a coalition of the other New England states by calling on the commission to order the immediate removal of the MOPR.

"The commonwealth supports elimination of the MOPR but opposes an approach to elimination that prolongs the effects of the MOPR any longer than necessary," Theoharides wrote. "I urge the commission to use its regulatory authority under the Federal Power Act to direct changes to the ISO-NE's tariff by taking the fewest risks and least time necessary to eliminate the MOPR."

The New England states, through the New England States Committee on Electricity (NESCOE), had previously said that they would not oppose the two-year transition proposal put forward by the grid operator. It was a near-consensus (barring New Hampshire) position that has been cited repeatedly by ISO-NE, serving as a powerful message to other stakeholders and helping secure enough votes for the grid operator's proposal to ultimately pass through NEPOOL.

NESCOE reiterated its position in a *comment*, noting that its lack of opposition to the delay comes with the major caveat that the group will "fiercely oppose any attempts to extend the deadline for full MOPR reform beyond [Forward Capacity Auction] 19."

And Connecticut stayed in line with the NESCOE position, writing in its own *comments* that it does not oppose the delay because of worries about the "fragile state of the ISO-NE markets" and the possible negative effects of immediately removing the MOPR.

NESCOE declined to comment specifically on Massachusetts' new stance, saying that its views are reflected in the filing.

Protests and Support

The states' comments were among more than 200 submitted by advocacy groups, companies and individuals ahead of last Thursday's deadline on an issue that has gathered an unusual amount of scrutiny for the grid operator. (See *ISO-NE Sends MOPR Filing to FERC, Teeing up Big Decision*.)

A large consortium of environmental groups *filed a protest* asking FERC to order the MOPR be immediately removed.

"ISO-NE's [FPA] Section 205 filing offers the commission a chance to reconsider the unjust, unreasonable and unduly discriminatory rates that have resulted from the string of commission orders establishing ISO-NE's current tariff and MOPR rules," the groups wrote.

They said that keeping the MOPR in place for another two years will keep state-sponsored clean energy resources from clearing the capacity market and impose higher costs on consumers. They also challenged the credence of the reliability worries that have been cited by ISO-NE in extending the MOPR for two more years.

"Despite the ISO's substantial analytical capabilities and unique access to data — all funded by ratepayers — the ISO's case for reliability needs contained in its filing is limited to extremely general and speculative concerns about capacity accreditation, retirement of existing resources and potential commercial-operation delays applicable to all new entry in the region," the protest says. The American Council on Renewable Energy also filed its own separate *protest*.

Writing in support of the ISO-NE proposal were groups representing power generators and suppliers in New England and nationally, as well as several individual companies.

"The filing strikes a just and reasonable balance among a wide range of stakeholder and ISO-NE interests; is supported by a large majority of NEPOOL, including supporting votes from each of the six NEPOOL sectors; and is the product of input from, and is unopposed by, the New England States Committee on Electricity," the New England Power Generators Association *wrote*. "This alignment is remarkable on a market design issue that has compelled countless pleadings and disagreements among stakeholders and policymakers in New England."

The Electric Power Supply Association *concurred* and called the filing a "balanced set of revisions."

Filing together, the three generation companies that had originated the proposal to delay elimination of the MOPR by two years — Calpine, Cogentrix Energy Power Management and Vistra — defended the ISO-NE proposal as a necessary safeguard that was developed and approved through a sturdy stakeholder process.

"It is critical that ISO-NE adopt a transition mechanism that appropriately balances the various interests of consumers and investors while making it easier for sponsored policy resources to enter the [Forward Capacity Market]. The specific transition mechanism ISO-NE has proposed accomplishes those goals in a just and reasonable manner," they *wrote*. ■

ISO-NE News

Maine Legislature Gives Final OK on Utility Accountability Bill

Consumer-owned Nonprofit Provision Removed in Amendment

By Jennifer Delony

Maine Senators voted 19-10 Monday to pass Gov. Janet Mills' utility accountability bill with an amendment that removed language related to a consumer-owned nonprofit takeover of the state's investor-owned utilities.

The bill (*LD 1959*) directs regulators to seek bids for an IOU if it "consistently fails" to meet specific service standards. Legislators, however, did not include the governor's proposal for an administration-led committee to supply regulators with a bid from a consumer-owned utility (COU).

Mills introduced her utility bill after vetoing a similar bill last year that provided for a COU takeover without a competitive bidding process. LD 1959 passed the House of Representatives last week and now goes to the governor for approval.

As amended, the bill strengthens a provision for imposing an administrative penalty on IOUs for not meeting service standards in a calendar year, allowing for up to a $1 million fine per year. Persistent problems with service would trigger an adjudicatory hearing by the Public Utilities Commission to determine if divestiture to a "qualified buyer" is warranted. The commission would adopt standards for service quality, customer service, field service and interconnection of distributed energy resources.

The amendment added an integrated grid planning provision that supports a "transition to a clean, affordable and reliable electric grid in a cost-effective manner."

Utility regulators would be required to initiate a proceeding this fall to identify priorities that the state's IOUs must address in grid planning to help with that transition. Plans would include load forecasts, energy supply data, hosting capacity analysis, emerging grid technologies analysis, and equity and environmental justice analyses.

The amendment also adjusts Mills' proposal for utilities to file 10-year action plans to address the effects of climate change on grid assets from every two years to every three years.

"For too long we've failed to take action to address the failures of [Maine's IOUs]," said Sen. Stacy Brenner (D), lead sponsor of the bill, in a statement. Supporters of the bill point to historically low customer satisfaction metrics for Central Maine Power and Versant Power as justification for new service standards.

"This bill will ensure our utility companies put the needs of their customers first, that we're planning a power grid that is reliable and ready for Maine's independent energy future and that we help protect ratepayers," Brenner said. ■

Maine's legislators sent a bill to Gov. Janet Mills that would require regulators to develop plans for Central Maine Power and Versant Power to transition to a clean and affordable electric grid. | *Versant Power*

Midwest Energy Policy Series Addresses JTIQ Projects

By Amanda Durish Cook

MISO and SPP planners discussed the prospects of the Joint Targeted Interconnection Queue (JTIQ) projects during a session on infrastructure in the Missouri Energy Initiative's Midwest Energy Policy Series on April 19.

The seven projects in the $1.65 billion JTIQ portfolio are projected to resolve 48 reliability constraints and enable 11.1 GW of generation projects on SPP's side of the RTOs' seam and 17.5 GW of projects on the MISO side. The grid operators are hoping to receive the portfolio's approval by the second half of 2023, but they first must hammer out a cost-allocation methodology for the projects. (See *Now, the Hard Part: MISO, SPP Tackle JTIQ Cost Allocation*.)

"Unfortunately, we're not quite over the hump just yet. … We still have to figure the cost allocation to get these projects built," MISO Director of Resource Utilization Andy Witmeier told attendees.

Left to right SPP's Neil Robertson, MISO's Andy Witmeier and RTO Insider's Rich Heidorn | *MEI*

But both he and SPP's Neil Robertson, senior engineer of interregional relations, agreed that the study has been a success so far.

Robertson said planners were given a "free hand" in developing the study, "unique" among their interregional planning, which is usually scripted according to their joint operating agreement.

Witmeier agreed that planners were given a "blank page" to study the transmission needs of multiple generator interconnection cycles in the RTOs' queues.

Robertson said staff are trying to distribute costs based on the projects' beneficiaries, including MISO load, SPP load, and interconnection customers on either side of the seam whose generation will flow between the footprints.

"We continue the theme of the free hand in developing innovative solutions here," Robertson said of a cost-sharing design.

Witmeier said the grid operators' "guiding principle" of cost allocation will underscore the study's aim to maximize capacity additions. He said while the two might consider assigning costs based on added benefits like increased flows or more economic dispatch, they will be secondary and fleshed out later.

Witmeier also said project duplicates between the JTIQ and MISO's regional long-range transmission plan (LRTP) emphasize the projects' necessity. MISO has decided that it will independently pursue 345-kV LRTP projects in North Dakota and Minnesota before they are included in the JTIQ study. With the two projects, the JTIQ portfolio would be reduced to about $1 billion. (See *MISO Stakeholders Uneasy Over Long-range Tx, JTIQ Overlap*.)

"It certainly means that it's transmission that needs to be built now," Witmeier said of the LRTP projects. He said MISO has decided it needs the lines now, rather than later, to reliably serve load, support new generation, and keep pace with members' changing resource portfolios.

"We see benefits to these projects now," he said, noting that MISO already has worked out a cost-allocation design for the LRTP.

The planners acknowledged that the RTOs' results differ in how much new generation the JTIQ portfolio can facilitate. They said they used their respective planning models and generation dispatch assumptions to estimate gigawatt amounts.

