ISSN 2377-8016 : Volume 2022/Issue 16 ▪ April 19, 2022

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

COVER: Buried HVDC cables in highway right of way (Italy-France Interconnector). | *Roda S.p.A.*

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

2022 Annual Subscription Rates:

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

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

In this week's issue

FERC/Federal News

US Interstate Highways: A NIMBY-free Corridor for Grid Expansion?

Proposal: Bury HVDC Lines in Interstate Rights of Way

By John Funk

An exhaustively researched report examining the use of the U.S. interstate highway system as a ready-made corridor for expansion of the nation's high-voltage transmission system, as well as a broadband internet access, concludes it can be done relatively quickly and at a lower cost than siting new transmission corridors.

Prepared for the Minnesota Department of Transportation by Seattle-based NGI Consulting and The Ray, an Atlanta nonprofit, the 81-page *analysis* offers national conclusions. It argues that "NextGen Highways" ought to include buried HVDC transmission lines co-located with fiber-optic cables.

The recommendation to open interstate rights of way (ROWs) is in line with *policy changes* issued in 2021 by the U.S. Department of Transportation giving state DOTs the option to allow utilities to site energy infrastructure, including pipelines and even renewable energy projects, within interstate ROWs.

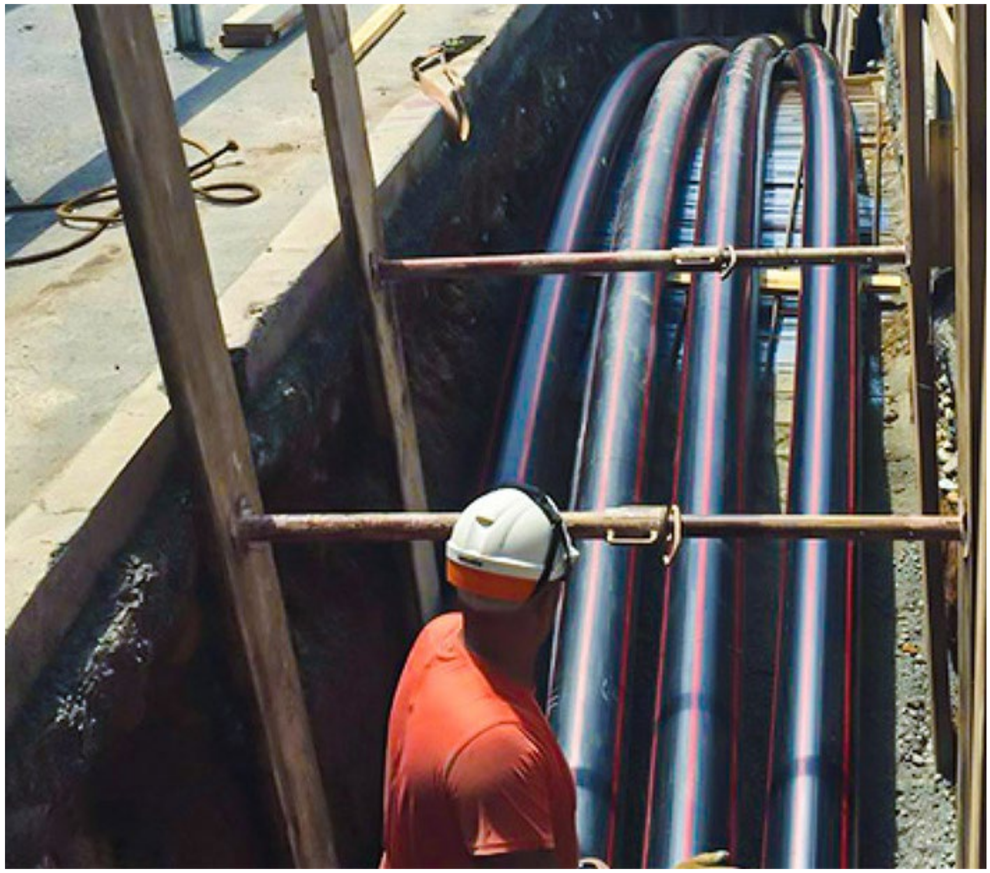
The release of the massive study also comes a year after the Biden administration *announced* the availability of $5 billion in loan guarantees to encourage the expansion of the grid, noting that decarbonizing transportation will require the grid to double or even triple in size.

The transportation sector accounted for 29% of carbon emission in 2019, more than power generation did, according to EPA, making transportation decarbonization a priority issue.

The report argues that state departments of transportation should:

- "site and build fiber in a way that allows for buried HVDC transmission to be co-located at a later date;
- "develop and invest in their relationship with utilities, public utilities commissions and other state agencies with transmission siting jurisdiction; [and]
- "determine the amount of operational funding required to support the co-location of electric and communications infrastructure in their ROW."

The report's recommendation of underground HVDC power lines is no accident. HVDC power lines can move power long distances without line losses and without inducing currents in nearby conducting materials. And unlike AC lines, HVDC lines can connect systems operating at different AC frequencies. Yet few HVDC lines have been built in the U.S., according to the report.



Buried HVDC cables in highway right of way (Italy-France Interconnector). | *Roda S.p.A.*

"Unlike the U.S. Interstate Highway System, the U.S. power grid is composed of many discrete regions. Modeling study after modeling study has shown that connecting these regions is critical to cost-effective grid decarbonization," the report states. "It is also critical for grid reliability and resiliency.

"Despite the importance of connecting the electric grid regions using interregional transmission lines, project after project has failed in the U.S. Since 2014, the U.S. has not built a single gigawatt of interregional transmission capacity. Meanwhile, China, Europe, South America and India have collectively built nearly 350 GW of interregional transmission capacity.

"Most recently, the construction of the New England Clean Energy Connect transmission line was stopped indefinitely by a public referendum in November 2021. This was an incredible result given that the New England Clean Energy Connect had already received the required regulatory approvals and was in the process of being built."

One of the most important conclusions of the study is that decarbonizing the grid itself — moving clean power to where it is needed, particularly for charging electric vehicles — will be less costly using HVDC transmission lines.

"As seen in Europe and now in New York state, buried HVDC transmission is being used to build the interregional transmission required to cost-effectively and reliably decarbonize the electric grid," the report said.

And in one of the dozens of supplemental documents attached to the report, the analysts explain in more detail that "many of the richest wind and solar resources are located far from the urban load centers where most of the country's energy is consumed. The nation's transmission infrastructure must at

FERC/Federal News

least double to accommodate the exponential growth of wind and solar that will accompany decarbonization.

"Without the addition of significant multiregional transmission, system planners will need to overbuild local renewable resources in order to manage weather patterns and meet demand, resulting in extreme curtailment of local wind and solar resources, even if high levels of storage capacity are available, dramatically increasing costs."

Additionally, the expected development of solid-state converters to replace conventional transformers will allow for the development of medium- and high-voltage charging stations, the report postulates, further arguing that the buildout of HVDC converter stations will create "economic development zones … logical locations to site fleet and over-the-road EV charging infrastructure and data centers."

While the study makes national recommendations, its analysis initially focuses on state DOTs because they control highway corridors and ROWs.

Most states, including Minnesota, have not permitted overhead transmission lines to run along highways because of the possibility of vehicular accidents. Many states limit transmission line intrusions to crossing over highways, the report found.

Wisconsin is one of the few states that does allow transmission lines to parallel highways inside the ROW and, according to the report, has permitted the construction of an overhead line to run inside an ROW after state lawmakers approved the practice in 2003.

That legislation requires utilities and grid companies building new transmission to first consider existing utility corridors and then highway and railroad corridors and even recreational trails before seeking to establish new utility corridors. The Wisconsin Department of Transportation (WisDOT) then amended its policies to reflect the new law, as did the state Public Service Commission (PSCW).

"In 2009, as a result of Act 89, WisDOT's updated utility accommodation policy, and the development of new transmission infrastructure, WisDOT and PSCW entered into a cooperative agreement 'to ensure that whenever practical, WisDOT and PSCW shall utilize existing transportation or transmission corridors instead of creating new corridors for electric transmission facilities.' …

"The legislation, policy and agreements described [here] have fostered a collaborative and trusting relationship between Wisconsin utilities and WisDOT and have resulted in the efficient, cost-effective and successful siting of over 800 miles of transmission infrastructure in and along interstate and highway ROW in Wisconsin," the report notes, adding that "Wisconsin has the playbook for siting transmission in DOT ROW."

The Great Plains Institute, based in Minneapolis; Satterfield Consulting in Madison, Wisc.; 5 Lakes Energy of Lansing, Mich.; and consultant Tracy Warren in D.C. assisted with the research and release of the report.

In a statement, Morgan Putnam, founder of NGI Consulting, announced the release of the report and what the team expects to do next.

"Given the positive findings from this study, we will be launching a NextGen Highways Coalition later this year. The coalition will facilitate conversations between state DOTs, transmission developers and governors to support the co-location of buried fiber and transmission in highway and interstate ROW." ■

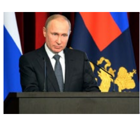
National/Federal news from our other channels

NACFE: Electric Vans Have Arrived — NetZero Insider

Report: US Must Double Nuclear Power to Hit 2050 Climate Goals — NetZero Insider

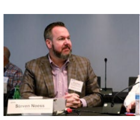
SEC Chair, Investors Defend Draft Climate Disclosure Rule — NetZero Insider

NERC: Substation Flood a Warning of Future Crises — ERO Insider



E-ISAC Warns of Escalating Russian Cyber Threats — ERO Insider

SERC Urges Industry Effort on Facility Ratings — ERO Insider



NERC Director Joins WECC Exec Team — ERO Insider

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

FERC/Federal News

Electricity Markets Benefit from Competition, Former Regulators Say

By Michael Kuser

The decades-long move to competitive wholesale and retail electric markets in the U.S. continues to stir controversy, but the numerous benefits can sway attitudes, several former regulators said.

The pace of innovation sped up when monopoly providers were invited to sit down and let others participate, former FERC Chair Pat Wood, now CEO of Hunt Energy Network, said during an R Street Institute webinar April 12. Wood, who led FERC from 2001 to 2005, previously headed up the Public Utility Commission of Texas.

The rules that clarify how technologies play in a market, interconnect and pay for their costs can have a dramatic impact, he said.

Pat Wood, Hunt Energy Network | *R Street*

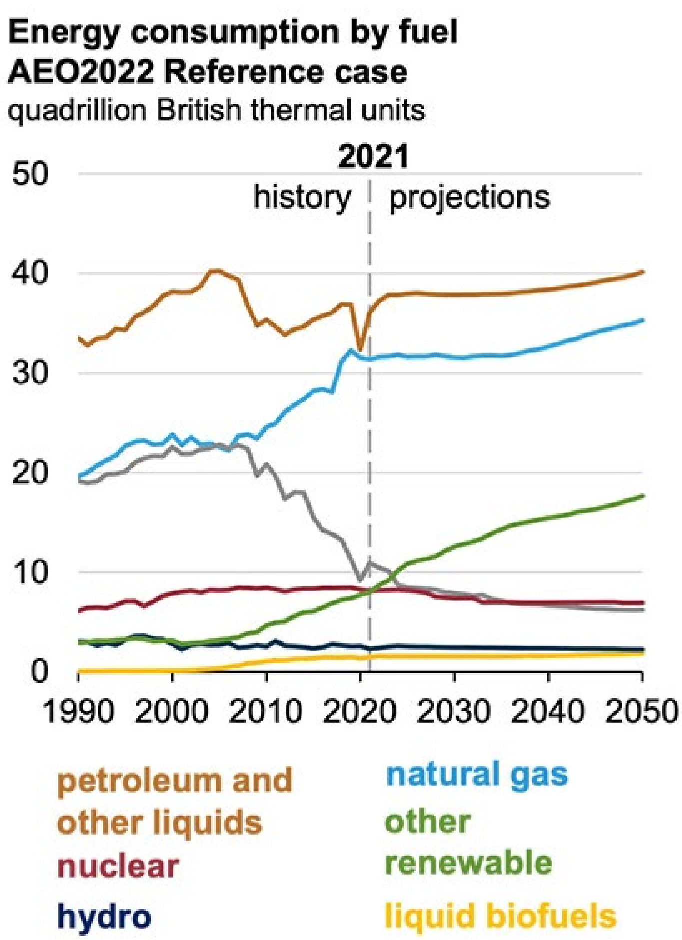
"We got in the early days in Texas a humongous slug of brand new gas-fired generation taking advantage of those clear rules and big welcome mats, and then right on their tails were wind and now solar coming here as well as in SPP and MISO," Wood said. "It's one thing to have a resource, but it's another to actually have the investment to capture it and convert it into electricity."

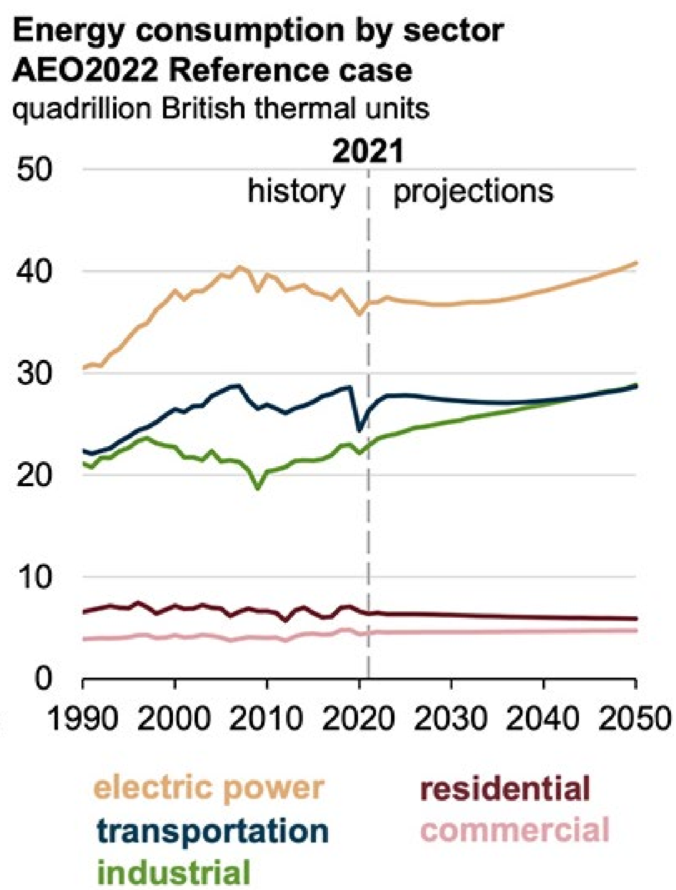
Unbundling more than a century of energy market structure, as FERC did with natural gas, takes some effort, thoughtfulness and authority, which the commission "had plenty of on the gas side and has considerably less on the power side, but a very dominant role nonetheless," Wood said.

New Technologies

New technologies from battery storage to aggregated distributed resources have the capacity to provide further benefits to consumers, but the existing framework within the RTOs/ISOs put up artificial barriers that prevented these resources from being compensated for all their attributes, said former FERC Chair Neil Chatterjee, a senior advisor at Hogan Lovells, who served on the commission from 2017 to 2021.

"We had two pretty significant FERC orders during my tenure: FERC Order 841 regarding storage and FERC Order 2222 regarding aggregated DERs. ... Some of the most significant actions the commission could have taken to address how to innovate within the market," Chatterjee said. "We were highly intentional on FERC Order 2222 for some of this innovation to have the opportunity to thrive."





According to EIA's 2022 Annual Energy Outlook, wind and solar incentives, along with falling technology costs, support competition with natural gas for electricity generation in the U.S. electricity mix. | *EIA*

FERC/Federal News

"Conservatives love it when new technologies come in and upend existing markets, [such as] when Uber comes in and breaks up the taxi unions. But for some odd reason when it comes to electricity, it's 'No, no. This is how we've been doing it for 125 years. We have to continue to do it in this manner,'" he said.

Chatterjee called that "an outmoded way of thinking" and expressed optimism that more conservatives — and more conservative states — will "embrace the benefits of free market competition."

"The southeast did at least take a step in the right direction with [the Southeast Energy Exchange Market] to move towards a market," he said. "I wish we'd gone farther in the Southeast, but I also understand the reluctance to engage in markets there." (See *Southeast Utilities Defend SEEM Proposal*.)

There is interest across the country in looking at market expansion, with $19 million in President Biden's budget to study RTO participation and its benefits, he said.

Landon Stevens, Conservative Energy Network | *R Street*

"I do want to clarify, ironically, that it's not necessarily a red state or blue state thing," Chatterjee said. "FERC could be more muscular in this area, but one of the reasons the commission has not [been] ... is that most of the senators on the Senate Energy and Natural Resources Committee, which is the committee that FERC nominees have to go through for confirmation, are now from non-RTO states. That in strange ways had a limiting effect of FERC acting in this regard, because it's not just Republican senators; there's Democratic senators who also have some reticence about this."

