ISSN 2377-8016 : Volume 2023/Issue 18 ▪ May 2, 2023

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

Southeast

Brattle Report Sees Benefits for SC RTO Membership (p.37)

FERC & Federal

Permitting Delays, Inflation Put Double Whammy on IIJA and IRA (p.3)

Congressional Republicans Seek Changes to Biden's Energy Policies (p.5)

CAISO/West

Committee Gives CAISO RTO Bill a Cool Reception (p.8)

MISO

MISO Suggests Changing Cost Allocation for South Projects (p.18)

MISO: Long-range Tx Needed for 369 GW in Interconnections (p.19)

PJM

NJ BPU Backs Plan for 2nd OSW Grid Upgrade Process with PJM (p.28)

COVER: South Carolina Rep. John "Jay" Taliaferro West IV (R) (left) and Sen. Tom Davis (R) at a May 1 hearing on Brattle's recommendations that the state join an RTO | *South Carolina Electricity Market Reform Measures Study Committee*

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

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Midwest Bureau Chief
John Funk

Mid-Atlantic Bureau Chief
K Kaufmann

Associate Editor
Shawn McFarland

Copy Editor/Production Editor
Rebecca Santana

CAISO/West Correspondent
Hudson Sangree

D.C. Correspondent
James Downing

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
John Norris

PJM Correspondent
Devin Leith-Yessian

SPP/ERCOT Correspondent
Tom Kleckner

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Chief Operating Officer / Co-Publisher
Merry Eisner

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Phaedra Welker

Customer Success Manager
Dan Ingold

Marketing Manager
Eau Rikhotso

Assistant to the Publisher
Tri Bui

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

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

In this week's issue

Correction

An article in last week's newsletter, *NYISO Operating Committee Briefs: April 20, 2023*, incorrectly reported that NYISO said that new transmission into New York City had increased capacity margins for Zone J (the city). The ISO said that new transmission into the Southeastern New York reserve region had increased the zone's margins.

FERC/Federal News

Permitting Delays, Inflation Put Double Whammy on IIJA and IRA

NEPA Not the Problem, Clean Energy and Enviro Groups Tell Senate EPW Committee

By K Kaufmann

Martin Durbin, U.S. Chamber of Commerce | *Senate EPW Committee*

Successful implementation of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act may hinge on Congress' ability to put politics aside and hammer out bipartisan legislation to streamline federal permitting, Martin Durbin, senior vice president for policy at the U.S. Chamber of Commerce, said Wednesday.

States and other recipients of federal funding from those laws "are struggling to use them since lengthy permitting processes can add years and uncertainty," Durbin told the Senate Environment and Public Works Committee during a hearing on permitting.

Inflation combined with permitting challenges is a double whammy, he said. "The longer it takes for shovels to hit the dirt, the less we're going to be able to build."

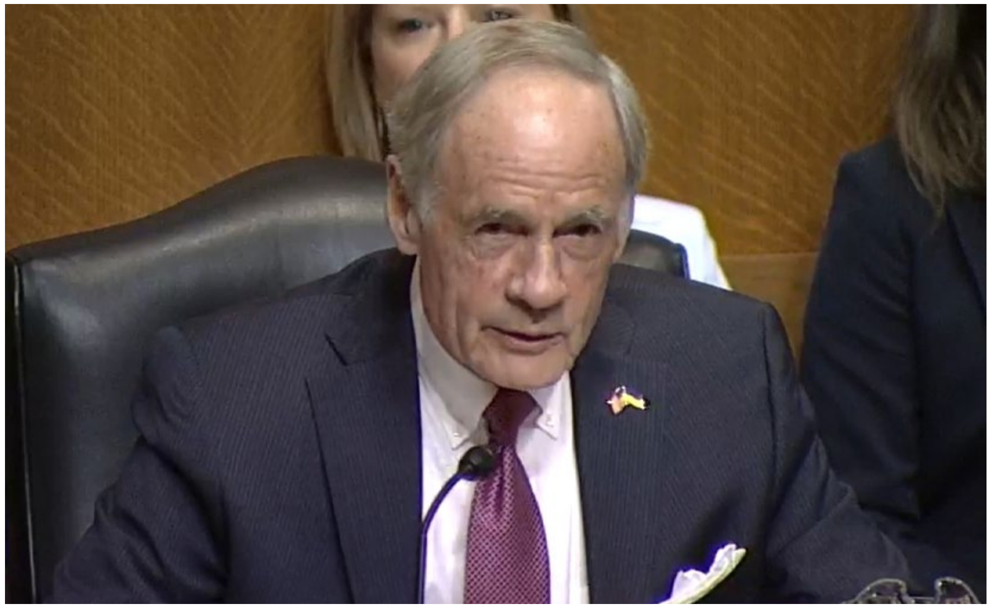
Durbin was one of five speakers at the EPW hearing, kicking off the search for bipartisan solutions to the permitting logjam facing clean energy and transmission projects, as well as those related to natural gas.

Sen. Shelley Moore Capito (R-W.Va.) | *Senate EPW Committee*

Both Committee Chair Tom Carper (D-Del.) and Ranking Member Shelley Moore Capito (R-W.Va.) stressed that a bipartisan bill passed through a "regular order" process — with committee hearings and negotiations, and broad stakeholder input — is needed to forge the needed compromises.

Carper's must-haves for "permitting reform," as the issue is commonly referred to, include lowering greenhouse gas emissions, maintaining "the fundamental protections provided by our nation's bedrock environmental statutes" and supporting "early and meaningful community engagement."

Legislation must also "provide businesses, especially clean energy businesses, with



Sen. Tom Carper (D-Del.) | *Senate EPW Committee*

certainty and predictability and help unlock economic growth," he said.

Capito wants a technology- and project-neutral approach with firm, enforceable deadlines for permitting and an expedited process for deciding legal challenges so projects don't "drown in litigation." She called for amendments not only to the National Environmental Policy Act (NEPA) but also to the Clean Water and Clean Air acts.

Permitting challenges "don't just impact [project] sponsors," Capito said. "They harm American workers and consumers with lost jobs, higher energy prices, traffic congestion, more pollution and many other missed opportunities that result from the failure to modernize infrastructure and energy systems. …

"If all we do is window-dress the failed system, it's not an option. We're not getting anywhere," she said. "At the end of an honest negotiation, neither side will get exactly what it wants, and we all know that."

Common Ground

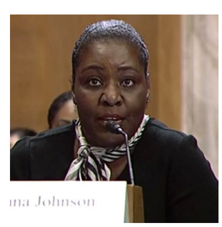
While Congress remains preoccupied with raising the debt limit, bipartisan efforts to find common ground on permitting reform are underway in both houses, driven in part by the billions for clean energy projects and other infrastructure in the IIJA and IRA. (See *Congress Doubling Down on Bipartisan Push for 'Permitting Reform.'*)

The EPW hearing focused on identifying both common ground and the harder-to-resolve flashpoints.

On the plus side were calls for early and robust community engagement and a close look at how to streamline permitting processes across federal agencies.

Christy Goldfuss, NRDC | *Senate EPW Committee*

"The U.S. must shift the value proposition around clean energy deployment and transmission and move to a model that delivers more benefits directly to communities that host this clean energy infrastructure while providing the benefits of clean energy to everyone," said Christy Goldfuss, chief policy impact officer of the Natural Resources Defense Council. "This shift will lead to less opposition and therefore faster timelines for getting clean energy projects and transmission deployed at scale."



Dana Johnson, WE ACT for Environmental Justice | *Senate EPW Committee*

Dana Johnson, senior director of strategy and federal policy at WE

FERC/Federal News

ACT for Environmental Justice, agreed, "We really need to start community engagement much earlier in the process … Advocates in that space noticed that when industry comes to them, when they are able to negotiate, when we have community meetings before a permitting process even begins, we are able to work in partnership to solve the challenges of bringing a project to fruition."

The U.S. Chamber of Commerce also "fully support[s] the idea of having early engagement of affected communities with the project developers and everyone else involved," Durbin said. "We agree that that can help to offset problems later down the road."

Christina Hayes, ACEG | *Senate EPW Committee*

Streamlining processes — without changing existing statutes — also got strong support. Christina Hayes, executive director of Americans for a Clean Energy Grid, said construction of new transmission must be doubled "to have a chance at hitting our [greenhouse gas] reduction goals. …

"Specifically, high-capacity, regionally significant transmission should go through a unified federal siting and permitting authority," Hayes said. "Bright-line thresholds for unified federal siting and permitting authority should be clearly established, which when included [with] a single point of contact for environmental review will provide for a comprehensive and legally durable siting and permitting process."


Jay Timmons, NAM | *Senate EPW Committee*

Jay Timmons, CEO of the National Association of Manufacturers (NAM), also spoke in favor of "consolidated processes with enforceable deadlines for the siting of new energy projects, including hydrogen, natural gas, nuclear and other emerging technologies, along with their infrastructure."

Programmatic environmental impact statements (PEIS) could also promote more efficient permitting, Goldfuss said. A PEIS looks at environmental impacts across a specific region, for example, the *Desert Renewable Energy Conservation Plan*, which sets out areas for renewable energy development on more than 10 million acres of desert lands in seven counties in Southern California.

Such an approach could allow permitting to "move toward a 'design one, build many' model that decouples broad swaths of the environmental review process from individual project timelines," Hayes said.

ACEG also supports "Smart from the Start" planning, which means "planning and siting development in ways that minimize potential impacts and conflict before project-by-project permitting even begins," Hayes said.

'Permitting Myopia'

But any change to key environmental laws — like Capito's call for amendments to NEPA and other environmental laws — are likely to be a point of contention.

Timmons of NAM cited figures from the White House *Council on Environmental Quality* (CEQ) that the environmental impact statements that NEPA may require for some projects take an average of 4.5 years to complete.

"More time is spent just projecting potential environmental impacts than it takes to actually construct and operate a clean hydrogen power generation facility," Timmons said. "We can and we should still set high standards for ourselves. Let's just modernize the process [so there are] fewer delays, fewer needless losses."

But Johnson argued that the delays and long permitting timelines attributed to NEPA are overstated, citing *decade-old estimates* from the Government Accountability Office that less than 1% of federal projects require a full environmental impact statement. Only 5% require a less rigorous environmental assessment and 95% receive a categorical exclusion, meaning no environmental review is required, she said.

Johnson also pointed to interconnection bottlenecks, not NEPA, as a major factor in delays for renewable energy projects. Other reasons for delays of large-scale energy projects include "poor project management, poor contracting approaches, contractors' financial issues, delayed approvals, delayed payments, clients' financial issues [and] challenges with the actual design of a project," she said.

Goldfuss agreed that "permitting myopia" has put too much attention on NEPA. "Broad claims that the permitting process … is broken and that NEPA is the problem are not borne out by the facts," she said.

Instead, she called on FERC to use its "backstop authority," established in the IIJA, to site lines within "corridors of national interest," which [the Department of Energy] must designate.

Using this authority would mean FERC could overrule state regulators and local policy makers' decisions on such projects, something it has yet to do.

FERC must also act broadly to allocate costs for large transmission projects crossing more than one state, Goldfuss said. If not, "Congress should pass legislation requiring FERC to adopt cost allocation rules that holistically reflect the multiple benefits of transmission."

How effective such legislation might be is uncertain given FERC's stalled efforts to approve new transmission planning and cost allocation rules with its current membership of two Democrats and two Republicans.

Both Carper and Sen. Ed Markey also pointed to the $1 billion in IRA funding to help federal agencies hire new staff and improve their permitting processes. That money represents "a new cure," Markey said. "Now we're applying the medicine, and we're waiting for it to kick in."

The House Debt Ceiling Bill

The narrowly passed Republican bill on the debt ceiling was a tangential concern in Wednesday's hearing.

Markey noted that the spending cuts in the bill would include the $1 billion to fund permitting improvements across federal agencies. "They want to starve the agencies and then say, 'Look how long it takes,'" he said.

He also defended NEPA as "a safeguard for communities. We need robust, upfront community engagement to power communities with clean energy while empowering them to be part of the [process]."

Sen. Sheldon Whitehouse (D-R.I.) grilled both Durbin and Timmons on whether they would support bipartisan permitting reform crafted by the EPW Committee versus GOP permitting changes in the debt ceiling law, which would primarily push for quicker permitting for fossil fuel projects.

Timmons sidestepped the question, saying NAM was not "going to engage in picking winners and losers between House versions and Senate versions. The interest is in working on a bipartisan … proposal that will actually get done, that everyone can feel good about."

Durbin said the Chamber had supported H.R. 1, the GOP energy bill included in the debt ceiling package. "We think it does move the ball forward," he said, but the organization also remains "fully committed to a bipartisan process." ■

FERC/Federal News

Congressional Republicans Seek Changes to Biden's Energy Policies

Attempt to Reduce Spending with Debt Ceiling Increase, Along with Criticism of FERC

By James Downing

During the same week President Joe Biden announced his re-election bid, congressional Republicans stepped up attacks on his energy agenda, with the House of Representatives passing legislation Wednesday trying to use the debt ceiling to force cuts on incentives.

Republicans from both the Senate Energy and Natural Resources Committee and the House Energy and Commerce Committee sent letters to FERC asking pointed questions about reliability, permitting and other issues as at least one of them gears up for oversight hearings. The Senate committee is holding its hearing this Thursday, while the House committee has yet to schedule one.

The Limit, Save, Grow Act of 2023 cleared the House on Wednesday on a 217-215 vote, with four Republicans voting against it and no Democrats agreeing to the measure, which would raise the debt ceiling at the expense of key Biden administration priorities.

"The Limit, Save, Grow Act is a common-sense approach to return to fiscal sanity by putting an end to Democrats' trillion-dollar spending sprees while ensuring veterans, Medicare and Social Security programs are strengthened and preserved," House Speaker Kevin McCarthy (R-Calif.) and other members of leadership said in a statement. "It will save taxpayers trillions of dollars by reclaiming unused COVID funds, stopping Biden's student loan giveaway to the wealthy and defunding his army of IRS agents."

Democrats uniformly trashed the bill, with the White House releasing a statement saying

The U.S. Capitol Building | *David Maiolo, CC BY-SA-3.0, via Wikimedia*

FERC/Federal News

that "the president has made clear this bill has no chance of becoming law" and calling on the House to raise the debt limit without strings attached. House Energy Committee Ranking Member Frank Pallone (D-N.J.) said the legislation puts polluters ahead of people.

"The bill repeals key climate provisions that Democrats delivered with the Inflation Reduction Act last year that are already making a huge difference in the clean energy transition," Pallone said in a statement. "Since its passage, we've seen about $28 billion in new domestic manufacturing investments. Companies have announced $242 billion in new clean power capital investments, and more than 142,000 clean energy jobs have been created across the nation."

FERC Oversight

Senate ENR Committee Ranking Member John Barrasso (R-Wyo.) sent a *letter* to FERC on Wednesday asking commissioners a number of questions about reliability and natural gas permitting. Committee Chair Joe Manchin's (D-W.Va.) staff declined to comment on the hearing.

NERC, several ISO/RTOs and others have expressed serious concerns about the future of reliability on their grids, Barrasso said.

"You must do all that prudently may be done to enhance reliability and control electric costs for families and businesses," he added.

Barrasso asked questions about what the impact of electrification efforts would have on reliability and affordability. He also focused on the recent report out of PJM saying about 40 GW is at risk of retirement largely because of state policies and the tight operations the RTO had near Christmas 2022. (See *PJM Board Initiates Fast-Track Process to Address Reliability*.)

"If electric grids suffer frequent reliability events or increasing reliability risks, doesn't the underlying structure of the markets responsible for the grid become unjust and unreasonable under the" Federal Power Act? Barrasso asked.

The senator praised FERC's recent approval of LNG export facilities in light of the ongoing invasion of Ukraine, but he also said the commission should get rid of the proposals pushed by former Chair Richard Glick to review the climate impacts of natural gas infrastructure.

"Both natural gas policy statements remain in draft form," Barrasso said. "Under no circumstances should the commission attempt to finalize these policy statements in anything like their current form. They must be scrapped."

In January the White House Council on Environmental Quality has issued an "interim GHG guidance" for federal agencies, and Barrasso asked whether and how FERC plans to apply that to its regulations.

House Energy Committee Chair Cathy McMorris Rodgers (R-Wash.) and Rep. Jeff Duncan (R-S.C.) — chair of the committee's Energy, Climate and Grid Security Subcommittee — also wrote FERC a *letter* on Wednesday focusing on reliability in ISO/RTO regions. They want answers by May 10.

They pointed to rolling blackouts in CAISO, shortages in MISO and SPP, and PJM's recent report about the 40 GW of potential retirements.

"The commission, as the federal agency responsible for the regulation of the nation's organized wholesale electricity markets, must better understand how RTOs/ISOs have affected electric reliability," the committee leaders said. "It is long past due for the commission to fulfill its statutory role by conducting a thorough, unbiased analysis on the reliability impacts of a policy for which it has advocated for more than 20 years."

The letter has several questions drilling into that topic including asking for a comparison between RTOs and traditional regulation when it comes to reliability. The letter also notes that generators have not been able to secure firm gas in the markets and asks if FERC ensures that market designs allow for that.

Some Want Solar Tariffs Back

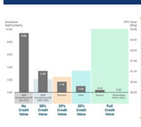
Sen. Manchin also announced last week that he was signing onto a joint resolution under the Congressional Review Act that would reimpose tariffs on solar cells from Asia, which President Biden had suspended as it led to shortages in supply. The main sponsor of *S.J. Resolution 15* is Sen. Rick Scott (R-Fla.), and Manchin is the lone Democrat among nine co-sponsors.

"The United States relies on foreign nations, like China, for far too many of our energy needs, and failing to enforce our existing trade laws undermines the goals of the [Infrastructure Investment and Jobs Act] and Inflation Reduction Act to onshore our energy supply chains, including solar," said Manchin. "I cannot fathom why the administration and Congress would consider extending that reliance any longer and am proud to join this CRA to rescind the rule."

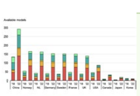
A similar bill cleared the House Ways and Means Committee on April 19; the Solar Energy Industries Association criticized the proposal in response.

"The United States currently lacks the capacity to produce solar panels and cells in adequate volumes to meet domestic demand," SEIA CEO Abigail Ross Hopper said. "The two-year duty moratorium allows planned solar installations to move forward while we scale domestic manufacturing in the near term. This strategic approach protects existing jobs while new ones are added, but it also helps sustain the robust environmental, national security and job-creating benefits offered by U.S. solar deployment." ■

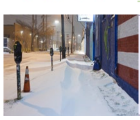
National/Federal news from our other channels



How Green is that Green Hydrogen? NetZero Insider



IEA Reports on Global Growth of EVs NetZero Insider



FERC Denies Rehearing on Cold Weather Standards ERO Insider

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

FERC/Federal News

Former Chairs, Rep. Casten Call for Bolder FERC

Agency Urged to Disregard Politics and Get Needed Work Done

By James Downing

From left: Voltus CEO Gregg Dixon, former FERC Chair Jon Wellinghoff, former FERC Chair Neil Chatterjee, and U.S. Rep. Sean Casten (D-Ill.) | *© RTO Insider LLC*

LEESBURG, Va. — FERC has become too politicized and should use its independent authority to move the electricity industry forward, two former commission chairs said April 24 at an event hosted by aggregation company Voltus in Northern Virginia.

Former Chair Neil Chatterjee, now a senior adviser with Hogan Lovells, said he has developed a relationship over the years with Voltus Chief Regulatory Officer Jon Wellinghoff, who chaired FERC under President Barack Obama, because during his tenure at the agency, he looked to build on his predecessor's work through major orders.

Wellinghoff was the force behind *Order 745* on demand response compensation, which became the subject of a U.S. Supreme Court case affirming FERC's jurisdiction over demand side resources, and Chatterjee helped shepherd through several orders expanding its authority in that area.

"A lot of what ultimately culminated in [orders] 841 and 2222, and 845, was me building upon the work that he had already done," said Chatterjee. "And that's how FERC needs to be. It was an independent agency because you actually didn't know the partisan affiliations of the different commissioners."

Now articles regularly spell out the political affiliation of the commissioners. (For the record, Chatterjee was a Republican appointee, and Wellinghoff was a Democrat.) Chatterjee argued parties should not matter.

"When it comes to something like the proper functioning of markets and the oversight and the reliability of the grid, these things should be independent and above politics," he said.

While Chatterjee got the initial Order 2222 through, many compliance filings are still before FERC. Wellinghoff said he hoped the commission would move those through and ensure that market rules for distributed energy resources are in line with the order.

"I hope that FERC does step up under 2222 — that they do carry out the spirit and intent of what you started there and actually ensure that these distributed resources do have a full opportunity to play in this market," Wellinghoff said. "Because if they do, the potential is huge."

Some forecasts put 28 million electric vehicles on U.S. roads by 2030, a figure that could double based on EPA's recent proposed emissions rules. (See *EPA Releases Emissions Rules Aimed at Boosting EVs*.) But even the smaller number means the country's behind-the-meter battery capacity will exceed its generating capacity, Wellinghoff said.

"It's going to be available to be used, and we have to effectuate the ability to use that resource," he said. "FERC is in the trenches on that right now."

Reason to be Proud

U.S. Rep Sean Casten (D-Ill.), a major supporter of FERC on Capitol Hill, said the commission has plenty of authority to move the needle on energy policy on its own, although it sometimes needs a push from Congress to get going. He has introduced a bill — the *REDUCE Act* — that would remove the state opt-out for wholesale demand response programs, as well as other bills on transmission, and he wants FERC to set a price on carbon to give zero-carbon assets their proper value on a grid awash in resources that have no marginal costs.

"I think a strong case can be made that FERC has authority, but perhaps not the obligation," Casten said. "And whether it's the REDUCE Act or others, we find ourselves in Congress saying, 'Well, let's just give you the obligation.'"

Casten argued that FERC is the most important agency for climate policy and said its adoption of wholesale competition, which led to rapid growth in natural gas combined cycle plants and a surge in capacity uprates for existing nuclear plants, was the main reason the industry moved away from coal.

"FERC's power comes from authority and independence," Casten said. "And I think FERC is a little bit afraid of its own shadow."

Casten said the fact that former FERC Chair Richard Glick was denied a renomination hearing after endorsing policies opposed by Senate Energy and Natural Resources Committee Chair Joe Manchin (D-W.Va.) — particularly around the climate impacts of natural gas pipelines — has also put a chill on the agency.

"My view is if you are appointed to a term running an agency as powerful as FERC, or a commissioner on an agency as powerful as FERC, you have five years to tell your grandchildren that 'you have reason to be proud of me,'" Casten said.

Worrying about whether a policy will impact a renomination hearing or offend a particular senator is no way to go about the job, he said.

FERC has been impacted by politics long before Manchin denied Glick a hearing, with Wellinghoff lamenting the fact that "Standard Market Design" for RTOs never got off the launching pad under Chair Pat Wood during President George W. Bush's first term.