"This was not what in the planning world we would call a common model study," Robertson said. "We did not collectively develop a single model that both organizations performed analyses on. We levered our regional model processes."

Had the RTOs tried to develop a common model, Witmeier said, "we'd still be doing the analysis today." He said creating a common model would be too time-consuming to meet their 18-month study timetable.

The planners also said the JTIQ study forced them to pivot from a "first-come, first-served" queue priority approach to a "first-ready, first-served" method.

Witmeier said MISO is still processing applications that were submitted in 2019 and 2020, while SPP is working on interconnection requests submitted in 2017. In some cases, MISO interconnection customers that entered the queue in 2018 are already signing generator interconnection agreements, the final step before grid access.

"It doesn't make sense for our projects to be held up by the projects in SPP's queue that still haven't been sited yet," Witmeier said. Robertson agreed that the grid operators must "evolve" beyond the instinct that whoever lines up first must finish first.

Panel moderator and *RTO Insider* Editor-in-Chief Rich Heidorn Jr. asked whether MISO and SPP are worried about state commissions opposing JTIQ transmission projects.

"I feel like MISO and SPP have both been very successful in recent years in getting a significant amount of transmission expansion projects built," Roberston said. "I can't necessarily say it hasn't been without its bumps in the road, but we have shown a consistent track record of success over the last, let's say, decade or so."

MISO News

Robertson acknowledged that MISO's and SPP's footprints contain multiple states with right-of-first-refusal laws and the RTOs "will have to account for that."

"We have a number of conversations ahead of us in getting to a complete cost-allocation methodology and accounting for the nuances around actually getting these facilities sited and constructed is certainly going to be a prominent component," he said.

Heidorn also asked whether MISO was considering speeding up plans for a project that could increase MISO's transfer capability between its Midwest and South region. He noted MISO Midwest came up short on supply in this month's capacity auction. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

Witmeier said MISO is discussing the potential of accelerating the study of potential projects. The RTO is not planning to address Midwest-South transfer projects until the final cycle of its four-part LRTP. (See *MISO Seeking New Tx Cost Allocation for Major Buildout*.)

MISO may "pull that trigger and move that forward," Witmeier said.

However, he said, any approved transmission project is years away from allowing increased flows between the regions.

"That's not going to be an immediate fix," he said.

Experts Expect Carbon Capture, Storage, Renewables

Other series panelists predicted a raft of renewable generation, carbon capture and energy storage ubiquity in the Midwest, but they worried that lengthy interconnection queues will hold up necessary capacity.

Evergy's Kayla Messamore said renewable technologies can't singlehandedly meet all capacity needs. She predicted carbon capture, some nuclear generation and hydrogen generation will make up "that last 20%" of fuel resources that need to be "a little more firm."

When asked what she would spend $1 billion on over the next five to 10 years to accelerate the energy transition, Messamore said she'd invest in a combination of wind and solar, longer-duration storage, and demand side management.

Anna Sommer of the Energy Futures Group said spiking energy prices should have more utilities focusing on demand response to control rates.

Messamore also noted that prohibitively high IC costs are limiting the generation that could interconnect to the system. She said new transmission is needed to integrate renewable generation and prevent energy price separation between regions that can't access low-cost renewable energy.

Great Plains Institute's (GPI) Patrice Lahlum said carbon capture and sequestration is poised for major growth.

She said that currently, 12 commercial-scale U.S. facilities capture about 25 million metric tons of CO_2 annually. She said the nation's growing carbon-management industry could deliver a 13-fold increase in CCS capacity by 2035, resulting in 210-250 million metric tons of annual emissions reductions.

Lahlum said GPI has tracked nearly 90 announced projects since 2018, with more than 50 announcements in 2021 alone.

She noted that the Infrastructure Investment and Jobs Act contains more than $12 billion in funding for carbon management. She said it's up to the industry to work together and create successful projects that capture emissions as intended.

Consortium for Battery Innovation's Matthew Raiford predicted a flourishing market for lead acid batteries. He said the advanced batteries are easily recyclable, keeping materials in a stable supply chain.

Some panelists worried about the hostility that existing renewable technology faces in the Midwest.

Renew Missouri's James Owen said some Midwestern communities are still anxious about wind development and mount opposition campaigns over noise levels, turbine height and blinking lights.

"We still think there's a lot of people that have a lot of misinformation," he said.

Owen said social media are a hotbed for false narratives that influence the public and lead to restrictive ordinances.

Enel North America's Gina Mace said combatting misinformation in communities is a major task for her company. She also agreed backlogged and time-consuming queues remain an obstacle to getting new generation built.

Mace also said though it appears transmission can support new generation, transmission construction can take the better part of a decade. She said it's unclear how near-term generation will come online.

Owens added that he remains concerned that a state public service commission can effectively veto multistate transmission projects. ■

MISO News

MISO Officials Explain 2022/23 Capacity Auction Mechanics

By Amanda Durish Cook

MISO officials last week answered questions about the more confusing aspects of the Midwestern shortfall and expensive prices in this month's capacity auction while stakeholders asked for more supply data prior to the auctions.

The RTO's 2022/23 Planning Resource Auction (PRA) resulted in the Midwestern zones, 1 to 7, being deficient by 1.2 GW of their collective planning reserve margin requirements and clearing at the $236.66/MW-day cost of new entry (CONE). (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.) However, on the zonal level, only zones 4 to 7 — which include parts of Illinois, Lower Michigan, Indiana, Missouri and western Kentucky — couldn't meet their local clearing requirements, and they couldn't find extra supply from the other Midwestern zones.

MISO's transfer limits between its subregions also kept the Midwest from accessing additional supply from the South that could have counteracted the regional capacity shortage.

Eric Thoms, MISO senior manager of resource adequacy operations, said the RTO's auction clearing engine uses subregional resource zones and includes the marginal cost of a binding subregional flow limit in prices. In the case of this year's auction, the South-to-North transmission limit bound. MISO used a 1,900-MW South-to-North limit and a 3,000-MW North-to-South transfer limit in the auction. The RTO begins with the usual 3,000-MW southbound and 2,500-MW northbound limits and subtracts firm service contracts to arrive at the transfer limits used in the auction.

MISO also used Zone 3's $236.66/MW-day CONE to price the entire Midwest because it is the cheapest of the CONE prices, and the auction is designed to apply the lowest CONE when an entire region is short. The CONE values differ by zone because the cost of building new generation varies regionally.

"The objective of the multi-zone optimization methodology is to minimize the overall costs of capacity," Thoms explained to stakeholders in a Resource Adequacy Subcommittee teleconference Wednesday.

Stakeholders asked MISO to telegraph a better feel of supply in the weeks and months leading into the auction. They said there was a large delta between confirmed unforced capacity and what was ultimately converted into zonal resource credits. Ahead of the 2022/23 planning year, MISO *anticipated* a 121-GW coincident systemwide peak, with 157 GW in total installed capacity and just short of 128 GW in total unforced capacity to cover it.

Consumers Energy says it will speed up the retirement of its J.H. Campbell coal plant in West Olive, Mich., by 15 years to 2025. | *Consumers Energy*

Stakeholders asked if MISO could have disclosed a level of accelerated suspended or retired megawatts ahead of the auction so market participants could have reacted and made more supply available.

Apex Clean Energy's Richard Seide said the auction results were "astonishing."

"I know things were getting tight, but if you read the data going into this year's auction, you didn't think it was going to go this way by a few hundred megawatts. You thought we were going to slide by again," Constellation Energy's John Orr said.

MISO Director of Resource Adequacy Coordination Zakaria Joundi said that while the RTO can't reveal unit-specific data, it is reviewing the usefulness of the preliminary PRA data it posts.

"I think the process should be more transparent, so that choices to bring more capacity to the market can be viable," Power System Engineering's Tom Butz said.

Taylor Martin of the Independent Market Monitor, Potomac Economics, said the IMM tries ahead of time to project what will be unavailable but is bound by multiple confidentiality rules. But he said the Monitor found no evidence of economic or physical withholding.

Thoms also said no market participants this year elected to pay a capacity deficiency charge to MISO. According to MISO rules, load-serving entities can opt to pay out all or a portion of their planning reserve margin requirement.

The auction results are emblematic of the tricky situation MISO faces in navigating its members' portfolio transition.

The 2022/23 capacity results brought longstanding criticisms of MISO bubbling back to

MISO News

the fore, including its lack of sturdier transmission connections between its South and Midwest regions, a bevy of thermal generation retirements and MISO's use of a vertical demand curve over a sloped demand curve in the auction.

MISO said members in recent years have been replacing retiring thermal generation with even more megawatts from new intermittent resources.