Between Extremes

People tend to resist change, and lawmakers and regulators are especially sensitive to changes to electricity markets, Wood said.

Part of the problem is that most of the public, including lawmakers and regulators, think there are two options, either the Texas model of completely deregulated open retail markets or the traditional Florida model with vertically integrated monopolies, said Landon Stevens, former policy adviser at the Arizona Corporation Commission and now director of policy and advocacy at the Conservative Energy Network.

"There's actually a continuum of competition, with policies, regulations and different innovations you can add between those two points," Stevens said.

Some Republicans can convince themselves that "joining the crony capitalism world ... is the chamber of commerce way to do things," Wood said.

Neil Chatterjee, Hogan Lovells | *R Street*

Monopolies are antithetical to governance of a free people, but regulators implemented them at the time because they viewed electric power supply as a natural monopoly, he said.

"Regulators shouldn't be shellacked when they blow the BS meter and say we're going to change this. But change needs to be gradual because people have contracts based on the old way of doing things," Wood said. "When people are jumping on the regulators for changing how solar tariffs work or net metering ... I don't like what they're doing either, but it's not unfair. They are doing their job; they're trying to allocate costs based on cost occurrence."

It is incumbent on states that care about creating customer benefits to perform rate design more correctly, but opponents of that are adept at shaping outcomes, he said.

"The status quo is hard as hell to bust," Wood said. ■

FERC/Federal News

FERC Dismisses Gas Policy Update Rehearing Requests

By Michael Brooks

FERC on April 12 dismissed 14 requests for rehearing of its revised policy statement on natural gas infrastructure and its interim policy on accounting for greenhouse gas emissions, citing that it had reverted the policies to drafts after the requests had been filed (*PL18-1-002, PL21-3-002*).

"The draft policy statements do not constitute any final commission determination," FERC said. "Because commission action is not final and because the rehearing parties are not aggrieved by a statement of policy, rehearing does not lie and dismissal is appropriate."

The decision was unanimous among the five commissioners, but Commissioner James Danly issued a concurring statement noting that making the policy statements drafts does nothing to alleviate the uncertainty expressed by the petitioners, nor does it address any of his concerns about their legality.

Though Danly agreed that the requests were null now that the statements were drafts, "the 'fog of indecision' still lingers over the development of natural gas infrastructure," he wrote. "What will happen [when the commission issues final proposals] is anyone's guess. I fear that the philosophy animating the issuance of the policy statements in the first place will ultimately result in similar issuances in the future."

Both Danly and fellow Republican Commissioner Mark Christie were strongly critical of the two updates, issued in February at FERC's monthly open meeting as final policies that would begin to apply immediately, including to projects already filed with the commission. FERC walked them back a month later at its next meeting, with the majority citing feedback it had received that they were confusing. (See *FERC Backtracks on Gas Policy Updates*.)

The rehearing requests were filed by several gas pipeline groups and trade associations, as well as several states including Texas and Louisiana. Among their complaints was the retroactive application of the policies, but FERC said that when it issues its final statements, they would not apply to pending projects.

FERC noted in its order that it would include the petitioners' requests as comments in the dockets, for which it is collecting public input by April 25. While Danly said he was gladdened by this, he expressed skepticism that the majority would address the petitioners' concerns.

"And I have a good basis for that concern," he wrote. "The interim GHG policy statement sidestepped many of the exact same arguments parties have made on rehearing, including the argument that the commission cannot do indirectly what it is prohibited from doing directly and that courts have found that Congress has vested the U.S. Environmental Protection Agency, not FERC, with the authority to regulate GHG emissions. Perhaps if the commission had thoughtfully (or even cursorily) considered these arguments in the first instance, it would not be in the position that it is now." ■

| Shutterstock

CAISO/West News

CAISO Sets 98% Renewables Record

By Hudson Sangree

CAISO said Thursday it set a record for renewables on its grid earlier this month when nearly all the ISO's electricity came briefly from clean, renewable resources.

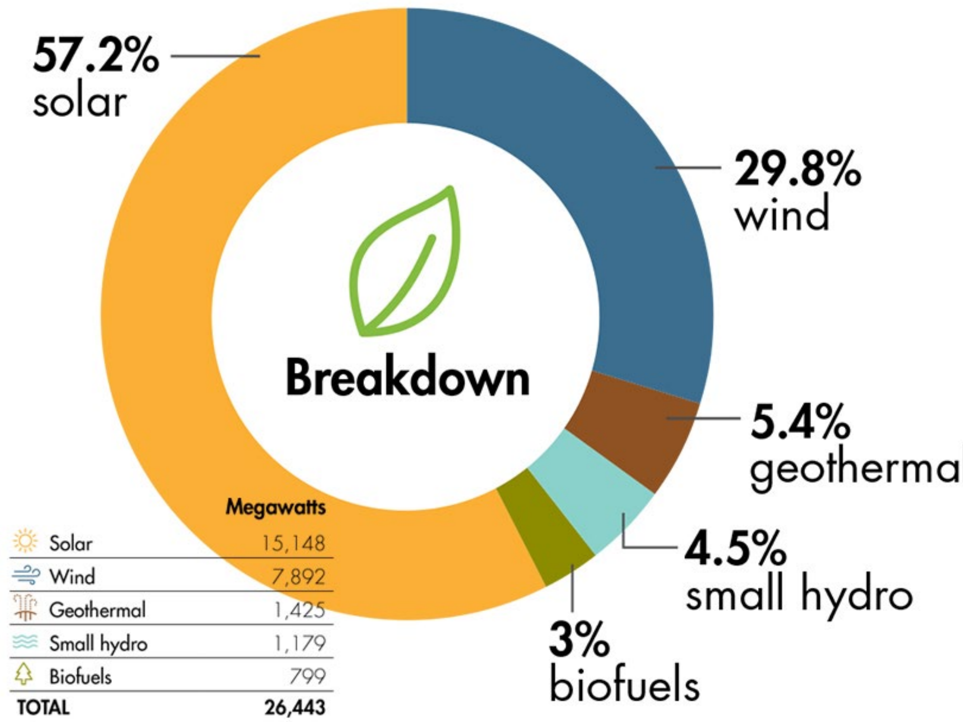
The peak of 97.6% happened at 3:39 p.m. PT on April 3 and broke the previous record of 96.4% set a week earlier on March 27. Even higher numbers are possible this month, the ISO said.

CAISO has been adding more renewable energy to its grid in support of the state's goal of achieving 100% clean power for retail customers by 2045.

"When we see renewable energy peaks like this, we are getting to re-imagine what the grid will look like for generations to come," CAISO Board of Governors Chair Ashutosh Bhagwat said in a news release. "These moments help crystallize the vision of the modern, efficient and sustainable grid of the future."

CAISO's installed renewable energy *mix* consists of about 57% solar, 30% wind and smaller amounts of geothermal energy, small-hydro resources and biofuels. About 32% of California's energy mix came from renewable power in 2020, the most recent year for which figures are available, according to the state Energy Commission.

The ISO also set a new solar peak of 13.6 GW early in the afternoon of April 8 and an all-time wind peak of 6.2 GW shortly before 3 p.m. March 4.



	Megawatts
Solar	15,148
Wind	7,892
Geothermal	1,425
Small hydro	1,179
Biofuels	799
TOTAL	26,443

A supply chart shows a breakdown of installed renewable resources serving CAISO load as of April 5 | *CAISO*

"Renewable peaks typically occur in the spring due to mild temperatures and the sun angle allowing for an extended window of strong solar production," the news release said. "ISO analysis forecasts a potential for more renewable records in April."

SPP reached a similar milestone last month when it became the first multistate grid operator to temporarily serve more than 90% of its demand with renewable energy. (See *SPP Stuns with 90.2% Renewable Penetration Mark*.)

SPP's footprint includes high-wind regions of the Dakotas, Kansas, Missouri, Nebraska, Oklahoma and Texas, and its resource mix includes about 31 GW of installed wind capacity. ■

CAISO/West News

BPA Foresees No Capacity Deficits in Binding WRAP

By Robert Mullin

The Bonneville Power Administration should have enough generation to avoid capacity deficits if it decides to join the "binding" phase of the Western Resource Adequacy Program (WRAP), the federal power marketing agency said Wednesday.

Participation in the WRAP will also have little impact on BPA's marketing of surplus power, Steve Bellcoff, a BPA public utilities specialist, told customers during a public meeting Wednesday.

Surplus sales are a key source of BPA's revenue, helping to defray overall system costs and reduce prices for the agency's "preference" customer base of publicly owned utilities.

BPA has already committed to participating in the initial "nonbinding" phase of the Western Power Pool's WRAP, scheduled to roll out in the third quarter of this year. In that phase, participants will be asked to offer "forward showings" of resource adequacy and availability seven months in advance of the summer and winter capacity periods but will not be penalized for failing to meet their requirements. (See *NWPP RA Program Taking Shape for Q3 Launch*.)

The agency has yet to issue a decision on whether to join the binding WRAP, which will impose penalties on participants that fail to close capacity deficits ahead of operating days.

"It's in the coming months that we'll start to get to a point where we're looking at the contemplation of a decision to join for Bonneville," Russ Mantifel, BPA Director of Market Initiatives, said during Wednesday's meeting.

During the meeting, Bellcoff described some key — albeit surmountable — challenges to how BPA can ensure that it has enough capacity to meet its WRAP obligations. The difficulties arise, in part, from conflicts between WRAP processes and how the agency manages a hydroelectric system subject to the vagaries of weather.

Bellcoff explained that BPA begins its forecasting from the resources side, examining historical stream flows, applying current constraints and operations, then modeling the expected energy available from its hydro resources to determine how much load can be served.

On the other hand, the WRAP forward showing capacity requirement starts with the P50 (50% or higher probability) load forecast, and then adds a planning reserve margin (PRM) to that forecast.

"So everything that is done [for the WRAP] is on the opposite side of what we do today," Bellcoff said.

Misaligned Timelines

Further complicating matters is the misalignment between WRAP timelines and BPA planning and forecasting horizons. The WRAP requires participants to submit forward showings by March 31 for the following winter season. Bellcoff noted that BPA doesn't begin its hydro modeling for the following winter until June, months after that submittal.

"Prior to our first modeling for the next water year, we don't have any idea what our water looks like in March or the following winter," Bellcoff said.

Similarly, the forward showings for the WRAP's summer season are due the previous Oct. 31, the start of the water year in the Pacific Northwest.

"The water forecast in October can be drastically different than what we would see in the spring, and those are important things because, in October, we're still pretty conservative [in projecting] for the following summer," Bellcoff said.

"There's just way too many variables in our water year planning to establish at the forward showing seven months in advance of the seasons that we have vital knowledge on what our hydro looks like," he said.

The conflicting timelines mean that BPA must rely on estimates from its long-term planning process to calculate expected capacity figures for the forward showings. Despite that complication, BPA's own scenario planning suggests the agency has enough resources at its disposal to avoid capacity deficits along any of the WRAP's operational timelines.

Bellcoff said the projected PRM requirements for the WRAP, based on data produced for the nonbinding phase, are 16% for winter and 12% for summer. For BPA that translates into PRMs of 1,102 MW and 768 MW, respectively.

"That's what gets added to the load," he said. "Those numbers are well within that wide-variety range that we look at today and plan for on the resource side, so they're all within the uncertainty we plan for today."

Bellcoff said that BPA also does not expect the WRAP to affect how its power operations department and trading floor work together to develop marketing strategies to deal with energy and capacity surpluses and shortages. And because BPA does not foresee capacity deficits, it does not expect WRAP to affect its marketing of surplus power to benefit preference customers.

A slide presented at Wednesday's meeting summed up BPA's perspective on the issue: "The capacity obligation associated with PRM is within today's range of resource and load variability. In advance of any specific condition, it is not known when, or if, the forward showing capacity requirement would become additive to BPA's trading floor's existing risk tolerance." ■

Spillway at BPA's Bonneville Dam. | © *RTO Insider LLC*

CAISO/West News

PG&E Settles Kincade, Dixie Fires with Prosecutors

Opponents Contrast $55M Settlement with CEO's $51M Pay Package

By Hudson Sangree

Critics last week denounced Pacific Gas and Electric's $55 million settlement with prosecutors over two massively destructive fires, comparing it unfavorably to the $51 million compensation package that CEO Patti Poppe received in 2021 and the utility's sharply rising electric rates for residential customers.

While "Poppe was raking in the money" last year, the company's equipment started the second largest wildfire in state history, the nearly 1 million-acre Dixie Fire, which PG&E said could cost it $1.15 billion, "much of it from homes and entire communities burned to the ground," the Environmental Working Group, a D.C.-based nonprofit, said in a statement.

PG&E's rates have risen 19% for average residential customers since Jan. 1, and the utility has asked the California Public Utilities Commission for 23% in cumulative rate hikes over the next four years. (See *PG&E Rate Request Prompts Protests*.)

"PG&E's customers may not know how high their monthly gas and electric bills may go this year, how they'll pay them, or exactly how much of California the company will burn to the ground in 2022," Environmental Working Group President Ken Cook, a California resident, said in the statement. "But when they learn that the head of PG&E earned $51 million last year, they will know this: PG&E is out of touch and out of control."

On April 11, PG&E and the Sonoma County District Attorney issued separate statements saying they had agreed to settle their dispute over the October 2019 Kincade Fire, which burned down large swaths of Sonoma County wine country and hundreds of homes and commercial structures. A broken jumper cable on a PG&E transmission tower sparked the blaze, the California Department of Forestry and Fire Protection determined.

The $20 million settlement with Sonoma County dismisses the numerous criminal charges that prosecutors had filed against PG&E and requires it to submit to an independent monitor and to create 80 new wildfire safety jobs in Sonoma County, District Attorney Jill Ravitch said in a statement defending the agreement.

"Although criminal charges are dismissed, the level of punishment and oversight provided by this judgment is greater than could be achieved against a corporation in criminal court," Ravitch said. "For the next five years, PG&E's operations in Sonoma County will be closely scrutinized. Furthermore, the costs of this oversight, as well as other payments under this judgment, will not be passed on to ratepayers."

The Kincade Fire destroyed homes and vineyards in Sonoma County wine country. | *© RTO Insider LLC*

CAISO/West News

Trust but Verify?

In a separate settlement April 11, PG&E said it had signed a $35 million stipulated judgement with the district attorneys of Plumas, Lassen, Tehama, Shasta and Butte Counties to resolve "any potential criminal prosecution" of the utility in connection with last year's Dixie Fire, which burned through all five counties over three months.

That settlement also subjects PG&E to an independent safety monitor for five years and requires the utility to hire 80 new fire safety workers across the five counties.

None of the total $55 million in settlement proceeds will be recoverable from ratepayers, PG&E said in an April 8 *report* to the U.S. Securities and Exchange Commission.

The CPUC fined PG&E $125 million for the Dixie Fire in December. (See *CPUC Assesses PG&E $125M for Kincade Fire*.)

In its 2022 *proxy statement* submitted April 7 to the SEC, PG&E said Poppe's total 2021 compensation of $51.2 million last year included her base pay of $1.35 million, a $6.6 million bonus and more than $41 million in stock, based partly on meeting operational performance and safety metrics.

"We are committed to doing our part, and we look forward to a long partnership with these communities [damaged by wildfires] to make it right and make it safe," Poppe said in last week's *news release*. "We respect the leadership of the local DAs, welcome the new level of transparency and accountability afforded by these agreements, and look forward to working together for the benefit of the communities we collectively serve."

Plumas County District Attorney David Hollister said in PG&E's statement that the utility's "new leadership team has demonstrated they are committed to change and will continue to work towards earning our trust. I appreciate this commitment and, to paraphrase the 40th president of the United States [Ronald Reagan], look forward to verifying these efforts as provided by today's agreement."

The Dixie Fire bore down on the historic town of Greeneville, which was later destroyed. | *U.S. Forest Service/ Lassen National Forest*

Others were not as enthused, including some who lost family members, homes and businesses in the catastrophic fires that PG&E equipment caused in 2015 and in each of the past five years. The fires included the November 2018 Camp Fire, which killed 84 people and leveled the town of Paradise.

During PG&E's five years of federal probation, resulting from the 2010 San Bruno gas pipeline disaster, PG&E started at least 31 wildfires, killed 113 people, destroyed nearly 24,000 structures and burned approximately 1.5 million acres, federal Judge William Alsup, of the U.S. District Court for Northern California, *wrote* in his final comments before reluctantly releasing PG&E from court supervision in January. (See *PG&E Ends Probation as a 'Menace to California,' Judge Says*.)

Survivors lamented the dropping of criminal charges and the settlement amounts, which they said were too low to deter PG&E from starting future fires.

In a statement by Reclaim Our Power Utility Justice Campaign, a coalition of 75 groups "fighting to hold PG&E accountable," Mary Kay Benson, a survivor of the 2015 Butte Fire, asked, "What would it take to actually hold PG&E accountable?"