"It used to drive me nuts at FERC when an order came in from an RTO and the words were different for the same thing," said Wellinghoff. "It's like we're in Europe, you know — PJM speaks Italian, and MISO speaks German."

Wood tried to push through a reform that would have the same market design all around the country, but he was ultimately "run out of town" by powerful utility interests who were opposed to having independent markets, Wellinghoff said. ■

CAISO/West News

Committee Gives CAISO RTO Bill a Cool Reception

By Hudson Sangree

California lawmakers voiced their concerns Wednesday with a bill that could eventually allow CAISO to become an RTO with a governing body independent of the state's governor and legislature.

Assemblyman Christopher Holden | *California Assembly*

Assembly Bill 538, by Assemblymember Christopher Holden, had its first legislative *hearing* before the Assembly Utilities and Energy Committee, of which Holden is a member and former chair.

The committee members allowed the bill to move on to the Assembly Appropriations Committee, chaired by Holden, but only after expressing their discomfort with the measure as it is now written and seeking assurances from Holden that he would make changes going forward.

Chief among their problems with Holden's measure was the potential lack of legislative oversight of an independent CAISO board. Another was the effect on in-state jobs. Labor unions, which wield strong political clout in California, vehemently oppose the measure because they believe it could lead to generation projects being built in neighboring states.

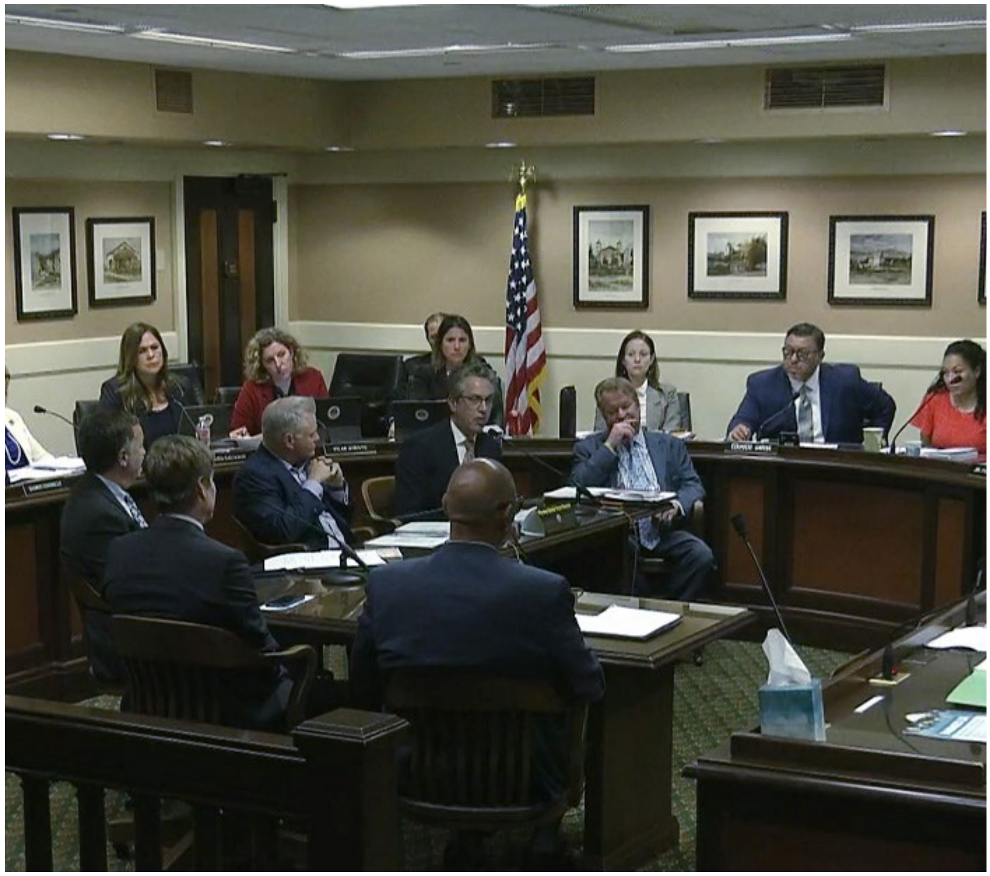
Assembly Utilities and Energy Committee Chair Eduardo Garcia | *California Assembly*

"We've really focused on the issue of the impacts on jobs and bringing the CAISO governance back to the legislature," Committee Chair Eduardo Garcia said.

The bill remains a work in progress, and Holden has committed to "resolving a lot of the difficult points … that still need some ironing out," Garcia said. That includes "wanting to have legislative oversight and some type of check-in."

"To my friends in labor and others who strongly oppose this bill … there will continue to be some conversations," he said.

CAISO is a public benefit corporation created by the legislature in 1998. The governor appoints its Board of Governors, and the state



Lawmakers listen to testimony from supporters and opponents of Assembly Bill 538. | *California Assembly*

Senate confirms them. That effectively makes all board members Californians, though it is not expressly required by statute.

CAISO's one-state governance has been the main sticking point in regionalization efforts. California lawmakers have refused to cede control, and other Western states will not join an RTO controlled by California politicians.

Holden's prior efforts to expand CAISO governance to include other states in 2017/18 failed because of opposition from his fellow Democrats in the legislature.

Like those efforts, AB 538 lays out a process for CAISO to develop its own proposal for independent governance without requiring legislative approval. (See *Lawmaker Introduces Bill to Turn CAISO into RTO*.)

"The Independent System Operator's Board of Governors may develop and submit to the [California] Energy Commission a governance proposal," it says. "The Independent System Operator shall provide notice and a copy of this submission to the Legislature and the Governor at the same time as it is submitted to the Energy Commission."

The Energy Commission and the state Air Resources Board would review the governance plan, holding public workshops and providing written comments, the bill says. The commission would then submit the proposal to the governor and legislature, but the measure is silent on whether lawmakers and the governor would have final say.

AB 538 would also require the formation of a Western states committee with an equal number of representatives from states with participating transmission owners in CAISO.

"The representatives from California shall be appointed by the Governor, subject to confirmation by the Senate. The committee shall provide guidance to the Independent System Operator on all matters of interest to more than one state," it says.

'Another RTO'

Committee members and opponents of the measure told Holden they could not accept the

CAISO/West News

lack of legislative oversight, the vague role of the Western states committee or the idea that California, which makes up about a third of the load in the Western Interconnection, might have the same number of votes as less-populated states.

Matthew Freedman, TURN | *California Assembly*

"Under this bill, California would give up meaningful control over the California ISO, marginalize the role of its elected officials and state regulators and invite greater involvement by the federal government and hostile private interests throughout the West," said Matthew Freedman, staff attorney with The Utility Reform Network, a ratepayer advocacy group that opposes the bill.

"If this bill passes, it's the last bill the legislature will ever consider relating to wholesale electricity markets," Freedman said. "The creation of a multistate RTO divests the legislature from having any ongoing role, and, in fact, you're being asked to make yourselves and state agencies and the governor completely irrelevant."

Proponents of the measure said it would further the 100% clean energy goals of California and other states in the West, reduce costs for ratepayers and promote reliability through centralized dispatch operations.

They noted that circumstances have changed substantially in the five years since Holden's prior attempts to make CAISO a multistate RTO.

The West has experienced strained supply during extreme weather, including blackouts and near misses the past three summers in California. More states, cities and utilities have adopted 100% clean energy goals like California's, requiring new transmission to move wind and solar power long distances. And two states, Nevada and Colorado, enacted requirements that their major transmission owners join RTOs by 2030.

They also noted that SPP is planning to establish a Western version of its Eastern Interconnection RTO, called RTO West.

Jan Smutny-Jones, Independent Energy Producers Association | *California Assembly*

"There is another RTO forming in the West, and you need to be aware of this," Jan Smutny-Jones, CEO of the Independent Energy Producers Association, told committee members. "It's called the Southwest Power Pool, out of Little Rock, Arkansas. They're aggressively working in our neighboring states to try to get them to join their RTO. This will be a different RTO than the one that would be built by the ISO."

SPP also has the Western Energy Imbalance Service and is developing Markets+, a program with a day-ahead market. The development of Markets+ and an SPP RTO could erode CAISO's successful Western Energy Imbalance Market, because participants in SPP's markets will not want to be in both, Smutny-Jones said. ■

Colo. Solar Project Beset by Supply Delays Wins FERC Extension

By Robert Mullin

A Colorado solar-and-battery project facing ongoing supply chain disruptions can postpone its operational start date by 21 months, FERC decided in a 3-1 vote last week.

The ruling means that the 100-MW Front Range-Midway Solar project, which will interconnect into the Public Service Company of Colorado (PSCo) balancing area, might commence commercial operation nearly 10 years later than originally proposed (*ER23-1108*).

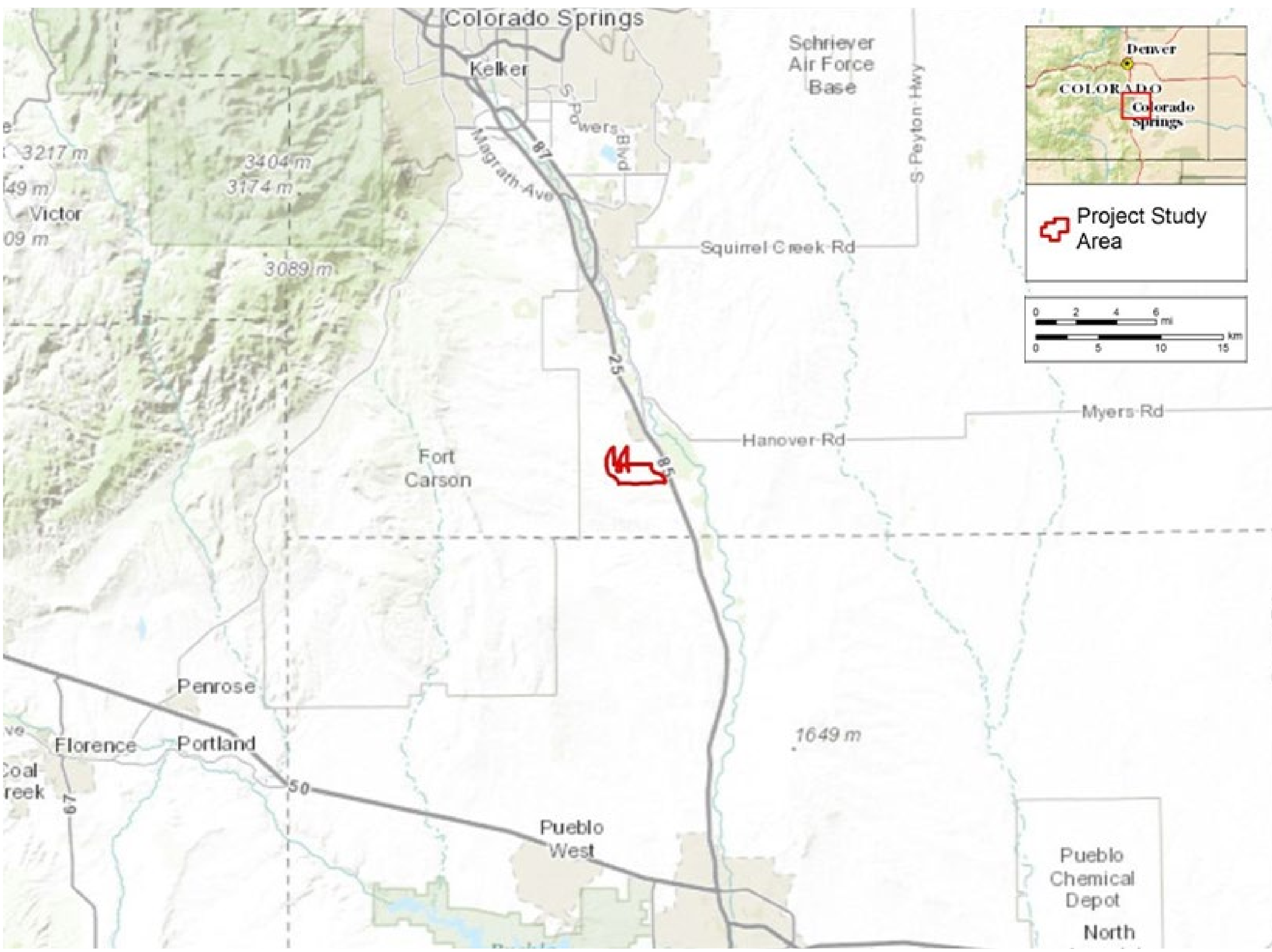
Xcel Energy subsidiary PSCo contested Front Range's February request to waive relevant sections of the utility's large generator interconnection procedures — and an amended large generator interconnection agreement (LGIA) — to allow the project to move its start date from March 31, 2024, to Dec. 31, 2025.

The Front Range project, which will pair a 100-MW solar photovoltaic facility with a 50-MW battery system, is being developed by Italy-based Enel and TradeWind Energy. The project was initially slated to begin commercial operation in July 2016 before Front Range and PSCo entered an amended LGIA that set a new deadline of Oct. 31, 2022.

In May 2022, FERC granted Front Range an 18-month extension to that deadline — to March 31, 2024 — "due to interruptions and delays in the project development process caused by the COVID-19 pandemic, port shutdowns within China and the prospect of new tariffs on modules."

In its most recent request for an extension, Front Range argued that additional supply chain disruptions have arisen since last May's order. They include power outages in China that have caused component capacity constraints, continued shipping delays for equipment and the U.S. government's June 2022 implementation of the Uyghur Forced Labor Prevention Act (UFLPA), which presumes that all goods coming from China's Xinjiang Uyghur Autonomous Region — the origin of many solar components — are the product of forced labor.

Front Range said it received a Notice of Detention from the U.S. Customs and Border Protection (CBP) in December for initial deliveries of PV modules that its supplier had



Location of the proposed Front Range Midway Solar project in Colorado | *Western EcoSystems Technology*

CAISO/West News

manufactured in China and delivered to a U.S. port. The company said that it does not expect the equipment will be released soon because CBP has not provided clear guidance on the standard necessary to overcome the presumption for detention under the UFLPA.

"As a result, Front Range states that it will need additional time to procure an alternative supply of PV modules for the project," FERC noted in its order April 25.

In its filing with FERC, Front Range contended that the project continues to be viable, noting that the developers have secured all necessary property rights to begin construction; negotiated easement agreements with PSCo and the Western Area Power Administration to construct the interconnection tie-line; completed necessary environmental assessments; obtained a critical permit from El Paso County; and posted the required financial security under the interconnection agreements.

Front Range said that since the May 2022 order, it has "procured the battery energy storage system and transformer, executed the purchase order for the necessary PV modules, and funded and completed the network upgrades delineated in the LGIA and surplus LGIA."

Waiver Requirements

Front Range also said its waiver request satisfies the commission's criteria for granting a waiver, contending that:

- the request was made in "good faith," as demonstrated by the progress the company has made in developing the project, which would have been completed last December "but for" the CBP detention of its equipment.
- the waiver is limited in scope, given that 21 months is a finite amount of time. Front Range also argued that the waiver would not relieve it of any financial obligations because it has already paid for the transmission upgrades needed to interconnect the project.
- the request seeks to address the "concrete problem" of overcoming the supply chain disruption created by the UFLPA and finding a new supplier.

Front Range also contended that the waiver would not cause harm to any third parties, given that it has already fully funded the need transmission upgrades.

In contesting the waiver request, PSCo argued that Front Range had previously exhausted its suspension right under the LGIA and noted that an additional waiver would push the project's commercial operation date to nearly a decade beyond the originally designated date.

The utility also contended that Front Range had not provided specific details about the impact of the UFLPA and the CBP's Notice of Detention, a point that Front Range later contested by saying that it had worked diligently to assemble the "traceability documentation" regarding the origins of its PV modules in order to expedite their release but was still awaiting review by CBP.

PSCo's protest also questioned the economic viability of the Front Range project, pointing out that the off-taker — the utility itself — had terminated its power purchase agreement for the project in January after Front Range failed to meet development milestones. The utility pointed to October and December 2022 letters from Front Range in which the company sought to renegotiate the PPA, say that current market conditions for solar development had rendered the original agreement "uneconomical and unfinanceable," raising questions about Front Range's assertion that completion hinged on the detention of the modules.

Front Range countered that the same letter stated that the project "has not failed" but was pointing to the fact that import restrictions had affected solar projects nationwide. The company said that PSCo had renegotiated PPAs for other solar projects and agreed to postpone their completion dates.

Commission Finding; Danly Dissent

In approving the extension, FERC determined that Front Range had satisfied its waiver criteria. The commission also found that, contrary to PSCo's assertion, the record demonstrated that Front Range has made "continued efforts" to contact the CBP to resolve the UFLPA matter.

The commission also dismissed PSCo's assertion that Front Range was seeking a waiver "merely to stay in an interconnection queue with the hope of securing an off-taker."

"Instead, Front Range provides evidence of global supply chain disruptions and ongoing permitting and regulatory approval processes since the May 2022 order affecting the project," the commission wrote.

FERC also said it was "not persuaded" by PSCo's contention that Front Range's 2022 letters to the utility suggested that the project was unlikely to be completed even before the UFLPA detention.

"While Front Range asserted that the project had become 'uneconomical' under the terms of the then-existing power purchase agreement while attempting to renegotiate those terms, we do not agree that this rendered the project unable to meet the March 31, 2024, commercial operation deadline, assuming that an agreement between the parties could have been reached," the commission said.

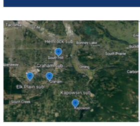
In a dissent against the ruling, Commissioner James Danly said Front Range's waiver "can hardly be" said to apply to a single deadline, given the project's previous delays.

"While implementation of the Uyghur Forced Labor Prevention Act in June 2022 may present new circumstances not at issue when the commission granted Front Range a prior waiver request, application of the UFLPA is an industry-wide issue and does not support a finding that granting a waiver here is limited in scope," Danly wrote.

He also argued that while Front Range had described its efforts to resolve the equipment detention issue, it did not explain any of its efforts to identify an alternative supplier for the PV modules.

"Front Range has also not addressed whether it has secured a new off-taker after termination of the power purchase agreement with PSCo due to Front Range's failure to meet project development milestones," he wrote. "Nor does Front Range state that it will construct the facility without an off-taker. For these reasons, Front Range fails to demonstrate that the waiver actually addresses a concrete problem." ■

West news from our other channels



Wash. Sabotage Suspect Pleads Guilty

ERO Insider

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

CAISO/West News

WECC Summer Outlook Weighs Hydropower, Wildfires

By Robert Mullin and Hudson Sangree

The West's heavy snowpack from this winter will be partly soaked up by soils parched during years of drought, limiting hydropower production throughout the summer in the Desert Southwest and Pacific Northwest, speakers said during WECC's annual summer outlook webinar on Wednesday and Thursday.

The two-day event offered a preview of summer conditions and operations in the Western Interconnection, with subjects that also included wildfires and extended weather forecasts.

"While we may have an increased amount of runoff initially, it doesn't mean that that runoff is just going to stay there unimpacted by the dried soils of the last couple of years," Sunny Wescott, lead meteorologist at the federal Cybersecurity and Infrastructure Security Agency, said in Wednesday's session. "Watching that snowpack melt, come down the mountains and get absorbed rapidly is going to be a condition that everyone needs to be aware of."

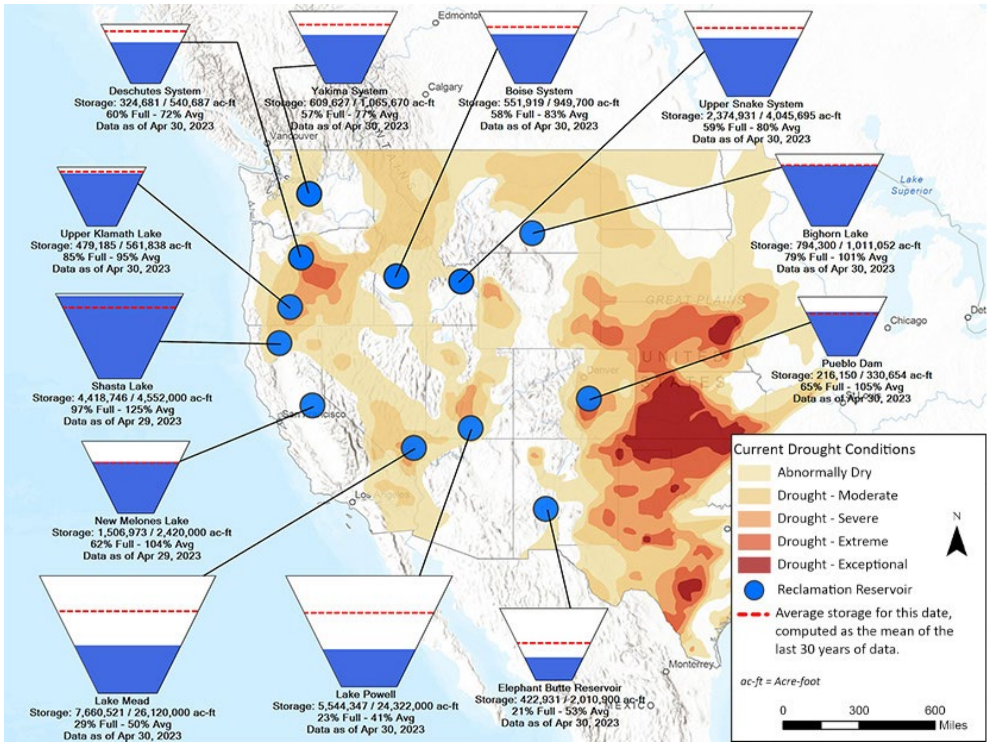
Clayton Palmer, an environmental specialist with the Western Area Power Administration, said the Southwest's decades-long "mega drought" has meant that since 1988, less water has reached hydroelectric reservoirs in a region where "water equals power."

"There's much less runoff for every millimeter of water that has fallen as precipitation during the winter period" from October through April, Palmer said.

Lake Mead and Lake Powell on the Colorado River have risen this winter as snow blanketed the Rocky Mountains, but the hydroelectric reservoirs remain significantly below their historical averages, he said. The Bureau of Reclamation is examining options for maintaining hydroelectric production at Hoover Dam, which has a 2,074-MW generating capacity, and Glen Canyon Dam, with a 1,320-MW capacity, in what is expected to be a drier future for the Colorado River Basin, he said.

"We shouldn't be using the word 'drought' since the word drought implies that something is temporary, that we have less water for a temporary period of time," Palmer said. "What we have is a 'drought,' to use that word in quotes, caused by an increase in temperature.

"The Colorado River Basin has increased in average temperature by 2 degrees Fahrenheit, and higher temperatures cause snowmelt to be absorbed in drier soils," he said. "The higher



Reservoirs in California are full, but those in the Southwest remain well below average. | *Bureau of Reclamation*

temperatures increase the dryness of the soils and increase evapotranspiration of the water that falls as snow … and decreases what we call the runoff efficiency. The runoff efficiency is how much of the water that falls as snow in the Colorado River Basin gets into the river."