The auction results come as Consumers Energy — Michigan's largest electric utility — and stakeholders last week announced that they reached an agreement to close all coal plants by 2025, which could make it one of the first large utilities in the nation to eliminate coal use. The proposal still needs the blessing of the Michigan Public Service Commission. (See *Consumers to End Coal by 2025 in IRP Deal with Mich. AG*.)

Michelle Bloodworth, CEO of coal lobbying group America's Power, said EPA's recent crackdown on coal ash could also idle a little more than 2 GW of coal-fired generation in MISO Midwest as early as the fall. She said MISO should also factor that development into its supply picture.

Stakeholders said it seemed that a lot of the new capacity that MISO and the Organization of MISO States were expecting per their annual resource adequacy did not manifest. Some wondered if the RTO needs to recalibrate its expectations of generation that will complete the interconnection process.

Monitor: Sloped Demand Curve, Please

Monitor David Patton said the auction shortage reinforces the need for a sloped demand curve in the auction, a call he's been making for 12 years now.

During the Market Subcommittee's meeting Thursday, Patton said MISO undervalues capacity, sending "bad signals" to market participants. He said MISO's long history of "near-zero" clearing prices spur too-early unit retirements.

"Since 2019, MISO lost almost 5 GW of capacity in the Midwest that would have been economic if the PRA had set efficient clearing prices," he said. "Most of these retirements were by unregulated merchant suppliers that rely on the market signals to make investment and retirement decisions."

2nd Regional Resource Assessment in the Works

MISO will pull together another long-term resource assessment by the end of this year, this time with assistance from its members.

Last year's first regional resource assessment showed a need for members to add almost 140 GW of new capacity within the next 20 years. (See *MISO Resource Assessment: 140 GW Needed Within 20 Years*.)

Last year, MISO relied only on public data it independently searched. The regional resource assessment this year will include data sourced directly from members to get a better picture of protracted resource trends. The RTO said it has collected generation information from 75% of its load for the 2022 assessment.

MISO said preliminary *results* show a lower level of nuclear retirements 20 years out; net neutral natural gas retirements and additions over two decades; and the same 35 GW of coal plant retirements by 2040 that it originally expected last year. It also foresees a 65% reduction in emissions from 2022 levels by 2040. ■

MISO News

MISO Stakeholders Insist on Consistency in Capacity Accreditations

By Amanda Durish Cook

Stakeholders told MISO on Wednesday it should use a consistent capacity accreditation process for both its conventional and non-thermal generators.

The request comes as MISO is evaluating new accreditation options for non-thermal generation. The RTO filed with FERC late last year to change its accreditation for conventional resources to a seasonal value based on a unit's past performance during tight conditions. The new accreditation is contained in a larger filing to create four seasonal capacity auctions (ER22-495). (See *Deficiency Notices for MISO's Seasonal Capacity Auctions Bid*.)

At the time, MISO elected to wait to propose a new accreditation for its other, intermittent generating units.

Now, MISO is evaluating three accreditation options for non-thermal resources:

- expanding its effective load-carrying capability (ELCC) calculation, currently in use for wind generation, to include solar generation and other intermittent resources;
- using an availability-based accreditation based on generator performance during "resource adequacy hours" — tight margin and emergency periods — over four historical planning years (This accreditation style is pending before FERC for MISO's conventional resources.); or
- employing a blend of ELCC and an availability-based accreditation.

The blended approach would have MISO identifying seasonal risky hours in addition to running a loss of load expectation (LOLE) analysis to identify possible shortfall events. MISO said it will "develop windows of risk for each season by combining resource adequacy hours and LOLE events." Capacity credits would be issued based on generator performance during the combined risk periods.

Stakeholders attending the Resource Adequacy Subcommittee's (RASC) teleconference Wednesday said they want comparability across accreditation of thermal and non-thermal resources. They said if thermal resources are going to be valued based on their historical contributions during times of system need, non-thermal resources need to be as well.

WEC Energy Group's Chris Plante questioned why MISO considers ELCC "good enough" for intermittent resources but not for conventional resources.

"Why are we making a distinction between intermittent and conventional resources when, at the end of the day, we're trying to determine the same thing?" he asked.

"We don't need to have apples-to-apples, but we at least need a fruit salad. We can't be throwing onions in," Clean Grid Alliance's Natalie McIntire said.

MISO staff said they're still considering accreditation designs. The RTO plans to hold a special workshop sometime in June and set a direction on a new accreditation in July. It said it will work on a design with stakeholders through the end of the year.

During the March RASC, McIntire encouraged MISO to pursue an entire rethink of its resource adequacy construct instead of developing a new capacity accreditation for intermittent resources. Other stakeholders have also asked MISO to assess the entirety of its resource adequacy construct.

MISO's Scott Wright told stakeholders the accreditation redesign for non-thermal resources is only a piece of the reforms MISO envisions needing as the resource mix transitions away from centralized, baseload generation.

"This is not the end or a destination," Wright said. ■

| © RTO Insider LLC

MISO News

MISO, SPP Announce New Interregional Stakeholder Meetings

By Amanda Durish Cook

With two ongoing interregional study efforts and a pledge for better seams coordination, MISO and SPP are launching a new biannual set of stakeholder meetings.

MISO said last week the RTOs will debut Common Seams Initiatives meetings twice per year starting next month.

The meetings will cover the grid operators' "strategic goals related to better seams coordination in support of improved reliability and market efficiency," MISO said. It pointed to the ongoing Joint Targeted Interconnection Queue study, recommendations from their state regulators, and updating their "freeze date" used determine their flowgates' firm transmission rights.

The RTOs have also pledged to conduct a targeted market efficiency project study this year that will search for smaller, congestion-relieving interregional projects. (See *MISO, SPP Take on 2nd Interregional Planning Effort*.)

MISO said it could add more annual Common Seams Initiatives meetings if necessary. SPP will host the first virtual meeting on May 17. MISO will organize an upcoming November slot.

Melissa Seymour, MISO's vice president of external affairs, said the RTOs aren't looking to replace any current meetings. The biannual meetings will serve as a one-stop update and stakeholder discussion on seams topics.

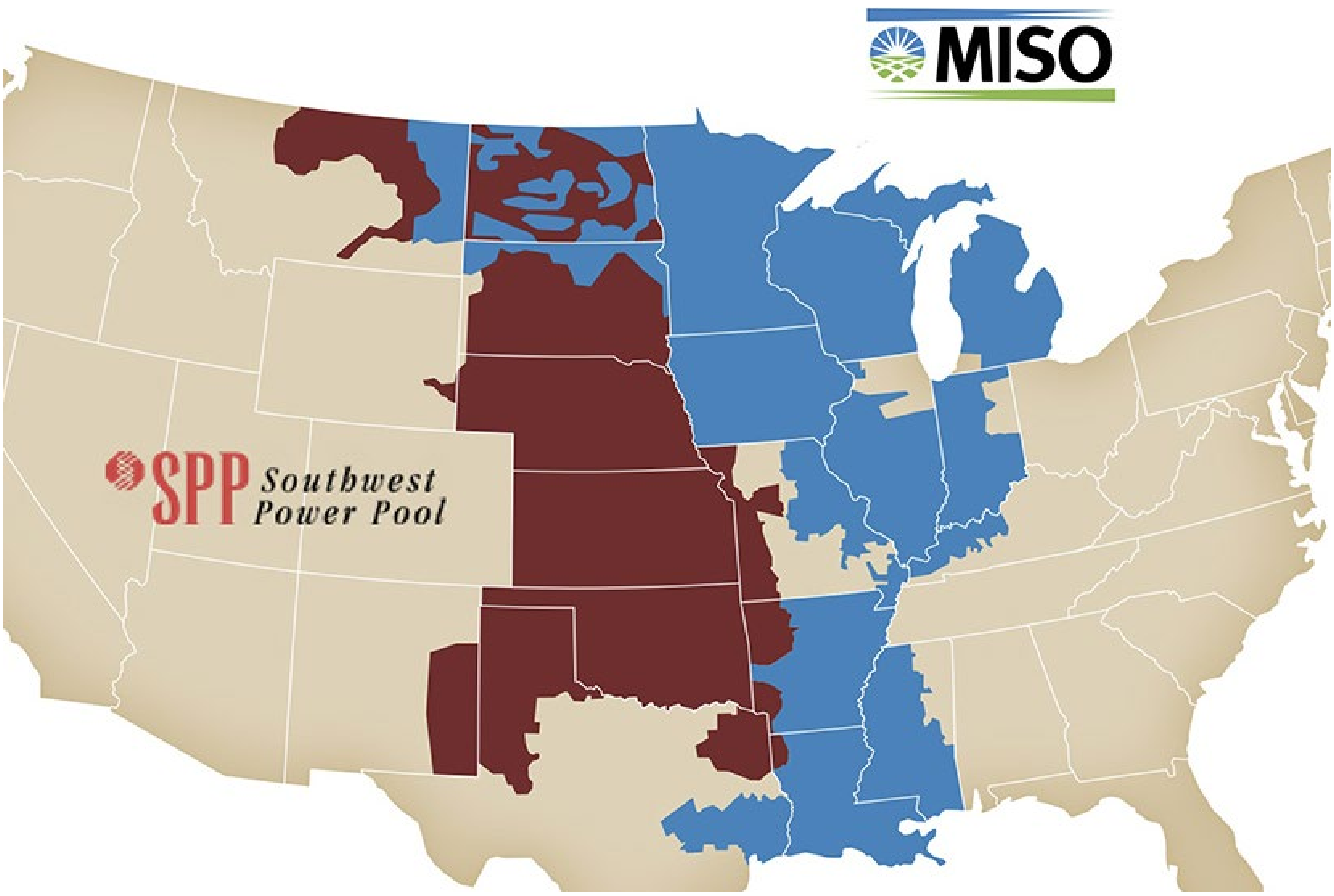
The common seams meetings announcement comes as MISO Independent Market Monitor David Patton last week said that SPP is not properly recognizing market-to-market flowgate constraints with MISO in its day-ahead market. (See *MISO Says System Volatility Here to Stay*.)