"How many more burned-down towns, more lives upended, more burned lungs do we need to see until we get justice?" Benson said. "For the millionaire executives at murderous PG&E, the money in this settlement is a rounding error and is an appalling way to mistreat the families, farmworkers, forests and lives damaged by this monstrous company." ■

West news from our other channels

New Draft of Advanced Clean Cars II Would Speed ZEV Sales — NetZero Insider

CARB Seeks More Inclusive Clean Cars 4 All — NetZero Insider

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

Ariz. Regulators Reject Massive Expansion of SRP Gas Plant

By Elaine Goodman

Arizona regulators have rejected Salt River Project's proposed expansion of the Coolidge Generating Station, a gas-fired power plant in Pinal County, citing concerns about the impacts on the nearby Randolph community.

The Arizona Corporation Commission voted 4-1 on April 12 to deny a Certificate of Environmental Compatibility for the project.

The expansion would have added 16 gas turbines to the Coolidge plant with a combined capacity of 820 MW. The generating station's current capacity is 575 MW from 12 single-cycle turbine units, according to SRP's website.

SRP said the project is needed to meet growing energy demand as more residents, manufacturers and industrial users move to the area. The utility is forecasting growth in peak demand of about 16% by 2025, or roughly 1,200 MW.

In addition, the expansion would provide reliability to support the addition of renewable energy, SRP said.

Commissioner Sandra Kennedy agreed that additional capacity is needed but said it doesn't have to come from "a polluting fossil-gas facility."

"An investment of $1 billion … on fossil-fuel infrastructure in 2022, when that money could instead be used to accelerate clean energy technology, is a tragic displacement of funds," Kennedy said.

The 575 MW gas-fired Coolidge Generating Station is located on Arizona's Pinal County. | *TC Energy*

Incomplete Info Alleged

Commission Chair Lea Márquez Peterson said SRP didn't provide complete information on the project.

SRP did not issue an all-source request for proposals for the expansion, saying it had previous RFPs that provided enough data, according to an order approved by the commission. But data from the past RFPs allegedly were not submitted as part of the record in the application.

A required power flow and stability study also wasn't provided to the commission, according to the order.

And even though SRP contracted with E3 to see how much solar plus storage would be needed to provide the same reliability as the natural gas expansion, the utility didn't provide the complete study to the commission's Line Siting Committee or to the SRP board before a vote to move ahead with the project, the order stated.

Commissioner Justin Olson was the lone "no" vote on denying the expansion. He said natural gas is a key component in the expansion of renewable energy because it provides reliability at times when renewable energy is not available.

"If we are going to eliminate any natural gas energy generation, or any expansion of it, we are not going to have the ability to meet the energy demands of Arizona residents," Olson said. "We've seen this happen in California."

SRP didn't respond to a request for comment on Thursday. But following the vote, SRP said on its website that it would "continue to evaluate what generation and market options to pursue in the near term to address the resource challenge this decision creates for serving our customers with reliable, affordable, sustainable energy."

Historic Community

Construction of the Coolidge Generating Station was completed in 2011. SRP bought the plant in 2019.

The power plant is near the community of Randolph in unincorporated Pinal County.

Commissioner Anna Tovar noted the historic significance of Randolph, which she described as a Black community founded in the 1920s by people who came from Arkansas and Oklahoma to pick cotton. Because they weren't allowed to buy property in nearby Coolidge, they settled in Randolph instead.

"I do not believe it is wise to put further pressure on this community to relocate," Tovar said. "The history is important, and we shouldn't lose that."

And even though SRP had made progress in mitigating impacts of the proposed project, Tovar said it wasn't enough.

"The increase in emissions, when combined with the pre-existing environmental and air quality issues, will result in an unacceptable total environment for the Randolph community," she said.

Reaction from environmental groups to the commission's vote was positive.

Adam Stafford with Western Resource Advocates called the decision "a win for climate action and environmental justice in Arizona."

"It's time for SRP to find clean alternatives and revisit its sustainability goals to adopt mass-based emissions reduction targets in line with what scientists say is needed to avoid the worst effects of climate change," said Stafford, who is WRA's managing senior staff attorney in Arizona.

Ellen Zuckerman with the Southwest Energy Efficiency Project also applauded the decision.

"At a time when far too many Arizonans are making painful economic decisions and falling behind on their bills, we simply cannot rubber-stamp $1 billion for improperly rushed and poorly vetted projects." Zuckerman said in a statement. ■

ERCOT Technical Advisory Committee Briefs

TAC Passes Contentious Outage Measure over Staff's Objections

ERCOT stakeholders on Monday declined to consider staff's appeal of a tabled revision request that would create a process allowing the grid operator to review, coordinate and approve or deny all planned outages.

The Technical Advisory Committee instead approved its version of the nodal protocol revision request (*NPRR1108*), as amended by several *joint commentators*. The measure now goes before the Board of Directors for its consideration April 27-28.

The measure was passed unanimously, 26-0 with a pair of abstentions, during an emergency webinar Monday after it was tabled following more than an hour of discussion last Wednesday during TAC's regularly scheduled meeting.

The measure was also tabled at the Protocol Revision Subcommittee (PRS) last November over concerns that staff's proposal was inflexible and could lead to an inability to get planned outages completed. That would lead to decreased reliability in the months when there is higher demand on ERCOT's generation fleet, they said.

Staff drafted NPRR1108 to meet the requirements of legislation passed last year in the wake of the February winter storm that nearly brought the ERCOT grid to its knees. *Senate Bill 3* included a provision that the grid operator "shall review, coordinate and approve or deny requests by providers of electric generation service ... for a planned power outage during any season and for any period of time."

Dan Woodfin, ERCOT | *Swagit*

Under ERCOT's original proposal, staff would review and coordinate all planned outages, including those submitted more than 45 days before the outage's planned start. The revisions would:

- define a process for calculating a maximum megawattage of planned outages that would be allowed for each day of the next rolling 60 months, based on a capacity assessment;
- require that a planned outage, or change to an approved outage, submitted more than 45 days in advance of the planned start time would no longer be "accepted" but would be approved on a first-come, first-served basis if the resulting aggregate planned outages are below the daily maximum megawattage for each day of the proposed outage's duration; and
- require that a planned outage or change to an approved outage submitted less than 45 days in advance of the planned start time would be evaluated against the maximum daily planned resource outage capacity (MDRPOC) and for impacts on transmission reliability.

Dan Woodfin, ERCOT's vice president of system operations, complained that the grid operator last November asked for stakeholder feedback within months. The lack of input has pushed back the methodology's implementation to fall 2023, he said.

Reliant Energy Retail Services' Bill Barnes, acting as the PRS advocate, said the NPRR included many inputs subject to discretion.

"Stakeholders needed to fully assess the methodology needed to see the results of the calculations," he said, explaining why the measure has remained tabled.

The two sides have traded competing versions of their comments, with ERCOT filing the last Sunday night. In the *comments*, staff proposed to allow nuclear generators to schedule planned outages, even if the resulting outage capacity would exceed the MDRPOC. They also agreed with the residential consumer segment that they should prove a report to TAC on the MDRPOC's effects.

Stakeholders stuck with the joint commentators' filing, which requires the MDRPOC for outages more than seven days ahead of the operating day be posted twice each to provide greater transparency and reduce the risk of potentially large changes when "stale monthly long-term MDRPOC projections" are replaced by the near-term projections less than seven days ahead of the operating day.

Reliant's Bill Barnes advocates for the PRS position. | *Swagit*

They also call for outage guardrails that are sensitive to concerns about weather variations during outage seasons to provide predictable minimum outage windows for resource owners and still allow ERCOT to deny outages on days over the MDRPOC.

ERCOT legal counsel Nathan Bigbee fired back Monday over the notion that the outage-approval process should be subject to TAC approval.

"There seems to be kind of a disconnect between industry in general and the ISO over what exactly the methodology should be," he said. "It seems likely the methodology we prefer is a methodology TAC would not endorse. Having that control would lead us down a path less in the interest of reliability. That's why we don't think it's appropriate. Ultimately, the board is going to be the arbiter of those decisions."

ERCOT can file additional comments on NPRR1108 with the board or appeal the decision to the Public Utility Commission for an appeal.

Unsecured Credit Limit Lowered

TAC on Wednesday approved a measure that reduces unsecured credit limits from $50 million to $30 million, but not before a back-and-forth between one member and a staffer over

ERCOT News

uplift that resembled Monty Python's classic "*Argument Clinic*" sketch.

"I fundamentally disagree with your concept of how the market works," Kenan Ögelman, ERCOT's vice president of commercial operations, told Morgan Stanley's Clayton Greer.

PRS amended *NPRR1112* in March to reinstate unsecured credit limits. ERCOT responded with comments that said eliminating unsecured credit "will reduce the inconsistent cross-subsidization of credit exposure and provide a more level playing field for market participants."

Members disagreed. Garland Power and Light's Dan Bailey said staff's response was "the most ridiculous problem ERCOT has tried to solve without solving the problem."

"From a market and consumer standpoint, taking a nuclear approach to credit is a little bit questionable," he said. "Why ERCOT would think this is the right direction to go has left me scratching my head. I'm baffled to see that ERCOT is going down this path."

TAC rejected an motion to amend the measure with ERCOT's comments, 3-16 with 11 abstentions. It attracted approval only from the two residential consumer representatives and retailer Reliant Energy.

A motion to approve PRS' recommended version passed 23-2 with five abstentions. The residential consumer representatives cast the two opposing votes.

RUC Process Changes Endorsed

The committee approved a pair of rule changes related to reliability unit commitments (RUCs), which have been increasingly used by ERCOT since last summer as part of its conservative operations approach.

NPRR1124 is intended to ensure generation resources recover their actual fuel costs when they are RUCed by setting the start-up price and minimum-energy price to the start-up cap and the minimum-energy cap.

The measure was opposed by all six consumer segment representatives, who objected to consumers bearing the increased costs.

TAC also approved a motion related to *NPRR1092*, which lowers the RUC offer floor to $250/MWh from $1,500/MWh, as amended by clarifying *ERCOT comments* April 6. Members approved the measure in March, pending an impact analysis from staff. (See "RUC Offer Floor Lowered to $250," *ERCOT Technical Advisory Committee Briefs: March 30, 2022*.)

ERCOT's Technical Advisory Committee meets in the ISO's new headquarters building. | *Swagit*

ERCOT News

Staff said it will cost between $50,000 and $75,000 and take four to six months to change the RUC offer floor, as proposed by the Independent Market Monitor. The measure still needs regulatory approval and prioritization.

The motion passed 25-1, with Luminant opposing and two representatives each from the cooperative and independent power marketer segments abstaining.

Ögelman Addresses Concerns with Board Interactions

Ögelman responded to stakeholder concerns about their interactions with the board's new Reliability and Markets Committee, saying that the directors are still working through the structure they want.

"The board's trying to figure out how they want to do business and what they might want to do differently," he said. "Right now, we have to beg everyone to be patient with us and work with the board to give them the processes they want. They have a vision … they're just not ready to share it yet."

Ögelman was responding to a clarification request from the Wholesale Market Subcommittee, which reports directly to TAC. ERCOT's bylaws require TAC to report to the full board, rather than a board committee; any bylaw changes would require a vote of the full membership, Ögelman said.

Two More SCT Directives Approved

TAC endorsed staff's response to two additional directives issued by the PUC related to the Southern Cross Transmission (SCT) project, a merchant long-haul HVDC transmission line that would connect ERCOT with systems in the SERC Reliability region.

In responding to the *14 PUC directives*, ERCOT staff found they would not need to study and determine transmission upgrades to address congestion caused by SCT (*No. 6*). Staff determined in the second directive (*No. 8*) that as of Jan. 1, 2021, DC ties should be required to have at least a 0.95 power factor leading/lagging reactive power capability, which several revision requests have already addressed.

The SCT would be capable of carrying 2 GW of power between Texas and SERC over a 400-mile, double-circuit 345-kV line. The project has FERC approval and a waiver from the commission's jurisdiction. It also has a certificate of convenience and necessity granted by the PUC in 2017 to Garland Power & Light, which owns the project's western endpoint.

The PUC last year directed its staff to file a memo asking the proceeding's parties for suggestions on accelerating the project, which has been under regulatory review for more than seven years (*46304*). (See *Texas Regulators Boost Southern Cross Project*.)

ESRs' Minimum Duration Set at 2 Hours

TAC's unanimously approved combination ballot included a recommendation from the Reliability and Operations Subcommittee to set a minimum duration threshold of two hours for energy storage resources (ESRs). Lower-duration ESRs would be prorated to their continuous real power capability for two hours.

The combo ballot included two additional NPRRs, a Nodal Operating Guide revision (NOGRR), two revisions to the Planning Guide (PGRR) and a change to the Settlement Metering Operating Guide (SMOGRRs):

- *NPRR1117*: aligns the protocols with the Settlement Meter Operating Guide revisions to allow for losses in short runs of connecting lines to be disregarded when the ERCOT-polled settlement meter (EPS) is not physically placed at the point of interconnection (POI).
- *NPRR1125*: clarifies that ERCOT may use available financial security held for other market activities should there be payment defaults in either of the two securitization proceedings. The change also specifies the prioritization for applying the securities when there are concurrent defaults for either invoices or escrow deposit requests.
- *NOGRR239*: delineates the responsibilities for providing security for data transmitted between ERCOT, qualified scheduling entities and transmission operators.
- *PGRR096*: establishes requirements for the consistent representation of distribution generation resources, distribution energy storage resources, settlement-only distribution generators and unregistered distributed generation in steady-state base cases.
- *PGRR098*: enables corrective action plans to be developed under certain outage scenarios to the existing reliability performance criteria.
- *SMOGRR025*: allows for losses in short runs of connecting lines to be disregarded in instances where the EPS meter is not physically placed at the POI and requires calculation to verify that the watts copper losses are below 0.001%. ■

— Tom Kleckner

ISO-NE News

ISO-NE Asks FERC to Dismiss Renewable Groups' Complaint

By Sam Mintz

ISO-NE shot back at renewable groups who have claimed its rules give unfair preference to gas generators. | *ISO-NE*

ISO-NE last week shot back at renewable groups who have challenged its rules and claimed that gas-powered generators get preference, saying that their complaint with FERC should be thrown out (EL22-42).

The grid operator's *motion* to dismiss filed Thursday comes a month after RENEW Northeast and the American Clean Power Association alleged that ISO-NE's rules around capacity accreditation and operating reserves don't adequately take into account the uncertainty of natural gas supply in the region. (See *Renewable Groups Challenge Gas 'Preference' in ISO-NE Rules*.)

Central to ISO-NE's response is the fact that new rules are already under development.

FERC should dismiss the complaint "because it is an improper attempt to circumvent the New England stakeholder process and it invites the commission to impose a solution that reflects only complainants' preferred outcome on their preferred timeline," the RTO said.

ISO-NE is about to start work on a framework for resource capacity accreditation within the next few months, it said, an "enormously complex project with significant implications for the reliability of the New England grid."

The project is budgeted to take two years, in line with ISO-NE's proposed transition away from the contentious minimum offer price rule in its capacity market. The grid operator is also launching a day-ahead ancillary services project, which it says would be the "appropriate forum" for the renewable groups' complaints about the reserve procurement process.

In asking FERC to toss the complaint, ISO-NE pointed to a previous case in California in which the commission dismissed a complaint seeking changes to CAISO's market rules that were "directly related to market design issues [already] under review by [CAISO] as part of [a] revised market design proposal."

ISO-NE also argued that the complaint should be dismissed on merit, saying that the region's tariff explicitly contradicts the groups' claims that gas generators have no obligations to report on their reserves or are excluded from fuel supply requirements. It also said that the relief proposed by RENEW and ACP is "unworkable."

In comments on the FERC docket, several renewable and environmental advocacy groups have backed the complaint, while several generation companies have put their support behind ISO-NE.

The New England States Committee on Electricity and the attorneys general of Connecticut and Massachusetts said in comments that the changes proposed in the complaint are premature and that the issues of capacity accreditation and reserve procurement need more comprehensive treatment through the NEPOOL stakeholder process. ■

ISO-NE News

ISO-NE Preparing to Move Forward on Day-ahead Ancillary Services

No Action by NEPOOL Markets Committee on Financial Assurance

By Sam Mintz

ISO-NE is ramping up its work on incorporating ancillary services in the day-ahead energy market.

In a *recent memo* and at the NEPOOL Markets Committee meeting April 12, officials from the RTO laid out the scope and timing of the project, which is a much anticipated addition to the market.

"Broadly, the day-ahead ancillary services project seeks to procure and transparently price the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving generation fleet," the memo says.

The proposal includes two components. One is an Energy Imbalance Reserve (EIR) feature that would incorporate load forecasting into the day-ahead market and procure energy to cover the gap when physical energy supply awards are below the forecast real-time load.