Forecasted annual generation in the Colorado River Storage Project, which consists of Glen Canyon and other dams in the upper Colorado basin, for 2023 through 2027 will hover around 4 million MWh, compared with an average of about 6.5 million MWh from 1971 through 2000, Palmer said.

In the Pacific Northwest, precipitation was 20% below normal this winter, but temperatures were lower, meaning "our snowpack generally throughout the Columbia River Basin is above normal," said Geoffrey Walters, senior hydrologist with the Northwest River Forecast Center.

"On the other hand, another primary component to water supply volume forecasts is the soil conditions, and the soil conditions have been dry, and they've been dry throughout the winter," Walters said. "And because of those dry soil conditions, water supply volume forecasts are lower than maybe what you would perceive just looking at the current snowpack. That's because when soil moisture is drier than normal, it [takes] more of that melting snowpack before it allows the runoff to enter the rivers.

"Vegetation is also going to take more of the snowpack from the available downstream supply for power production or other uses," he said.

The center is predicting water supply that is 83% of the normal April-to-September volume at Grand Coulee Dam, which has a generating capacity of 6,809 MW. At the Dalles Dam, which has a 1,780-MW capacity and is a key measuring point for Columbia River water flow, supply will be 85% of normal this summer, Walters said.

Wildfire Outlook

On Thursday, WECC took up the topic of wildfires.

While wildfires are not exclusive to the West, they are "a particularly Western concern," Vic Howell, WECC director of reliability risk management, said Thursday in opening a panel on summer wildfire preparations.

Howell asked panelists about the biggest concerns their utilities have related to fires.

Chris Potter, control center real-time manager

CAISO/West News

with AltaLink, said it's all about "location, location, location" for the Alberta, Canada-based transmission provider, indicating that risks vary by geography.

Potter described the region's "Chinooks," a weather phenomenon occurring in the southern part of the province in which warm and dry westerly winds blow off the Rocky Mountains onto the prairie, rapidly elevating temperatures by as much as 50 F. Wind speeds during those events can reach 60 mph, he said.

"The biggest risk for us is that wind, because if we were to have a line that goes down, which is obviously more probable, in the high wind conditions … [if it starts a fire], it's going to spread very, very quickly and cover a lot of ground," Potter said.

Alberta also faces a risk of utility pole fires, he said, particularly along highway corridors lined with wood poles supporting wooden cross-arms. These fires are usually the result of automobiles kicking up dust containing road salt, which causes deterioration on the transmission line insulators, increasing the risk of line arcing under damp conditions, which can set fires to the poles.

"Wind-driven events" present the biggest risk in Southern California Edison's 50,000-square-mile territory, nearly 30% of which is considered at high risk of wildfire, according to Raymond Fugere, the utility's director of wildfire safety. Fugere pointed to two "big drivers" of wind-driven fires for SCE: when airborne "foreign objects" come into contact with power lines, causing them to fall; and "line slap," which can eject molten particles onto the ground and ignite fires.

Christopher Sanford, senior system operator with the Bonneville Power Administration, vouched for the foreign object risk.

"When I was a system operator, getting a call that a trampoline is hanging in a line 40 feet above the ground, it's kind of bizarre, but those things do happen," Sanford said, adding that BPA is seeing high winds more frequently now than even 10 years ago.

"We can see a microburst with 100-mph winds and dry lightning, and that's a great combination for starting fires," he said.

As a federal power agency that operates about 15,000 miles of transmission but no distribution lines, BPA is also concerned about having clear communication and coordination with other entities in the region during high fire-threat events.

"BPA's actions are influenced by what other utilities do, whether it's an adjacent [transmission operator], or it's one of our distribution customers. … Our impact when we take out a line under a public safety power shutoff [PSPS] can be far greater than a local area impact. [If] we take out significant transmission for wildfire prevention, that could impact down into California and up into Canada," Sanford said.

System Hardening

Turning to the subject of potentially new challenges Western utilities will face during the upcoming wildfire season, Fugere pointed to the fact that while 95% of California was in drought conditions a year ago, that figure has dropped to zero after a winter of heavy rain and snow.

"So that is going to present some very unique challenges," Fugere said, including an increase in "grass crop growth," which elevates the risk of roadside fires ignited by cars. This will require the utility to adjust its schedule for "structural brushing," the process of clearing grass and brush around the base of utility poles to prevent sparks from setting fires. The increase in soil moisture this year means the grass will grow back after an initial clearing.

Sanford said that while Northwest winter precipitation levels were not as extreme as in California, the season was wet enough to pose particular concerns for the grasslands of central Oregon and Washington.

"We do take on similar actions with system hardening with clearing around wood poles, [and] clearing and using other techniques to preserve wooden poles to reduce the impact of an outage," Sanford said. "We've also done a lot of hardening around our substations," including clearing brush to a perimeter of 50 feet where permitted. He said such actions have in the past created "well defended" areas that can function as a fire command post.

Fugere and his colleague Cameron McPherson extolled the success of SCE's wildfire prevention efforts. Fugere said the utility has seen a 98% reduction in the number of structures burned within its territory since initiating fire-hardening measures in 2017, even while facing more extreme drought conditions.

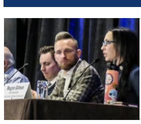
"Our insurance company has told us that we reduced our risk for catastrophic wildfires probably by about 80% — of have a fire that will hit a billion dollars [in costs]. So that's the mark we're really driving towards also. We want to continue to drive that down as far as we can," Fugere said.

McPherson, SCE's principal manager for PSPS operations, said the utility's efforts have significantly reduced the need for shutoffs, relegating their use to the most extreme weather events.

"Although used sparingly, due to the impact it has on our customers, there's no doubt it's extremely effective once we de-energize the lights," he said. "The question then becomes, was there a potential fault condition on the line, had it been energized, that could have led to a catastrophic wildfire?"

McPherson said the findings from post-PSPS patrols indicate that SCE's hardening efforts are paying off. He thinks the utility may even have the opportunity to raise the wind-speed thresholds for invoking PSPS in order to reduce their "scope, frequency and duration." ■

West news from our other channels



Nev. Bill Would Require Gas Company Efficiency, GHG Plans — NetZero Insider

CARB Approves Clean Locomotives Regulation — NetZero Insider

CARB Adopts Clean Fleets Rule Despite Broad Skepticism — NetZero Insider

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

ERCOT News

CenterPoint's $43B Capex Plan on Track

Houston Utility's Earnings Beat Wall Street Projections

By Tom Kleckner

CenterPoint Energy navigated high interest rates and milder winter weather to turn in a "tremendous start" to 2023, the company said last week.

"We also have great momentum from the continued execution of our long-term growth strategy through which we have deployed more than $8 billion of capital over the past two years," CEO David Lesar told financial analysts Thursday.

The Houston-based company reported earnings of $313 million ($0.49/diluted share), compared to $518 million ($0.82/diluted share) for the first quarter of 2022. Last year's opening quarter included gains from the sale of Energy Transfer common and preferred units and local gas distributors in Arkansas and Oklahoma.

CenterPoint's adjusted earnings of 50 cents/share beat the Zacks consensus estimate of 48 cents, the 12th straight quarter it has met or exceeded expectations.

The utility said it deployed about $1 billion of the $3.6 billion capital it has planned for the year during the quarter. It has a long-term goal of investing $43 billion of capital through 2030 in its Texas and Indiana footprints.

Legislative and regulatory decisions went CenterPoint's way during the quarter. Texas issued its state gas company about $1.1 billion of securitization funds related to the extraordinary gas costs it incurred during the February 2021 winter storm. The bonds are not on the utility's balance sheet.

The Texas Public Utility Commission also approved the recovery of costs incurred during the storm for its leased emergency temporary mobile generation units.

"It highlights the commission's awareness of the important role of this critical tool can play to help mitigate the number and duration of customer outages during extreme weather events," Lesar said.

On Wednesday, CenterPoint filed an *integrated resource plan* (IRP) for its Indiana business that would end its use of the state's coal by 2027. The company *said* the proposed plan will save customers nearly $80 million compared to the continued use of coal and will reduce carbon emissions by more than 95% over the next 20 years.

Coal generation currently accounts for 85% of the electricity for the utility's southwest Indiana customers. By 2030, CenterPoint projects more than 80% of its electricity in the state will be generated by solar and wind, with natural gas providing the rest.

The company plans to convert its last coal plant, F.B. Culley 3, to natural gas by 2027 and maintain its 270-MW capacity. It will also add 200 MW of wind and 200 MW of solar by 2030; another 400 MW of wind resources could be added by 2032.

CenterPoint plans to submit the final IRP to the Indiana Utility Regulatory Commission by June 1, with a response expected next year. The plan is also designed to comply with MISO's new, more stringent capacity requirements to meet peak energy demand across all four seasons. The company serves 150,000 customers in southwestern Indiana.

CenterPoint's share price finished the week at $30.47, a gain of 12 cents from Wednesday's close. ■

CenterPoint plans to go coal-free in Indiana by 2030. | *CenterPoint Energy*

ISO-NE Stakeholders OK DER Aggregation Plans, Generator Relief

By Rich Heidorn Jr.

The NEPOOL Markets Committee last week approved ISO-NE's proposed compliance filing to FERC on distributed energy resource aggregation but rejected the RTO's concerns in backing LS Power's bid to save Ocean State Power's (OSP) capacity supply obligation (CSO).

The committee overwhelmingly supported *tariff changes* to allow the gas-fired combined cycle plant to unwind a 64-MW capacity increase while maintaining its CSO for its existing 270 MW.

In Forward Capacity Auction 15, Ocean State Power cleared as a "repowering" to increase its output to 334 MW, a 24% increase, and was awarded a seven-year rate lock at $3.98/kW-month.

LS Power's Dilemma

Since winning the award, however, LS Power has become concerned it may not be able to complete the upgrade economically — and by the RTO's June 1, 2026, deadline for commercial operation — because of rising prices and supply chain challenges.

The company said it was surprised to learn that failing to add the incremental capacity as promised could cause it to lose its CSO for its existing capacity. "Under the ISO's interpretation of the tariff, there is no way for a 'repowered' resource to unwind future [Forward Capacity Market] commitments, leading to an unexpected and nonsensical 'bet-the-plant' situation," it said in a *presentation* by Ben Griffiths, director of New England market policy. "If OSP had cleared as greenfield new or as a minor uprate, we would not be here today: The tariff is unambiguous in the ability of these resources to shed incremental obligations."

The company's proposed tariff change would allow it to cancel the 64 MW of incremental capacity while ensuring the RTO retains 270 MW of capacity. The plant, in Burrillville, R.I., has connections to two interstate pipelines and 2 million gallons of on-site oil storage, enough for three days at full output.

The company said it would accept the same penalties that would apply if a minor uprate (less than 20%) or a greenfield project were terminated: forfeiture of the price lock and $2 million in financial assurance on the 64 MW that OSP cleared in FCAs 15 to 17.

Southeast New England customers would avoid having to pay $3.98/kW-month for 334 MW of capacity in FCAs 16 to 21, LS Power said. Because the two most recent auctions cleared around $2.60/kW-month, the savings would be about $15 million in FCAs 16 and 17, it said. Generators would benefit from the elimination of 64 MW of capacity from the supply stack in future auctions.

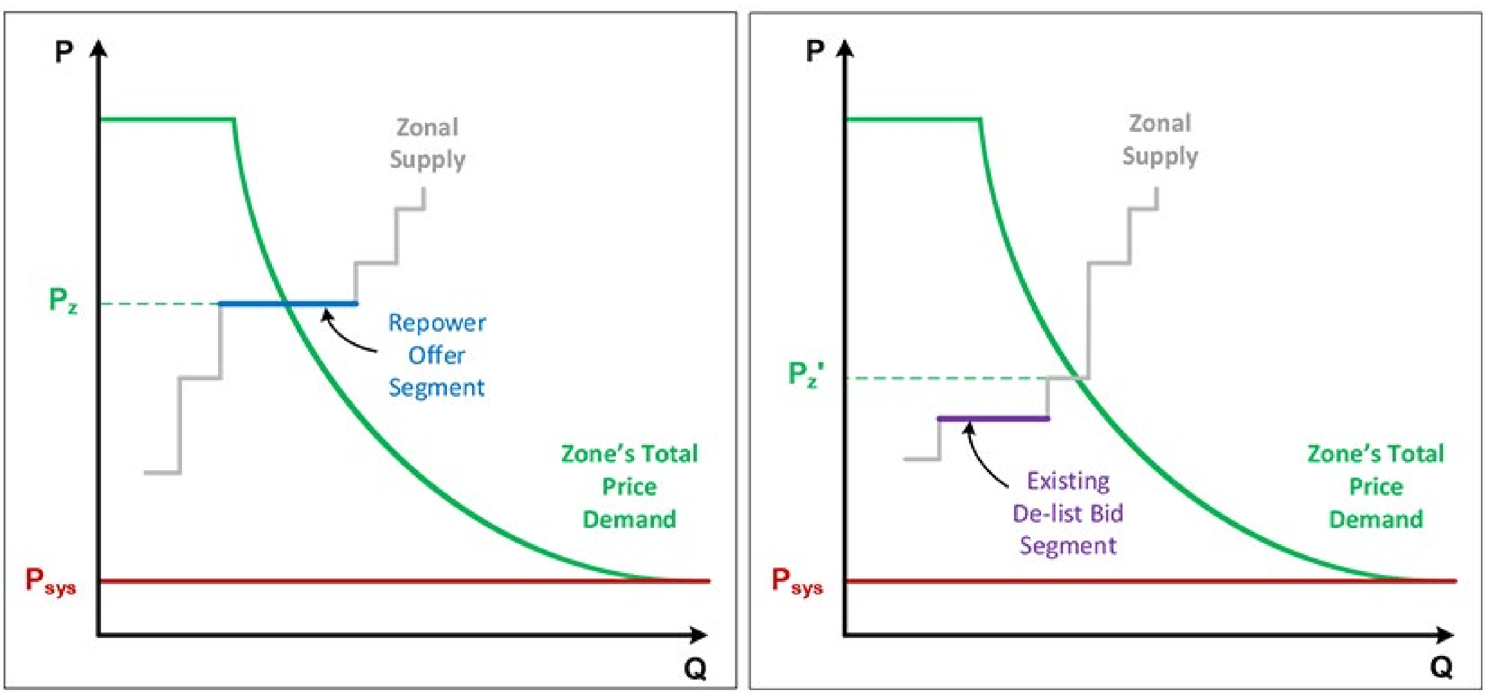
The company said the current repowering provisions were intended to allow existing capacity to obtain price locks, which are no longer permitted.

It said market power concerns in current rules were over the ability of only new resources to set the clearing price. Now that existing resources can set clearing prices, "concerns about toggling between new/existing do not matter in [the] same way," it said.

The company said the 20% threshold for repowering is "largely arbitrary" for market mitigation. "Our 64-MW 'repowering' … would have been considered an uprate if OSP had a starting capacity of 320 MW instead of 270 MW," it said.

ISO-NE's Internal Market Monitor issued a *memo* saying it needs more time to vet the design changes and market power considerations.

"We do think taking a fresh look at the repowering rules in the tariff is a good idea, but



The effect on Forward Capacity Auction outcomes if a marginal new repower offer clears and sets the zonal clearing price (Figure 1) and the effects if the existing capacity instead is awarded a Capacity Supply Obligation with an infra-marginal de-list bid (Figure 2). | *ISO-NE*

ISO-NE News

we have a number of concerns with the proposed rule changes and the short evaluation time frame. In summary, the evaluation will need to assess incentives to limit the exercise of market power and gaming, and provide a clear and commensurate remedy if a participant is unable to perform on its repowering obligation," the Monitor said.

The current rules were "intended to act as a strong deterrent to potentially setting a higher clearing price and securing a multiyear revenue stream, and subsequently toggling back to the original status," the Monitor added. "This proposal does not factor in the potential market harm caused by the clearing of the repowering resource in the FCA, and may not adequately incentivize market participants to deliver on obligations obtained in the auction."

Andrew Gillespie, the RTO's director of market development, also weighed in with a separate *memo*.

Gillespie said the RTO's primary concern is "the incentive and appropriate compensation problems created if existing capacity effectively participates in the FCA as new capacity and sets the FCA clearing price." He noted that new capacity offers are subject only to buyer-side mitigation, with no downward mitigation.

Despite the RTO's concerns, LS Power's motion passed the committee with 83% of the vote, with unanimous support (excluding abstentions) from the Generation, Transmission, Supplier, Alternative Resources and End User sectors. The Publicly Owned Entity sector was unanimous in opposition.

The proposal will next be considered by the Participants Committee. But it's far from certain that FERC would approve it, given the IMM's concern that it would amount to retroactive ratemaking.

Compliance Filing on DER Aggregation

The committee also voted overwhelmingly in support of the RTO's proposed response to FERC's March 1 order requiring changes to its rules for DER aggregations under Order 2222 (ER22-983). (See *FERC Gives ISO-NE Homework on Order 2222*.)

Renewable energy groups had criticized ISO-NE for not going far enough to remove barriers for DERs to participate in wholesale markets, as required by Order 2222.

The commission agreed, saying the RTO failed to show that its proposed energy and ancillary services market participation models accommodate the physical and operational characteristics of behind-the-meter DERs. It flagged ISO-NE's choice to require measurement of most behind-the-meter DERs at the retail delivery point, rather than allowing sub-metering.

Henry Yoshimura, director of demand resource strategy, *presented* the new filing, which the RTO plans to submit by May 9. The filing addresses six issues raised by FERC.

The RTO drafted tariff revisions for four items:

- small utility opt-in requirement;
- existing rules requiring market participants providing energy withdrawal service to register a load asset;
- dispute resolution rules; and
- applying nonperformance penalties to aggregations.

However, ISO-NE will provide additional explanation defending its proposed metering configuration rules. In addition the RTO and several of its utilities filed for rehearing on the sixth issue, rules governing the submission of metering data by DER aggregators.

FERC ordered ISO-NE to revise its tariff to designate the DER aggregator as the entity responsible for providing required metering information to the RTO.

Yoshimura said FERC's requirement would run afoul of state policies that make host utilities responsible for providing metering services to all energy market loads and resources in the region. He said compliance would require modification of current agreements and costly changes to metering infrastructure and processes.

"Additional design elements would be needed to avoid costly delays in energy market settlement from potential data transmission errors and energy balance reporting, and to prevent double-counting of services," the RTO added. "DER aggregators would need to install and operate costly and redundant metering and communications systems that no other energy market participant is required to install and operate."

Any alternative metering requirements would depend on the commission's final orders concerning acceptable metering configurations and the rehearing request on submission of metering data.

The RTO's motion passed with 78.6% in favor, with unanimous support from the Generation, Transmission and Publicly Owned Entity sectors. The Supplier sector was mostly in favor, while Alternative Resources was split, and End Users were mostly opposed. ■

ISO-NE News

FERC Rejects Pump Storage Bid for ISO-NE Inventoried Energy Program

By Rich Heidorn Jr.

FERC last week rejected a request to include pump storage facilities in ISO-NE's Inventoried Energy Program saying it was outside the scope of the RTO's recent compliance filing prompted by an appellate remand (*ER19-1428-006*).

Last June, the D.C. Circuit Court of Appeals found ISO-NE's Inventoried Energy Program, to go into effect for winter 2023, to be unjust because it would unfairly pay nuclear, coal, biomass and hydroelectric resources for fuel storage (ER19-1428-005). The program pays generators for maintaining up to three days' worth of potential energy (e.g., fuel) on-site that can be converted into electricity at ISO-NE's direction.

The court said FERC had failed to consider protesters' argument that including those resources was improper because they were unlikely to change their behavior in response to the program's incentives.

"Acceptance of compensation incentives — for a distinct category of generators that are unlikely to respond to those incentives — was arbitrary and capricious," the court said. (See *Court Strikes a Blow to ISO-NE Winter Plan*.)

FERC in September issued an order on remand implementing the D.C. Circuit ruling and ordering the RTO to revise its tariff to eliminate those resources from the program. (See *FERC Seeking Solutions for New England Winter Reliability*.)

The RTO filed the requested tariff revisions in November. But it also noted that stakeholders — supported by Brookfield Energy Marketing, the National Hydropower Association and RENEW Northeast — had filed an amendment to the changes carving out pump storage projects from other hydropower and allowing it to participate in the program.

They said that because pumped hydro resources participate in the markets as binary storage facilities, a subcategory of electric storage facilities (which are permitted to participate in the Inventoried Energy Program), pumped hydro should be allowed to participate regardless of the D.C. Circuit's ruling that hydroelectric resources are not permitted.

ISO-NE said it did not view the amendment as consistent with the D.C. Circuit's order but would not oppose including pumped hydro in the program if FERC determined that the amendment met the compliance mandates.

In approving the RTO's tariff revisions on April 24, the commission rejected the amendment as beyond the scope of the compliance filing. "The only question before the commission in this proceeding is whether ISO-NE's filing complies with the directives of the September 2022 order. Protesters are effectively arguing that the September 2022 order should be modified to exclude a subset of hydroelectric resources from the compliance directive. These protests are essentially late-filed requests for rehearing of the September 2022 order." ■

Brookfield Energy's Bear Swamp Reservoir | *HDR, Inc.*

MISO Suggests Changing Cost Allocation for South Projects

By Amanda Durish Cook

CARMEL, Ind. — As it prepares to address long-term transmission needs in its South region, MISO is proposing to replace total subregional cost allocation in favor of a half-regional, half-local zone cost-sharing plan.

The 50-50 split to subregion and cost-allocation zones may eventually supersede the RTO's current postage stamp cost allocation in place for the first two long-range transmission plan (LRTP) portfolios. The new allocation methodology would take effect in regional transmission plans for MISO South, comprised mostly of Entergy operating companies.

MISO says assigning half the costs to a subregion "considers broadly spread benefits and accounts for changing beneficiaries over time." Allocating the other half to cost-allocation zones is a more granular approach and "may account for differing policy given the mapping of zones."

The grid operator's zonal boundaries mostly follow state lines and divide the footprint into a dozen zones, which can contain multiple transmission-pricing zones.

During a cost allocation working group meeting April 25, MISO's Milica Geissler said the RTO is aiming for an allocation that's "reflective of the portfolio in front of us."

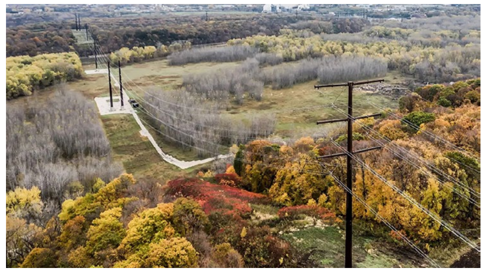
MISO said it will refine and test its proposed design over the coming months. Geissler said staff are open to suggestions that would adjust the 50-50 split.