During a Market Subcommittee teleconference Thursday, Patton said the oversight must be costing SPP members several million dollars in balancing congestion. He said he continues to work with the RTO and its Monitor to persuade it to properly model constraints.

Seymour said SPP might not be neglecting to recognize constraints but just may have a different method of modeling them than MISO does.

"I'm not sure that they don't model that day-ahead congestion on the market-to-market flowgates," she said.

But Patton insisted that SPP considers the constraints, but doesn't model them, "which is essentially ignoring them." He said MISO probably has grounds to file a FERC enforcement complaint against SPP but added that's not the quickest way to arrive at a solution. ■



MISO and SPP seams | *MISO and SPP*

MISO News

MISO Keeps Reduced Schedule for Rest of 2022

By Amanda Durish Cook

MISO's Planning Advisory Committee met in January for the first in-person meeting of the year. | © *RTO Insider LLC*

MISO's stakeholder meeting schedule for the rest of 2022 will maintain the reduced cadence that it introduced at the beginning of the year.

The main stakeholder committees will meet both in virtual and in-person formats eight times per year instead of monthly, which has displeased some stakeholders.

The RTO's first schedule included meetings through May, with a commitment to assess the post-pandemic schedule's effectiveness. Stakeholder committees usually set a full calendar year of meetings in December. (See *Stakeholders Call for MISO to Rethink Pared-down Meeting Schedule*.)

MISO's head of stakeholder relations, Bob Kuzman, said the grid operator remains willing to devote extra time to important topics, as evidenced by scheduling a special April 15 stakeholder call and allotting additional time during an April 20 Resource Adequacy Subcommittee (RASC) teleconference to discuss capacity auction results. He pointed out that per stakeholder request, the RTO will also schedule a special workshop in June to discuss a new capacity accreditation for non-thermal generators.

Kuzman said during the RASC meeting that it's easier to add special stakeholder workshops to a calendar containing fewer meetings.

But some stakeholders disagreed and said it was easier to cancel regularly scheduled meetings rather than pull together one-off workshops.

"I think if there was a meeting in June, we wouldn't have to schedule a workshop," WEC Energy Group's Chris Plante said of the RASC schedule. Plante said he would like to see the main stakeholder committees return to monthly meetings.

RASC Chair Kari Hassler said the new schedule's rollout was probably "not the best," but that it's clear MISO has been trying to respond to stakeholder feedback.

Stakeholders are also trying to determine how best to suggest planning and market improvements with staff. The grid operator no longer conducts an annual stakeholder prioritization of market tasks and improvements under its *Integrated Roadmap* process.

Plante said MISO still needs an "avenue for stakeholders to opine on issues as they come up."

"Rather than having paperwork, we're going to rely on the discussions at the meetings themselves," MISO's Laura Rauch said during a Market Subcommittee teleconference last week.

She said if stakeholders come forward to the Steering Committee with important enough issues, MISO will urge them to make a presentation in stakeholder meetings.

The RTO said stakeholder-submitted issues "will be reviewed and placed on the management plan as appropriate," provided they fit with MISO's strategic plan, don't negatively impact the markets and MISO has enough manpower to analyze solutions. ■

Midwest news from our other channels

Whitmer Outlines Final Carbon-neutral Plan for Mich. NetZero Insider

Consumers to End Coal by 2025 in IRP Deal with Mich. AG NetZero Insider

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

NYISO News

NY Climate Council Ramps Up Natural Gas, Alt Fuels Planning

By Michael Kuser

New York's Climate Action Council on April 18 agreed to form new committees to help develop the state's plans for reducing natural gas use, expanding alternative fuels and adopting economy-wide measures to cut emissions.

The CAC is holding public hearings through June 10 on its draft scoping *plan* that lays out steps needed to achieve the emission limits set by the Climate Leadership and Community Protection Act. The council has received 8,000 written *comments* and heard 200 people comment through four of 10 hearings, CAC Director Sarah Osgood said.

The original timeline to end the public comment period in mid-May proved unrealistic, she said. (See *NY Officials Set 2022 Schedule for Climate Plan*.)

"While others would prefer that the climate actions happen faster, we also heard concerns about affordability of electricity and the cost of the transition, specifically the cost associated with moving homes to all electric," Osgood said. "A number of commenters expressed concerns about potential job losses among energy and utility workers and encouraged the council to take action that would ensure that the issue would be addressed."

Administrators are planning to provide a distilled summary of the comments a month after the close of the comment period, Osgood said.

Committee Tasks

State officials and contractors *presented* outlines of what committees on gas system transition, alternative fuels and economy-wide measures could focus on in the coming months, with the council meeting at least monthly or more often as the workload increases over the summer, Osgood said.

The CAC will recruit volunteers for the committees to start meeting in May so the council can complete a final scoping plan by year-end that shows how the state will reduce economy-wide greenhouse gas emissions 40% by 2030 and no less than 85% by midcentury from 1990 levels, she said.

The gas transition will outline a coordinated plan to downsize the gas system, led by the Department of Public Service and supported by the New York State Energy Research and Development Authority (NYSERDA), Long Island Power Authority, New York Power Authority and the Department of Environmental Conservation.

The committee will consult with utilities, environmental justice groups and sectoral experts and draw upon successful plans in other jurisdictions, as will the alternative fuels committee in developing draft guidelines on the use of hydrogen, renewable natural gas and other biofuels.

DEC Deputy Commissioner Jared Snyder opened a discussion about the economy-wide committee, which will look at the certainty of emission reductions, the certainty of carbon price impacts on disadvantaged communities and affordability, and some competitiveness issues, such as the risk of leakage from carbon pricing.

NYSERDA will provide the council with analyses on existing carbon pricing knowledge and experience in other jurisdictions as well as the effects of a price on carbon specifically in New York, said Vladimir Gutman-Britten, assistant director of policy and markets.

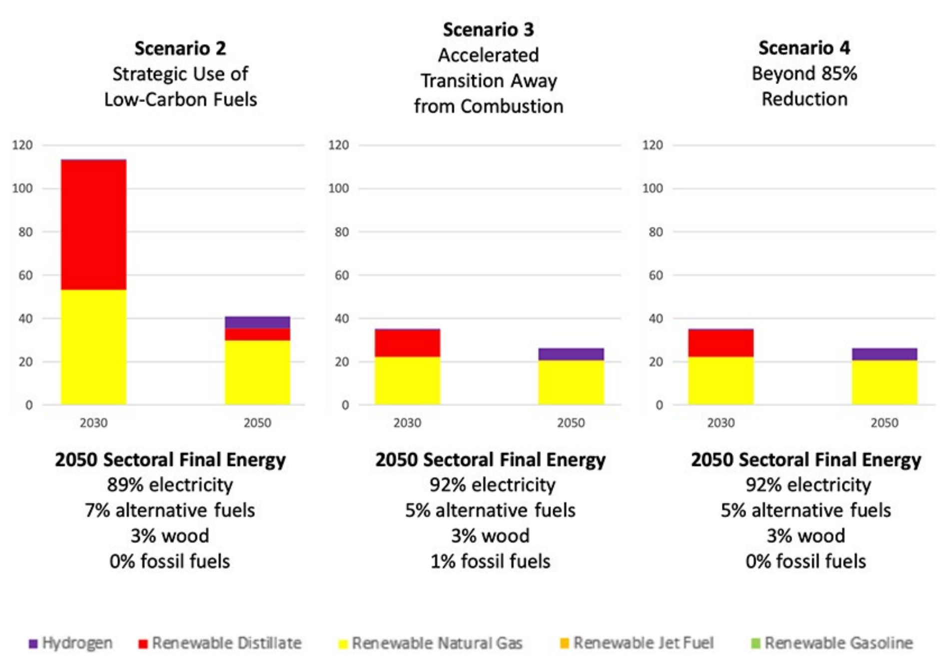
"We want to share data on some of the key policy design choices in pursuing a system like this and the particular tradeoffs that might come with it," Gutman-Britten said. "This analysis will help elucidate the impact of such a carbon tax on emissions and a variety of macroeconomic metrics, such as economy-wide energy spending, leakage of emissions and economic activity."