The other is Flexible Response Services (FRS), which would procure 10- and 30-minute fast-start and fast-ramping capabilities in the day-ahead market.

Longer-duration ancillary services, like the previously proposed Replacement Energy Reserves, will be deferred while ISO-NE focuses on the former two.

Much of the grid operator's work to develop the new market features was completed as part of the Energy Security Improvements proposal that was ultimately rejected by FERC. (See *FERC Rejects ESI Proposal from ISO-NE*.) But ISO-NE is finishing up some calculations and technical work, as well as preparing to redo its impact analysis and market power evaluation for the new proposal.

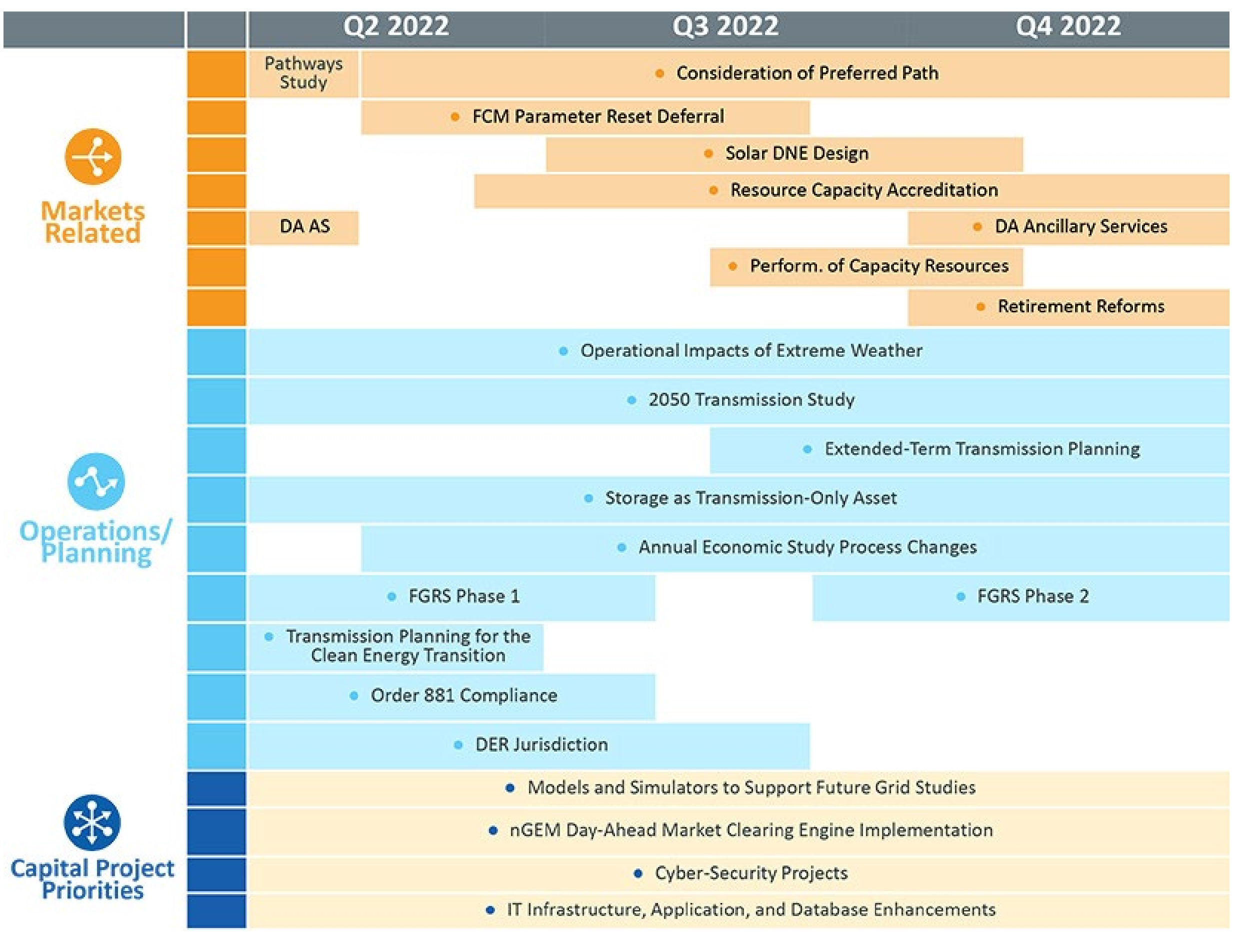
The RTO is planning to work on the proposed new day-ahead services throughout this year and next, filing it with FERC by the end of 2023 with an implementation date either at the end of 2024 or beginning of 2025.

Still no Go for Proposed FA Changes

The MC again declined to recommend changes to the ISO-NE financial assurance policy that are being proposed by Competitive Power Ventures.

CPV's Joel Gordon had brought forward *more changes to his proposal* to, among other things, address concerns with the amount of financial assurance that would be required for solar projects.

The proposal is designed to penalize companies that don't meet development milestones, a timely topic after the fiasco surrounding Killingly Energy Center earlier this year. But like at the February MC meeting, it failed to get enough support from the committee to recommend advancing it to the Participants Committee. ■



Day-ahead ancillary services are part of ISO-NE's 2022 work plan. | *ISO-NE*

Mass. Democrats Take on ISO-NE over MOPR

By Sam Mintz

Several big voices in Massachusetts and D.C. politics are turning up the heat on ISO-NE as FERC considers the grid operator's proposal to delay elimination of its contentious minimum offer price rule (MOPR) by two years.

In a *speech outside ISO-NE headquarters* last week, Sen. Ed Markey lambasted the organization as secretive, part of an "oil and gas conspiracy," and standing in the way of the transition to clean energy.

"Instead of giving us the green light for our clean energy revolution, ISO New England is proposing to send us on a detour," Markey said. "By proposing to delay the elimination of a rule that puts fossil fuel generation ahead of cleaner, cheaper alternatives, ISO New England is risking reliability and cost savings for residents across Massachusetts."

Known for his affinity for wordplay and developing new acronyms, the senator said the MOPR should be called "Minimizing Our Potential for Renewables," and that ISO-NE should be called the "dependent" system operator because "it's dependent on gas and oil."

"They have been in the past, they are today and their rules say they want to be in the future as well," Markey said.

Markey's speech also elicited support from Department of Energy official Jigar Shah.

"Time to find solutions instead of holding up clean energy projects waiting for more studies," *tweeted* Shah, director of the DOE Loan Programs Office.

The two-year "transition" to eliminating the MOPR from ISO-NE's capacity market, now in front of FERC for a decision, has received a high level of scrutiny from environmental advocates, elected officials and the renewables industry who have questioned ISO-NE's claims about reliability worries stemming from an influx of renewables and possible corresponding retirement of merchant generators. (See *ISO-NE Sends MOPR Filing to FERC, Teeing up Big Decision*)

Sen. Ed Markey speaks outside ISO-NE headquarters last week. | *Sen. Ed Markey via Twitter*

In an email to *RTO Insider*, ISO-NE spokesperson Matt Kakley defended the process that produced the proposal.

"Our robust, federally-approved stakeholder process includes the ISO, the energy industry, representatives from the New England states and advocacy groups. ISO New England's proposals are fully examined and discussed before undergoing review by our federal regulator prior to implementation," Kakley said.

Markey's claims of conspiracy, Kakley added, are "so outlandish they do not warrant a response."

"In addition, we are independent of the resources competing in the wholesale markets and do not favor any resource type over another. In fact, ISO New England employees work every day to ensure that all energy resources can compete in the market, can interconnect safely to the regional power grid and can operate reliably," he said.

A Senatorial Plea to FERC

Markey also wrote a letter, along with Sens. Elizabeth Warren (D-Mass.) and Bernie Sanders (I-Vt.) calling on FERC to reject the filing and force ISO-NE to immediately remove the MOPR.

"At the very moment when New England should be fully embracing the transition to renewables and the related socioeconomic opportunities, this decision to undermine state actions and renewable energy deployment is a terrible and ill-timed mistake," *the senators wrote.*

They specifically called on federal regulators to use their authorities under Sections 205 and 206 of the Federal Power Act to "require immediate reform" of the MOPR.

"In doing so, FERC will signal that renewable energy should be allowed to fully and freely compete in wholesale markets," they wrote. "This will ultimately lead to lower prices for household customers and facilitate our overdue and necessary transition to a decarbonized electricity grid."

Experts have said that FERC could respond to the filing in several possible ways, including accepting it, rejecting it outright or sending it back with a finding that the status quo is unjust and unreasonable and an explicit order to immediately terminate the rule. ■

MISO News

MISO Considers Adding Smaller Congestion Relief Projects

By Amanda Durish Cook

| © RTO Insider LLC

MISO on April 12 said that it is contemplating adding a class of smaller, congestion-relieving projects under its annual transmission planning.

Engineering adviser Ben Stearney told stakeholders during a Planning Subcommittee meeting that staff was inspired by its Targeted Market Efficiency Projects (TMEPs) process with PJM. MISO studies TMEPs for interregional purposes only, not under its own regional planning.

Stearney said the RTO may introduce additional TMEP-style planning to its annual Transmission Expansion Plan (MTEP) to alleviate the footprint's increased congestion. He said "a TMEP-like process in a regional context" with a traditional production cost analysis could produce smaller transmission projects that clear congestion near existing generation resources.

Under MISO's TMEPs process with PJM, projects must cost less than $20 million, completely cover installed capital cost within four years of service and be in service by the third summer peak from its approval. The projects are assessed using a shorter time horizon than interregional market efficiency projects.

Stearney said staff are conducting an "exploratory investigation" and could introduce a TMEP-like component in time for MTEP 23. MISO will begin building the MTEP 23 economic models near the end of the year.

WPPI Energy engineer Steve Leovy said he appreciated the evaluation because congestion costs have skyrocketed in the last two years and because MISO hasn't conducted a market congestion planning study as part of MTEP since 2019. Leovy said the grid operator lacks "ongoing economic planning occurring in the near term." He pointed out that MISO's long-range transmission planning looks out at least 10 years, leaving immediate congestion fixes unaddressed.

The RTO's members late last year questioned whether MISO's planning is sufficiently addressing mounting transmission congestion.

Leovy has said generators in the footprint's northwestern system with firm transmission service are feeling congestion's squeeze and has said MISO's economic modeling may not be capturing all congestion-relief opportunities.

The RTO might be assigning network upgrades that don't consider all impacts of new generation projects given the raft on new projects in the Northwest, Leovy contends.

Last month, MISO's Independent Market Monitor warned that MISO's day-ahead and real-time congestion increased this winter by 142% and 118 %, respectively, compared to last winter. The Monitor said about half of the real-time congestion could be attributed to wind generation. (See *MISO Says System Volatility Here to Stay*.) ■

MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest

By Amanda Durish Cook

MISO's 10th annual Planning Resource Auction (PRA) saw all its Midwestern zones clearing at the nearly $240/MW-day cost of new entry (CONE), signaling the prospect of temporary outages and a dire need for additional generation.

Zones 1 to 7 — which include the Dakotas, Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana and Wisconsin — all cleared at $236.66/MW-day in the 2022/23 capacity auction, MISO announced Thursday. Zones 8 to 10 — Arkansas, Louisiana, Mississippi and Texas — did not feel the pinch and cleared at $2.88/MW-day.

MISO said that even with nearly 97 GW worth of offers, 1.3 GW of resource contributions external to MISO and 1.9 GW worth of imports from MISO South, MISO Midwest remained a little more than 1.2 GW short of its 101.2-GW planning reserve margin requirement.

The RTO said 8 GW in its North and Central regions were exposed to the CONE clearing price. MISO's load-serving entities that don't have enough contracted capacity to cover their load obligations use the PRA. During a teleconference with stakeholders on the results Friday, MISO Director of Resource Adequacy Coordination Zakaria Joundi said that only 8% of load participated in the auction this year. Participation in the PRA is voluntary.

Ahead of the 2022/23 planning year, MISO *anticipated* a 121-GW coincident systemwide peak, with 157 GW in total installed capacity and just short of 128 GW in total unforced capacity.

The grid operator attributed some of the shortfall to post-COVID load increases.

It also said that even though it has about 4 GW more worth of installed capacity footprint-wide than it did in 2018, it has about 8 GW less in accredited capacity, reflecting an uptick in intermittent generation and retiring thermal generation. Unless members build more capacity that can reliably generate, MISO said, "shortfalls such as those highlighted in this year's auction will continue."

Joundi said that although MISO is maintaining "decent amount of installed capacity," accredited capacity "keeps going down."

He said as generation retirements and suspensions were being replaced with lower-accredited renewable resources, MISO demand levels rebounded as the nation emerged from the worst of the pandemic.

"We couldn't find enough capacity in the North-Central region," Joundi said.

MISO's South-to-Midwest transfer limit bound in the auction, limiting imports that could pass to the north, Joundi said. The South finished the auction with about 2 GW of surplus.

"This is an outcome we've been worried about for a decade," MISO Independent Market Monitor David Patton said. He said the capacity auction's vertical demand curve — which values reliability requirements over economics — doesn't produce efficient enough economic signals and has caused generation that should be otherwise economic to retire. The Monitor has been a vocal proponent of a sloped demand curve for years.

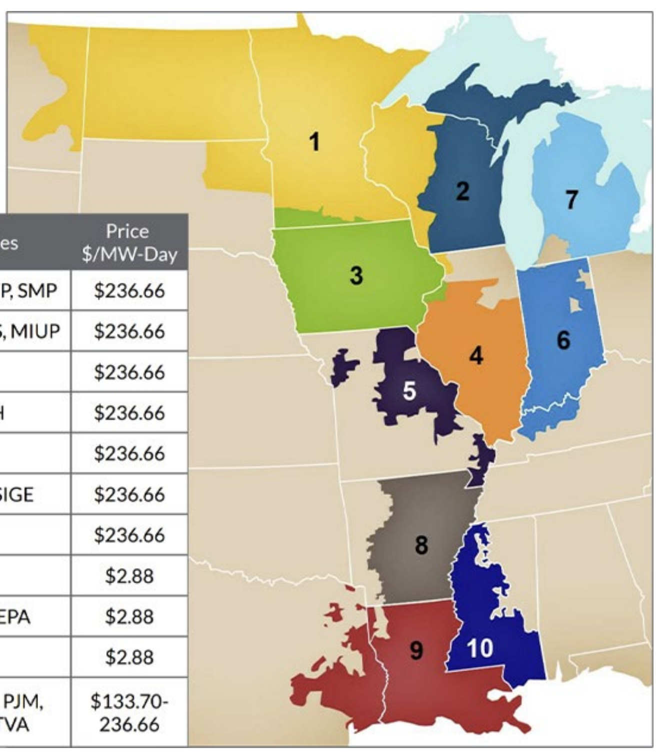
"We obviously have been sounding the alarm for some time," Michelle Bloodworth, CEO of coal trade organization America's Power, said of thermal retirements. She said she foresees a worsening retirement crisis over the next decade.

In a press release, the RTO said it "remains committed to continue its work with members and state regulators to maintain grid reliability."

"We have anticipated challenges due to the changing energy landscape and have communicated our concerns. … We have prepared for and projected resource fleet transformation, but these results underscore that more attention is required to offset the rate of acceleration," MISO CEO John Bear *said*. "These results do not undermine our ability to meet the immediate needs of the system, but they do highlight the need for more capacity flexibility to reliably generate and manage uncertainty during this transition."

MISO said zones 1 to 7 will head into the June 1 start of the planning year with a chance of temporary load shedding. Joundi told stakeholders to prepare for more frequent emergency procedures throughout the planning year. He also said MISO is evaluating the resource forecasting information it receives from members.

"The reality for the zones that do not have sufficient generation to cover their load plus their required reserves is that they will have increased risk of temporary, controlled outages to maintain system reliability," MISO President and COO Clair Moeller said. "From a consumer perspective, those zones may also



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$236.66
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$236.66
3	ALTW, MEC, MPW	$236.66
4	AMIL, CWLP, SIPC, GLH	$236.66
5	AMMO, CWLD	$236.66
6	BREC, CIN, HE, IPL, NIPS, SIGE	$236.66
7	CONS, DECO	$236.66
8	EAI	$2.88
9	CLEC, EES, LAFA, LAGN, LEPA	$2.88
10	EMBA, SME	$2.88
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$133.70-236.66

Zonal clearing prices in the 2022/23 MISO capacity auction | *MISO* face higher costs to procure power when it is scarce."

Patton has reviewed and certified the auction results.

Coalition of Midwest Power Producers representative Travis Stewart said the results were a bit of a head-scratcher, as the Midwest appeared to have sufficient capacity based on unforced capacity values heading into the auction. He said it seemed that more market participants are holding back supply up to MISO's 50-MW withholding threshold, but Patton said he didn't discover any withholding that would run afoul of MISO's rule.