Geissler said her presentation should be construed as an "introductory first step." She said she envisions staff and stakeholders building on the proposal through the summer so there's a cost allocation direction by the end of the year.

"I think we're going in with an open mind and seeing what ideas shape up," Geissler said. "Our intent is not to prove out a 50-50 split. That's the one thing I'm interested in learning about the most: what the split needs to be."

The first round of stakeholders' written feedback to the plan are due May 12.

Geissler said MISO always has the option to add a footprint-wide allocation construct in the future. She said the half-and-half approach is custom-built for the LRTP's third cycle of projects.



The Huntley-Wilmarth transmission line project in Minnesota | *Michels Corporation*

MISO said its proposal won't disturb the 100% postage stamp rate to load used for the first two LRTP portfolios in the Midwest region.

MISO has said it's targeting a FERC filing in early 2024 to modify its current postage stamp cost-allocation methodology for the final two LRTP portfolios. Stakeholders have long expressed interest in an allocation that more precisely reflects how transmission benefits are dispersed.

Stakeholders Split over Plan

Stakeholders didn't appear quite sold on the allocation plan's first draft.

Sustainable FERC Project attorney Lauren Azar said disparate allocations for the same class of LRTP projects doesn't "jive" with FERC's Order 1000, which requires identical project types be assigned identical allocations. She asked whether MISO would create a separate classification for projects in MISO South.

Staff said they haven't considered creating a new project category.

Azar also said that a 50-50 regional-zonal split is not as accurate an allocation as a blanket postage stamp rate that better captures benefits over time. She offered to explain the advantages of postage stamp allocations during an upcoming cost-allocation meeting.

MISO's environmental sector, one of 11 stakeholder divisions, is advocating the continued use of a postage stamp rate. Its members say that is the best way to share project costs as beneficiaries change and reliability benefits remain tricky to quantify into dollar values.

Bill Booth, a consultant to the Mississippi Public Service Commission, said he wants projects justified through measurable benefit metrics, not hypothetical ones. He also suggested allocations should be tailored to states' differing decarbonization goals.

"I'm suggesting that some states might place different values on decarbonization," Booth said. "I don't think MISO can snap a cookie-cutter approach on this."

He said FERC already has acknowledged in accepting the grid operator's first LRTP cost-allocation design that MISO will propose a different methodology for MISO South projects. In its order, the commission said the postage stamp rate is an appropriate tool under Order 1000 and is considered in effect for MISO South. It also said it wouldn't speculate on possible replacement allocations MISO may file in the future. (See *FERC OKs MISO's Bifurcated Cost-allocation Tx Design*.)

In its filings to FERC, the Mississippi PSC said it would protest a postage stamp rate as not specific enough were it applied to Southern projects.

The Union of Concerned Scientists' Sam Gomberg advised MISO against allowing states to back out of select LRTP benefit metrics, depending on their policies.

"I would caution MISO against wandering into that very dense forest," he said.

Gomberg said the emissions-reduction component of decarbonization goals have "very, very real benefits that save lives, whether you want to admit that or not."

Southern Renewable Energy Association Executive Director Simon Mahan asked whether a third cycle of LRTP projects will even occur, alluding to the $3.6 billion of reliability projects MISO South put forward as part of this year's regular transmission planning effort. Those projects might negate the need for some LRTP projects. (See *Initial MTEP 23 Ignites Familiar Arguments over MISO South's Reliability Spending*.)

Jeremiah Doner, director of cost allocation and competitive transmission, said MISO remains committed to proposing projects for its South region under the LRTP process.

Werner Roth, an economist with Texas' Public Utility Commission, said he was disappointed that MISO revealed a first draft on the new cost allocation while the Organization of MISO States is still weighing other approaches.

OMS is in the middle of collecting and reviewing stakeholders' suggestions on MISO's proposal.

Roth also said he didn't see a "generator-pays" component to the proposed allocation, something that multiple MISO states have conveyed interest in. ■

MISO News

MISO: Long-range Tx Needed for 369 GW in Interconnections

By Amanda Durish Cook

MISO last week laid out more reasons why it needs a second long-range transmission plan (LRTP) portfolio, saying it will connect several hundred gigawatts of new resources over the next 20 years to avoid reliability crises.

The grid operator expects to add 369 GW of new resources, mostly renewable, by 2042. Even with 103 GW of capacity expected to retire from the existing fleet, MISO will have 466 GW of installed capacity. However, only 202 GW of that capacity is accredited; staff assumes a declining effective load-carrying capability for the renewable additions.

During a teleconference Friday with stakeholders, James Slegers, MISO's senior expansion planning engineer, said the RTO's middle-of-the-road, 20-year future scenario shows that it needs transmission capacity to manage resource expansion and increased load.

MISO has three transmission planning futures, ranging from conservative to aggressive. The second LRTP cycle is based on the second future, which assumes all states' climate goals and members' integrated resource plans are realized.

Staff have said the second portfolio could cost as much as $30 billion. MISO aims to recommend the portfolio during the first half of 2024. (See *MISO Says 2nd LRTP Portfolio Still in Flux*.)

Slegers said an energy adequacy analysis indicates risks will be most pronounced during the "twilight hours" on hot summer days, when load is still high, solar has dropped off and wind production is low. He said MISO could find itself needing up to an additional 29 GW of flexible resources over what it has now for those three or four hours in 2042 on the most challenging operating days.

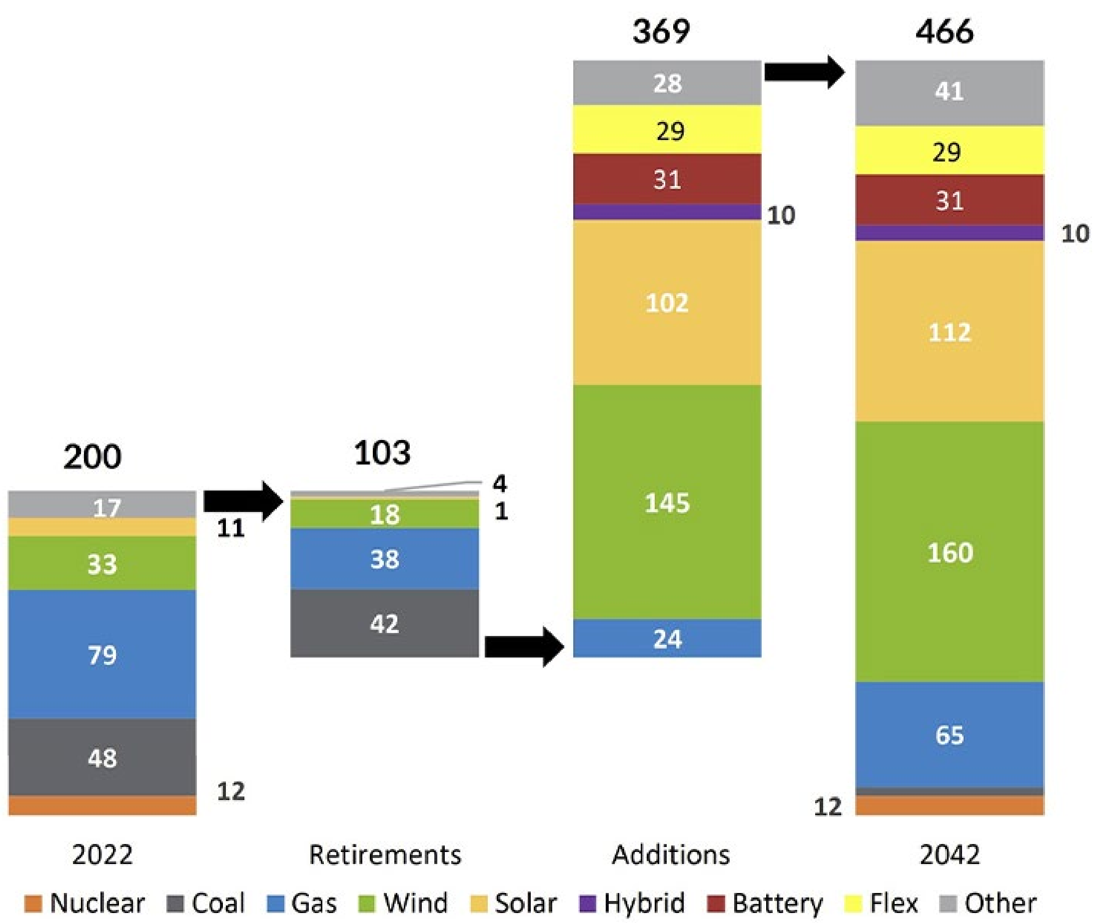
Staff said they expect to connect new types of flexible resources to the system, including green hydrogen, long-duration battery storage, small modular nuclear reactors, and reciprocating internal combustion engines. The RTO forecasts 3 GW of offshore wind farms in the Gulf of Mexico will meet Louisiana's goal of net-zero carbon emissions by 2050.

MISO says the second LRTP's benefits include avoided load-shedding during extreme weather events, less transmission investment, greater access to capacity and meeting decarbonization goals.

Having completed the latest resource expansion forecasts, staff will now build reliability and economic models into the fall meant to identify beneficial projects.

MISO is also considering hosting a Planning Advisory Committee meeting May 31-June 1 to delve into the footprint's need for future 765-kV and HVDC lines alongside other transmission technologies. Committee leadership has invited stakeholders to prepare presentations.

MISO will host its next LRTP workshop June 5. ■



Forecasted installed capacity of new and retired resources under MISO's second planning future | *MISO*

MISO News

ACORE: MISO Should Retool Market for Resources' Transition

By Amanda Durish Cook

A new American Council on Renewable Energy (ACORE) report recommends MISO make multiple changes to its markets to take advantage of a shifting resource mix.

ACORE's Michael Coggin, grid strategies vice president and the report's author, said during an April 25 webinar that he would like see markets with new design elements maximize optimal dispatch and minimize control room operators' out-of-market commitments.

Goggin said MISO should improve the accuracy of its market participants' minimum generation levels and filed ramp rates by tightening their rules. He said the grid operator should ensure submitted generator bid parameters reflect the units' true flexibility, including ramp rates and start-up times or minimum output limits that aren't physical but economic in nature. He said bid parameters that underplay a unit's actual flexibility result in excess payments to slow-moving generation.

"I think a common theme across our recommendations here is to use markets," he said. "Markets are extremely effective and efficient for aggregating a lot of information, which is what the power system has. In many of these RTOs, you have thousands of generators, millions of customers. … Markets are extremely good for aggregating that information and sending the right price signal to the generator to do what is needed to maintain reliability."

Goggin said incoming battery storage, which is nearly "perfectly flexible," has a lot of reliability potential. However, he said MISO's market is "shortsighted" in that it currently prohibits dispatchable renewable energy from furnishing a range of operational reserves.

"We think this is harming customers because wind and solar resources have extremely flexible capabilities to provide a range of operating reserves," he said.

Much of MISO's existing generation is inflexible and can't be dispatched up and down quickly, Goggin said. He said MISO should make a point to "price inflexibility" and remove uplift and out-of-market payments from inflexible resources, saying a failure to so can harm the resource transition.

"Traditionally, we got used to operating the power system that way, but now that we have new resources that are highly flexible, and you can actually add things like batteries to your existing plant, we think that a lot of the market design that made sense decades ago no longer make sense," he said.

Goggin said controllable wind and solar resources are "underappreciated." They're underused for flexibility services, he said, and left navigating market rules that weren't designed for them.

"We hear a lot from RTOs fretting about losing so-called flexible resources and talking about the need to directly compensate for flexibility. And that may be true, but I feel like there's often less thought put into how to get rid of these market features that reward inflexibility," Sierra Club senior attorney Casey Roberts said.

Roberts said she thinks resources owners understating flexibility in their bid parameters is a pervasive problem and that RTOs should take steps to hold them accountable. She said observing how many thermal resource owners alter their startup times compared to what was on the books before MISO introduced its new availability-based capacity accreditation was "interesting."

"Several generation owners suddenly discovered they were a lot more flexible than they had previously thought and asked for waivers from those rules so their 'true' greater flexibility could be reflected in their capacity accreditation," she said.

Roberts also said MISO is making an unfortunate choice by disqualifying its wind and solar resources from providing ramping capability. (See *MISO Plans to Bar Intermittent Resources from Ramp Capability*.)

"This is not based on the technical capabilities of these resources, but rather an inability of MISO's own software systems to discern whether any resource's ramp-up capability would actually be deliverable or whether they appear to be available to deliver ramp-up because they're curtailed due to transmission constraints," Roberts said. "That results in a situation where MISO has to manually confirm each resource's availability to deliver ramp up, which it's willing to do for thermal resources but not for renewable energy simply because there are so many of them it would be an untenable problem."

That issue illustrates that MISO needs software and transmission upgrades in market updates, she said.

Michael Goggin, Grid Strategies | *ACORE*

Leeward Renewable Energy's Emma Nix agreed that RTOs need transmission buildout to support interconnecting inverter-based resources. She said that MISO is entering capacity markets' next phase considering the daily times that capacity is most needed.

Goggin urged MISO to use a sloped demand curve in its capacity auction and account for simultaneous unavailable capacity caused by widespread generation outages. He said it's common for much of the generation portfolio to trip offline at the same time during weather events. (See *MISO Charts Course on Capacity Auction's Sloped Demand Curve.)*

MISO should add probabilistic forecasting to commit resources and shrink the time it takes to commit resources as close to real-time as possible, he said. MISO can reduce forecasting errors by shortening the time that passes from commitment to output, Goggin said.

He praised real-time, five-minute markets as the most effective means of incenting flexibility. He said energy price caps can sometimes interfere with the market because they can mask the operating day's riskier periods and can trigger units to prematurely release all available output. He added that higher wholesale market price caps will have "very little" rate impact because most customers will never pay a real-time price. ■

MISO Releases JTIQ Portfolio Cost-allocation Details

DOE Funding's Impact on Portfolio Projects Remains Unknown

By Amanda Durish Cook

CARMEL, Ind.— MISO last week released details about how it will allocate costs for its portion of the $1 billion Joint Targeted Interconnection Queue (JTIQ) portfolio of 345-kV projects with SPP.

The grid operator plans to recover a 90-10 split from incoming generation and load, respectively, for their cost share of the JTIQ portfolio through a monthly charge. MISO said it and SPP's generation developers will make fixed payments that reduce the select transmission pricing zones' revenue requirements over 20 years.

During a Planning Advisory Committee (PAC) meeting Wednesday, MISO counsel Chris Supino said the RTOs will use a subscription model for JTIQ planning cycles. When 125% of the portfolio's megawatts are spoken for, it will be considered fully funded.

Should the grid operators come up short on new megawatts before all JTIQ projects are in-service, load will temporarily pay for the unclaimed megawatts. Generation projects that queue up will repay load later.

MISO staff said they are still outlining the process of what happens when a JTIQ portfolio doesn't have enough willing takers of transmission capacity through new generation in the queue. However, Supino said it's unlikely that the portfolios won't be fully subscribed and funded, as they're planned to support the evolving resource mix.

Supino said MISO is considering adding a new JTIQ participation agreement to its generator interconnection agreements that would bind parties to the cost schedules' terms.

Potential federal funding might complicate the process. The Department of Energy in early March said the RTOs and two member entities can apply for full funding under its *Grid Resilience and Innovation Partnerships* (GRIP) program. (See *DOE Clears JTIQ Projects to Proceed with Funding App*.)

Clean Grid Alliance's Beth Soholt asked how payments might be modified should the DOE award funding to the portfolio.

"That's a great question, but we can't assume we'll have a pot of money until we actually get that money," Supino said.

Supino said staff plans to mention the DOE application when memorializing the JTIQ study and payment process in its joint operating agreement with SPP. The RTOs plan to file with FERC as early as July.

Supino said he doesn't yet know how DOE funding will affect repayments or reimbursements.

During a April 25t cost-allocation working group meeting, Mississippi PSC consultant Bill Booth asked MISO to provide more details around the payments' "timing and flow." He said he wanted to know whether cost assignments to load will be capped and how they would be tracked in the case of temporary overpayment.

Sustainable FERC Project's Natalie McIntire said that analyses indicate load will receive 20% on the JTIQ projects' benefits, but only shoulder 10% of the cost.

Stakeholders asked during the PAC meeting whether staff will begin a JTIQ portfolio for the MISO-PJM seam.

Dave Johnston, an Indiana Utility Regulatory Commission staffer, said he thought it was premature to ponder a MISO-PJM JTIQ portfolio when the MISO-SPP's process is untested and cannot be deemed a success yet.

MISO's Andy Witmeier said in March that it's more cost-effective for comprehensive seams planning to replace the RTO's "back-and-forth, across the fence" affected system study process with SPP that identities expensive

JTIQ Portfolio	Location by RTO	Cost E&C ($M)
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley 345 Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	MISO - SPP	1,060.7

10-year Adjusted Production Cost (APC) Benefits		
MISO	SPP	Total
$55.7	$132.9	$188.6

JTIQ portfolio map with costs and adjusted production cost benefits | *MISO and SPP*

MISO News

network upgrades.

"A lot of time those solutions are too costly for those set of projects to take on," Witmeier said. He said it's appropriate that most JTIQ projects' costs be allocated to generation because they are designed to facilitate new resources.

"They're not being built to fix market-to-market congestion or increase transfer capability, he said. "There might be tertiary benefits."

"This is all new and novel, and if we want this to work, we're going to have to accept some level of risk," SPP's David Kelley said. "I truly believe this is going to be successful and our new way of planning."

That risk could be reduced considerably if the JTIQ portfolio wins up to a 50% share of funding through the GRIP program.

The Minnesota Department of Commerce is leading the DOE application, due May 17, with help from the Great Plains Institute. The Institute's Matt Prorok said during April's Organization of MISO States board meeting that the parties have a "compelling case."

Chris Supino, MISO | *© RTO Insider LLC*

If the federal dollars are approved, the awards will be granted to RTOs and transmission developers. Prorok said parties must negotiate any awarded grant.

Prorok said the DOE application shouldn't interfere with the RTOs' cost-allocation discussions with their stakeholders.

"If the DOE can help us out with funding, I think those [cost-allocation] discussions will go very smoothly," Kansas Corporation Commissioner Andrew French said during the Gulf Coast Power Association's MISO-SPP conference in March.

"I hope JTIQ can move forward, and we can use it as proof of concept," he said.

Aubrey Johnson, MISO's vice president of system planning, has said DOE funding would provide certainty to members and make interconnections more attractive for developers.

During MISO's Board Week in March, Johnson said more needs to be done to figure out how DOE funds will intermingle with cost allocation. He joked that the process won't be as simple as the DOE "cutting a $500 million check, as much as I ask them to." ■

Midwest news from our other channels

Mich. Petition to Ban Solar Projects on Farms Withdrawn for Now — NetZero Insider

Vision for U-M EV Center: Building Ecosystem Where Auto Industry was Born — NetZero Insider

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

NYISO News

NYISO Stakeholders Debate Proposed Interconnection Queue Overhaul

Discussion Focuses on Timelines, Penalties and What is Actually Being Replaced

By John Norris

| © RTO Insider LLC

ALBANY, N.Y. — NYISO stakeholders discussed the merits and pitfalls of the ISO's proposed phased window approach to fundamentally rework its interconnection study processes after it was presented in greater detail during the Transmission Planning Advisory Subcommittee's meeting April 19.

After studying how to expedite its interconnection queue, which has experienced project backlogs and delays since New York passed the Climate Leadership and Community Protection Act in 2019, NYISO recently settled on a three-stage approach that would stack a group of overlapping projects into a queue window. (See *NYISO Previews Plan to Expedite Interconnection Queue*.)

Stakeholders were mostly receptive but still had many concerns about the proposal, including about its timelines and scheduling; penalties for leaving the queue; and whether certain studies in one phase might be more appropriate elsewhere.

NYISO will take stakeholder feedback from last month's meeting and address them at the subcommittee's next meeting this Friday.

Application Review Period

Thinh Nguyen, NYISO senior manager of interconnection projects, summarized the proposal.

"The queue window leverages all the class year processes," but instead of performing studies at the end, after developers have made significant financial commitments, "it puts all the analyses upfront to be done together so developers can make more informed decisions," Nguyen said.

Therefore, the critical first step in the queue window would be the application review period. This "pre-act" review would serve as a "project filter," said Nguyen, because during this time, developers would submit site-control requirements and application fees, undergo initial modeling demonstrations and create their base cases, which are the starting points for any interconnection study, showing much about a project's feasibility.

The idea is to enable developers to make important decisions about whether they want to enter or exit the queue without either facing withdrawal penalties or disrupting other potential projects in the queue window. Nguyen also said that the intention of this period is to validate a certain project application's worthiness and if it can be considered in the interconnection study.

After submitting all required application materials and a nonrefundable application fee, developers would be able to submit a study deposit if they decide they want to proceed into the queue window.

Phase 1

"Phase 1 is similar to late-stage [Class Year] optional physical feasibility studies but is a more limited clustered study, rather than the individual studies as done today," Nguyen said.

During this period, NYISO would review project design requirements provided by developers to determine a project's feasibility, such as if existing infrastructure can physically accommodate the project or if it has environmental issues.

This would allow developers with projects identified by NYISO as having potential feasibility issues to decide whether they want to study this issue further or if it is enough to dissuade them from moving on.

Nguyen said Phase 1 "lets developers know if they may run into some problems," so that they can decide to either exit the queue entirely or rejoin later in another window "without delaying other projects."

Should a developer withdraw their project in Phase 1, NYISO would refund them 80% of the study deposit, though projects that move forward to Phase 2 and then decide to withdraw would forfeit the entire deposit.

At the end of this period, NYISO would publicly publish every developer's decision so that others can understand how a given queue window or project could be affected.

Phase 2

Projects that pass Phase 1 feasibility requirements and posted relevant deposits would enter Phase 2, which is "almost like the system impact reliability study but with a twist," said Nguyen.

Phase 2 would create binding cost estimates that are based on identified equipment and work upgrades necessary to interconnect a proposed project, which is unlike current processes that produce a nonbinding cost estimate.

NYISO News

Nguyen said Phase 2 is "tailored" to gives developers a "heads-up about some of their potential system upgrades that would be beyond the POI [point of interconnection]."

"This could be a step where we can streamline a lot of processes that we have today," he said.

During Phase 2 the queue's base cases would also be updated to reflect projects that were either rejected or withdrew during Phase 1 and the ISO performs limited analyses, such as short circuit, localized stability and screening deliverability analyses to generate useful information that reduces Phase 3 study times.

Developers who accept Phase 2's results and project binding cost estimates would be required to post a project's dollars-per-megawatt cash deposit before moving to Phase 3. Projects withdrawn during Phase 3 would see 25% of the cash deposit forfeited.

Like Phase 1, project decisions made in Phase 2 would be posted publicly by NYISO.

Phase 3

"Phase 3 is basically the final study for developers to know the certainty of their cost allocations," Nguyen said.

During Phase 3, NYISO would update relevant base cases to reflect any projects that withdrew and perform any additional analyses needed to determine a project's final cost allocation based on potential upgrades identified by the ISO.