State planners, he said, are not endorsing a policy of carbon pricing but choosing it because of limitations on modeling tools available, adding that "while we will be evaluating this one type of policy, we still think it would provide insights into how other approaches might work."

Additional analysis may include potential effects of a large-scale investment program, including a sense of scale and the kinds of emissions reductions such a program might be able to yield under different spending choices, Snyder said.

The idea is "to unpack the kind of impact that pricing and an investment program might have on specific clean energy solutions ... key technology things like EVs, heat pumps and things like that so we can better understand how the economics of those solutions change as a result of different policy choices the state will make," Snyder said.

Kevin Hansen senior vice president and head of public policy at Empire State Development, the state's main economic development agency, urged the economy-wide committee to continue "to think about impacts on businesses and workers and the issue of leakage." ■



Alternative fuels utilization — Buildings | *NREL*

NYISO News

New York TOs Again Defend Local Tx Project Rights

By Michael Kuser

New York transmission owners on Wednesday again rejected challenges to their new public policy category of local transmission development for purposes of cost sharing and recovery (*20-E-0197*).

The NYTOs, including state investor-owned utilities, the New York Power Authority (NYPA) and the Long Island Power Authority, *told* state regulators that LS Power, the Alliance for Clean Energy (ACE-NY), and New York City were mistaken in their concern with the NYTOs' proposed cost sharing and recovery agreement (*CSRA*) for so-called phase 2 projects.

Phase 1 projects are traditional utility investments that address system reliability or resilience issues, while phase 2 projects are investments made primarily to satisfy requirements of the Climate Leadership and Community Protection Act (CLCPA).

The NYTOs in January had urged the Public Service Commission to reject LS Power's argument that costs of local transmission can only be allocated under the NYISO tariff's Order No. 1000 processes and that any regional cost allocation is preempted by FERC's exclusive jurisdiction over transmission. (See *New York TOs Defend New Public Policy Tx Category*.)

This month, the NYTOs rejected LS Power's insistence that phase 2 projects must go through NYISO's public policy transmission planning process: "Transmission projects identified through each NYTO's local planning process have never been subject to the NYISO PPTPP or its competitive solicitation process and are properly within each NYTO's planning authority."

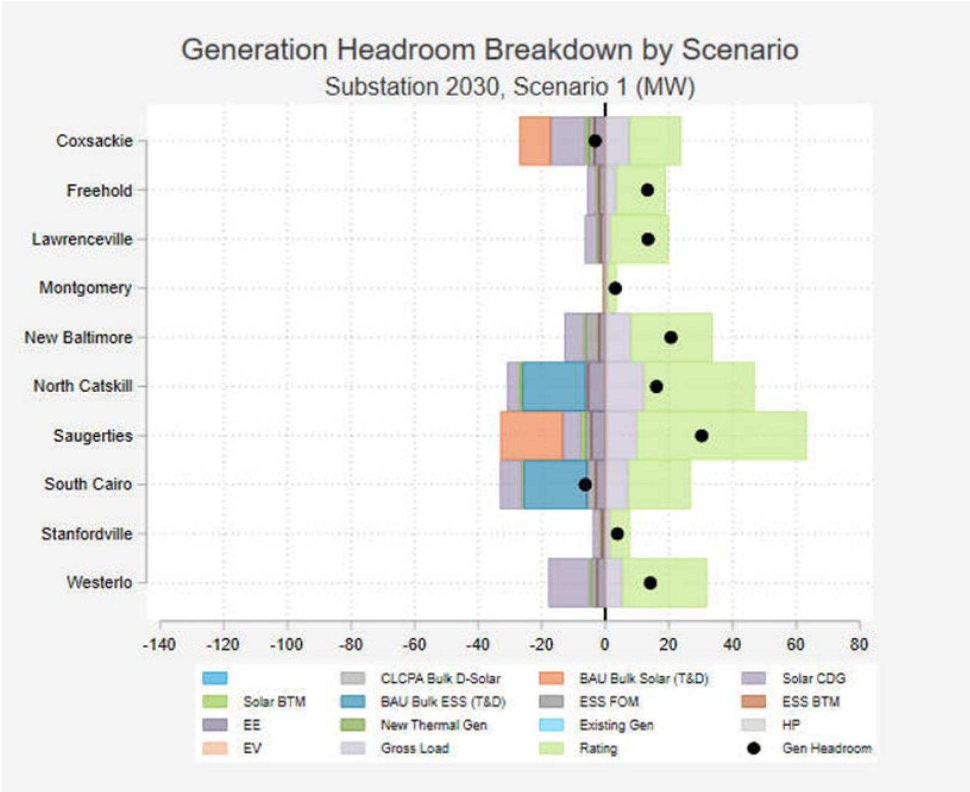
Forcing project development through the ISO would only serve to address bulk power transmission facility needs, not local system capacity shortfalls, the NYTOs said.

Under Order 1000, regional transmission facilities are those that must be regionally planned, competitively selected and eligible for regional cost allocation.

ACE-NY and the City

ACE-NY *asked* the PSC to establish a cost containment mechanism for phase 2 projects, a request the NYTOs said should be rejected as being outside the scope of the proceeding.

The NYTOs said they balanced competing



Under CLCPA planning conditions, most substations experience a sharp decline in generation headroom that tracks the deployment of renewable resources. The only exceptions are the Stanfordville and Montgomery substations, which remain stable with marginal generation headroom available throughout the planning period. | *JU*

interests in developing a voluntary CSRA under the basic premise that incurred costs of projects approved by the commission would be recoverable.

Regulators will use the cost recovery mechanism for only those projects approved as meeting the statutory objectives under the CLCPA, including a predetermined rate of return and capital structure, the NYTOs said. The CSRA, they added, does not provide for preapproval of all project costs. In addition, the PSC and all interested parties reserve the right to contest project costs incurred by the sponsoring NYTO, and therefore it would be inappropriate to impose generic involuntary cost caps.

New York said it is concerned about inconsistency between the CSRA and the rate schedule, according to the city's Feb. 8 *comments* in the proceeding. Regarding cost recovery for NYPA customers, the NYTOs contend that under the CSRA, NYPA "will be allocated costs of approved transmission projects in the same manner as other [load serving entities] under rate schedule 18," and that the rate schedule does not apply to NYPA, the city noted in its comments.

The CSRA and rate schedule, however, are correct, according to the NYTOs.

A provision of the CSRA relating to NYPA as a load-serving entity "recognizes NYPA's customers will be responsible for CSRA-related costs to the same extent as other end-use customers in New York served by a load serving entity," the NYTOs said.

NYPA said it will not use the CSRA or accompanying rate schedule to recover the costs of its transmission projects for the following reasons:

- NYPA does not have a retail service area or local transmission and distribution system and therefore, under the Accelerated Renewables Act, will not be developing phase 2 projects for inclusion in the utilities' capital plans; and
- NYPA uses the NYPA transmission adjustment charge, which already allocates those costs statewide, to recover its transmission-embedded costs. ■

NYISO News

FERC Fines NY Hydro Operator $600K for Safety Violations

By Michael Kuser

Oswegatchie River High Falls near Fine, N.Y. | *Mwanner, CC BY-SA 3.0, via Wikimedia Commons*

FERC on Thursday ordered the former operator of an upstate New York dam to pay $600,000 in civil penalties for failing to make needed repairs over six years and retain possession of all property needed to access the facility (*P-9685-034*).

Ampersand Cranberry Lake Hydro has 60 days to pay the fine for violating its hydroelectric license for the Cranberry Lake Project, located in St. Lawrence County, N.Y.

The project is owned by the Oswegatchie River-Cranberry Reservoir Regulating District Corp. (OR-CRRDC), a state municipal corporation. It includes a 57,400-acre-foot reservoir contained by dam that is 195 feet long and 19 feet high.