The price separation between MISO Midwest and South in previous auctions became even more pronounced this year. In the 2021/22 auction, zones 8 to 10 cleared at an all-time low of 1 cent/MW-day, while zones 1 to 7 cleared at $5/MW-day. (See *MISO Capacity Auction Values South Capacity at a Penny*.)

This is the second time CONE has made an appearance in the PRA. Zone 7, which covers MISO's territory in Michigan, was MISO's first local resource zone to clear at the then $257.53/MW-day CONE, in the 2020/21 auction.

The Organization of MISO States and MISO's joint annual resource adequacy survey in 2020 warned of possible capacity shortfalls in the Midwest by 2022. However, by 2021, the survey had moved the risk into 2023. (See *OMS-MISO Survey Sees Uncertain Supply Future* and *2021 OMS-MISO Resource Adequacy Survey Shows Less Cause for Concern*.)

"We didn't necessarily expect this outcome to happen this year," Joundi said. He reminded stakeholders that the OMS-MISO survey is a snapshot in time, and circumstances have changed since the last one. "Slight surpluses did erode."

MISO said this year's auction results show a need for market redefinition and more efforts to make resources more available. It could also be one of MISO's last single annual capacity auctions. The grid operator has filed for FERC permission to conduct four seasonal auctions beginning in 2024. It has also asked to implement a minimum capacity requirement, in which LSEs must demonstrate that they've secured half of their load obligations prior to the auction. Last month, FERC issued MISO a deficiency notice for outstanding questions of the design. (See *Deficiency Notices for MISO's Seasonal Capacity Auctions Bid*.)

At a Feb. 28 executive update with stakeholders, MISO General Counsel Andre Porter said the RTO's seasonal auction and long-range transmission planning are meant to ensure it has adequate reserves amid changing resource portfolios and increasingly unstable weather.

"Even while we wait, volatility and uncertainty continue," Porter said of FERC's decision time on the seasonal auction. He said MISO is encouraging states to scrutinize their resource adequacy plans to make sure they're appropriate for a changing landscape.

But Patton said that the long-range transmission plan will only help auction results if a project increases the transfer capability between Midwest and South. MISO doesn't plan on addressing the constraint in the long-range transmission effort anytime soon.

Patton said the RTO should consider asking for greater flow capacity between the South and Midwest when it next refreshes the transmission use agreement it has with SPP and other parties. "That is something we should think about as that agreement gets renegotiated."

Some stakeholders called for an operational analysis of adding transmission capability between the regions. ■

MISO News

MISO Focuses Stakeholders on $10B LRTP Projects

By Amanda Durish Cook

MISO convened a special meeting of its Planning Advisory Committee Wednesday to underscore the urgency for $10 billion in long-range transmission projects in its Midwestern region.

Jarred Miland, the RTO's senior manager of transmission planning coordination, stressed the grid operator's pressure to build transmission as members' generation portfolios transition to cleaner resources.

"The resource portfolio has been changing rapidly over the past 10 years and reliability will become increasingly difficult as renewable energy increases across the footprint," Miland told stakeholders.

He said the long-range transmission portfolio (LRTP) seeks to "provide an orderly and timely transmission expansion effort that supports key goals," including keeping system performance reliable in greater supply volatility and accessing lower-cost and cleaner energy.

MISO's first set of long-range projects could be the largest portfolio of regional projects ever proposed in the U.S. The grid operator has projected that the $10.4 billion package will yield anywhere from $23 billion to $52 billion in financial benefits over the projects' 20- to 40-year lifespans, resulting in a 2.6:1 overall benefit-to-cost ratio. (See *MISO Updates Stakeholders on $10B Long-range Tx Package*.)

The *LRTP* is broken down into six groupings of 18 line segments. Staff assumes all projects will be built by 2030.

Miland said "work is still ongoing" to determine whether some segments will be open to competitive bidding. MISO plans to post a draft list of the portfolio's competitive facilities by June 1.

Staff calculated the portfolio's benefits by quantifying transmission's ability to solve reliability issues, reduce congestion and fuel costs, avoid new generation and other transmission investments, trim reserve margins, avert loss-of-load events and meet utility and state decarbonization goals.

MISO adviser Joe Reddoch said the RTO played it conservatively when approximating the projects' benefits and did not overstate savings. He said although the level of benefits will differ between Midwestern transmission pricing zones, they all stand to receive benefits.

While WEC Energy Group's Chris Plante worried aloud that the LRTP's benefits were too optimistic, Sustainable FERC Project attorney Lauren Azar said the identified list of benefits was probably "too narrow."

Clean Grid Alliance *said* the projects can enable the additional 52.7 GW of renewable power projected in the most conservative of the three planning scenarios. That would power about 12 million homes and support 213,000 jobs, the group said.

Stakeholders asked whether MISO has accounted for the spiking costs of building materials and labor.

Aubrey Johnson, executive director of system planning, said staff will update cost estimates over the next month, but that he doesn't expect the figures to change much. He said MISO was cautious from the start when estimating project costs and said he only expects "fine-tuning around the margins."

The Planning Advisory Committee will vote on whether to recommend the portfolio to the Board of Directors during a May 27 meeting. The board will vote on the portfolio on July 25.

Determining LRTP's Effect on the Interconnection Queue

MISO is determining how long-range projects will interact with its generator interconnection queue.

During an Interconnection Process Working Group meeting April 11, MISO's Jesse Phillips said staff is planning to monitor when new generation projects making their way through the queue are affected by a long-range transmission project.

Phillips said if a project is found to resolve a constraint found in network upgrade studies and is approved by the board within a year of an interconnection customer striking a generator interconnection agreement, the customer will not be financially responsible for transmission upgrades. He said the generation project will then be contingent upon the transmission project instead of a network upgrade.

Generation projects that entered the queue as early as 2017 could be affected by the new considerations, Phillips said

Stakeholders expressed doubts that the long-range projects will be built in time to support new generation projects advancing through the queue. Several pointed out that the transmission projects don't have specific in-service dates yet.

Some also asked whether MISO would consider reinstating projects to the queue that were previously priced out by high network upgrades. Before staff embarked on their long-range planning, some stakeholders criticized the RTO for placing the system expansion's financial burden on generation developers.

Phillips said staff is in the early stages of analyzing how they should treat projects affected by the LRTP. He said MISO is accepting written opinions through April 29 on how to integrate long-range projects into interconnection studies.

The discussion came as generation projects are experiencing multiple *delays* in the interconnection queue's definitive planning phase. MISO is also trying to get a feel for how many developers are lining up to enter the queue this year. Staff are asking developers for a heads up on whether they plan on submit projects by the Sept. 15 deadline.

MISO said the submittals will be used for resource forecasting and won't supplant the need for a queue application. It also said the information developers share will be non-binding and confidential.

In March, the queue contained 848 projects totaling 133 GW of installed capacity. Solar projects accounted for 62% of the capacity, with wind, storage and hybrid formats each responsible for 11%. ■

NYISO News

NYPSC OKs 2 Huge Clean Energy Contracts for New York City

Power Lines from Canada and Upstate to Cost $60B over 25 Years

By Michael Kuser

The New York Public Service Commission on April 14, 2022 conducted its regular monthly session both in person and via teleconference. | *NYDPS*

The New York Public Service Commission on Thursday voted 5-2 to approve separate 25-year state contracts to buy electric power from the 1,300-MW Clean Path New York (CPNY) and the 1,250-MW Champlain Hudson Power Express (CHPE) projects that will bring solar, wind and hydropower from upstate and Canada into New York City (*15-E-0302*).

The two transmission projects, Tier 4 renewable resources under the state's Clean Energy Standard, are projected to cut New York City (Zone J) fossil-fired generation by 51% and to bring up to $5.8 billion in social benefits, including greenhouse gas (GHG) reductions and air quality improvements and $8.2 billion in economic development across the state that will benefit disadvantaged communities.

NYPSC Chair Rory Christian | *NYDPS*

"New York City relies heavily on aging fossil fuel generation — simply put, if we can't deliver renewable energy to New York City we can't reduce emissions from that fossil fuel fleet," said PSC Chair Rory Christian. "Based on the over 30 proposals received, these options are the best available."

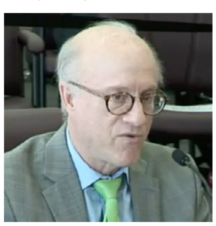
The projects, he said, support the goals set by the Climate Leadership and Community Protection Act and align with the New York State Constitution supporting each person's right to "clean air, water and a healthful environment."

CPNY, developed by the New York Power Authority (NYPA) and Forward Power, a joint venture of Invenergy and energyRe, will be tied to 23 generation facilities and bring upstate solar and onshore wind into the city from its origin point in Delaware County with a start date of June 30, 2027. The constant rate contract over 25 years pays $129.75/MWh for 7,870,865 MWh/year for a total contract price of approximately $25.5 billion.

The CHPE, developed by Transmission Developers and Hydro-Québec's U.S.-based subsidiary HQUS, will run from the state's border with Canada to Queens, with portions of the line running underneath the Hudson River. Its contract begins Dec. 15, 2025, and increases by 2.5% per year. Starting at $97.50/MWh for 10,402,500 MWh/year, the 25-year total contract price is approximately $34.6 billion.

The actual program payments will be calculated at those strike prices minus reference energy and capacity pay prices as defined in each contract, with the renewable energy credit (REC) payments dependent on future energy and capacity commodity prices, said Marco Padula, an economist at the state's Department of Public Services. "The petition presents ratepayer impacts that are projected as the net REC costs over time under a range of projected energy and capacity price forecasts."

City Lights



Robert Rosenthal, NYDPS | *NYDPS*

New York City filed a notice in November stating its intent to enter into a 25-year contract with the New York State Energy Research and Development Authority (NYSERDA) to procure Tier 4 RECs, which, when combined with the city's load share-based allocation of offshore wind RECs, would be equivalent to its entire load, said Robert Rosenthal, general counsel for the DPS.

The city is taking a lead to reduce GHG emissions by backing up its policies with a significant financial commitment, providing a model for other branches of state and municipal governments to follow, Rosenthal said.

On April 9, the state Office of General Services (OGS) filed a letter of intent stating that it would also be entering into a contract with NYSERDA for Tier 4 RECs associated with energy used by all state agencies located in the city.

"DPS sees this all-of-government approach as a significant development that will meaningfully reduce utility ratepayer impact of implementing the CLCPA, and it will strongly encourage other branches of government to make commitments under Tier 4 similar to those made by New York City and OGS," Rosenthal said.

The city's efforts are encouraging signs that future investments will not solely be borne by ratepayers but spread out equitably through a more expansive all-of-government approach, Christian said.

"Many comments received, including those

NYISO News

from the Real Estate Board of New York, highlighted the growing demand for RECs through voluntary corporate and consumer action as another potential source for savings," he said. "It is likely that many building owners will procure Tier 4 RECs, potentially a very significant quantity of RECs, for compliance with various local laws, such as local law 97 in New York City," Christian said. (See *NY Stakeholders, Residents Split on HVDC Tx Projects*.)

NYPSC Commissioner David Valesky | *NYDPS*

Commissioner David Valesky quoted from the comments filed by the largest property owners in the city who "are eager to explore participating in this voluntary market to determine how purchasing these RECs can enhance our corporate goals and local law 97 compliance strategies."

Regarding voluntary participation versus mandates, "the reality of local law 97 cannot be understated and is significant to say the least, so I think these are important commitments," Valesky said. "They're meaningful commitments in terms of reducing the impact of these projects on ratepayers across the state."

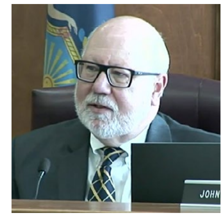
Ratepayer Concerns

NYPSC Commissioner Diane X. Burman | *NYDPS*

The commission had to vote on the projects based on the record, which shows the known cost to ratepayers "are unacceptably high," said Commissioner Diane Burman, who voted against the order.

Commissioner John B. Howard also voted no, concerned that the projects received little publicity and discussion west of the Hudson River.

"In fact, of those entities who commented from central and western New York, they were by and large opposed to this order," Howard said. "While this petition received extensive press coverage from the New York City-based media, nary a word was written about it in the upstate media, so in any discussions I had with individuals upstate, they had little or no awareness of the impacts to customers in their region."



NYPSC Commissioner John B. Howard | *NYDPS*

He urged the commission to more aggressively seek the opinions of those customers who will pay most of the bills, since electricity customers outside of the city will pay 60% of the Tier 4 cost for the contracts.

"Even today, we have heard over and over again that the vast majority of benefits to this proposal accrue to New York City because customers pay for Tier 4 on a pure kWh basis," Howard said. "Combined with a relatively lower cost retail electric cost outside of New York City, particularly upstate, the percentage of increase on customers' bills will be higher upstate."

The contracts, he said, will have a "disproportionate impact" on large customers and "we cannot sacrifice upstate New York economic competitiveness as we decarbonize our economy." ■

NYISO News

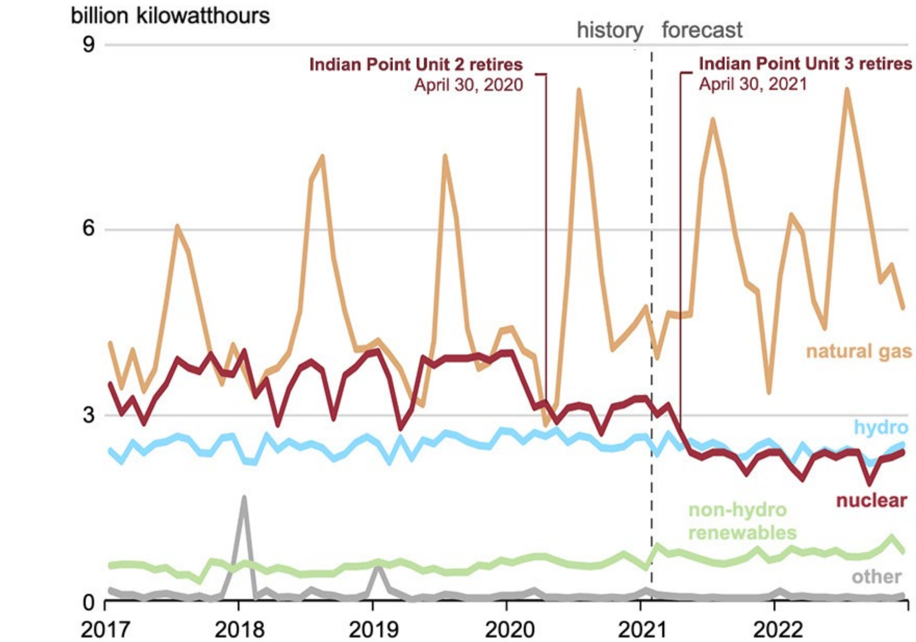
NYISO Business Issues Committee Briefs

Manual Updates for GFER Results

The NYISO Business Issues Committee on April 11 approved *revisions* to the Transmission and Dispatch Operations *Manual* regarding updates required to share Generator Fuel and Emissions Reporting (*GFER*) survey results with all New York transmission operators (TOPs), effective April 29.

"These changes require that all TOPs [including NYISO] have access to the GFER fuel survey results in order to adequately evaluate energy constraints and develop seasonal operating plans," said John Stevenson, gas and electric technical specialist.

The revisions are a result of NERC Project 2019-06, which, among other changes, updated standards to require TOPs to include in their data specifications provisions for reporting the cold weather information identified by generator operators in their cold weather plans. (See *NERC Board OKs Cold Weather Standards*.)



Electric power sector generation by source in NYISO (January 2017 to December 2022) | *EIA*

March LBMPs Drop with Milder Weather

NYISO locational-based marginal prices averaged $56.78/MWh in March, down from $94.06/MWh the previous month and nearly double the $28.59/MWh average in March 2021, Rana Mukerji, senior vice president for market structures, said in delivering the monthly operations *report*, attributing the monthly decrease to lower fuel prices and milder weather.

Day-ahead and real-time load-weighted LBMPs came in lower compared to February. Year-to-date monthly energy prices averaged $100.65/MWh, a 116% increase from $46.57/MWh a year ago.

March's average sendout was 390 GWh/day, down from 429 GWh/day in February and higher than 381 GWh/day a year earlier.

Transco Z6 hub natural gas prices averaged $4.47/MMBtu for the month, down from $6.17/MMBtu in February and up 99.6% year-over-year.

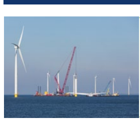
Distillate prices were up 105.2% year-over-year. Jet Kerosene Gulf Coast averaged $25.68/MMBtu, up from $19.79/MMBtu in February. Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $27.02/MMBtu, up from $20.46/MMBtu in February.

March uplift increased to -9 cents/MWh from -$1.77/MWh the previous month, and total uplift costs, including the ISO's cost of operations, came in higher than those in February.