Doreen Saia, an attorney with Greenberg Traurig, sought clarification, asking whether "Phase 3 is essentially becoming an additional deliverability study and additional SUF [system upgrade facility] study," which Nguyen confirmed as correct.

Nguyen explained that the structure of NYISO's proposal intentionally stacks projects together into a single queue window and staggers their study processes to "minimize the potential restudy or interaction between projects as much as possible." This means, for example, a project might not commence Phase 3 studies until another project finishes its processes in the same window.

"The idea is that subsequent queue window projects will be able to consider upgrades identified in prior queue window projects," which makes the queue "more manageable, because subsequent projects will know exactly who the group of projects prior to them are and what decisions they have to make," he said.

Nguyen said that NYISO's proposed "concept is much better than what we have today because when we studied projects individually, they had no idea what going on with other Class Year members … creating more uncertainty for those project developers."

A developer who accepts their Phase 3 cost allocations would be required to post security for any system deliverability or facility upgrades necessary for interconnection to complete the queue window study process.

The Phase 3 decision-making period, like the end of the Class Year process, would be an iterative process that repeats until every queue window project member either accepts or rejects their cost allocations.

Stakeholder Comments

Stakeholders shared many concerns, both specific and general, about NYISO's proposed revisions during last month's meeting.

Several stakeholders commented that the proposed penalties incurred by developers withdrawing from the queue window may be overly burdensome, prohibitive and unequal, as bigger projects may be susceptible to higher fines than smaller ones. Some singled out the 20% for a Phase 1 departure as too high.

NYISO attorney Sara Keegan, however, said the amount is "consistent with other ISOs," with SPP taking 20% from projects leaving at the end of its Phase 1 study. Nguyen said this is "a penalty that deters projects that are just not ready yet."

Mark Reeder, representing the Alliance for Clean Energy New York, concurred, saying how he saw the 20% forfeiture "as the penalty for those starting and not being ready," which to him seemed good because "we don't want a lot of people jumping in and then out [of the queue] without a good reason."

Vitaly Spitsa of Consolidated Edison asked what deliverables would come out of Phase 2 and whether, by this point in the process, developers would have access to sufficient information to make critical decisions about moving ahead in the queue.

Nguyen said that by the end of Phase 2, "developers will know exactly what the potential cost is of their binding POI" and about any necessary upgrades, which "definitely isn't all the information but is sufficient information for a developer to make a decision about whether they want to move to the next phase."

Anthony Abate, lead energy market adviser with the New York Power Authority, said NYISO's illustrations of its queue window were "deceptively simple" and that "the devil's in the details," referencing how lengthy discussions during the meeting show that stakeholders need more information about the structure and timeline of the proposal.

Although much of the meeting was spent answering stakeholder questions or addressing comments of concern, some attendees expressed optimism about the ISO's proposal.

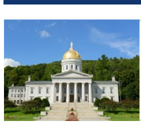
Shane O'Brien, senior director with Aypa Power, said "from the developer's side, this is a step in the right direction," because NYISO's proposal addresses "administrative inefficiencies" and "those downtime wait periods" where developers may be waiting for others before they can make their own decisions.

However, a remark by Saia seemed to best capture the sentiment among the stakeholders present at the meeting.

In reference to how NYISO's proposal would remove much of the Class Year studies, such as the system impact reliability study or siting and permitting processes, Saia said, "We must make sure that whatever we do in this new process, [former] processes align, because if they don't, then it's great that you fixed this, but it's going to create discordance somewhere else that causes the whole thing to die under its own weight.

"NYISO needs to indicate that you acknowledge and recognize [these concerns] because I don't think you're going to be able to get any real signoff on this without those assurances," she said. ■

Northeast news from our other channels



Vt. Governor to Veto Building Decarbonization Measure

NetZero Insider

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

NYISO News

Upgrade to Ease NY Transmission Bottleneck 75% Complete

LS Power, NYPA Energize New Substation on Central East Energy Connect

By John Cropley

A $615 million project to ease one of the transmission bottlenecks in upstate New York is nearing completion.

State officials last month announced the Central East Energy Connect (CEEC) upgrade undertaken by LS Power Grid New York and the New York Power Authority is now 75% complete with energization of a new substation in Princetown, west of Schenectady.

The 345-kV CEEC runs 93 miles from the Utica area east to the Albany area. The upgrades are designed to not only increase the CEEC's capacity but improve its reliability and resilience. Steel monopoles are replacing wooden H-frame towers that are more than 60 years old in some cases. Four existing substations along the route are being upgraded, and two new substations have been built and are now in service.

Completion is anticipated later in 2023 and will result in a nearly five-fold increase in capacity.

The CEEC upgrade arose from a December 2015 finding by the state Public Service Commission that a Public Policy Transmission Need existed for new 345-kV transmission facilities to move power from upstate to downstate. LS Power and NYPA submitted a joint proposal in August 2019, and the PSC adopted it in January 2021. Work began the next month.

As thousands of megawatts of wind and solar generation capacity are planned upstate to carry out New York's clean energy transition, the need for such transmission lines will only grow.


Work continues on the Central East Energy Connection upgrade near Schenectady, N.Y., in late March. | *NYPA*

The CEEC is just one of several such transmission projects on the drawing board or in progress across upstate New York, and far from the largest:

- The rebuild of NYPA's 86-mile Moses-Adirondack Smart Path is nearing completion.
- NYPA and National Grid began work in December on Smart Path Connect, which will add 45 miles on the north end of Smart Path and 55 miles on the south end, where it will connect to the CEEC.
- New York Transco is progressing on the New York Energy Solution, a rebuild of 54 miles of north-south transmission lines in the Hudson Valley south of Albany; the 456th and final monopole was erected last month.
- Last year NextEra Energy Transmission New York completed the Empire State Line, which runs only 20 miles but includes a new 345-kV hub for western New York and links to the state's largest electric producer, the Niagara Power Project.
- Work recently began on the Champlain Hudson Power Express, a $6 billion project running 340 miles underground and underwater from Quebec to New York City.
- NYPA, energyRE and Invenergy have teamed up on a 175-mile underground and underwater transmission line called Clean Path NY that would run southeast through the Catskills to New York City and is now in the permitting process. With associated wind and solar generation projects, the price tag is estimated at $11 billion.

The planning continues, as New York works toward an emissions-free grid by 2040, with concurrent increases in power demand and variability of power supply.

The PSC in February approved 62 transmission upgrades with a combined capacity of 3.5 GW and an estimated cost of $4.4 billion. Last month it approved an $810 million clean energy hub designed to increase transmission capacity in New York City amid the demand of electrification, with many more upgrades expected there in the decades to come. ■

NYISO News

NYISO Proposes 48 Market Projects for 2024

DPS Expanding Peak Hour Definition; ISO Discusses Proposed Reliability Plan Topics

By John Norris

ALBANY, N.Y. — NYISO on Wednesday *presented* the Budget and Priorities Working Group (BPWG) with 48 market *projects* that it is proposing to be included in its 2024 budget.

The projects include 13 concerning the capacity market, 22 on the energy market and two for transmission congestion contracts. The total is 11 more than were proposed at this time last year in the project prioritization process. The ISO deemed six of the 48 as being mandatory for next year and 29 as priorities.

NYISO anticipates giving stakeholders a clearer indication about each of these projects' potential resources, budgets, feasibility and constraints either later this month or in early June. It will on May 22 both review proposed 2024 enterprise projects and discuss any updates made to the proposed market projects. Stakeholder advocacy and draft scoring surveys are scheduled for the BPWG on May 31.

The ISO asks stakeholders to send any additional feedback or questions to *kpytel@nyiso.com* by May 15.

Peak Hour Definition

The New York Department of Public Service also told Wednesday's BPWG meeting that its *definition* of peak hour is being expanded to consider more than a single hour when determining transmission owners' and load-serving entities' obligations.

The department said the change is necessary because it will more accurately determine future peak loads, track customer usage on an hourly basis and more equitably allocate capacity costs among LSEs.

"This project isn't changing the way that we forecast but is more about how that capacity obligation gets allocated to transmission owners and thus to those load-serving entities," said Christopher Graves, DPS chief of utility programs.

2023 Project Milestones

NYISO also gave the BPWG a status *update* about projects prioritized in the ISO's 2023 budget. (See *NYISO Outlines Timelines for 2023 Projects*.)

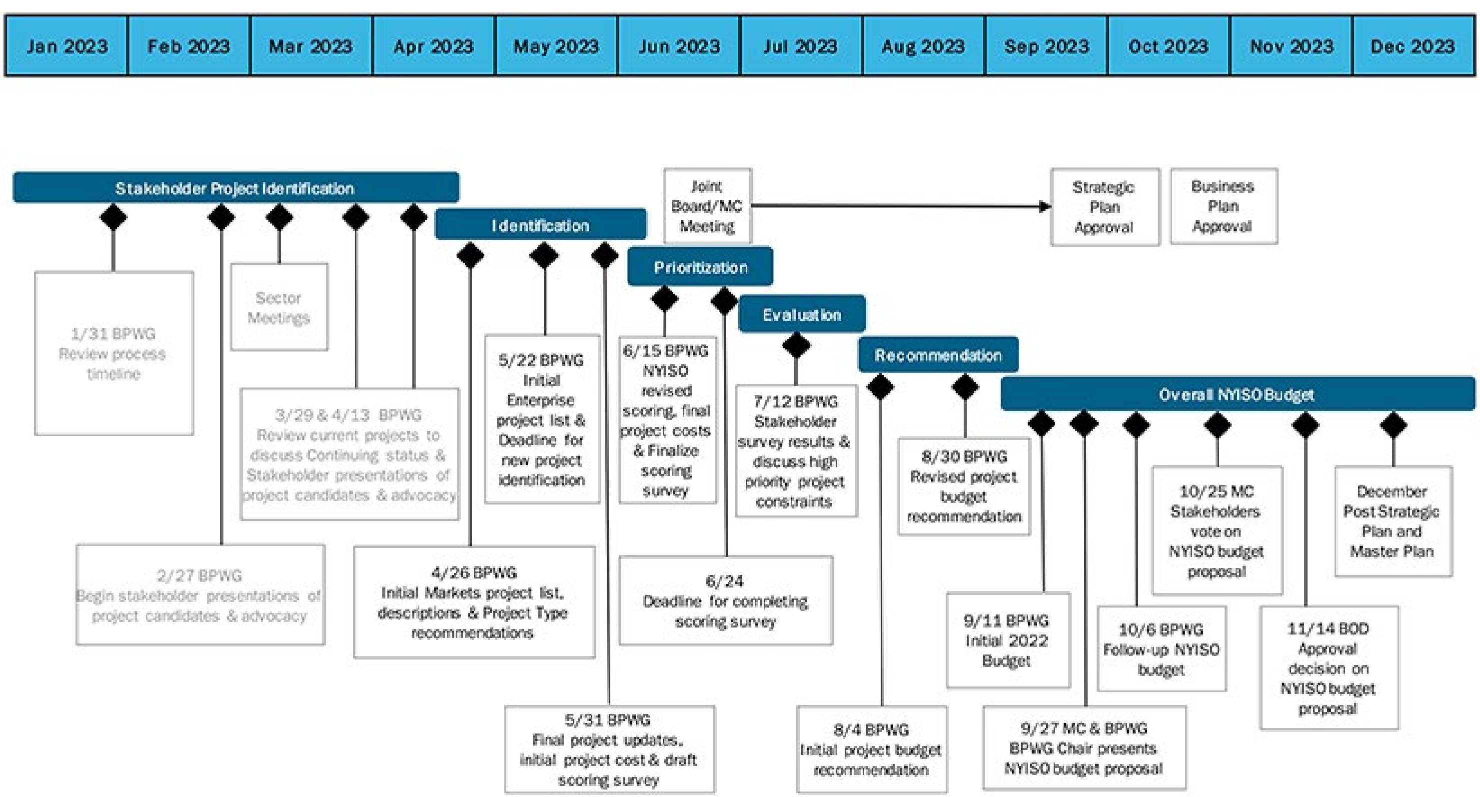
Most projects remain on schedule, but two — upgrading the load forecasting data repository system, and securing better communication channels for market participants to exchange information — are at risk of not meeting their end-of-year milestones.

Meanwhile, the schedule for distributed energy resource participation modeling will most likely be delayed until July.

NYISO will return next quarter to update stakeholders about the status of these projects.

Comprehensive Reliability Plan

NYISO on April 25 *presented* its proposed topics for the biennial 2023-2032 Comprehensive Reliability Plan (CRP) at the joint meeting of the Electric System Planning Working Group, Transmission Planning Advisory Subcommittee and Load Forecasting Task Force.



2024 proposed project prioritization timeline (issued before April 26) | *NYISO*

NYISO News

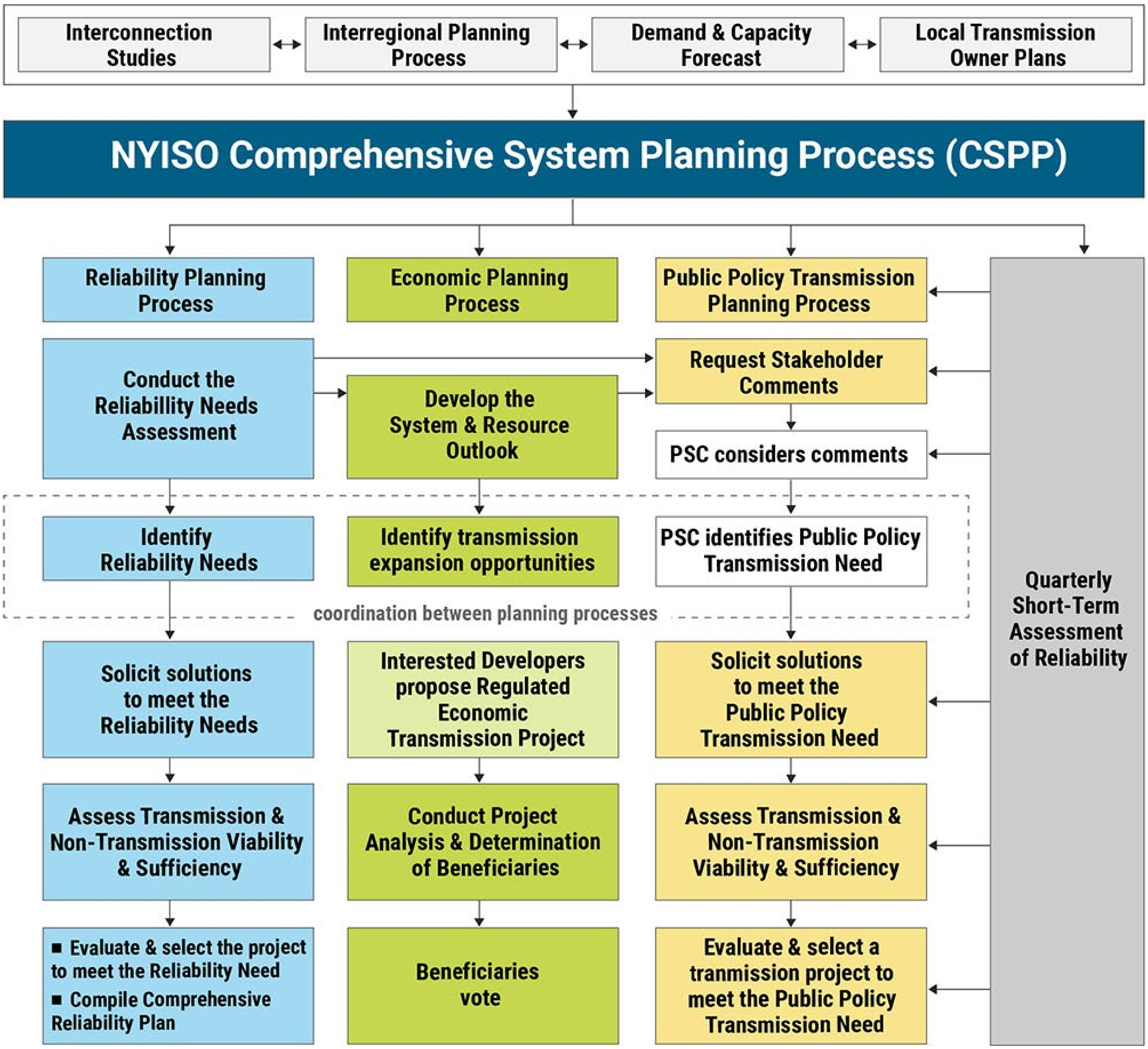
The topics include winter gas constraints, extreme weather events, the integration of large load scenarios into transmission security and resource adequacy considerations, near-term reliability risks, and subjects identified within the "*Road to 2040*" section of the Reliability Needs Assessment (RNA), such as dispatchable emission-free resources (DEFRs).

The CRP is the last part of the *reliability planning process*. It evaluates the viability and sufficiency of the proposed solutions identified in the 2022 RNA. (See *NYISO RNA Raises Concerns over Timing of Peaker Unit Retirements*.)

Stakeholders attending last week's meeting pointed out that NYISO continues to discuss DEFRs as part of its proposed solutions to future resource adequacy needs but has yet to flesh out what those resources include or will look like.

NYISO responded that DEFRs represent technologies that either have not been discovered or have not evolved enough to be used at scale, but it stressed that it understood stakeholder concerns.

The ISO will spend the second and third quarters of this year presenting results from the draft CRP, then target the fourth quarter to obtain committee approval. ■



Flowchart of NYISO's comprehensive system planning process | *NYISO*

NJ BPU Backs Plan for 2nd Grid Upgrade Process with PJM

By Hugh R. Morley

The New Jersey Board of Public Utilities on Wednesday agreed to ask PJM to approve a plan for the state to undertake a second solicitation process under FERC's State Agreement Approach (SAA), this one for grid upgrades to handle the recent increase of 3.5 GW in planned offshore wind power.

The four-member board voted unanimously to ask PJM to incorporate into its planning process the state's goal of developing 11 GW of capacity by 2040, which Gov. Phil Murphy increased from 7.5 GW in September. (See *NJ Seeks Stakeholder Input for 3rd OSW Solicitation*.)

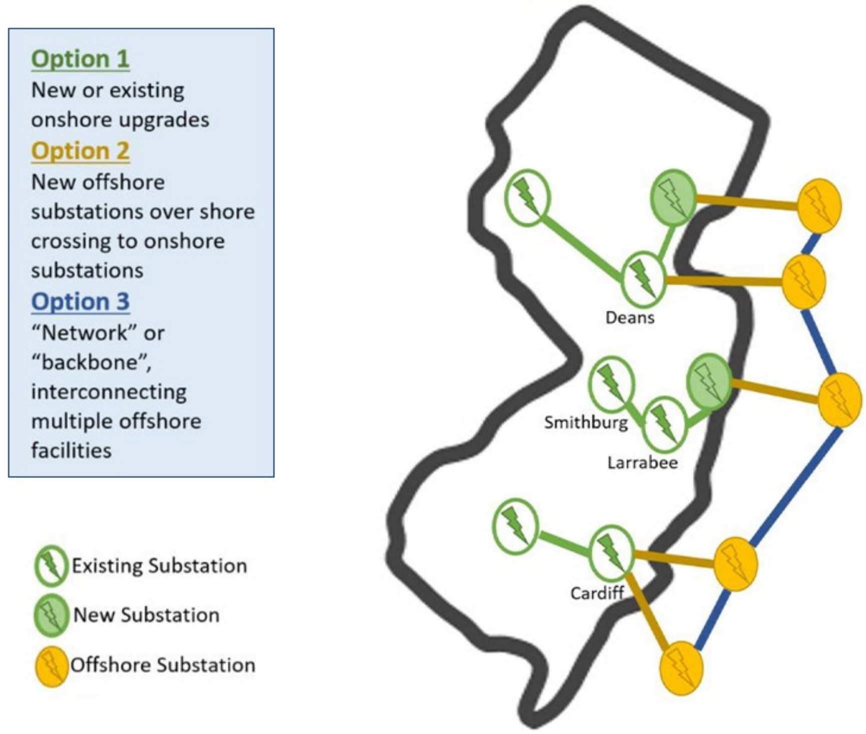
The vote came six months after the board concluded the first SAA solicitation by awarding contracts totaling $1.07 billion for transmission upgrades to deliver 6,400 MW of offshore wind generation to the PJM grid. FERC backed New Jersey's plan in April 2022. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

In its latest solicitation, which it calls SAA 2.0, the board is seeking solutions for three options, according to the *order* approved Wednesday:

- upgrading the onshore PJM regional transmission system to accommodate increased power flows from OSW facilities. This would leave OSW developers responsible for bringing power to the newly constructed onshore substations.
- connecting onshore substations to offshore substations.
- creating an offshore transmission "backbone" that would connect to the offshore substations.

The order recommends that the offshore cable system tie into the grid at the 500-kV Deans substation in Northern New Jersey, saying that it "is located near high electric load centers" and is accessible to the lease areas likely to service the state. In addition, PJM has in the past identified the Deans site as having the capability to handle the expected power injection.

"This process will examine whether an integrated array of open-access transmission facilities, both onshore and potentially offshore, can achieve New Jersey's expanded offshore wind goals in an economical and timely manner," PJM said in a statement.



A New Jersey Board of Public Utilities graphic shows potential transmission upgrades to connect 3,500 MW of offshore wind to the PJM grid. | *N.J. BPU*

The RTO said it will include New Jersey's needs for offshore wind-related transmission improvements in a competitive proposal window tentatively set to open in 2024.

Complicated Initiatives

New Jersey officials, including BPU President Joseph Fiordaliso, have expressed concern that efforts to boost the use of electricity with wind and solar power will create a demand for interconnections that the grid can't handle. Fiordaliso has repeatedly said he fears that the state will develop plenty of solar and OSW projects but have "no place to plug them in."

At the same time, New Jersey is facing pushback against the rapid expansion of the OSW sector from commercial fishermen, local residents and the tourism industry, who fear a negative impact from turbines off the Jersey Shore, and from Republicans and business groups worried about the cost.

In a statement, Fiordaliso called the decision "extremely important for the future of our offshore wind program."

During the BPU's meeting Wednesday, he said that the approval "does not obligate the board to anything" but will initiate the kind of study necessary for such a large and complicated project.

"These are not easy decisions to make. Some of them are very complicated initiatives," he said. "We just don't go into these initiatives willy-nilly. There's an awful lot of research that goes into it. How is it going to affect the ratepayer? That's No. 1. How is it going to move us forward in achieving our goal? All of these things have to be evaluated before we say 'yes, let's pull the trigger.'"

PJM CEO Manu Asthana said in a statement that New Jersey has been "a pioneer in developing infrastructure needed to achieve its ambitious offshore wind policies."

The BPU "recognized early on the value of PJM's independent, competitive and proven transmission planning process, and we look forward to continuing to help New Jersey achieve its offshore goals reliably and as cost-effectively as possible," Asthana said.