"The dam has a high hazard potential rating, which means that a failure of the project works would result in a probable loss of human life or economic or environmental losses," FERC said.

Under FERC rules, hydro licensees are required to maintain property rights to their projects to provide access to the land associated with a dam in order to make repairs when necessary.

"In this particular case, Ampersand didn't maintain those access rights. And thus, if something does go wrong or might go wrong, they don't have the ability to access the site to make repairs that are necessary," FERC Chairman Richard Glick said in a statement Thursday. "And this particular dam is classified as having a high hazard potential, so that's something that we take very seriously."

Thursday's order follows an October 2021 commission issuance directing Ampersand Cranberry Lake to explain why it should not be assessed a civil penalty for violating its hydroelectric license and a November response by the company acknowledging that it failed to retain possession of all project property, in violation of its license. (See *FERC Hits NY Hydro Plant for Delayed Repairs*.)

FERC granted Ampersand Cranberry a license for the project in 2015 after the company promised to complete safety work related to the facility's fuse plug spillway in the dam's embankment and to raise the earthen embankment crest. The company notified the commission last July that it had agreed to terminate its lease and give up access rights to the project site to settle litigation with OR-CRRDC, which sued the company in 2019 over its failure to make rent payments.

FERC said the settlement came despite its repeated warnings that terminating the lease would violate the company's license and would not relieve it of its responsibility to complete the outstanding work on the dam. ■

PJM News

FirstEnergy Q1 Earnings down Compared to Year Ago

Company Considering Consolidating Ohio and Pennsylvania Utilities

FirstEnergy's Akron, Ohio, headquarters | *DangApricot, CC BY-SA-3.0, via Wikimedia*

By John Funk

FirstEnergy on Thursday reported first-quarter adjusted earnings of $288 million ($0.51/share) on revenue of $3 billion, down 18% from first quarter 2021 adjusted earnings of $335 million ($0.62/share) on revenue of $2.7 billion.

Operating earnings, before adjustments for one-time charges, were 60 cents/share, the midpoint of the company's earnings guidance for the quarter and down 9 cents from 2021.

During a call with analysts Friday, CEO Steven Strah argued that the results for the quarter were the midpoint of where the company said it would be during its fourth-quarter 2021 call in February.

"We're off to a solid start in 2022 ... in line with the midpoint of our guidance," Strah said. "With our financial performance, operational momentum, portfolio of assets and robust long-term business model, we are in a strong position, and I'm optimistic and excited about the future."

FirstEnergy's share price fell $2.11 (4.38%), closing Friday afternoon at $46.01.

As in recent previous quarterly analyst calls, Strah spent time at the beginning of the session describing how the board of directors and new management team is working to reform the company in the months since it pleaded guilty to a deferred federal prosecution charge stemming from the $61 million bribery and racketeering investigation that so far has led to the indictment of the former speaker of the Ohio House of Representatives and four associates.

During those remarks, Strah said the company was "beginning a long-term review" of the possible benefits of combining the Ohio and Pennsylvania distribution companies "from a legal, financial, operational and branding perspective."

In answer to a question from an analyst later, Strah explained that the "potential benefits are the potential for increased efficiencies in some of our administrative functions. And there is also a possibility that it could provide us better access to capital markets."

CFO John Taylor said first-quarter results included several special items, the largest of which was a 6-cent/share charge associated with the redemption and early retirement of an $850 million note in January.

"The year-over-year change was primarily driven by a slight increase in operating and other expenses, primarily related to planned plant outages in West Virginia, and higher storm costs and employee benefits, partially offset by lower uncollectable expense," he said.

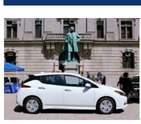
"These costs were partially offset by higher customer demand and the continued economic recovery in the commercial and industrial segments.

"It's important to note that our operating costs were in line with our forecast as discussed on the fourth-quarter call. ... As customers continued resuming normal work and social activities, deliveries to commercial customers increased 7.6% ... which is a significant increase in this customer class, while sales to industrial customers increased 2.5%, with many sectors including steel and automotive showing recovery from recessionary conditions.

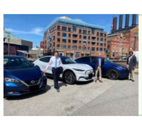
"Overall customer demand continues to slowly return to pre-pandemic levels," Taylor said. Residential sales were about 3% higher than 2019 levels, while commercial and industrial sales were about 4% and 2% below 2019.

Unmentioned during the call or even the earnings report was the retirement of Bob Mattiuz, chief FERC compliance officer. As reported by cleveland.com on April 15, FirstEnergy spokeswoman Jennifer Young said Mattiuz is retiring effective July 1 as FERC reviews "FirstEnergy's analysis about how it'll issue customer refunds with interest for improperly accounting for part of the approximately $71 million used" in the bribery scandal. ■

National/Federal news from our other channels


NJ Awards $7.6 Million For Local Govt EVs

NetZero Insider


Md. PSC Approves Updates to Utility EV Charging Programs

NetZero Insider


Md. Climate Change Panel Chasing New Law's Ambitious Goals

NetZero Insider

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

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Wednesday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

RTO Insider will be covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:15-9:20)

B. Stakeholders will be asked to *endorse* proposed revisions to *Manual 1: Control Center and Data Exchange Requirements* resulting from a periodic review and revisions to NERC standards CIP-012, COM-001 and EOP-008. (See "Manual 1 Revisions Endorsed," *PJM Operating Committee Briefs: April 14, 2022*.)

C. The committee will be asked to *endorse* proposed revisions to *Manual 14F: Competitive Planning Process* resulting from a periodic review. The changes were endorsed at the April 12 Planning Committee meeting. (See "Manual 14F Revisions Endorsed," *PJM PC/TEAC Briefs: April 12, 2022*.)

D. Members will be asked to *endorse* Operating Agreement *revisions* intended to appropriately document the underfrequency load shedding (UFLS) relay requirements applicable to East Kentucky Power Cooperative. A recent review of revisions showed "potential confusion" in EKPC's appropriate UFLS requirement that needed to be corrected. (See "EKPC UFLS Requirements Endorsed," *PJM Operating Committee Briefs: April 14, 2022*.)

E. Stakeholders will be asked to *approve* revisions to the Energy Price Formation Senior Task Force *charter*. The proposed charter edits relate to the delay in reserve price formation implementation, from May 1 to Oct. 1.

Endorsements (9:20-10:40)

1. Deactivation Process Timing (9:20-9:45)

The committee will be asked to *endorse* a proposal to update the process timing for generation deactivations. The proposed deactivation process would establish quarterly study times for requests, with periods beginning Jan. 1, April 1, July 1 and Oct. 1. (See "Deactivation Process Timing Update Endorsed," *PJM PC/TEAC Briefs: March 8, 2022*.)

2. Interconnection Process Reform (9:45-10:20)

Members will be asked to *endorse* a proposal to change the interconnection process and a transition to the new rules. The proposal was developed at the Interconnection Process Reform Task Force. (See *PJM Planning Committee Endorses 'Fast Lane' Criteria for Gen Projects*.)

3. Resource Adequacy (10:20-10:40)

Stakeholders will be asked to *endorse* a proposed *issue charge* for the Resource Adequacy Senior Task Force addressing the procurement of clean resource attributes. The issue charge includes discussing the potential benefits and drawbacks of a forward procurement of clean resource attributes and the social cost of carbon in wholesale markets. (See "Procurement of Clean Resource Attributes," *PJM MRC/MC Briefs: March 23, 2022*.)

Members Committee

Consent Agenda (1:25-1:30)

C. The committee will be asked to *approve* proposed revisions to *Manual 34: Stakeholder Process* to update the paper ballot process. PJM wants to revise Manual 34 before the Annual Meeting on May 17, which includes the Board of Managers election and General Session, to allow for remote voting. (See "Remote Voting for Annual Meeting," *PJM MRC/MC Briefs: March 23, 2022*.)

Endorsements (1:30-1:50)

1. Interconnection Process Reform (1:30-1:50)

Stakeholders will be asked to *endorse* a proposal as endorsed by the MRC (see agenda item No. 2 above). PJM is seeking a same day vote on the issue at the MRC and the MC. ■

— Michael Yoder

SPP News

FERC Rejects Conditional Withdrawals from Tri-State

By Tom Kleckner

FERC last week rejected United Power's request for clarification and to provide Tri-State Generation and Transmission Association with a nonbinding, conditional withdrawal notice (*ER21-2818*).

The commission agreed with Tri-State's position that conditional withdrawal notices are not permitted under its contract termination payment (CTP) tariff that FERC accepted in November 2021. (See *FERC Accepts Tri-State's Exit Fee Calculation*.)