The ISO's local reliability share climbed to 27 cents/MWh in March from 4 cents/MWh the previous month, while the statewide share increased to -36 cents/MWh from -$1.77/MWh in February. ■

— Michael Kuser

Northeast news from our other channels



Mass. Senate Passes Bill to Amend OSW Price Cap Rules — NetZero Insider

Mass. Commission Readies Proposal for State Clean Heat Standard — NetZero Insider

177-MW Morris Ridge Project Builds Buzz for Solar Beekeeping — NetZero Insider

Mass. Transportation Bond Bill Seeks to Unlock $4B in IIJA Funds — NetZero Insider

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

PJM News

Va. AG, SCC Staff Question Costs on Dominion's OSW Project

By Martin Berman-Gorvine and Rich Heidorn Jr.

Dominion Energy's proposed offshore wind project in Virginia has run into some stiff headwinds as it seeks state regulators' approval.

In testimony filed with the Virginia State Corporation Commission (SCC), commission staff and the state attorney general's Division of Consumer Counsel questioned the cost of the 2.6-GW Coastal Virginia Offshore Wind (CVOW) project and called for ratepayer protections (*PUR-2021-00142*). A consultant for Synapse Energy Economics also questioned Dominion's ability to bring the project in on budget, citing its lack of experience with offshore wind.

The filings were made as the SCC prepares for hearings on the project beginning May 16. In November, Dominion announced that the projected cost had increased by more than 20% to $9.8 billion, citing "commodity and general cost pressures." (See *Dominion's OSW Project to Cost $9.8B, up from $8B*.)

Based on testimony by consultant Scott Norwood, the Consumer Counsel *filing* says that the project is not needed to serve the company's system capacity requirements through at least 2035; that the capital costs are about twice or three times the cost of solar resources; and that the company is overstating the forecasted economic benefits.

The filing acknowledged that the legislature's Virginia Clean Economy Act of 2020 (VCEA) "declared that utility-owned offshore wind electric generation facilities are … in the public interest" and directs the commission "to give due consideration to economic development and social cost of carbon benefits of the project."

But given the high fixed cost of CVOW and the "significant risks" to customers, if it is approved, Norwood recommended that the SCC hold Dominion strictly to the $9.8 billion cost figure; that the SCC hold the company to minimum standards on capital, operations and maintenance costs, and operating performance; and that the agency have "the company publicly commit to in-service dates." Moreover, the company should "be required to file periodic status reports … that address the performance and cost of the project through the construction period and for at least the first year of commercial operations."

Dominion Energy's only experience with offshore wind is a two-turbine pilot project that began operations in late 2020. | *Dominion Energy*

If Dominion finds that an in-service date is going to be delayed by more than six months or that it will overrun the $9.8 billion estimated cost by 5% or more, the filing says, the SCC "should require that the company make an immediate filing with the commission that provides notice of the delay or cost increase, provides an explanation of the reasons for the delay or cost increase, and which reopens the question of prudence" of the project as a whole.

Presumption of Prudence in Jeopardy

Katya Kuleshova, of the SCC's Division of Public Utility Regulation, *testified* that levelized cost of energy (LCOE) sensitivity analyses show scenarios in which the project's cost exceeds 1.4 times the cost of a conventional simple cycle combustion turbine — which would eliminate the project's "presumption of reasonableness and prudence" under the VCEA.

Kuleshova said staff also were concerned that the project's energy production is expected to be at its highest during shoulder months and at its lowest during summer afternoons, when it is needed the most.

"In the absence of the statutory presumption of prudence, staff does not take a position on the prudence of the project," she said, recommending the commission order a performance guarantee and cost overrun protections to mitigate risks to ratepayers.

In an email to *RTO Insider* on Thursday, a spokesperson for Virginia Attorney General Jason Miyares said that his office cannot comment on "pending litigation."

Dominion responded to the filings with a statement saying, "Offshore wind's zero fuel cost and transformational economic development and jobs benefits are needed now more than ever."

Company spokesperson Jeremy Slayton also noted that none of the parties intervening in the docket had opposed the project's approval.

PJM News

"We are pleased all parties to the case have focused on ways to have the best possible project, and none have opposed it," Slayton said.

Testifying for activist group Clean Virginia, Maximilian Chang, principal associate with Synapse Energy Economics, recommended that the SCC "conduct an assessment to evaluate if the current utility-owned model for the CVOW is the most appropriate mechanism for the second 2,600 MW of offshore wind for Virginia, as outlined in the Virginia Clean Economic Act legislation. As part of this assessment, the commission may consider other forms of offshore wind procurement, including but not limited to power purchase agreements and/or offshore renewable energy credits."

The problem, in Chang's view, is that outside of CVOW, Dominion's project team appears to have limited direct offshore wind project experience that would show its ability to complete the project on time and within budget. Like the consumer counsel, he recommended that the SCC impose a capital cost cap for the project, but he also suggested that the cap exclude the $500 million the company is requesting for financial hedges and contingency. If the project's capital costs increase beyond $9.8 billion, Chang said, the commission should set clear guidance that Dominion could be on the hook for overruns. The utility should also be required to submit regular progress reports, and to hire an independent monitor, he said.

In addition to 176 14.7-MW wind turbines, the project includes 3 miles of submarine transmission; a new Harpers Switching Station, located on the grounds of Naval Air Station Oceana; three new overhead 230-kV transmission lines between the new Harpers station and the existing Fentress Substation; the expansion of the Fentress station; a partial rebuild of Line 271; and a rebuild of Line 2240. Dominion estimated a cost of $774 million for transmission and $374 million for substation work, for a total of $1.15 billion.

Dominion requested a final order by Aug. 5, which would allow onshore construction to begin in the third quarter of 2023, followed by offshore construction in the second quarter of 2024, with construction finished in mid-2025. Commissioning of the turbines would begin in August 2025 and continue through the end of 2026.

Economic Impact

The company says the project will create approximately 900 jobs and have $143 million in economic impact annually during construction, increasing to approximately 1,100 and almost $210 million annually during its operation.

Norwood said Dominion's cost-benefit analysis is flawed because it compared total production costs of the system in a scenario with the project, to costs of the system under an alternate scenario that assumes the company would not replace CVOW's capacity and energy with other renewable resources. The utility's modeling created "illusory benefits" for the CVOW project, he said.

Norwood also criticized Dominion for failing to include sensitivity analyses to assess the impact of uncertainty in forecasted commodity prices, carbon emissions prices or PJM energy prices. "For example, the commodities price forecasts used for all CBA scenarios assumes that Virginia remains as a member of the Regional Greenhouse Gas Initiative and that federal CO_2 legislation becomes effective in 2026," he said.

The commission will hear public testimony via phone May 16 and hold an evidentiary hearing in Richmond beginning May 17. Both hearings will be *webcast*. Those wanting to speak as a public witness must *register* by May 12. ■

PJM News

FERC Approves PJM-NJ Transmission Agreement

Commission Says NJ Users Will be Solely Responsible for Costs

By Hugh R. Morley

FERC gave final approval Thursday to the State Agreement Approach (SAA) sought by the New Jersey Board of Public Utilities and PJM that gives the greenlight for the state and RTO to build transmission to deliver 7.5 GW of planned offshore wind (*ER22-902*).

The commission concluded that the agreement would require all costs of the transmission to be borne by New Jersey customers, rejecting claims by PJM transmission owners that they could potentially be liable in the future. It said that the SAA protects the TOs because any such cost allocation would have to be approved by FERC.

The order gives final approval to a process that is already far advanced and that the BPU expects will conclude in the fall, either with its adoption of one or more proposed transmission enhancements or a rejection of all the submissions based on price, risk, environmental impact and other factors. The BPU had asked FERC to rule on the application by Friday.

Tying OSW to the Grid

The SAA sets up a framework by which PJM and New Jersey are granted permission to create a planning, selection and execution system for transmission improvements — in this case to respond to the expected surge in power from offshore wind projects — for which solely New Jersey customers would foot the bill. In a filing with FERC, PJM said it expects the resulting infrastructure to be in service for 30 to 40 years.

Thirteen developers submitted 80 proposals under the SAA solicitation process opened by the BPU in April 2021 and closed in September. (See *PJM, NJ Staff Brief Stakeholders on State Agreement Approach*). The BPU on April 12 held the final of four public hearings, in which the developers outlined their proposals and the board heard public and stakeholder comment on several issues, including grid integration concerns, the permitting and environmental issues of the proposals, and how to control the cost of the projects to ratepayers. (See related story, *NJ Seeks Efficiency, Savings in OSW Transmission Process*.)

Under the proposal, New Jersey would commit to paying 100% of the cost of the transmission but could seek to allocate some costs to other generation projects that use the additional capacity. The projects would be funded by a tariff authorized by FERC that would amortize the cost of the projects over their life. PJM would then allocate the costs to the utilities serving the state, who would in turn charge the cost as a transmission fee in ratepayer bills.

The state is seeking to generate 7.5 GW from offshore wind by 2035, about half of which the BPU awarded in two solicitations, with another three expected, the first of them in January. Each of the projects awarded so far — Ocean Wind 1 and 2, developed by Ørsted; and Atlantic Shores, by a joint venture between EDF Renewables North America and Shell New Energies US — included a plan to build accompanying transmission infrastructure. (See *NJ Awards Two Offshore Wind Projects*.)

However, the SAA offers the potential to create a network of infrastructure that could serve several projects. Developers testified in public hearings that such a system could result

Artist's conception of the northern edge of the Ocean Wind farm, as seen from the beach at Atlantic City | *Ørsted, PSEG*

PJM News

in lower costs to taxpayers and, in reducing the number of cables and amount of infrastructure needed, reduce the environmental impact and disruption in towns where the cables run ashore.

Future Beneficiaries

While the New Jersey Division of Rate Counsel, clean energy advocates and two offshore wind infrastructure developers filed statements of support for the SAA proposal, the Ohio Public Utilities Commission's Federal Energy Advocate (FEA) and some PJM TOs opposed the plan, expressing concern at different elements of the cost-sharing provision. They argued that the SAA's cost allocation rules were too broad or vague and could result in other states being charged, based on a claim that the transmission projects would provide "incremental reliability benefits to non-sponsoring states."

The FEA said the rules are especially too broad in case one of the projects developed under the SAA is expanded to provide transmission service to neighboring states. It argued that costs should only be allocated if the future user voluntary agreed to participate in the expansion of the projects, and not simply because they receive its benefits.

PJM transmission owners also expressed concern about the cost allocation provisions.

But FERC concluded that the proposal's language clearly states that the "BPU would be committing New Jersey customers for the cost of any SAA projects that [the] BPU elects to sponsor."

The commission said that while it is true that the SAA leaves open the possibility that future users outside New Jersey could be charged, the agreement means that "approval by the commission of a subsequent cost allocation filing is necessary to implement such an allocation." The BPU and PJM's answers in response to the FEA and TOs' concerns, "and the SAA agreement itself explain that no costs will be allocated to customers outside of New Jersey unless and until the commission accepts a future cost allocation filing as just and reasonable," FERC said.

The section of the agreement that allows non-New Jersey users to be allocated costs "merely contemplates that future users of the SAA project could be asked to pay their fair share of costs ... [that] will be defined in a future filing with the commission," FERC said.

The commission also said that the FEA and TOs' concerns about future cost allocations were "premature."

"Any cost allocation to 'future users' is contingent on the commission reviewing and accepting a future cost allocation filing, and until any such filing is received, the SAA agreement allocating costs stands in place."

Disagreement Between FERC's Republicans

In a dissenting opinion, Commissioner James Danly said the language of the SAA agreement clearly states that "'PJM shall allocate to any future user of a SAA project ... a *pro rata* share of the total costs,'" which could be non-New Jersey users.

"The cost-sharing provision settles the single most important cost allocation detail: whether anyone besides the ratepayers in New Jersey can have the costs of a state 'public policy' project foisted upon them," he wrote. "The answer to that question is 'yes,' the costs of a state's pet project can be passed on to other states' ratepayers."

He said that the issue is important because "many in the industry have been concerned that certain states might seek to shift or socialize the costs of the transmission projects that will be required to achieve their bold (some might say 'brash') renewable portfolio goals to the ratepayers in other states. Now, the filed rate allows that very result."

But fellow Republican Commissioner Mark Christie disagreed with Danly, concurring with the majority that the order makes no presumption about future cost allocations.

"The only proposal on the table now is New Jersey's State Agreement Approach agreement, which does not allocate any costs to customers, wholesale or retail, in states other than New Jersey," Christie wrote. "Moreover ... today's order makes clear that while the order does not attempt to answer any questions about whether any future cost allocations are just and reasonable, it does answer that such proposed allocation must be consistent with the State Agreement Approach."

Offshore Infrastructure Options

In launching the solicitation for proposals, BPU and PJM set out a rough guiding framework of suggested elements and infrastructure improvements. They included four onshore locations on the existing grid — one in North Jersey, two in the center of the state and one in the south — that are suitable interconnection points. (See *Fierce Competition in Plans to Upgrade NJ Grid*.)

The board also identified several "power corridors" through which lines could run onshore from the coast to the connecting sites, and five suggested routes for cables running underwater to the shore. Finally, the BPU suggested an "offshore transmission backbone" running parallel to the coast, to which the turbines would connect and on which several substations would be sited.

The SAA proposal asked the commission to approve a variety of issues, among them to enable the BPU to assign transmission capability created by SAA projects to OSW generators selected by the BPU's solicitation process. The application also sought approval for the BPU to allow OSW generators to be studied through PJM's interconnection queue and grant incremental rights, if eligible, associated with any incremental transmission capability created by SAA projects. (See *PJM, NJ Seek FERC OK for OSW Tx Process*.)

The SAA, according to FERC, is "a supplementary transmission planning and cost allocation mechanism in PJM's Operating Agreement through which one or more state governmental entities authorized by their respective states, individually or jointly, may agree to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state public policy requirements identified or accepted by the state(s)."

PJM proposed the SAA to comply with Order 1000's requirement for procedures to address transmission needs driven by public policy requirements in the regional transmission planning process. ■

NJ Seeks Efficiency, Savings in OSW Transmission Process

Developers Vie over Which System Will Best Protect Ratepayers

By Hugh R. Morley

The cost to New Jersey ratepayers of building transmission infrastructure tying the state's offshore wind projects to the grid could be cut, and the risk of cost overruns diminished, under some of the 80 proposed projects submitted to the state Board of Public Utilities (BPU), stakeholders at a hearing into the issue argued April 12.

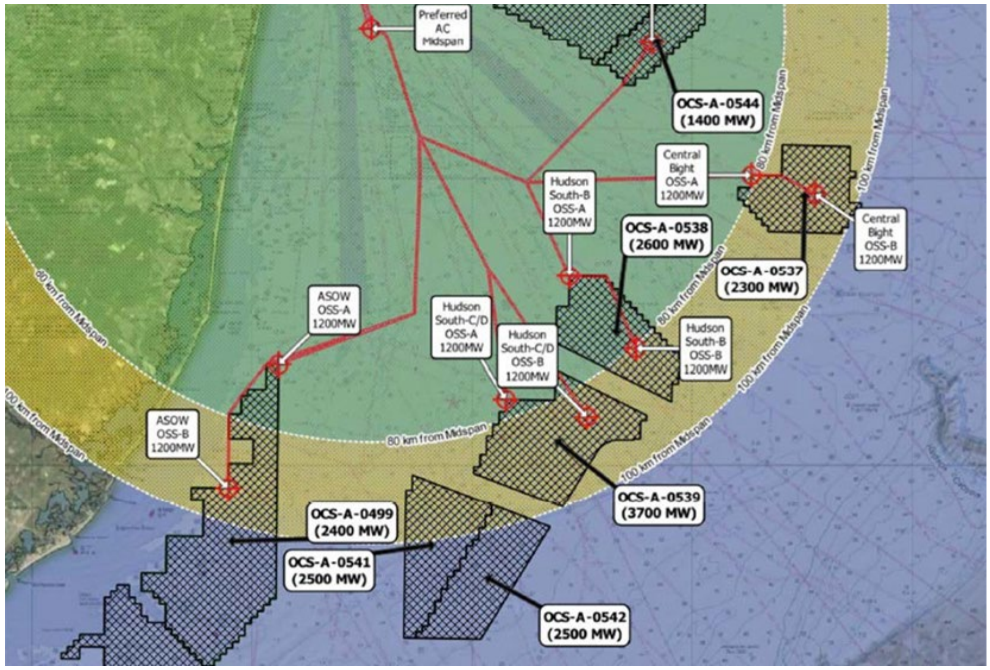
Such a strategy, if approved by the BPU, would provide a transmission system for about half of the 7.5 GW of offshore wind planned by the state, said developers and stakeholders during the three-and-a-half hour hearing on the BPU's planning process with PJM under FERC's State Agreement Approach (SAA). That would be a stark departure from the plans in place for the development of transmission infrastructure for the first half of the planned offshore wind capacity.