Jim Ferris, deputy director of the BPU's Division of Clean Energy, said that the order only allows the board to embark on the SAA process, and any submissions would be evaluated "in concert" with PJM and not go ahead without the BPU's approval. He added that

PJM News

the process includes "extensive protections for ratepayers, including cost-containment options." Moreover, it does not preclude exploration of "opportunities for coordinating on regional offshore wind transmission up to and including a regional offshore wind backbone transmission system," he said.

"While the second SAA is being initiated as a New Jersey-only effort, discussions with other states and federal stakeholders in this important area are continuing," Ferris said.

Key among those discussions would likely be whether any of six successful bidders in the February 2022 auction for federal leases for OSW projects totaling 5.6 GW in New York and New Jersey would participate in a regional grid upgrade project. (See *Fierce Bidding Pushes NY Bight Auction to $4.37 Billion*.)

Commissioner Dianne Solomon, who has in the past expressed concern at the rising costs of New Jersey's clean energy plans, backed the SAA proposal but encouraged BPU staff to continue looking for a regional approach to executing grid upgrades.

"We should be working as diligently in trying to get to that solution as the SAA solution," she said. "I have no objection to doing them in tandem," she added, urging staff to "put your pedal to metal" in pursuing a regional solution.

Reducing Costs, Risks

The board said staff "continues to believe" that the SAA process will result in "more efficient or cost-effective transmission solutions versus a non-coordinated transmission planning process." The process also will "significantly reduce the risks of permitting and construction delays" and minimize environmental impact, it said.

The BPU picked its final contractors in the first SAA from among 80 proposals submitted by 13 developers who responded to the solicitation. At the time the board initiated the solicitation process, the state's goal was to create 7.5 GW of capacity by 2035, and so it did not account for the extra 3.5 GW subsequently approved by Murphy.

The BPU picked only solutions to upgrade onshore transmission facilities and proposals for upgrades to resolve reliability criteria violations resulting from offshore generation injections. It did not pick any of the proposals for offshore transmission in large part because they did not result in a reduction in the number of cables, Andrea Hart, the BPU's senior program manager for offshore wind, said at the time. The BPU instead has required applicants in the state's third OSW solicitation to propose solutions.

BPU staff in the first solicitation selected a $504 million project that it called the Larrabee Tri-Collector Solution, which included parts of Jersey Central Power and Light's proposal and pieces of Mid-Atlantic Offshore Development's proposal. The BPU also approved $575 million in seven smaller projects to upgrade existing onshore transmission identified by PJM as necessary to support the OSW injections.

Ferris told the board Wednesday that the first SAA process would mean "New Jersey ratepayers will realize hundreds of millions of dollars in savings from the selection of these transmission projects, compared to the estimated cost of transmission facilities that would otherwise be necessary to achieve New Jersey's 7,500-MW goal in the absence of the SAA solicitation." ■

Devin Leith-Yessian contributed to this report.

PJM News

NRC: Ground Settling Damaged Water Lines at Ohio Nuclear Plant

5-Member Federal Inspection Team Now at Davis-Besse

By John Funk


Davis-Besse nuclear plant in northern Ohio | *NRC*

The U.S. Nuclear Regulatory Commission has begun a special inspection to investigate ground settling at the Davis-Besse nuclear plant in northwest Ohio, including two incidents that damaged dedicated fire-protection water lines.

The commission said last week that a five-member special inspection team arrived at the power plant on April 24.

"The NRC determined a special inspection was necessary," the commission said in a release citing that "multiple occurrences of ground settling" have occurred at the plant, including one in October and another just weeks ago that damaged the water lines. Neither settling incident occurred under the containment building holding the reactor.

The inspection team has expertise in plant fire protection, component aging, operations, geology, seismology and other geotechnical sciences, and license renewal.

Originally licensed in 1977, Davis-Besse is now licensed to operate until 2037. The 894-MW plant is owned by Akron-based Energy Harbor. A company spokesman did not return a call seeking comment.

The "special inspection team will establish a historical sequence of events related to ground-settling zones and assess the licensee's actions to evaluate, monitor or mitigate the phenomenon and its potential impact on equipment important to safety," the NRC said.

The team will review plant records related to ground settling, repair records related to the impacts of ground settling and geological assessments done before the plant was built, according to an NRC spokesperson, who added that the October incident was the first one affecting plant equipment of which the commission is aware.

In both cases, plant workers immediately repaired the water lines and on-site NRC inspectors reviewed their work reports. No incident reports were filed because the damaged lines were immediately repaired and did not require shutdown of the reactor.

Energy Harbor is being acquired by Texas-based Vistra in a deal expected to be completed by the end of 2024. (See *Vistra Pays more than $3 Billion for Energy Harbor*.) ■

PJM News

FirstEnergy Pressured to Acquire W.Va. Coal Plant

By John Funk

Pressure to purchase and run a West Virginia coal-fired power plant poses financial and political complications for Ohio-based FirstEnergy.

Analysts participating in the FirstEnergy's first-quarter earnings conference call Friday questioned whether the company's regulated West Virginia subsidiary Monongahela Power would purchase the Pleasants Power Station, a deregulated plant the company previously owned that is now struggling to compete in the PJM market and slated for shutdown on May 31.

The Public Service Commission of West Virginia in December asked FirstEnergy to consider approving Mon Power's purchase of the 44-year-old, 1,300-MW coal plant, located on the West Virginia side of the Ohio River.

FirstEnergy briefly owned Pleasants after buying the Pennsylvania-based utility Allegheny Energy in 2011. But in 2017 it tried to move ownership and operation of the plant from what had become unregulated Allegheny Energy Supply to regulated Mon Power. FERC blocked the move. (See *FirstEnergy Shutting Down Unsold Coal Plant*.)

The plant is now owned by Maryland-based Energy Transition and Environmental Management, a company that demolishes old power plants and repurposes the sites. ETEM is leasing the plant to its previous owner, Energy Harbor, which will handle shutdown at the end of this month.

Energy Harbor is the company that emerged from the bankruptcy of FirstEnergy's power plant subsidy FirstEnergy Solutions.

FirstEnergy agreed to review the request from the PSC, but earlier this spring it asked for a subsidy of $3 million/month to cover operating Pleasants for a year while it continues to evaluate whether to purchase and operate it as a regulated facility. Consumer groups and the state's consumer advocate are opposing the idea.

FirstEnergy CFO Jon Taylor explained the West Virginia situation to analysts during a review of the company's rate increase plans pending or planned before utility regulators across its 10 electric distribution companies.

"Mon Power proposed an option to enter into an interim arrangement with Pleasants' current owner that would keep the plant operational beyond its May 31 deactivation date. This would allow the needed time to do a thorough analysis and evaluation as requested by the West Virginia PSC," he said.

Taylor said the PSC approved the company's request for the subsidy earlier in the week.

Pleasants Power Station in Belmont, W.Va. | *Library of Congress*

"We will begin negotiations with the plant's current owner. If we reach an interim agreement that we believe is in the interest of customers and FirstEnergy, we will submit it to the commission. And if approved, this would allow recovery of associated costs through a surcharge. If we can't reach an agreement that is in the interest of our customers, we will file an update with the commission," he said.

A complication is that Mon Power and a second regulated FirstEnergy subsidiary, Potomac Edison, already own two other large coal-fired power plants in the state.

If FirstEnergy approves Mon Power buying Pleasants, the company will likely close one of the other plants, said Taylor. "We don't see it as a viable option for Mon Power to operate three coal-fired power plants in West Virginia," he said.

FirstEnergy "is moving forward with efforts to support the energy transition across our footprint," Taylor told the analysts. "And we remain committed to our climate strategy and our goal to achieve carbon neutrality ... by 2050."

The company is planning to build five solar farms in the state with a total output of 50 MW, he said.

An analyst with KeyBanc asked whether the company will face an "impossible situation" and will "pay a political price" in the state if it does not purchase the Pleasants power plant.

Interim CEO John Somerhalder responded that the company is committed to working closely with the state. Noting that the Pleasants plant is newer and equipped with enhanced environmental controls, the request from the PSC is "a good question that needs to be evaluated," he said.

Somerhalder's review of the company's overall financial performance in the first quarter was equally upbeat.

"Despite record-high temperatures across our footprint this winter, we're off to a good start in 2023 as we continue positioning FirstEnergy for greater resiliency and growth by strengthening our financial position, enhancing our operations and optimizing the customer experience," he said.

The company reported first quarter earnings of $292 million ($0.51/share) on revenue of $3.2 billion. That compares with earnings of $288 million a year ($0.51/share) on revenue of $3 billion. ■

PJM News

PJM MRC Briefs

Renewable Dispatch

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee on Wednesday endorsed a new renewable dispatch structure proposed by the RTO and the Independent Market Monitor.

The endorsement directs staff to return to the committee with revised tariff and manual changes incorporating the market changes. PJM's Darrell Frogg said the structure would *provide* better data to allow dispatchers to anticipate the output of renewables and increase transparency on performance and forecast accuracy through regular reviews with stakeholders. (See "PJM, Monitor Present Renewable Dispatch Proposal," *PJM MRC/MC Briefs: March. 22, 2023*.)

The construct would replace the use of curtailment flags sent to generators through the Inter-Control Center Communications Protocol (ICCP) with economic basepoints. Generators would be directed to follow those basepoints regardless of curtailments because of the potential for inadvertent curtailments.

Renewable resources would be required to offer into the day-ahead market unless they receive approval for an exception for a physical constraint from PJM and the Monitor. Their offers would be based on forecasts of both weather and equipment availability produced by either the market seller or PJM.

Generators would be required to update their critical parameters in real-time security-constrained economic dispatch (SCED) every five minutes and on an hourly basis for parameters in intermediate-term SCED cases.

The lost opportunity cost structure currently available for wind resources would be extended to solar, making them available for payments when they follow dispatch through SCED basepoints.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the proposal appears to leave a lot undefined at this point. Frogg agreed, but he added that those details will be filled in as tariff and manual language is developed.

Capacity Performance Penalties

Stakeholders discussed three *proposals* to change when generators can be assigned Capacity Performance (CP) penalties and how they are calculated. Proponents described the changes as an effort to put market changes in place while stakeholders consider longer-term proposals being drafted through the Critical Issues Fast Path (CIFP) process. (See *PJM Presents More Detail on CIFP Proposal*.)

All three would shift the charge rate from being based on the net cost of new entry to the Base Residual Auction (BRA) clearing price for that delivery year. If the alternative calculation was applied to the 2023/24 delivery year, it would result in a $394/MWh penalty, versus the status quo of $3,177/MWh.

The proposals differ in both the stop-loss limit (SLL) and the trigger for the performance assessment intervals (PAIs) that define when a generator can be assigned penalties or bonuses based on how they match up against their obligation.

LS Power and the *Monitor* are proposing a limit set at twice the BRA clearing price, while *American Municipal Power* used a lower SLL at 1.5 times the clearing price.

For the PAI trigger, LS Power and AMP suggested mirroring the provisions in PJM's CIFP proposal, which would only allow PAIs when there is a real-time reserve shortage and declaration of emergency procedures more severe than pre-emergency demand response. Stakeholders said that DR should be utilized like any other capacity resource, and its dispatch shouldn't subject other resources to penalties.

"It puts some discipline around when PAIs are called; it gives you some indication about when we're getting close to when a PAI may be called," LS Power's Tom Hoatson said.

The Monitor's proposal would predicate the implementation of a PAI on a shortage of primary reserves and a PJM declaration of a regional emergency.

LS Power's Marji Philips said that FERC's 2021 order on PJM's market seller offer cap caused generation owners to lose the ability to adequately represent the risks they take on by participating in the capacity market. By reducing CP penalties, she said the proposal would de-risk the capacity market.

Vitol's Jason Barker said the purpose of the penalties is to incent behavior, and reducing that wouldn't lead generators to make the investments lessening the likelihood of events similar to the December 2022 winter storm.

"From our perspective there has to be a meaningful penalty," he said.

PJM's Adam Keech said the RTO is comfortable with the proposed changes to the PAI trigger, but it has concerns with reducing penalties without addressing the other side of the ledger: winterization and other mandates that would require capacity resources to improve their ability to perform. He said that the high penalties were a tradeoff to limited hard rules, and the proposals would significantly decrease penalties without introducing other ways of ensuring performance.

Marji Philips, LS Power | © *RTO Insider LLC*

The LS Power proposal was introduced to the committee as a quick fix, meaning that the issue charge, problem statement and solution could be voted on during the same meeting. Noting the hourslong discussion it generated on Wednesday, some stakeholders questioned if it met the criteria of an issue that could be addressed with minimal stakeholder input.

Special meetings of the MRC and Members Committee have been scheduled for May 4 and 11, respectively, to further discuss the issue and potentially vote on endorsement

Stakeholders Endorse Manual 11 Changes

Stakeholders endorsed *revisions* to Manual 11, which pertains to energy and ancillary services market operations, through the biennial cover-to-cover review of the document. Stakeholders deferred a vote on the changes during last month's MRC meeting to allow more time to review amendments proposed in an effort to align the language with PJM's other governing documents. (See "Other Stakeholder Discussions," *PJM MRC/MC Briefs: March. 22, 2023*.)

The revisions presented at the second read on March 22 were revised to remove changes to the operating parameter definitions affecting the minimum run time for combined cycle units. The excised language is anticipated to return after being reviewed by the Governing Document Enhancement & Clarification Subcommittee. ■

— Devin Leith-Yessian

PJM News

PJM Stakeholders Discuss Monitor Contract Review

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM stakeholders provided feedback to the Board of Managers on a potential review of the Independent Market Monitor contract during the Markets and Reliability Committee meeting Wednesday.

Manager David Mills said the current deliberations are focused on the structure of the contract, not the performance of the current contract holder, Monitoring Analytics, nor whether the company will continue to hold the contract.

"It's been quite some time since these documents were reviewed, and in that time, PJM has had a significant amount of turnover on the board," Mills said. "This is not a performance review or referendum on Monitoring Analytics."

Paul Sotkiewicz, president of E-Cubed Policy Associates, pushed for the board to consider issuing a request for proposals.

"If it turns out Monitoring Analytics is the best outfit to do this, that's great … but I do think this should be open to a competitive process," he said.

Vitol's Jason Barker said the contract states that the PJM board has the responsibility to evaluate the Monitor's performance, but it doesn't provide any measure to benchmark against. He advocated for a third party to be retained to look at topics such as whether Monitor comments are pertinent and influence the outcome of FERC orders, and the impact of Monitor participation in the stakeholder process.

"We encourage the board not only to retain this provision … but also to use it," he said.

Susan Bruce, of the PJM Industrial Customer Coalition (ICC), said the cost of market manipulation in PJM's market is high and customers are willing to pay for a monitor who can push for stronger competition. While she said discussion of the Monitor's role is appreciated, she cautioned against holding an RFP, saying that continuity is critical to the IMM's work.

"There's a place here for history and understanding how the markets work," she said.

The topic of reviewing the contract was first raised in the board's Competitive Market Committee. Mills, the committee's chair, reiterated the board's commitment to a monitor empowered to curtail market manipulation.

"None of this is intended to tear apart or destroy the foundation of a strong market monitor," he said.

Monitoring Analytics President Joe Bowring | © RTO Insider LLC

The board had previously solicited stakeholder input through the Liaison Committee and last month at the Organization of PJM States Inc.'s meeting, where Mills said comments addressed data access, intellectual property rights for proprietary software and calculations used by the Monitor, and how the contract handles succession.

Mills said the board plans to provide a public written summary of the comments it has received this month. ■

PJM News

P3 Challenges FERC Ruling on PJM Changes to 2024/25 BRA at 3rd Circuit

By Devin Leith-Yessian

The PJM Power Providers (P3) last week *asked* the 3rd U.S. Circuit Court of Appeals to overrule a FERC order allowing PJM to recalculate the reliability requirement parameter for Base Residual Auctions (BRAs) after bids have been submitted but before the auction closes.

The commission's February order was centered on the 2024/25 auction, which would have seen capacity prices increase fourfold for the DPL South locational deliverability area. (See *FERC OKs PJM Proposal to Revise Capacity Auction Rules*.)

PJM attributed the increase to the reliability requirement calculation including resources that didn't ultimately bid into the capacity auction. It explained that certain resources, such as disproportionately large generators or intermittent resources, can cause an increase in the reliability requirement to account for the imports needed when they are unavailable.

The RTO "ran an auction consistent with the rules; they didn't like the outcomes of that auction, and they changed the rules," P3 President Glen Thomas told *RTO Insider*.

He said that changing auction rules after companies have entered bids in part informed by those rules amounts to retroactive ratemaking and undermines confidence in the markets.

"If that's going to be the new normal, that's going to be something everyone participating in the PJM markets is going to have to consider," he said.

P3 in its filing pointed to Commissioner James Danly's dissent from FERC's order in which he predicted it would be struck down by the courts for violating the filed-rate doctrine. He compared changing auction parameters after bids have been submitted to a game of blackjack in which the house changes the rules after the cards have been revealed.

"The house saves a bit of money on one hand, but no one ever plays blackjack at the Federal Energy Regulatory Casino again. That is this case. The only difference is that the capacity market is not a game but rather the mechanism by which we ensure sufficient generation resources are built and maintained to keep the lights on," Danly wrote. ■

Glen Thomas, P3 | © *RTO Insider LLC*

PJM Stakeholders Refine CIFP Capacity Market Proposals

By Devin Leith-Yessian

VALLEY FORGE, Pa. — Stakeholders last week continued to refine proposals to overhaul PJM's capacity market through the second phase of the RTO's Critical Issues Fast Path (CIFP) process.

The first stage two meeting on April 19 featured presentations from American Municipal Power (AMP), the Independent Market Monitor and a joint proposal from the East Kentucky Power Cooperative and Daymark Energy Advisors.

A second meeting on April 26 included presentations from MN8 Energy and the Capacity Coalition, a group of five generation companies collaborating to create a combined package. Vistra and Autumn Lane Energy were also scheduled to present on the that day but had to postpone until May 17 because of time constraints.

The proposals aim to address several issues highlighted by the PJM Board of Managers when it initiated the CIFP process in February, including evaluating whether the Capacity Performance (CP) construct is adequately incentivizing resources to meet their obligations and creating stronger winter or seasonal requirements for accreditation and fuel security standards.

The second phase of the process involves forming proposals, which will be finalized in the third stage and voted on by the Members Committee in August. PJM's Dave Anders reiterated that there is not a hard line between the second and third phase, and proposals can continue to be created and modified at any point.

EKPC and Daymark Propose Two Types of Capacity

The proposal from EKPC and Daymark would create base and emergency capacity variants, with the latter being designed to address extreme weather conditions. Emergency capacity would also be required to have firm fuel or the technical equivalent to it, be available to commit within two hours' notice and demonstrate the ability to financially withstand any non-performance penalties should it not operate.

"Should they fail to perform and thus not be paid as a consequence of that nonperformance and it could have a substantial impact, the next step should not be that they leave the market because that would be problematic," Daymark's Marc Montalvo said.

The base capacity would be focused on addressing systemic conditions and wouldn't include winterization requirements above those already mandated by NERC. However, the PJM proposal would require all capacity resources to winterize to a higher standard or not receive any revenues for those months.

Adrien Ford of Old Dominion Electric Cooperative said multiple connections to gas pipelines may not be useful as a firm fuel qualification, given that in some locations a single pipeline connection can be more reliable than multiple pipelines in another location.

AMP Seeks Subannual Accreditation

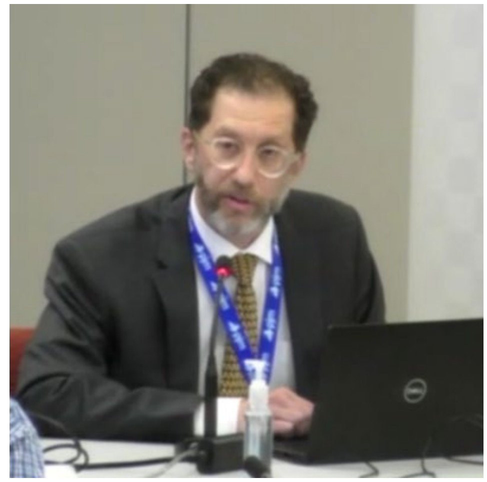
AMP presented a proposal that would create sub-annual accreditation and replace capacity performance, which penalizes and rewards generators depending on whether they meet their obligations during emergencies. Under the concept, all capacity resources would be required to participate in sub-annual auctions, which would clear after the annual Base Residual Auctions (BRAs). Auctions would also be held closer to the delivery year, a shorter time frame than the current three-year advance schedule, reflecting market participants' experience with auction delays leading to compressed timelines.

"The idea would be that we don't do away with annual [accreditation] outright. … We firmly believe that the majority of the capacity that clears should be annual, but recognize that monthly or seasonal has value," AMP's Steve Lieberman said. The specifics of how granular sub-annual could go would depend on stakeholder feedback in the coming months, he said.

The proposal would replace CP with a regular testing requirement consisting of a penalty and reward structure based on testing performance. The incentives would be based on capacity market revenues and operate on a "pay as you go" basis.

Independent Market Monitor Adds Detail to Proposal

Monitor Joe Bowring provided additional detail on the proposal he unveiled during the first-phase CIFP meetings. The proposal would seek to identify the energy needs for each hour of a delivery year and provide capacity revenues that cover the avoidable costs for



Steve Lieberman, American Municipal Power | *PJM*

generators meeting that need. Capacity would be paid based on annual auction clearing, hourly supply and demand and an annual avoidable-cost rate (ACR).

The Monitor's plan would base accreditation on a unit's installed capacity (ICAP) multiplied by its modified availability factor (MAF), an attribute which aims to provide a methodology to capture the availability of all resource types by incorporating forced outage rates, maintenance outages and intermittent resource availability. Bowring said availability would be a stronger measure than PJM's current effective load-carrying capability (ELCC) measure.

All resources holding capacity interconnection rights (CIRs) would be subject to a must-offer requirement for that capacity and weekly generator testing. Capacity resources would also be required to possess firm fuel or the technical equivalent. For intermittent resources, that would mean being obliged to perform at their full possible output when called upon. Winter Storm Elliott last December showed, however, that firm fuel is not a guarantee of the ability to perform when called upon.

Weekly testing may be considered an "extreme position" for many stakeholders, Bowring said, but he argued that regular testing throughout the year, not just during the summer, recognizes that resources need to be able to perform any time of year.

"If there had been adequate testing, we would not have had either the polar vortex or Winter Storm Elliott" challenges, he said.

Casey Roberts, with the Sierra Club, questioned whether the Monitor's proposal would consider gas generators to be available if they

PJM News

did not nominate for fuel ahead of potential emergency conditions. Bowring responded the proposal doesn't currently address that, but it is something all proposals will have to weigh.

Capacity Coalition Presents Short- and Long-term Proposals

Emma Nix of Leeward Renewable Energy and John Horstmann of AES presented a Capacity Coalition proposal that aims to introduce short-term changes to the capacity market through the CIFP process, while putting long-term changes on the table.