United provided its conditional withdrawal notice in December and sought clarification from the commission that utility members may begin the two-year advance notice withdrawal period under the currently effective tariff, such that it could rescind its notice at any point up to its January 2024 withdrawal date.

The commission agreed with Tri-State's contention that conditional, nonbinding or revocable notices of intent to withdraw were not valid under its CTP tariff. It said that conditional notices would create significant risk to remaining members and hamper its ability to plan for withdrawals.

"We find that the conditional notices of withdrawal that have so far been provided to Tri-State are invalid, because the tariff does not permit such conditional notices," FERC said.

The commission said that "as the all-requirements supplier to its utility members, Tri-State has an obligation to acquire sufficient capacity for all its utility members, and significant uncertainty regarding this amount could have cost impacts for all Tri-State utility members."

The order also covered conditional notices filed by Poudre Valley Rural Electric Association and Northwest Rural Public Power District. Along with United, the cooperatives comprise about 30% of Tri-State's peak load, preventing it from reliable system planning given the uncertainty over the load's continued inclusion in two years.

"FERC's order supports the important principles of fairness and equity for all of our cooperative members, ensuring remaining members are unharmed should another member pursue the early termination of its long-term, all-requirements power contract," Tri-State CEO Duane Highley said in a *statement*.

Tri-State's first CTP methodology filing was submitted in April 2020. FERC accepted it subject to refund but also established hearing and settlement judge procedures. The process was repeated several times as the co-op filed policies and other calculation methods in response to member protests.

Last May, FERC rejected the CTP methodology without prejudice, leading to Tri-State's latest filing in September. Many of the complaints centered on members being able to see the calculations. (See *FERC Rejects Tri-State Exit Fee Proposal*.)

Members seeking to terminate their wholesale electric service contracts and co-op membership must provide a two-year advance notice of their intention and pay its CTP to Tri-State on the withdrawal date.

Tri-State has 45 members, including 42 utility distribution cooperatives and public power district members in four states that supply power to more than 1 million electricity consumers across nearly 200,000 square miles of the West.

FERC has scheduled a hearing next month on the CTP tariff. ■

Colorado-based Tri-State has won a FERC decision over membership's non-binding, conditional withdrawals. | *Tri-State G&T*

Company News

BlackRock Decision Unearths FERC Wariness of Investor Influence on Utilities

By Sam Mintz

FERC on Wednesday agreed to reup BlackRock's blanket authorization to buy stock in utility companies for another three years, but not without some of the commissioners saying they were wary of the power of massive investors to shape energy companies' decisions (*EC16-77-002*).

The four participating commissioners (Commissioner James Danly having recused himself) saw no reason to upend a precedent set more than a decade ago by FERC, which allows the company to own up to 20% of any individual utility.

The investment giant had first requested a blanket authorization in 2010. FERC approved it at that time and has extended it twice since.

"We find that the reauthorization will not have an adverse effect on competition, rates or regulation," the commission said. "As applicants explain, there have been no changes in material facts and circumstances since issuance of the blanket authorization order that would alter or affect the commission's prior analysis."

The reauthorization was not without opposition: Consumer advocacy group Public Citizen *filed a protest* arguing that it is "impossible for a fund manager of BlackRock's size and scope to remain a passive investor."

"BlackRock's accumulation of voting securities constitutes control over utilities, and its horizontal power over competing utilities harms competition," the group wrote, calling for a hearing to assess the company's influence.

FERC denied that request, writing that BlackRock has given it enough assurance that it will not be able to influence utilities. But commissioners from both parties said that they had taken heed of Public Citizen's warning and are eager to closely examine the way FERC examines such requests in the future.

"I acknowledge Public Citizen's concerns about the lack of analysis on the effects on competition, just and reasonable rates, and regulation related to the accumulation of acquired interests in public utilities," wrote Democratic Commissioner Allison Clements.

She said that FERC should take a look at the analysis it requires when evaluating blanket authorizations to make sure any transactions they lead to "do not have an adverse effect on competition and that entities granted such blanket authorizations lack control over the utilities whose interest they acquire."

Republican Commissioner Mark Christie also said that the worries raised by Public Citizen were "compelling" and called for future scrutiny into investment companies' control over utilities.

BlackRock in particular, Christie wrote, has been "openly aggressive" in trying to influence corporate policy using its financial power.

"The important question is whether huge asset managers like BlackRock are able to exert undue pressure on regulated public utilities or their holding companies to engage in practices that may undermine their primary responsibilities of delivering reliable power to consumers at just and reasonable rates," Christie wrote. ■

FERC this week re-upped BlackRock's blanket authorization to buy utility shares. | *Shutterstock*

Company News

NextEra Shares Tumble on Solar Supply Woes

By Tom Kleckner

Solar panels at NextEra Energy's corporate HQ in June Beach, Fla. | *© RTO Insider LLC*

NextEra Energy lost almost 10% of its market value last week after telling the financial community that a federal government decision on solar panels and cells supplied from Asia could delay some of its projects.

The Department of Commerce *said* in March that U.S. trade officials will investigate whether imports of solar energy equipment from four Southeast Asian nations are circumventing tariffs on goods made in China. (See related story, *Solar Sector Braces for Tariff Probe Impact*.)

During the company's first-quarter earnings call with analysts Thursday, NextEra management said that 2.1 to 2.8 GW of the company's planned solar and storage projects may be delayed until 2023 because suppliers are not shipping solar panels to the U.S. while they wait on a final decision.

NextEra Energy Partners CEO John Ketchum said being unable to purchase solar panels from Southeast Asia will force renewables companies like his to instead source their materials from China. NextEra bills itself as the world's largest producer of solar and wind energy.

"China is the only country in the world that would have panels available to sell because … the U.S. panel manufacturing industry, which is incredibly small even at full capacity, only has the ability to satisfy 10 to 20% of the entire U.S. demand," he said. "The U.S. industry is sold out until 2025. It forces you back to China … which is an absolutely perverse outcome, an outrageous outcome, quite frankly, and one we intend to make sure that the Commerce Department clearly understands because that's an unintended consequence that I don't think anybody wants."

NextEra *announced* a first-quarter net loss of $451 million (-$0.23/share), as compared to $1.67 billion ($0.84/share) for 2021's first quarter. The Florida-based company said it expects to grow shareholder dividends at a 10% annual rate through 2024.

The company's share price closed the week at $73.95, down $7.54 from its close the day before the earnings announcement and a 9.3% drop over two days. ■

Company Briefs

CenterPoint Shareholders Rebuke CEO Lesar's Compensation

CenterPoint Energy shareholders last week rejected CEO David Lesar's compensation package in a nonbinding vote that sent a message to the utility's board that they disapprove of the nearly $38 million Lesar received in 2021.

The vote came two days after a report by watchdog Energy and Policy Institute showed that Lesar's compensation in 2021 was far higher — in some cases two to three times higher — than CEOs of similar companies, as his compensation more than tripled from 2020 ($12 million).

CenterPoint defended Lesar's 2021 compensation, noting it was boosted by a one-time retention award provided in stock.

More: *Houston Chronicle*

FirstEnergy Agrees to Settlement to Resolve Ratepayer Lawsuits over HB6

FirstEnergy Corp. CEO Steven Strah last week told investors that the company recently reached a $37.5 million settlement to resolve four lawsuits filed by ratepayers who sued the utility over the House Bill 6 scandal.

It is unclear whether the money will be spread out among the individual plaintiffs in the cases or among FirstEnergy's 2 million Ohio customers. As of Friday, no settlement documents had been filed in dockets of any of the lawsuits. The settlement also resolves three federal lawsuits: *Smith v. FirstEnergy Corp. et al.*, *Buldas v. FirstEnergy Corp. et al.*, and *Hudock and Cameo Countertops, Inc. v. FirstEnergy Corp. et al.*

More: *Cleveland.com*

Twitter to No Longer Allow Climate Disinformation in Ads

Twitter last week announced it will no longer allow "misleading advertisements" that "contradict the scientific consensus on climate change."

"We believe that climate denialism shouldn't be monetized on Twitter and that misrepresentative ads shouldn't detract from important conversations about the climate crisis," Twitter sustainability executives Seán Boyle and Casey Junod said. The company did not say specifically how it would make decisions about what's prohibited, but the post says the new effort will be in line with Twitter's existing policy on "inappropriate content."

The European Union also announced that member countries have agreed to a new policy requiring Big Tech do more to address harmful content, including disinformation and hate speech.

More: *Axios*

Federal Briefs

GSA Has Cut Emissions by 51% Since 2008

The General Services Administration (GSA), which helps federal agencies build, purchase and retrofit office space, last week said it has cut its building portfolio's annual operational greenhouse gas emissions by 51% compared to fiscal 2008 levels.