Each of the three offshore wind projects awarded by the BPU so far — Ocean Wind 1, Ocean Wind 2 and Atlantic Shores, which collectively would generate 3.758 GW of power — will design and develop their own transmission infrastructure. But the SAA process would allow one or more developers focused solely on transmission issues to design the infrastructure to connect projects awarded in the future to the grid.

Having a single project serve several projects could reap efficiencies of scale, create a more reliable system and reduce the cost to ratepayers through competitive bidding coupled with cost caps to prevent the amount paid by ratepayers from escalating beyond the contracted amount, developers said.

Becky Walding, executive director of development for NextEra Energy Transmission MidAtlantic, said the company had calculated that the process could save "customers billions of dollars" if it results in transmission infrastructure serving several wind farms, rather than each providing their own cable system.

"There is the possibility for substantial cost savings," added Theodore Paradise, executive vice president of transmission strategy for Anbaric Development Partners. "If you're avoiding more cables, more trenching, more shore landings, more upgrades [and] more substation expansions because you're making the most out of the breaker positions that you have in a substation, those are the sorts of things that can really save some money."



Final lease areas make HVAC more attractive for more than 70% of uncommitted offshore wind capacity. | *Rise Light & New Jersey BPU*

But Larry Gasteiger, executive director of trade association WIRES, urged the BPU to proceed with caution. Cost caps can be weakened by "exclusions" that allow items to be charged outside the cap, and focusing on a project's cost can sometimes be detrimental to ratepayers, he said.

"The real question here is: Do you really want the cheapest upfront design for your transmission solutions?" he said. "It raises a number of other related questions such as, what is the risk tolerance for what may be a cheaper, but less proven or unproven design over perhaps something that may wind up being more costly in terms of the design, but uses a more well established or more proven track record as the basis for that design?"

Risk vs. Cost Trade-off

The issue of how best to structure the development of future transmission infrastructure emerged as one of the most contentious topics at the BPU's fourth and final hearing into the SAA proposals, which focused on "ratepayer protections and cost controls." Under the SAA process, the BPU, working with PJM, solicited proposals for developing links between the grid and the offshore wind projects.

The last meeting in the series included a presentation by Michelle Manary, acting deputy assistant secretary of the Energy Resilience Division at the U.S. Department of Energy, on federal funding for offshore wind, and a panel discussion afterward that included three transmission project developers; Gasteiger; the director of the New Jersey Division of Rate Counsel; and a representative of PSEG, which owns 25% of one of the state's offshore wind projects and submitted transmission proposals with Ørsted.

Earlier hearings presented the 80 proposals submitted by 13 developers and focused on permitting and environmental issues and grid integration issues.

The BPU, working with The Brattle Group expects to decide by October whether to adopt any of the proposals. Alternatively, it could reject them all and continue as it has so far. (See *Fierce Competition in Plans to Upgrade NJ Grid*.) The board has held two offshore wind solicitations and awarded three projects, each of which included the design of a transmission system to bring the power to the grid. Three more solicitations are planned, the first to take place in January 2023. (See *NJ Awards Two Offshore Wind Projects*.)

Rate Counsel Director Brian O. Lipman said the BPU, in assessing the proposal, needs to focus on key benefits to the state, and not get distracted by broader issues.

"For this proceeding, the real issue is not about addressing the pre-eminent challenge of climate change, but rather how will New Jersey select resources that are economically sustainable and environmentally sustainable; in this case, transmission lines," he said. "The only issue is whether any of the proposed offshore wind transmission projects meet these goals. And if so, which are the best fit?"

The rate counsel encouraged the state only to support projects that would benefit New Jersey and not "promote regional solutions to OSW development along the Atlantic Seaboard." New Jersey ratepayers should "not be placed in the position of subsidizing OSW development benefits for other states and regions," he said. State officials in the past have expressed a more expansive view, saying they want New Jersey to be an offshore wind manufacturing and supply chain hub that can serve other states. (See *NJ Plans 'Flagship' R&D Innovation Center for Wind*.)

Lipman said the BPU should pick projects that fit the state's needs and not "facilitate overdevelopment" that could "place New Jersey ratepayers in the position of having to bear the risk of future project OSW transmission benefits that never materialize." He added that the BPU should look for projects that "offer to mitigate or assume some risks," such as development, financial, market and regulatory risks, and require the developer to take on some of them.

"It is likely that any offer to mitigate these risks will not come free," he said. "Thus, balancing risks and costs to determine the most advantageous proposal or proposals will involve some tradeoffs."

Structuring the Deal

The projects would be funded by a tariff authorized by FERC that would amortize the cost of the projects over their life. PJM would then allocate the costs to the utilities serving the state, who would in turn charge the cost as a transmission fee in ratepayer bills.

How that will impact ratepayers is not clear. Lathrop Craig, vice president of development for Public Service Enterprise Group, said the company has yet to calculate the cost of transmission, which will in any case vary depending on which project or projects the BPU chooses. But PSEG calculated that the entire cost of each of the three offshore wind projects approved so far would for the average residential account be "in the low single-digit dollars per month," so the cost of just transmission would be much less, he said.

Speakers differed, however, on the best way to keep those costs down and curb the risk to ratepayers of rising costs.

Clint Plummer — CEO of Rise Light & Power, a New York-based wind project development company that is a subsidiary of LS Power — argued that giving the developer responsibility for all the offshore transmission infrastructure, as well as developing the project, would secure efficiencies by "putting the developers in control of every piece of the project." That strategy has worked successfully in the past, he said.

"You give the developers not only the ability to manage their projects to deliver a lower cost to ratepayers, [but] you put more of the risk on the developers" and keep it off the ratepayers, Plummer said. Rise submitted a proposal to provide the onshore interconnection by developing a former fossil fuel plant, the Werner Generating Station in South Amboy, on a bay that fronts the New York Bight. He also argued that "it's very difficult to optimize a wind farm if you don't control the means by which you're delivering your final product to market."

But other developers argued that a separate competitive selection process to pick the transmission infrastructure would drive down costs.

"The competitive pressure of the State Agreement Approach will create tremendous value for New Jersey ratepayers in terms of cost savings and risk mitigation," said Lawrence Willick, executive vice president of transmission regulatory for LS Power, which submitted proposals to build both onshore and offshore transmission infrastructure.

The process also will protect ratepayers by including cost caps "to actually contain the cost of transmission" development and prevent them from getting burdened with cost overruns from issues such as unforeseen schedule delays, said Anbaric's Paradise.

AC vs. DC

A key element of the transmission system's cost structure, however, comes from the technology used, said developers, who offered differing visions at the forum. The issue centers on whether the project uses high-voltage alternating current (HVAC) or HVDC, which is more efficient for transferring power over long distances because it incurs less power loss.

Rise CEO Plummer said HVDC systems come in "large blocks" of 1,100 to 1,500 MW, and that unless the project is a multiple of those sizes, its use would result in the creation of wasted capacity. HVAC, meanwhile, comes in blocks of 400 MW, which is far more flexible and suitable for most of New Jersey's offshore wind areas, he said.

"HVDC makes a lot of sense for sites that are really far from shore," he said. But more than 70% of the offshore wind area still to be leased in New Jersey "can connect to the shore with HVAC technology," he said. "That has real advantages because HVAC is not only a more proven technology in the offshore environment, but it also is a lot cheaper."

Willick agreed that the "distances really aren't that long to justify the higher cost of the DC terminals," and that HVAC systems have the benefit of lasting longer than HVDC systems, which would likely need to be replace during the project's life.

"So really, if an AC approach does work, and is feasible, then that's the best approach," Willick said. "It integrates with the existing system and avoids the high cost and losses of the DC equipment."

Paradise argued that HVDC is the best option if the state is planning for large capacity. Such a system would avoid creating "the spaghetti of all of those radial lines" running from each project to the shore and be cost effective, he said.

Anbaric submitted proposals for both transmission corridors and an offshore network. It estimated that New Jersey's entire planned wind farm capacity of 7,500 MW could be handled by five HVDC cables, whereas it would require 19 HVAC cables, Paradise said.

"If you're going to go big in terms of significant amounts of megawatts and building out robust transmission systems," HVDC is preferred, he said. "So, if New Jersey is saying 7,500 [MW] is a down payment, but we want to go to 15,000 [MW], then designing a system is really important."

NextEra's Walding said the company designed the projects it planned to submit in two scenarios, AC and DC, and found the latter to be cheaper.

"We actually didn't even propose the AC because it was significantly more, to the tune of 50% more expensive," she said. "It ended up with more platforms in the ocean on that design. And, so from a cost perspective, we didn't feel like it was the right thing." ■

PJM News

PJM Operating Committee Briefs

By Michael Yoder

Reliability Products and Services Assessment Endorsed

PJM Operating Committee members last week unanimously approved an initial recommendation to evaluate the need to procure additional reliability-based generation as more intermittent resources are integrated into the RTO's grid.

Chris Pilong, director of operations planning, and Alex Scheirer, a PJM senior client manager, *reviewed* the proposed "initial direction" regarding reliability products and services — the outcome of discussions in the Resource Adequacy Senior Task Force (RASTF).

Members began looking at a list of generator "reliability attributes" in January, Pilong said, examining PJM's renewable integration studies and papers to determine the recommendations for addressing the potential for new reliability services and the next steps in the stakeholder process at the RASTF and other committees and task forces.

Pilong said stakeholders will discuss reactive capability and supply issues in the Reactive Power Compensation Task Force to ensure PJM is able to "utilize, measure and compensate the full reactive capability of synchronous and non-synchronous generators independent of their power output." The issue also calls for discussions on the ability of all resources to follow voltage schedules and demonstrate performance.

On the issue of regulation service, Pilong said, stakeholders recommend reviewing existing regulation market signals and considering future system needs as part of the regulation market redesign issue charge approved by the Market Implementation Committee last year. (See "RTO to Propose Review of Regulation Market," *PJM MIC Briefs: Nov. 3, 2021*.)

Members recommended that the Energy Price Formation Senior Task Force consider how to value flexibility of generation within the existing or modified ancillary services, Pilong said, while another recommendation has the RASTF exploring how to value fuel assurance for all resources that can be relied upon for "unexpected system conditions."

Pilong said PJM and stakeholders may evaluate methods for data submission and review the existing penalty structure if data reporting requirements in PJM manuals are not followed regarding energy assurance. He said a potential problem statement and issue charge could be brought to the OC in the future to examine manual language changes.

"As we're seeing the renewable penetration grow, we think we need to tighten those rules up a little bit more," Pilong said.

Regarding black start resources, stakeholders recommended continuing to monitor activities at the OC special sessions on fuel requirements for black start resources and the discussions at the RASTF on black start flexibility, fuel and energy assurances.

Members also recommended the RASTF consider specific unit performance requirements to handle the increasing number of extreme weather events in the region.

Dynamic line ratings, such as those provided by LineVision's overhead line monitoring system, can allow increased transmission capacity and provide grid operators with real-time situational awareness of potential problems. | *LineVision*

Dynamic Rating Issue Endorsed

Stakeholders unanimously approved an issue charge and endorsed a proposed solution as part of the "quick fix" process regarding facilitation of the integration of dynamic line ratings (DLRs) into PJM operations.

Chris Callaghan, PJM senior business solution engineer, *reviewed* the *problem statement* and *issue charge* addressing interim manual revisions on DLR integration. PPL is tentatively scheduled to go live in June with a DLR system on some of its transmission lines.

PJM wanted to "enable the operational implementation of dynamic ratings" through temporary manual revisions, Callaghan said, which will be in place pending submission of the RTO's FERC Order 881 compliance filing set to be completed by the end of the month.

In December, FERC ordered transmission providers to end the use of static line ratings in evaluating near-term transmission service and required transmission providers to employ ambient-adjusted ratings for short-term transmission requests of 10 days or less for all lines that are impacted by air temperature. (See *FERC Orders End to Static Tx Line Ratings*.)

The solution included new language in *Manual 1: Control Center and Data Exchange Requirements*, *Manual 3: Transmission Operations* and *Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA)* that develops new guidance and requirements related to the operational and technical implementation of dynamic rating systems.

The committee also unanimously endorsed a separate issue charge for the creation of a new task force to explore other issues related to the implementation of DLR in PJM. Callaghan *reviewed* the *problem statement* and *issue charge* related to the new task force reporting to the OC.

Key work activities of the task force include discussions on any impacts of DLR to the auction revenue rights and financial transmission rights markets, any impacts to the seasonal ratings used in the PJM planning processes and any other considerations regarding the notice of an intent to implement DLR in the RTO.

Out-of-scope items in the issue charge include modifications to the Operating Agreement, tariff or manuals that "infringe upon the terms of the Consolidated Transmission Owners Agreement," including requiring transmission owners to install or implement DLR on lines.

The task force is set to begin by August or after the completion of PJM's Order 881 compliance filing.

EKPC UFLS Requirements Endorsed

Stakeholders unanimously endorsed a quick-fix solution to appropriately document East Kentucky Power Cooperative's under frequency load shedding (UFLS) requirements in PJM.

Denise Foster Cronin of the EKPC *reviewed* a *problem statement* and *issue charge* addressing the documentation of UFLS and the changes to the *Operating Agreement*.

The purpose of the UFLS requirement is to avoid an uncontrolled loss of load situation, Foster Cronin said, and the requirement establishes a total percentage of load shed that must be achieved when system frequency drops to a certain level to maintain the system.

All electric distributors must comply with the UFLS requirement established by their respective NERC region. When EKPC integrated into PJM in 2013, the cooperative was in the SERC region of the ERO.

Before EKPC's integration, PJM's OA documented a UFLS requirement for entities in the PJM's Mid-Atlantic, West and South regions. But the OA was not changed with EKPC's 2013 integration to incorporate the cooperative's applicable UFLS requirement, and it wasn't included in any of the regions.

In 2018, EKPC was added to PJM West when the RTO worked with stakeholders to clarify the region definitions in its governing documents. However, other entities included in PJM West are in the ERO's ReliabilityFirst region, while EKPC remained in SERC, which has slightly different UFLS requirements.

Foster Cronin said a recent review of the region revisions showed "potential confusion" in EKPC's appropriate UFLS requirement and needed to be corrected. She said the oversight did not create a reliability problem for the cooperative.

"We really wish for these changes to ensure there's no confusion as to what is the appropriate under frequency load shedding requirements applicable for us," Foster Cronin said.

The MRC will vote on the solution and corresponding OA revisions at its April 27 meeting.

Manual 1 Revisions Endorsed

The committee unanimously endorsed changes to Manual 1 as a part of the periodic review.

Bilge Derin, PJM senior engineer, *reviewed* the changes to *Manual 1: Control Center and Data Exchange Requirements*, saying the changes partially resulted from revisions in NERC standards CIP-012, COM-001 and EOP-008.

Minor changes were made throughout the manual, Derin said, including removing revision numbers from where NERC standards are referenced and replacing the term "member" with "PJM member" where applicable to keep the term uniform throughout the manuals.

In Section 2.5.6: Recovery Procedures, PJM clarified the loss of control center functionality procedures and documentation relating to EOP-008 and TO/TOP Matrix.

In Section 3.2.1.1: PJMNet Communications System, the language was clarified to ensure PJM is responsible for protecting all real-time assessment and real-time monitoring data through the PJMNet private network as the data is "in transit" between the PJM control centers and its routers. The RTO must also make sure all data is encrypted.

Stakeholders will vote on the manual changes at the April 27 MRC meeting. ■

PJM PC/TEAC Briefs

By Michael Yoder

Planning Committee

Interconnection Process Subcommittee

PJM is proposing the creation of a new subcommittee to continue discussions of interconnection process changes after work in the Interconnection Process Reform Task Force (IPRTF) finishes.

Jason Connell, PJM director of infrastructure planning, provided a first read of the draft charter of the Interconnection Process Subcommittee (IPS) at last week's Planning Committee meeting. Connell presented the concept of the new subcommittee at the March 8 PC meeting. (See "Interconnection Subcommittee Initiative," *PJM PC/TEAC Briefs: March 8, 2022*.)

Connell said PJM staff have continued internal discussions and talks with stakeholders about creating the new subcommittee to carry on discussions on additional interconnection issues identified in the IPRTF. He said the purpose of the IPS is to provide a stakeholder forum to "investigate and resolve specific issues related to the interconnection process and associated agreements, governing documents and manuals."

Discussion topics featured in the charter include:

- education on current and future interconnection processes and agreements with clarifications around implementation;
- development of improvements of interconnection process rules in the tariff and related PJM manuals;
- encouraging continued dialogue between stakeholders and PJM on best business practices and coordination with neighboring RTO/ISOs on interconnection.