The short-term changes include retaining the status quo of exempting renewable resources from the capacity market must-offer requirement, developing transparent and coherent triggers for a Performance Assessment Intervals (PAI), increasing market seller's flexibility in reflecting their risk in their market seller offer caps (MSOCs), and changing how thermal resources are accredited to reflect expectations of how they would operate through weather and historical performance.

The proposal says that, in the short term, the status quo must-offer exemptions for intermittent and limited-duration resources should remain in place given that capacity is an annual product that commits those resources around-the-clock at times they may not reasonably be expected to be provide capacity. Renewable and storage resources need the exemption so they can adjust their capacity offers based on their individual risk tolerance for Capacity Performance penalties should a PAI be called when the resource is not online, Nix said. Implementation of the seasonal proposal in the long-term would negate the need to maintain the must-offer exception in the short term.

The proposal would also only allow generators to be penalized when there has been advance notice of a PAI, when PJM is not exporting to non-firm load commitments in other regions and when the RTO does not have adequate system reserves. It would limit the bonuses derived from the penalties to only be payable to resources that participate in the capacity market. They are currently paid to any generator that performs above expectations.

PJM's Becky Carroll said the RTO's proposal to eliminate the pre-emergency demand response as a PAI trigger could effectively allow DR deployments to serve as advance notice for the potential for generators to be subject to penalties, though she added that there could be PAIs that don't follow a pre-emergency DR call.

Horstmann said there's an open question as to what obligations a capacity resource committed in PJM might have to serve load in other regions during an emergency. The coalition proposal seeks to define that as being an obligation to serve PJM's load.

John Horstmann, AES | *© RTO Insider LLC*

The proposal also calls for the creation of Capacity Performance quantified risk (CPQR) values for resource classes, to reduce the administrative burden in the unit-specific MSOC process while still allowing companies to reflect their risk across their portfolio.

The long-term side of the proposal calls for a transition from a single annual price to a seasonal capacity model consisting of 12 monthly intervals and four daily intervals by 2030.

The seasonal proposal would align accreditation and offers with how resources are capable of performing during specific times of day. Most important, the RPM auction would set the price for each interval allowing market forces to appropriately establish prices based on PJM system supply and demand needs to incentivize new capacity entry, particularly during times of system need. The coalition includes Leeward, AES, Pine Gate Renewables, Ørsted and Cypress Creek Renewables.

MN8 Energy Suggests 'Pay as You Go' Model

A proposal from MN8 Energy aims to build on PJM's proposed accreditation and risk modeling — namely, capturing a larger breadth of factors affecting generator operation, such as temperature impacts and lead time — while proposing a "pay as you go" model for performance assessment, a seasonal capacity market and additional inputs to CPQR.

MN8's presentation said PJM's two-tiered PAI system risks including hours that are not relevant to maintaining reliability and could incentivize some resources in a discriminatory fashion. The PJM proposal would have a minimum of 30 assessment hours for each delivery year, with generators' performance being assessed in the tightest hours if there are not 30 emergency hours in a delivery year.

The proposal would instead use a pay-as-you-go design for performance assessment where a performance factor would be determined for each generator at the end of a delivery year to calculate compensation. Those resources that underperform would collect a portion of revenues cleared in the BRA, while overperformers would receive all their cleared revenues plus a portion of uncollected revenues as a bonus.

Should the capacity market continue to carry a significant risk of penalties, the MN8 proposal suggests that CPQR should consider opportunity costs, expectations of penalties and bonuses, and the costs to manage risk. ■

Southeast

Brattle Report Sees Benefits for SC RTO Membership

Legislature-commissioned Report to Inform Decision on Future of State Regulation

By James Downing

Participating in an RTO could provide South Carolina with benefits of up to $362 million per year, according to a report Brattle Group presented to a special joint legislative committee on Monday.

The *report* to the Electricity Market Reform Committee found that joining PJM would lead to the most benefits (up to $362 million per year), followed by South Carolina — and possibly some of its neighbors — forming a new organized market in the Southeast (up to $187 million). The report also covers a system like CAISO's Western Energy Imbalance Market (as much as $25 million in net benefits) or setting up a joint dispatch agreement (JDA) between that state's utilities that would save up to $11 million annually.

Duke's two South Carolina utilities operate under a JDA, which could be expanded to include Dominion, Santee Cooper (a state-owned public utility) and others that serve the state.

South Carolina could also integrate with an existing RTO, but under a new governance model that would be similar to the Western EIM, with the addition of a day-ahead market and resource adequacy pooling.

Brattle said its savings projections were in line with other benefits studies around the country, which show 4 to 8% operational savings from RTO membership. When Louisiana joined MISO, it was able to cut its reserve margin from 18% to 12%, which is consistent with the savings projected in South Carolina.

All the scenarios include operational benefits because they let power flow more freely over a wider region, but joining or creating an RTO comes with additional investment cost savings from coordinating resource adequacy over a broader region, which enables lower reserves for the state.

No Loss of Reliability

At Monday's hearing, Brattle principal and report co-author John Tsoukalis said that the lower reserve margin would still provide the same level of reliability.

"Everybody in the market can achieve the same level of reliability with a slightly reduced reserve margin," he added.

South Carolina Rep. John "Jay" Taliaferro West IV (R) (left) and Sen. Tom Davis (R) at a May 1 hearing on Brattle's recommendations that the state join an RTO | *South Carolina Electricity Market Reform Measures Study Committee*

The main reason joining PJM leads to more benefits than setting up a new Southeast RTO is that South Carolina's immediate neighbors have similar supplies, so trading power would not bring the state's utilities as much income as linking up to the more expensive market serving the Mid-Atlantic and Midwest, Tsoukalis said.

Committee members at the hearing asked questions about Brattle's conclusions, and legislators will use the report to inform their decision on any changes to the state's regulatory structure. Committee co-chair Sen. Tom Davis (R) said at the hearing that the committee must make recommendations to the full legislature by January.

Setting up a joint JDA, an EIM or a new RTO are all lengthy processes that would include coordinating with entities outside of South Carolina's control.

Joining PJM is the most expeditious path to full RTO membership, with PJM in the past having taken on new members in as little as 18 months.

"Under this model, South Carolina would operate within all existing RTO market and governance structures, including the option to retain its vertically integrated and state-jurisdictional utility structure," Brattle said in the report.

Brattle found the biggest benefits came to South Carolina when it worked with its neighbors on its decision, advising the legislature to especially reach out to North Carolina. Dominion Energy North Carolina is in PJM already, but the rest of the state is not in any market.

South Carolina is also considering retail market reforms, but Tsoukalis said that moving on wholesale reforms first would make the most sense as they will inform potential changes to its retail regulations.

The committee posted a *document* of comments on the study, and while the state's utilities largely focused on technical findings, AARP South Carolina opposes joining an RTO, saying it bases its views on "the realities of RTOs after 25 years in states that have them."

"Our members in Texas and California have suffered from power interruptions and higher electricity prices caused by the complicated new RTO-induced structures where no one is clearly in charge of keeping the lights (and air conditioning and heating) on," AARP said. ■

Southeast

FERC OKs Duke Energy Rate Changes to Reflect Tax Cuts

By James Downing

FERC on Friday approved Duke Energy's settlement with two co-ops to reflect lower corporate tax rates from the Tax Cuts and Jobs Act of 2017 enacted under former president Donald Trump (*ER23-1206*).

FERC Order 864 required utilities to reflect the cut in the federal corporate income tax from 35% to 21% in their formula rates, specifically their accumulated deferred income tax (ADIT). ADIT is meant to account for the timing differences between filing taxes with the IRS and the method of computing them for regulatory and ratemaking processes.

The lower federal taxes meant that some of utilities' ADIT collected from consumers was no longer due to the IRS. Order 864 was meant to ensure that ratepayers were made whole for those over-collections and that going forward utilities would have to reflect tax changes in their rates in a transparent manner.

Duke made its initial compliance filings for Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida in 2020, as required, but FERC sent it back for some additional clarifications. (See *FERC Directs More Clarity in Order 864 Filings*.)

The utility filed changes, but a limited protest came from two of its wholesale customers: North Carolina Electric Membership and Central Electric Power Cooperative.

The two customers said that Duke proposed changes that were not required by FERC's initial order. Duke's filing would have changed how it calculated "average rate assumption method" (ARAM) rates, using the "best available data" instead of calculating them in the fourth quarter of the previous year.

They argued that the changes were ambiguous and would let Duke base its calculation on a period other than the fourth quarter of the previous year, which could lead to a mismatch in how ARAM and ADIT rates are calculated. Neither the customers nor FERC had a chance to fully vet the proposal, they said.

Duke asked FERC to hold the proceeding in abeyance so it could negotiate with the co-ops and came to a deal with them before submitting the compliance filing approved Friday.

The firm is proposing revisions to each utility's formula rate to clarify that the ARAM rate used for the amortization of excess deferred income tax from the tax cut will be the "ARAM rate based on the last filed final federal corporate income tax return, after all permitted federal extensions" as of the date of posting the annual update.

FERC found that Duke's proposal complies with Order 864 and addresses the co-ops' concerns, making their protest moot.

The commission accepted Duke's proposal to return excessive ADIT to customers — or collect shortfalls from them — effective June 1, 2020. The commission said the utility had held customers harmless for the new tax rates in its 2018 and 2019 annual updates. FERC agreed that the June 2020 date would not adversely impact customers. ■

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

SPP News

SPP Board/Members Committee Briefs

Working Groups Begin Addressing Grid of the Future

KANSAS CITY, Mo. — SPP members and the RTO's Board of Directors last week embraced an advisory group's report on a future grid that is fast approaching, directing stakeholder groups to begin addressing the group's recommendations.

The board on April 25 accepted the Future Grid Strategy Advisory Group's (FGSAG) *report* that identified potential gaps between future state projections and current trajectories, and urged increased organizational awareness of the opportunities to shape the future grid.

The directors had charged the group in 2021 to explore how the grid will change over the next 10 to 15 years and to make recommendations that help SPP and its membership prepare for those changes. The report identifies trends and strategic pathways that could be disruptive and game changing and makes 32 recommendations to address them.

SPP says the grid's future is "vitally important" to its stakeholders and that the FGSAG's work sets the stage for their discussions and readies staff to meet its members' needs. Of course, that work will have to be balanced with ongoing initiatives.

"We are often dealing with what's right in front of us and trying to react to changes that are occurring. … Things can look very complicated when we're trying to address them," Advanced Power Alliance's Steve Gaw, a member of the group, said during the board's quarterly meeting. "If we only look down in front of our feet at what we are about to step on, we sometimes lose our way because we don't look up. This is an attempt I think not to say that we should be constantly looking up and forgetting what's right in front of us, but an attempt to balance what's going on out ways in front of us so that we don't lose our way with distraction of what's the latest urgency."

"I think one of the challenges is how do you balance all of this new work with the existing work," Director John Cupparo said. "The work groups that are going to be tasked these assignments would come back with some timelines and work plans for how that work will fit in with all the existing [work] so that we can see the balancing of that and understand the tradeoffs."

The FGSAG gathered assessments last year from surveys, industry experts and organizational expertise to compile a list of recommendations. The Strategic Planning Committee endorsed the work in January and requested the board to direct the appropriate organizational groups to begin considering each recommendation.

Steve Gaw, Advanced Power Alliance | *© RTO Insider LLC*

The group categorized the results into four areas: consumer trends, policy implications, resource impacts and transmission possibilities. Four sub-teams then drafted white papers that examined each topic's concerns and defined preliminary recommendations. Because the sub-teams' recommendations had some overlap and common themes, the full FGSAG reviewed and consolidated them into a final list, grouped into five categories:

- energy adequacy/modeling/planning;
- grid services/market design/operations;
- transmission;
- demand-side resources; and
- innovation and collaboration.

The report sets out a three-phase plan to address its recommendations and provide progress reports back to the SPC:

- educate primary working groups on the relevant recommendation and secondary and advisory working groups for input as needed;
- draft initiatives that address the recommendations and develop tasks and outcomes to ensure their inclusion in SPP's comprehensive roadmap; and
- report quarterly on the initiatives' progress and update the board on their implementation's appropriateness, scope and pace.

The effort has been led by Mark Ahlstrom, NextEra Energy Resources' vice president of renewable energy policy and board chair of Energy Systems Integration Group, a nonprofit engineering, resources and education association.

"Basically, what we're planning to do is to take the recommendations that apply to each of the organizational groups out to them over the next six months or so, start the process of educating them, helping them understand it, get their feedback, and then engage other secondary and advisory groups," Ahlstrom said. "It's going to be an evolving set of things that we have to make sure we're on top of and we get feedback and we evolve and improve as we go. I think you're going to be seeing a lot of us as we continue to make sure that we keep ahead of the curve on what has to be done before we get to that 10- to 15-year time frame."

The Inflation Reduction Act has added a complicating factor. The FGSAG said it attempted to document the legislation's expected implications but that it will take more time and analysis to fully understand and address all its implications on generation, electrification, loads for green hydrogen production and economic development.

"What is already certain, though, is that the IRA's impact on the SPP region will be dramatic," the report said, pointing to tax credits for renewable, nuclear, green hydrogen production and energy storage.

"I can't emphasize enough this is not going to be a one-and-done," Ahlstrom said. "This is going to be an ongoing activity, but hopefully about a year from now, we would expect to see some sort of plan about how this will be taken up in methodical way by the various organizational groups and by staff."

MMU Report: Energy Prices up

SPP's Market Monitoring Unit gave the board and stakeholders a first peek at its annual report on the SPP market and its outcomes that reflect changing conditions.

According to the *report*, high natural gas prices resulted in increasing energy prices; the Panhandle Eastern hub's average gas price of $5.83/MMBtu, up 69% from the year before, led to day-ahead and real-time prices of $48/MWh and $43/MWh, respectively, up 80% and

SPP News

75% from 2021. Data from February 2021 was excluded to avoid skewing the metrics.

The SPP market also experienced continued higher renewable penetration and increased make-whole payments, congestion and revenue neutrality uplift. Keith Collins, the MMU's vice president, said he wouldn't be surprised if wind energy reaches a 40% share of SPP's generation mix this year.

"SPP is in fact a wind system. At one time it was a coal system, but I think SPP is in fact a wind-dominated system," he told stakeholders.

The MMU said the market's challenges — increasing variability and supply uncertainty, out-of-market reliability actions, higher make-whole payments and more negative prices — are not necessarily new developments. It said addressing resource adequacy is "perhaps the most important lesson" from the severe winter storms of the last two years; the key issues include a lack of a seasonal resource adequacy requirement; fuel availability risks; correlated output and outages among similar resources; and an accreditation process that does not reflect actual resource performance.

"The SPP system was lucky to have significant imports from MISO, PJM and others. SPP cannot plan to count on these systems to help SPP in a future event as a wider regional cold snap could limit imports," the report says.

"It's important to know that the resources we have in the system can be counted on during these events," Collins said. "We need incentives to ensure that that capacity is available. … We know we're moving to winter [resource adequacy] requirements. I think we've seen evidence that having requirements in the shoulder periods as well is actually a growing importance."

The MMU is adding four new recommendations for 2022:

- consider limitations on virtual trading during emergency conditions;
- address limitations with the ramp capability introduced last year;
- improve situational awareness of transmission upgrades and the process to reassign projects; and
- improve congestion-hedging mechanisms to make them more equitable.

The Monitor said it "has and will continue to engage in the SPP stakeholder processes to help promote improved resource adequacy in the SPP market."

EDP Renewables' David Mindham (right) questions the MMU's Keith Collins about the monitor's 2022 market report. | *© RTO Insider LLC*

The final market report is expected to be released in May. The 267-page opus will likely meet with approval from Google's Betsy Beck, who has a market monitoring background and professes to read market reports "back to back, cover to cover every year."

"I love these State of the Market reports. There's always so much great information in the report itself," she said. "The MMU puts a tremendous amount of work and really good analysis, and you can get a sense of all the different pieces of the market — how things are working well together or not — from reading the report."

Uri Helps SPP Response to Elliott

SPP staff told the board and members that lessons learned from the 2021 winter storm (also known as Winter Storm Uri), many of which are still being incorporated into daily processes, were "extremely helpful" in the grid operator's response to the December winter storm (also known as Winter Storm Elliott) when accredited generation fell short of demand at times.

Still, staff identified 11 recommendations during a *thorough review* of its performance during Elliott that could help the RTO and its stakeholders be better prepared for extreme events in the future. The recommended changes are to internal processes, tools or functions and should not require additional resources or stakeholder prioritization to complete, staff said.

The board approved the latest recommendations as part of its consent agenda.

Mike Ross, senior vice president for external affairs and stakeholder relations, said almost two-thirds of recommendations from Uri are complete. He said the rest should be completed by 2025, depending on FERC and other approvals, and that staff have recommended staying the course on the Uri recommendations.

The new recommendations include improving situational awareness of neighboring conditions; adding extreme weather risks to SPP's transmission planning process; and identifying options to better mitigate and manage congestion during extreme winter events. SPP did not have to shed load during Elliott as it did during Uri, but the balancing authority area came close, and Empire Electric District had to shed about 25 MW of load for 15 minutes. (See "December Storm Raises Same Issues," *SPP MOPC Briefs: Jan. 17-18, 2023*.)

"While there was no load shed directed by SPP, we came closer than we would have liked," Ross said.

The two storms have both presented significant challenges to maintain reliability, staff said. Coal outages and derates were actually

SPP News

worse during Elliott, Ross said, and drove home the point that two "historic" extreme weather events 20 months apart are a harbinger of what the future holds.

"I think we're going to stop using the term, '100-year storm,'" SPP CEO Barbara Sugg said.

Sugg Drops the Mic

Sugg reflected on the year's first months that included a tornado touching down within a half-mile of the RTO's headquarters building in Little Rock, Ark., continued market expansion into the Western Interconnection and advancements in clearing the generator interconnection queue's backlog.

In sharing the organization's progress against its strategic plan, Sugg pointed to the traditional dinner that follows the Regional State Committee meeting the night before the board meeting as an example of SPP's stakeholder-driven culture. The casual dinner brings together the board's directors and the RTO's staff, members, regulators and other stakeholders.

"It was loud; it was rowdy; and it was fun. It felt like old times, and it was great to see everybody having a good time," she said. "Just that dinner alone is one of the things that makes SPP extremely unique, because you will not find that in another region. Building relationships … is the cornerstone of SPP and is really what makes SPP great."

SPP CEO Barbara Sugg | © *RTO Insider LLC*

In closing her report to the board, Sugg reiterated a statement she has made before: "There is no place I would rather be than working collaboratively here with all of you and back at the office with all of our amazing staff to achieve our vision of leading our industry to a brighter future while delivering the best energy value. That's my mic drop moment."

2022 Annual Report Available

SPP has released its annual report for 2022 and for the third year in a row, it will be in a *virtual format*.

The report details the grid operator's performance during the year. The RTO says it provided $3.787 billion in value to its members and expanded the services it is providing stakeholders in the Western Interconnection.

It also summarizes SPP's response to Elliott, improvements to generation interconnection, development of a consolidated transmission planning process, and staff's and members' focus on the future grid.

New Members Committee Reps

The Members Committee welcomed three new representatives who will serve in an interim capacity until they are officially elected during the October membership meeting:

- Stacey Burbure, legal counsel for American Electric Power, replacing AEP's Peggy Simmons;
- Al Tamimi, vice president of transmission planning and policy for Sunflower Electric Power, replacing retired Sunflower CEO Stuart Lowry; and
- Christy Walsh, director of federal energy markets for Natural Resources Defense Council's Sustainable FERC Project, replacing Invenergy's Daniel Hall.

The meeting was also Tom Christensen's last as an MC member. He is retiring from Basin Electric Power Cooperative in May as senior vice president of transmission, engineering and construction.

Basin Electric Power's Tom Christensen sits through his last SPP board meeting. | © *RTO Insider LLC*

Consent Agenda Passes

Members and the board approved a consent agenda that contained one revision request:

- *RR530*: identifies consistent criteria for when it is acceptable to implement a transmission reconfiguration, and outlines responsibilities for the reliability coordinator and transmission operator in developing mitigation plans to avoid system operating limit exceedances.

The consent agenda included several other items, including:

- the Oversight Committee's recommendation for the 2023 industry expert pool that will review and evaluate proposals for competitive transmission projects. The pool includes 15 holdovers from last year and two new members: independent consultant Frank Lembo, a former chief engineer with Consolidated Edison, and Mark Lawlor, a renewable developer with EDP Renewables and Clean Line Energy Partners.
- a 26% increase for Basin Electric's 60-mile, 230-kV sponsored upgrade project in North Dakota near the Canadian border. An additional 5 miles of transmission line bumped the project's cost from $64.9 million to $81.4 million. ■

— Tom Kleckner

South news from our other channels

Texas RE Sees Opportunity in Cold Weather Standards

ERO Insider

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

SPP News

SPP's REAL Team Swings into Action

Stakeholder Group to Address Resource Adequacy Issues

By Tom Kleckner

Texas commissioner Will McAdams explains the REAL Team's work on resource adequacy to the Regional State Committee. | *© RTO Insider LLC*

KANSAS CITY — SPP's Board of Directors last week approved the scope of a team formed to address resource adequacy challenges and endorsed the group's plans for dealing with resource accreditation.

SPP's board and its state regulators created the Resource and Energy Adequacy Leadership (REAL) Team earlier this year. It was clear then to stakeholders that the group had a monumental task in front of it.

The team is charged with providing guidance, prioritization and policy recommendations to increase the assurance that energy can be continuously and cost-effectively provided within SPP's balancing authority footprint. The team is also expected to address applicable recommendations from the RTO's grid-of-the-future work and resource-adequacy issues identified by other initiatives.

When REAL Team chair and Texas Public Utility Commissioner Will McAdams found himself staring at a slide during an April 24 presentation to the Regional State Committee, he paused momentarily.

"And this is our implementation calendar," McAdams said. He paused again. "This is an aggressive calendar, and we're going to do our best."

Kansas commissioner and RSC chair Andrew French said the team's task is even larger than he first imagined in preparing the initial draft scope.

"I knew it would be a heavy lift, but as I've listened in on a couple of the first meetings and realized how important these issues are to everyone and how many extra issues there are, we're realizing it's going to be a heavy lift," he said. "I'm more convinced than ever that it's a worthwhile lift, that strategically, it's absolutely essential to set the foundation for us moving forward."

The REAL Team plans to deliver adjustments to SPP's resource accreditation policy in October. FERC in March rejected SPP's capacity accreditation methodology for wind and solar resources on procedural grounds and granted clean energy interests' rehearing request of its prior acceptance. (See *FERC Grants Rehearing of SPP Capacity Accreditation Proposal*.)

Next year, REAL plans to produce a resource adequacy methodology and related policies, a seasonal resource adequacy construct, value-of-lost-load and expected-unserved-energy metrics, and future capacity accreditation and planning reserve margins.