The Biden administration has set a government-wide goal of cutting emissions by 50% by 2032, which means the GSA is about a decade ahead of that target. The GSA has set its own target of hitting net-zero emissions across its 370 million rentable square feet by 2045.

More: *Axios*

Natural Gas Pipeline in Doubt After SCOTUS Rejection

The U.S. Supreme Court last week declined to hear Spire's appeal of a lower court's decision that could close a 65-mile pipeline that runs through parts of Illinois and Missouri. The court rejected the appeal without comment.

FERC approved the pipeline in 2018, and it became operational in 2019. However, the Environmental Defense Fund sued in 2020, claiming the pipeline was approved without adequate review. A panel of the U.S. Court of Appeals for the District of Columbia ruled that FERC had not adequately demonstrated a need for the project and vacated approval.

FERC last year issued a temporary certificate allowing the pipeline to remain operational. The temporary order continues to stand while the agency considers Spire's appeal to FERC seeking new approval.

More: *The Associated Press*

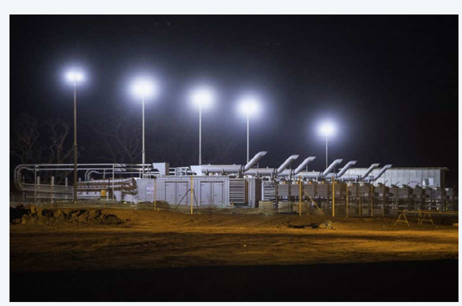
Syrah Resources Gets DOE Loan for Louisiana EV Battery Plant

The Department of Energy last week announced it is lending $107 million to graphite miner Syrah Resources to expand its electric vehicle battery parts plant in Louisiana.

The company plans to use the money to help fund the expansion of a plant that will process graphite mined from Mozambique into anodes, the positively charged electrode of a battery. The facility is expected to produce enough anodes to build 2.3 million EVs by 2040.

It is the first loan in more than 10 years from a special funding program of the department. While the program, known as the Advanced Technology Vehicles Manufacturing loan program, has lent to automakers Ford and Tesla in the past, the Syrah loan would be the first not directly made to an automaker.

More: *Reuters*



State Briefs

CALIFORNIA

PG&E Wildfire Victim Trust Lobbies For $1.5B State Loan

The PG&E Fire Victim Trust, the multibillion-dollar fund responsible for paying wildfire victims, last week lobbied Gov. Gavin Newsom and the Legislature for a loan of about $1.5 billion to help fully compensate the nearly 70,000 survivors.

The lobbyist said without the state's help, the trust probably can't make the victims whole. For the victims to receive the full $13.5 billion the company agreed to pay, the trust must sell its shares for about $14.15 a share. PG&E's share price has consistently traded at significantly below that target price.

Although state leaders rebuffed earlier pleas, the lobbyist said Newsom's staff has indicated it's willing to explore some form of assistance.

More: *The Sacramento Bee*

COLORADO

Bill Would Require EV Charging Stations at New Large Buildings

The House of Representatives last week advanced a policy to require electric vehicle charging equipment at new large residential and commercial buildings.

The latest version of the bill would require new commercial buildings above a certain size to have EV charging for at least 10% of parking spaces. New multifamily apartment buildings would require charging infrastructure for 20% of parking spaces.

The bill would also require new buildings to include the electrical system capacity to expand electric vehicle charging to more parking spaces in the future.

More: *Colorado Newsline*

FLORIDA

Ag Commish Seeks 100% Renewable Energy Despite 'Not Much Hope'

Agriculture Commissioner Nikki Fried last week unveiled a proposal that would gradually increase state utilities' electricity to 100% renewable by 2050.

Under the proposal, utilities would have three interim goals for renewable energy: 40% by 2030, 63% by 2035 and 82% by 2040. In 2050, the rule envisions 100% renewable energy. The rule is not final and could face several challenges. The state Department of Agriculture and Consumer Services would mainly be able to track compliance, not enforce it.

Fried expressed little confidence in hitting the targets. "I don't have a lot of hope under the given circumstances, but that's why we're having this conversation. That's why we're putting it out there."

More: *The Associated Press*, *WUSF Public Media*

IOWA

Utilities Board Denies Request to Pause Cardinal-Hickory Tx Line

The Iowa Utilities Board last week denied a series of motions requesting a pause in the construction of the Cardinal-Hickory Creek transmission line.

The board issued an order denying a pause on construction requested in February by opponents of the $492 million project, saying the motions did not clearly state legal grounds on which regulators could stay construction of the line, which was approved in May 2020.

More: *Telegraph Herald*

OHIO

Duke Energy Customers to Receive Bill Credit

Duke Energy residential natural gas customers should soon see a one-time bill credit of approximately $133 following a settlement between the company and the Public Utilities Commission last week.

The settlement is a result of proceedings related to Duke Energy's expenses for environmental remediation of manufactured gas plants from 2013 to 2019 and the implementation of the Tax Cuts and Jobs Act of 2017. Under the terms, Duke will eliminate $85 million in costs that would otherwise be billed to customers and the approximately $4.8 million remaining insurance proceeds will be used to fund its low-income and senior citizen bill assistance programs.

More: *Cincinnati Enquirer*

Judge Orders FirstEnergy to Turn Over Records Tied to Bribery Scandal

Attorney Examiner Megan Addison of the Public Utilities Commission once again ordered FirstEnergy Corp. to hand over thousands of documents to the Consumers' Counsel, partially rebuffing the company's request for a four-month delay.

The ruling caps a fight over records the company has already given to federal regulators for an audit but has fought to withhold from the Consumers' Counsel, which represents residential ratepayers before the PUC. The audit, released in February, focused in part on "significant shortcomings" of oversight of FirstEnergy's lobbying and political conduct.

FirstEnergy has until May 20 to turn over the documents. However, specific records pertaining directly to the company's lobbying practices regarding legislation must be turned over by May 6.

More: *Ohio Capital Journal*

TENNESSEE

Franklin County Denies Solar Farms

The Franklin County Commission last week voted 15-0 with one abstention to not allow commercial renewable energy facilities within the county.

Recent opposition focused on potential impacts from large-scale solar farms covering hundreds of acres prompted the commission to take action that prohibits large commercial operations. An initial resolution called for a six-month ban. However, the commission amended the resolution to say "indefinitely."

Silicon Ranch and Cypress Creek Renewables had recently proposed solar farms in the county.

More: *Herald Chronicle*

VIRGINIA

Amazon Announces 2 Solar Farms

Amazon last week announced it will add a 200-MW project in Pittsylvania County and a 50-MW project in Frederick County to bring the number of utility-scale facilities the company has in the state to 19.

Amazon, which has set a goal of operating on 100% renewable power by 2025, also announced 37 new renewable energy projects around the world, bringing its total to 310 in 19 countries.

More: *Cardinal News*

Youngkin Signs Energy Generation Property Tax Exemption into Law

Gov. Glenn Youngkin last week signed a bill into law that creates a property tax exemption for residential and mixed-use solar energy systems up to 25 kW in size.

The exemption follows the passage of the Clean Economy Act, which is expected create up to 29,000 jobs.

More: *SEIA*

WEST VIRGINIA

Appalachian Power Seeks $297M Rate Increase

Appalachian Power last week asked the Public Service Commission for a $297 million rate increase, citing a "steep and rapid rise in energy and fuel costs over the past several months."

The average residential customer would see an increase of about $18 a month. The current average bill is about $155.

More: *West Virginia Public Broadcasting*

WISCONSIN

Evers Releases State's First Clean Energy Plan

Gov. **Tony Evers** last week released the state's first Clean Energy Plan, which is meant to serve as a blueprint for meeting his goal of carbon-free electricity by 2050 and to help meet the state's commitment of cutting half of all greenhouse gas emissions by 2030.

The plan is a recommendation, though it is intended as an actionable framework with four primary paths: promoting clean energy technology by expanding incentives; expediting the development of utility-scale solar projects; phasing out natural gas generation as well as the consideration of nuclear power; and creating clean energy apprenticeship programs.

According to the Department of Natural Resources, the state's net greenhouse emissions fell by about 9% from 2005 to 2018.

More: *Wisconsin State Journal*

WYOMING

PacifiCorp Seeks $26M Rate Increase Due to Extreme Weather

PacifiCorp last week filed a $26 million (4%) rate increase request with the Public Service Commission.

The company cited extreme weather and climate conditions that have spiked electric demand and have temporarily driven up wholesale power prices.

If approved, its average residential customer would see their monthly bill increase by $1.97 beginning July 1.

More: *WyoFile*