No wonder McAdams drew chuckles when sharing the team's deliverables timeline.

"All of this we hope to tackle in year one," he said.

McAdams said the 14-person team, comprised of SPP board members, stakeholders and state regulators and staff, will be "looking at challenges resulting from resource mix changes, high intermittent energy penetration into the system, and how our [load-responsible entities] can cope with that to ensure a reliable reliability standard is ultimately met."

"This needs to occur during events of extreme weather, increased demand and evolving customer behavior," he said. "REAL Team over the next year and possibly onward, will provide guidance, prioritization and policy recommendations to increase assurance that there will be sufficient energy to cost-effectively meet load requirements."

The RSC last week unanimously approved the *REAL Team's scope.* It also endorsed its proposal to respond to the FERC ruling — having the Supply Adequacy Working Group (SAWG) break effective load-carrying capacity (ELCC) and performance-based accreditation into two separate revision requests. REAL said the ELCC change should reflect FERC's guidance to add a definition of seasonal net peak load and address the accreditation of renewable and thermal resources in a similar manner.

The proposal further directs SAWG to harmonize the two RRs and explain how the treatment of resources is equitable and appropriate, filing both changes with the board and RSC before the October governance meetings.

The Board of Directors approved the motion April 25 as part of its consent agenda.

"This shows us that we need to better describe our methodology with repackaging and re-presenting this policy to the FERC," McAdams said. "Ultimately, we need to make an attempt to compare them on an apples-to-apples basis, even though the resources are different.

"My hope as chair ... is that we start thinking about what FERC can approve in a timely way.

SPP News

These are important policy building blocks that we need to have in place in order to move off first base toward a reliability framework that we can actually defend and build upon and that we can hold the system accountable to," he added. "We do not want to offer them proposals that they can just reject out of hand, which costs us time that we do not have. We need to be crafting proposals that have a degree of certainty that [they] will be passed."

Member Value Up to $3.787B

SPP staff updated its *member value statement* during the quarterly stakeholder briefing that followed the RSC meeting, saying its analysis found the RTO provided $3.79 billion in net savings to members in 2022, a 41% increase from the year before and a 22-to-1 return on investment.

According to the report, the biggest savings came from the Integrated Marketplace's day-ahead, real-time and transmission markets ($2.3 billion) and reduced costs and required reserves within the RTO's footprint ($1.03 billion).

"That's driven mostly by significant increases in the cost of gas and wholesale energy … [When prices rise] the benefit of participating in SPP's [markets] obviously goes up," said Mike Ross,

SPP's Bruce Rew | © *RTO Insider LLC*

SPP's senior vice president for external affairs and stakeholder relations.

Ross said the market benefits are estimated by comparing what the cost of energy would be in the legacy balancing area versus SPP's Integrated Marketplace.

"We've already seen much lower energy prices to start 2023," he said.

The annual statement, based on a methodology developed by staff and stakeholders, quantifies the value SPP provides member organizations through reliability coordination, regional transmission planning, market administration and other services.

"This remarkable benefit-cost ratio demonstrates we are driving value beyond reliability," CEO Barbara Sugg said.

In other quarterly reports:

- SPP said it established new marks for wind energy and renewable energy on March 16 when it hit 23.8 GW and 24.89 GW, respectively, breaking records set in February. The grid operator has more than 32 GW of available wind resources.
- Xcel Energy (NASDAQ:XEL) subsidiary Public Service Co. of Colorado's April entry into the Western Energy Imbalance Service (WEIS) market has tripled its size to more than 13 GW. The utility's load topped 6 GW in April, while WEIS' weekly average this year has regularly been above 3.5 GW. A recent report revealed the WEIS market provided $31.7 million in net benefits to its 12 participating utilities in 2022 at a benefit-cost ratio of 7-to-1.
- SPP's Integrated Marketplace now has 195 financial-only and 119 asset-owning market participants, for a total of 314. ■

SPP News

FERC Approves SPP's Resource Adequacy Changes

By Tom Kleckner

FERC last week approved two SPP revisions to its tariff that would provide load-responsible entities (LREs) with an alternative short-term, nonpunitive approach to deficiency payments for their summer resource adequacy requirements (RAR).

The commission April 24 accepted the RTO's proposal specifying that LREs making the deficiency payments will be sufficient for the current year's RAR (*ER23-1216*) and a second revision that adds a deficiency payment structure applicable in certain circumstances and based on a sufficiency valuation curve (*ER23-1218*). The revisions are effective today.

Deficient LREs that make the payment are essentially buying capacity needed to make it sufficient for the current year's RAR from other entities with excess capacity, SPP said. It would then consider those LREs sufficient for the current year's applicable requirement.

Both revision requests were approved in January by SPP regulators, stakeholders and its Board of Directors after months of trying to reach consensus. (See *SPP Board/Members Committee Briefs: Jan. 31, 2023*.)

FERC said the proposed revisions are just and reasonable and not unduly discriminatory or preferential. In the first order, it said SPP's proposal clarifies the responsibilities for both LREs that make deficiency payments, and LREs or generator owners with excess capacity that receive revenues from those payments. The latter group cannot subsequently contract to sell any of that excess capacity being paid revenue distributions to any other entity in the grid operator's balancing authority area during the applicable summer season.

"We find that this will ensure that SPP can rely on the designated excess capacity for the SPP balancing authority area during the applicable summer season," the commission wrote.

The RTO said in its request that without an assurance from entities receiving excess capacity revenue that they will not subsequently contract that same capacity to someone else, the BAA could see increased reliability risk if that capacity is contracted and made otherwise unavailable for serving load.

The commission also found SPP's proposed sufficiency valuation curve to be a "reasonable method" to estimate the value of excess accredited capacity needed to resolve LRE deficient capacity in the RTO's footprint and to calculate LREs' deficiency payments after a planning reserve margin (PRM) increase.

FERC agreed with the SPP's Market Monitoring Unit that this valuation of deficient and accredited capacity is "commensurate with regional resource adequacy needs, without removing the long-term planning incentive of SPP's current deficiency payment approach."

It said SPP's proposed sufficiency valuation curve eligibility criteria is reasonable because it specifies the circumstances under which a deficient LRE may rely upon the methodology following a PRM increase, while ensuring that an LRE unable to meet the prior PRM is not relieved from its obligations under SPP's deficiency payment mechanism.

SPP increased its PRM from 12% to 15% last year. It developed a mitigation strategy to address members' concerns that they wouldn't have enough time to meet the new requirement. (See *SPP Board of Directors Briefs: Dec. 6, 2022*.) ■

Company News

Entergy, NextEra Tout Clean Energy Efforts

By Tom Kleckner

Entergy told financial analysts Wednesday that it is investing to improve reliability and resilience and "significantly" expand its clean energy footprint.

"We're working to improve operational and regulatory outcomes, support our customers' industrial growth and economic development in our region, invest in renewable clean energy and resilience," CEO Drew Marsh said during the company's first quarter earnings call.

On April 24, Entergy's leadership joined Texas Gov. Greg Abbott and four of the state's five regulatory commissioners to break ground on the *Orange County Advanced Power Station,* which will use turbine technology and a plant layout that can support dual fuel capability for hydrogen in the future.

"That facility will ensure that we have moderate and reliable infrastructure to support existing customers and the rapidly growing customer base in our Southeast Texas region," Marsh said. "The optionality helps ensure the plant's long-term viability and creates improved energy security and operational flexibility for our customers."

The 1.22-GW combined-cycle plant's construction is expected to be complete in 2026. Texas regulators approved the plant last year.

Entergy reported earnings of $311 million ($1.47/share), compared to $276 million ($1.36/share) for the same period a year ago. The adjusted earnings were short of Zacks Investment Research's projection of $1.36/share.

Entergy's share price closed at $105.50 Wednesday, a loss of $2.26 for the day.

NextEra Beats Expectations

NextEra Energy on April 25 *reported* better-than-expected results of $2.09 billion ($1.04/share), up from 2022's first-quarter net loss of $451 million (-$0.23/share).

The Florida-based company's adjusted earnings of $0.84/share beat the Zacks consensus estimate of $0.75/share, the fourth straight quarter it has exceeded EPS expectations.

NextEra attributed the financial performance to a clean energy investment push that has protected it from natural gas price swings. The company says it is the first in history committed to moving past net zero to "*real zero*" — using only wind, solar, battery storage, nuclear, green hydrogen and other emissions-free sources.

Its NextEra Energy Resources subsidiary added more than 2 GW of new renewables and storage projects to its backlog during the first quarter, bringing the total to more than 20 GW. The company said its Florida Power & Light subsidiary increased its solar portfolio to 4.6 GW during the quarter, more than any other utility.

FPL's recently filed 10-year site plan proposes to build nearly 20 GW of solar over the next decade.

"We believe the expansion of cost-effective solar and storage will provide a valuable hedge for our customers against volatile natural gas prices," NextEra CFO Kirk Crews told investors. ■

Texas regulators (first four on left) join Texas Gov. Greg Abbott (fourth from right) and Entergy senior officials for groundbreaking of the utility's Orange County Advanced Power Station. | *Entergy*

Company News

Xcel: Nuclear Water Leaks' Costs 'not Material'

By Tom Kleckner

Xcel Energy executives told financial analysts Thursday that the recent radioactive water leak at a nuclear plant will not result in a material hit to earnings.

CEO Bob Frenzel said during the company's quarterly conference call with analysts that the costs to repair two water leaks since last November "were not significant." Xcel has estimated the costs to be about $2 million.

A pipe broke at Xcel's Monticello Nuclear Generating Station last year, leading to a leak of more than 400,000 gallons of tritium-laced water. The company and state regulators did not disclose the leak until March.

Xcel patched the leak but discovered a second, smaller leak in March during a refueling outage. It has been pumping out the water and tritium from an aquifer under the plant, a process that is not expected to end until later this year or early next year.

"There was no risk to people or the plant," Frenzel said. "It's really about pumping water out. I expect they probably have two more weeks before they finish loading fuel and restarting the plant, but it is ready to go."

Minneapolis-based Xcel *reported* first-quarter earnings Thursday of $418 million ($0.76/share), compared to $380 million ($0.70/share) over the same period last year. Earnings reflected the recovery of electric and natural gas infrastructure investments and other regulatory outcomes, partially offset by higher depreciation, operations and maintenance expenses, and interest charges.

Frenzel told analysts that Xcel continues to make progress on its clean energy transition plans. The company is reviewing proposals for 6 GW of new generation in its various jurisdictions and anticipates regulatory decisions on the proceedings in the latter half of the year.

Xcel has also submitted multiple projects to the U.S. Department of Energy for funding consideration, including hydrogen hubs in the Midwest and West, and grid resilience investments in Colorado.

The company's share price closed at $70.26 on Thursday, a gain of 58 cents on the day. ■

A radioactive leak at Xcel Energy's Monticello nuclear plant is not expected to post material costs | *Xcel Energy*

Company Briefs

Enel: Oklahoma Top Candidate for US Solar Panel Factory

Enel last week said Oklahoma was the leading candidate to become the home of its major U.S. solar panel and cell factory.

The facility is expected to be among the largest to produce solar cells in the country. Enel said it planned to produce at least 3 GW of modules and cells per year.

Enel already has a significant presence in Oklahoma with a $3 billion portfolio of wind projects and an office in Oklahoma City. It is also considering a site near Tulsa.

More: *Reuters*

Siemens Opens EV Charger Manufacturing Facility in Texas

Siemens last week announced that it has opened a new manufacturing hub in Carrollton, Texas, that is focused on building EV chargers.

The company said the facility will manufacture Buy American-compliant level 2 AC chargers called VersiCharge Blue that range from 48 to 80 amps and will contribute to its goal of building 1 million EV chargers for the U.S.

More: *WFAA*

GM, Samsung Plan New EV Battery Cell Factory in US

General Motors and South Korea's Samsung SDI last week announced that they plan to invest more than $3 billion in a new EV battery cell plant in the U.S.

The companies did not announce the intended location of the new factory, which is expected to begin operations in 2026. GM and Samsung SDI plan to jointly operate the factory, which is expected to make nickel-rich prismatic and cylindrical cells.

Samsung was picked as the partner after some Chevrolet Bolt batteries made by LG caught fire, forcing GM to recall about 142,000 vehicles. The recall cost GM about $1.9 billion, but the automaker was reimbursed by LG.

More: *The Associated Press*

Federal Briefs

Michigan Companies, Individuals Face Charges in Diesel Emission Scheme

U.S. District Attorney Mark Totten and EPA officials last week announced that three Michigan-based companies and 11 individuals have been charged with violating federal air pollution laws as part of an alleged scheme to disable emission-control systems on hundreds of semi-trucks.

The defendants are accused of disabling the emission controls on semi-trucks from about 2012 to at least 2018. The alleged scheme involved the coordination of hardware mechanics, software programmers, trucking customers and developers and distributors that provided equipment and tools to carry out the plan.

All three companies and nine of the 11 defendants have signed plea agreements and intend to plead guilty to a felony charge, Totten said.

More: *Crain's Grand Rapids Business*

Senate Votes to Overturn Biden Truck Pollution Limit

The Senate last week voted 50-49 to undo a Biden administration rule that aims to cut pollution from heavy-duty trucks. Sen. Joe Manchin (D-W.Va.) voted with Republicans to get rid of the rule, while Sen. Dianne Feinstein (D-Calif.), who has been absent from the Senate amid health issues, did not vote.

The rule in question aims to cut down on nitrogen oxides that can harm the respiratory system and are also components of acid rain.

Despite its passage, the resolution is not expected to prevail. The White House recently said President Biden would veto the effort, and it is unlikely to win the two-thirds majority needed to override a veto.

More: *The Hill*

BLM Seeks Comments on Proposed Libra Solar Project

The Bureau of Land Management last week announced it is seeking public comments on the proposed Libra Solar Project in Mineral and Lyon Counties, Nevada.

The project would generate up to 700 MW on approximately 5,500 acres of BLM-managed public land.

The 30-day scoping comment period will close May 23.

More: *Bureau of Land Management*

State Briefs

COLORADO

RAQC Could Ban Sale of Gas-powered Mowers, Blowers

According to draft policies at the Regional Air Quality Council, all sales of gas-powered home lawn mowers, trimmers and leaf blowers would be banned in the metro Denver area beginning in 2025.

Some proposals would also ban the summer use of existing gas-powered lawn equipment by big institutional users such as schools or parks beginning in 2025, and by commercial users a year after that.

The RAQC said no formal vote will be taken until later in the spring, but draft policies are circulating in a working group and the agency presented outlines of the idea in this month's Air Quality Control Commission meeting.

More: *The Colorado Sun*

INDIANA

Bill to Halt Stricter Coal Ash Rules Heads to Governor

A bill that would prevent the state from making coal ash rules stricter than federal ones is headed to Gov. Eric Holcomb's desk.

The bill also states that the Ohio Valley Electric Corporation does not have to follow new state rules for its coal ash ponds at its Clifty Creek power plant until it can meet federal requirements.

More: *Indiana Public Radio*

House Gives Approval to Anti-ESG Investing Bill

The House last week voted 66-29 to pass a bill aimed at preventing leaders of the state's pension funds from investing any of the funds' $45 billion with firms that consider environmental, social and governance principles in their investment decisions.

Business groups dropped much of their opposition after the initial proposal was rewritten and the Senate removed provisions such as one that would have had the treasurer's office compile and publish a list of companies that had made ESG investment commitments. The Chamber of Commerce, the state's largest business group, and some other organizations objected to earlier versions of the bill and called proposed investment limitations "anti-free market." An analysis of the first version of the proposal projected that the limitations would cost the pension system $6.7 billion over 10 years.

More: *The Associated Press*

IOWA

Utilities Board Approves Grand Junction Solar, Storage Project

The Utilities Board last week signed off on the 150-MW Grand Junction solar-plus-storage project in Greene County.

According to the application, the facility will generate up to 100 MW of solar and 50 MW in battery storage on about 1,103 acres.

Grand Junction must file final design plans with the UB and prove it has obtained all city and county permits. Then, it will need to file a status report of its progress every 180 days. If Grand Junction fails to complete the project within two years of the permit issuance date, it must file a new application.

More: *Daily Energy Insider*

KANSAS

Gov. Kelly Signs Anti-ESG Law

Gov. **Laura Kelly** last week signed a bill that will restrict state officials from using environmental, social and governance factors when investing public funds or deciding who receives government contracts.

"This bill will ensure that public dollars — particularly our state pension fund — are invested in ways that produce the highest possible returns with the lowest acceptable risk, and that public contracts are awarded to the entities best-qualified to fulfill them," Treasurer Steven Johnson said in a statement.

The bill will take effect July 1.

More: *The Associated Press*

KENTUCKY

Kentucky Power Planning for Wind, Solar by 2037

In its Integrated Resources Planning Report filed last week with the Public Service Commission, Kentucky Power said it intends to add 800 MW of new solar and 700 MW of new wind generation over the next 15 years.

In addition, Kentucky Power said it intends to build a combined gas turbine plant for an additional 480 MW and 50 MW of battery storage.

The company stated it plans on cutting its greenhouse gas emissions by 90% compared to its 2005 output.

More: *CNHI News*

MONTANA

Senate Advances Bills to Keep Climate Change out of State Permitting

The Senate last week advanced amendments to a bill that would stop state agencies from considering climate impacts when issuing permits, unless the federal government recognizes carbon dioxide as a pollutant that can be regulated under the Clean Air Act.

Similarly, Republicans on the Senate Judiciary committee advanced separate legislation, House Bill 971, which bans state permitting agencies from considering carbon dioxide.

The bill would also unwind a 2020 Supreme Court ruling that plays a major role in a lower court's decision to halt construction of a NorthWestern Energy power plant so light pollution and carbon dioxide emissions can be reviewed.

More: *Missoulian*

NEW YORK

Stony Brook to Spearhead Governors Island Climate Center

Stony Brook University last week announced that it will spearhead a new 400,000-square-foot climate change research and education hub.

The Trust for Governors Island's selection of the Long Island research institution culminated a two-year search that will transform a southern chunk of the island and is expected to usher in more frequent ferry service along with new open space for the public.

The New York Climate Exchange will host academics working on climate projects, along with students for educational programs and workforce training. It will have an incubator program for up to 30 businesses each year, as well as an accelerator program to launch initiatives that support communities affected by climate change.

The center's opening is anticipated for 2028.

More: *The City*

NORTH DAKOTA

Grand Forks County Issues Moratorium on Wind Farm Siting

The Grand Forks County Commission last week enacted a 90-day moratorium on the siting of wind farms while it reviews current policies and procedures.

County Administrator Tom Ford said if a parent company has foreign investment, it will also face scrutiny by the Committee on Foreign Investment in the United States.

More: *KFGO*

OHIO

Appeals Court Halts Pipeline Through Preserved Union County Farm

The Third District Court of Appeals on

April 17 blocked the construction of a natural gas pipeline across Union County farmland preserved with agricultural easements.

The ruling comes more than three years after a family first heard of plans by Columbia Gas of Ohio to bury a natural gas pipeline beneath their land. The land has been protected from non-farm development since 2003, when Arno Renner donated an agricultural easement to the Department of Agriculture. After the family refused to sign off on the easements, the company took them to court in November 2021 to appropriate the easements by eminent domain.

More: *Farm and Dairy*

OKLAHOMA

Bill Would Exempt Natural Gas from Price Gouging Law

Lawmakers last week pressed forward with a bill that would exempt natural gas from the state's price gouging laws, nearly two years after residents were hammered with record high gas costs during a weather-related emergency.

Sen. John Montgomery (R-Lawton) said the exemption of natural gas modernizes the Emergency Price Stabilization Act, which prevents people from hiking the price of goods more than 10% during a state or federal declaration of emergency. Petroleum commodity markets are one of the few exceptions currently built into the law, and Montgomery said natural gas always has been considered a byproduct of oil.

The measure has cleared both the House and Senate, but now returns to the House before heading to the governor's desk.

More: *Enid News & Eagle*

TEXAS

Annual EV Fee Bill Headed to Governor's Desk

A bill that would impose an annual $200 fee for the registration or renewal of an EV and a $400 fee for the registration of a new EV is headed to Gov. **Greg Abbott's** desk after passing the House last week.

Legislators said the fees would make up for gasoline taxes that EV drivers aren't paying and would be used for transportation projects. The money collected would go into the state's highway fund.

If signed, the law would go into effect Sept. 1.

More: *KTBC*

FERC Delays Approval for Electric Competition in Lubbock

FERC last week did not grant full approval to Lubbock Power & Light to enter retail competition, but the commission asked for more time to review the application.

LP&L needs final approval from FERC before it can migrate the remainder of LP&L customers from SPP to ERCOT. The company said it will continue work to prepare for the transition to competition while also working through the federal approval process.

More: *KCBD*

NRG to Cancel Natural Gas Plans if Certain Bills Pass

NRG Energy last week warned that changes to a plan to secure the state's grid against power outages like the ones that occurred during the February 2021 freeze could cause it to rethink construction of additional generation facilities.

At issue is Senate Bill 6, which would create an "electricity insurance" program using state funds to pay for 10,000 MW of new natural gas generation in case of a grid emergency. The bill, however, diverges from the Performance Credit Mechanism plan approved by the Public Utility Commission earlier this year, which would pay certain generators a credit for being ready to go when demand surges.

NRG is in the later planning stages for a 700-MW natural gas unit at its Cedar Bayou site, and the company is considering adding two smaller units near Houston. If the projects are completed, they would add around 1,500 MW of new generation in the state. However, if the state goes with the bill and state-sponsored generation, NRG said it will not invest private capital to compete against the state.

More: *Houston Chronicle*

VIRGINIA

Del. Davis to Take on New Role with State DOE

Del. Glenn Davis (R-Virginia Beach) last week resigned from the House of Delegates to serve as director of the state's Department of Energy.

Davis will replace former Director John Warren, who announced his retirement in January.

More: *The Virginian-Pilot*

Henry County Rejects Axton Solar Project

The Henry County Board of Zoning Appeals last week voted 4-2 to reject the Axton solar project.

Vesper Energy had gained approval from the board in December for a 1,000-acre project that had been studied for more than two years. Vesper had been approved for 1,200 acres and was denied a request for an expansion, so the company withdrew and reapplied. However, most of the board sided against Vesper over a percentage requirement in the county's solar ordinance.

Vesper Energy Community Affairs Manager Alex Rohr said after the vote that the company would see what could be done to accommodate the concern regarding land percentage.

More: *Martinsville Bulletin*

WISCONSIN

Dane County First to Achieve 100% Renewable Energy

Dane County recently became the first county in Wisconsin, and the fourth in the U.S., to receive 100% of its energy from renewable sources after the completion of the Yahara Solar Project last week.

The county partnered with Alliant Energy and SunVest Solar to install 33,000 solar panels at a 90-acre solar farm site in Cottage Grove, which allowed the county to achieve its goal sooner than expected.

Prior to the Yahara Solar Project, only 40% of the county's electricity was renewable.

More: *The Daily Cardinal*