Connell said PJM fields many questions from developers on how the RTO plans to implement aspects of the interconnection process not explicitly described in the manuals and the tariff. He said PJM wants to use the subcommittee as an "incubator" for discussions on complex interconnection issues and to come up with solutions.

The IPS will report to the PC, Connell said, but some of the issues to be discussed may impact operations and markets, requiring reports to the Market Implementation Committee and the Operating Committee. Connell said PJM intends to begin holding meetings of the new subcommittee by June and establish a near-term agenda if endorsed by stakeholders.

"PJM was very much in favor of doing this, as it has seen the benefits of the discussions that have taken place at the IPRTF over several months and the consensus that we've been able to build around the Planning Committee's endorsed package," Connell said. "We want to continue that dialogue in order to continually refine and improve the interconnection process to facilitate the renewable transition."

Ken Foladare of Tangibl Group said his company supports the new subcommittee and the concept of having an "ongoing discussion" of the interconnection process. Many renewable customers will want process changes and improvements "quite frequently," he said, asking if PJM could implement a process where proposed changes are considered annually in one batch instead of piecemeal because the number of changes "could get a bit difficult to manage."

Connell said PJM would have to "look at the magnitude of the changes" proposed and "batch them appropriately" depending on their urgency.

"We certainly don't want to overwhelm the standing committees with monthly changes as we're moving through," Connell said.

Sharon Midgley of Exelon said it "makes a lot of sense" to have the new venue for interconnection discussions. She said Exelon wondered how the subcommittee will "work mechanically" and how issues will be prioritized.

Dave Anders, director of stakeholder affairs for PJM, said the IPS will operate similarly to other subcommittees that report to a standing committee, pointing to the Cost Development Subcommittee as an example. He said Manual 34 stipulates that subcommittees are allowed to take on work that's within the charter of the group.

Any disagreement among stakeholders in the group should be addressed by the PC, Anders said.

Midgley said she would like to see some expectation language included in the charter so that stakeholders "know the bounds and the rules under which we're engaged" in the committee.

RSCS Charter

Monica Burkett, PJM senior lead knowledge management consultant, provided a first read of proposed changes to the charter of the Reliability Standards and Compliance Subcommittee (RSCS).

Burkett said the RTO is looking to improve discussions and find more efficiencies in the RSCS, including maintaining up-to-date information on issues. She said several changes are being proposed to improve what compliance information is provided and shared with stakeholders in the subcommittee.

Burkett said the charter updates include "simple tweaks" to language for clarification.

One item proposed to be removed from the charter language is the development of a list of functions performed by other registered entities "in support of PJM compliance." Burkett said the list of functions are reviewed at the RSCS, but they are never developed by the subcommittee.

Under the responsibilities section of the charter, PJM removed the item "cooperate with PJM with regard to data requests and submittals related to NERC and regional reliability standards" and inserted "allow for exchange of best practices and discussions surrounding upcoming data requests related to NERC and regional reliability standards."

The committee will be asked to vote on the charter at next month's PC and OC meetings.

Manual 21A ELCC Changes Endorsed

Stakeholders endorsed an issue charge and manual revisions related to an effective load-carrying capability (ELCC) model run timing update and other changes to reflect the continuation of the current method of providing unit-specific backcasts only as requested. The endorsement received 182 votes in support (97.3%) and 182 votes (97.3%) favoring the changes over the status quo.

Joshua Bruno, senior analyst in PJM's resource adequacy planning department, reviewed the changes to *Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, along with the problem statement and issue charge.

PJM rules allow voluntary submission of unit-specific wind and solar parameters for development of backcasts for newer resources, Bruno said, but current manual language has an expiration date of March 1 for voluntary

PJM News

submissions. The submission of unit-specific parameters for all wind and solar is mandatory after the expiration date.

The alternative method is to use a zonal back-cast, Bruno said, which PJM has found to be an "adequate" process.

The quick fix called for removing the March 1 expiration date, which would allow PJM to continue the current practice in which newer resources can elect to submit the unit-specific data or use the zonal backcast.

Bruno said another change in the proposal would have the 2025/26 Base Residual Auction use the December 2022 ELCC run instead of the older July 2022 run. He said the change would allow for the most recent data to be used when calculating the accredited unforced capacity (UCAP) for the 2025/26 BRA, with the July 2022 run to be removed from the schedule.

The issue charge and manual revisions now go to the April 27 Markets and Reliability Committee meeting for a first read.

Manual 14F Revisions Endorsed

Stakeholders unanimously endorsed revisions to *Manual 14F: Competitive Planning Process* related to the biennial review.

Joseph Hay of PJM's infrastructure coordination department *reviewed* the revisions that featured two main changes to the manual.

First, the critical energy/electric infrastructure information (CEII) in Manual 14F was referenced over to Manual 14B because the latter is the source document for PJM's CEII. Hay said the change will eliminate the requirement to edit Manual 14F whenever a change is made to 14B.

The second significant update was that the Secure File Transfer Tool used to submit all proposals was replaced with a requirement to use "Competitive Planner" to submit proposals. Hay said the Secure File Transfer Tool is still available for stakeholders and will be used to submit supplemental data on an "as needed" basis.

The manual changes will see a vote at the April MRC meeting.

Transmission Expansion Advisory Committee

AEP Supplemental Project

A stakeholder questioned a supplemental project presented by American Electric Power at

Energy Harbor's 1,504.3-MW W.H. Sammis Power Station at Stratton, Ohio, is set to be deactivated in 2023. | *FirstEnergy Solutions*

last week's Transmission Expansion Advisory Committee meeting.

Will Burkett of AEP presented the need for work to be done on the Conesville-Bixby 345 kV line in Central Ohio. Burkett said the 51.1-mile line has seen total of 10 outages since 2015, and some of the failures have been "catastrophic in nature."

Of the 342 structures making up the line, Burkett said, 73% are wood structures installed in the early 1970s. An additional 25% of the structures are steel installed between 2010 and 2021, Burkett said, with the replacements "performed proactively" at and along major interstates. The remaining 2% of the structures are steel installed in the early 1970s.

Burkett said when the line was constructed in the 1970s, it used an H-frame design with wood poles and laminated crossarms rather than solid wood crossarms. He said 30 of the structures are currently rotting or have heavy rust and other serious flaws.

Sharon Segner, vice president at LS Power, asked if there is an in-service date associated yet with the project.

Burkett said AEP is working on a solution and doesn't yet have a timetable or costs for the project.

"We're just bringing the concerns we have out there, and we'll work to develop solutions to address those needs and bring that back to stakeholders," Burkett said.

Segner asked why the project "doesn't appear to be going through a competitive process" despite being greater than 100 kV.

TEAC Chair Suzanne Glatz said the line is a supplemental project need, which is not subject to the competitive process in FERC Order 1000.

Segner said it will be "interesting" to see the price of the project when a solution is developed and expressed interest in "understanding the regional benefits" of the project.

"Obviously 51 miles of a 345 kV line likely has regional benefits," Segner said.

Generation Deactivation Notification

Phil Yum of PJM's system planning modeling and support department *provided* an update on recent generation deactivation notifications, including Energy Harbor's large coal units in Ohio and West Virginia.

Energy Harbor requested deactivation of coal-fired units 5-7 of the 1,504-MW W.H. Sammis Power Station in the American Transmission Systems Inc. (ATSI) transmission zone in Stratton, Ohio. The company also requested the deactivation of the 13-MW diesel unit at Sammis.

Energy Harbor also announced that it requested deactivation of units 1 and 2 of the 1,278-MW Pleasants Power Station in the Allegheny Power Systems transmission zone at Willow Island, W.V.

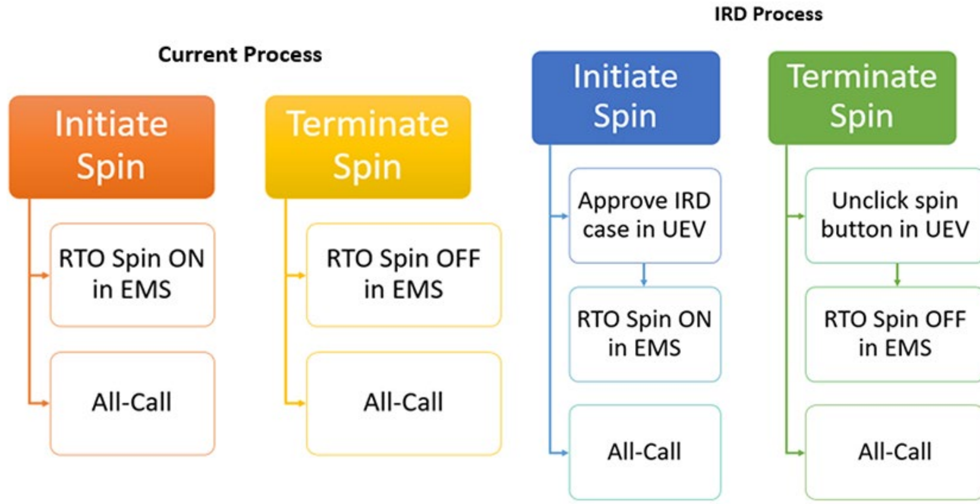
Yum said reliability analyses are underway for the Sammis and Pleasants units. Energy Harbor requested a deactivation date of June 1, 2023 for the units.

The 1.9-MW Ottawa County Landfill in the ATSI transmission zone requested a deactivation date of May 31, while the 81-MW Essex 9 gas-fired generation unit in the Public Service Enterprise Group zone in New Jersey requested a deactivation date of June 1. PJM completed reliability analyses for both units, and no violations were identified. ■

PJM News

PJM MIC Briefs

By Michael Yoder



PJM's proposed intelligent reserve deployment proposal. | *PJM*

Start-up Cost Offer Development Endorsed

PJM Market Implementation Committee members last week unanimously endorsed a revised proposal from the RTO and its Independent Market Monitor to address start-up cost offer development.

At the MIC's April 13 meeting, Tom Hauske, principal engineer in PJM's performance compliance department, *reviewed* the joint proposal to revise *Manual 15: Cost Development Guidelines* that came out of discussions at the Cost Development Subcommittee (CDS).

The CDS initially brought two proposals for first reads to the October MIC meeting. (See "Start-up Cost Offer Development," *PJM MIC Briefs: Oct. 6, 2021*.) But a vote on the proposals was postponed to allow more discussions and have stakeholders reach consensus on a single proposal.

Manual 15 currently allows the start-up costs for combined cycle units to include fuel costs after generator breaker closure and synchronization to the grid, a feature not available to other unit types, such as steam and nuclear plants. The revisions align start-up costs for all units with a soak process, or units that use steam turbines.

For units with a soak process, including steam, combined cycle and nuclear units, some of the soak costs are included in the start-up costs from PJM's notification to the "dispatchable output" and from the last breaker open to the shutdown process.

Units that don't have a soak process, like combustion turbines and reciprocating engines, maintain the status quo, with start-up costs that include costs from the time of PJM's notification to the first breaker close and from the last breaker open to the conclusion of the shutdown process.

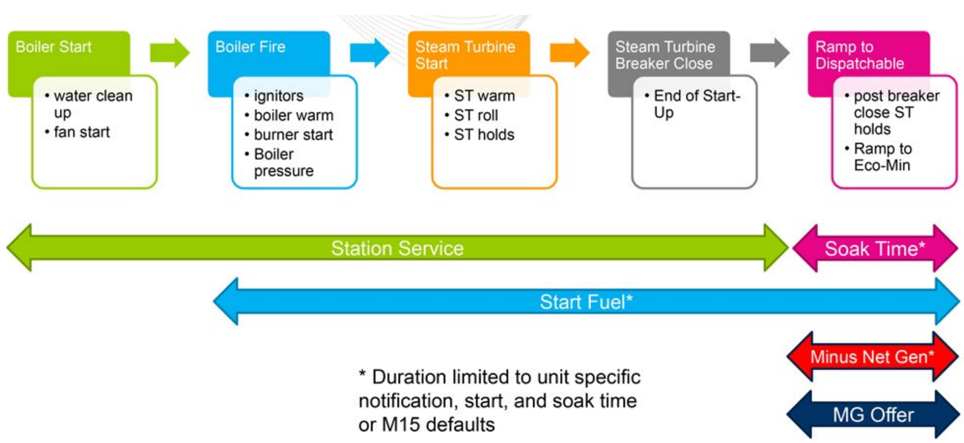
"We're not implementing soak time at this point," Hauske said. "We're just allowing generators that have a soak process to include those costs in the startup cost."

The revisions feature several other changes to Manual 15 to provide additional guidance and clarification, Hauske said, including equations to calculate start-up costs, station service calculations for units with and without a soak process and unit-specific parameter limits on includable costs.

Manual 15 currently allows generators to include an additional labor cost in their start-up costs, Hauske said, but generators already are permitted to include the labor cost in the unit's capacity offer through its avoidable cost rate (ACR). The proposal calls for eliminating the labor cost language in the tariff and Operating Agreement offer cap sections and the start-up cost calculation so all the operating labor is includable in the ACR.

Hauske said PJM will provide a six-month window for implementation to allow market sellers the opportunity to have their fuel costs or net generation used for the offset to be reviewed by the Monitor prior to the proposal going into effect.

The proposal will be presented as a first read at the April 27 Markets and Reliability Committee meeting.



PJM's revised steam unit start-up cost offer procedure. | *PJM*

Stability Limit Changes

Zhenyu Fan, senior engineer in PJM's real-time market operations, *provided* education and a first read of conforming updates to *Manual 11: Energy & Ancillary Services Market Operations* and *Manual 28: Operating Agreement Accounting* regarding stability limits in markets and operations.

In early 2021, stakeholders endorsed PJM's proposal on stability limits capacity constraints that included language limiting lost opportunity cost (LOC) credits for any generation reduction required to honor the stability limit in the RTO. The limiting of LOC compensation led to debates among PJM members. (See "Stability Limits Endorsed," *PJM MRC/MC Briefs: Jan. 27, 2021*.)

PJM News

FERC ruled in February that PJM is within its rights to refuse (LOC) payments to generators that are temporarily required to limit output to prevent loss of synchronization and additional strain on the system during transmission outages. (See *FERC: PJM Right to Block Gen Stability Limit Payments*.) The tariff changes take effect June 1.

Zhenyu said PJM will use a new generator output constraint to enforce the stability limit for real power megawatt-only limits. He said the shadow price of the constraint will not be included or reflected in locational marginal pricing (LMP).

To provide greater transparency, Zhenyu said PJM added a new section to Manual 11 related to stability limits that describes the modeling, clearing and reporting process on the stability limit in the market. Updated language related to stability limits in Manual 28 included additional clarification that LOC credits are not paid for megawatts associated with a stability limit reduction.

Paul Sotkiewicz of E-Cubed Policy Associates said he disagreed with FERC's decision on LOC payments. Sotkiewicz also disagreed with the proposed manual language, saying the changes don't provide for "workarounds or a reconfiguration change" between PJM and the transmission owners to find ways to eliminate a stability problem.

"There's a very easy workaround that eliminates the transient stability problem, and what I find alarming here is that there's not going to be any effort made to do that," Sotkiewicz said.

Phil D'Antonio of PJM asked Sotkiewicz to elaborate on a possible solution in the manual language. D'Antonio said his perspective has been that adjusting the system in an outage situation resulting from instability and limitations can end up "pulling the system apart even more."

Sotkiewicz said he would want to look for "easy switching options" that are available to "eliminate the transient stability limit."

"We've actually been in conversations with PJM operations, and we have found those solutions in the past," Sotkiewicz said.

D'Antonio said he'll take the suggestion back to PJM's operations group for additional discussions before the next MIC meeting.

The committee will be asked to endorse the manual revisions at the May MIC meeting.

Intelligent Reserve Deployment Changes

Damon Fereshetian, senior engineer in PJM's real-time market operations, *provided* a first read of additional updates to *Manual 11* and *Manual 28* related to intelligent reserve deployment (IRD).

Stakeholders in December endorsed a PJM proposal to improve the deployment of synchronized reserves during a spin event. (See "Synchronous Reserve Endorsed," *PJM MRC/MC Briefs: Dec. 15, 2021*.)

The proposal created an IRD, which is a security-constrained economic dispatch (SCED) case simulating the loss of the largest generation contingency on the system and for which approval of the case will trigger a spin event. The proposal included taking the megawatts of the largest generator contingency and adding them to the RTO forecast to simulate the unit loss. PJM can then flip condensers and other inflexible synchronized resources cleared for reserves to energy megawatts and procure additional reserves to meet the next largest contingency.

Fereshetian said Manual 11 changes include the addition of new language that an approved IRD case "supersedes" any other approved real-time SCED cases for the same target time to be used as the reference case for the locational pricing calculator (LPC). In the verification section, PJM added clarifying language that the response to a synchronized reserve event is "based on the resource following dispatch instructions and is capped at the expected response."

Manual 28 included minor clarifying changes.

The MIC will be asked to endorse the revisions at its May meeting.

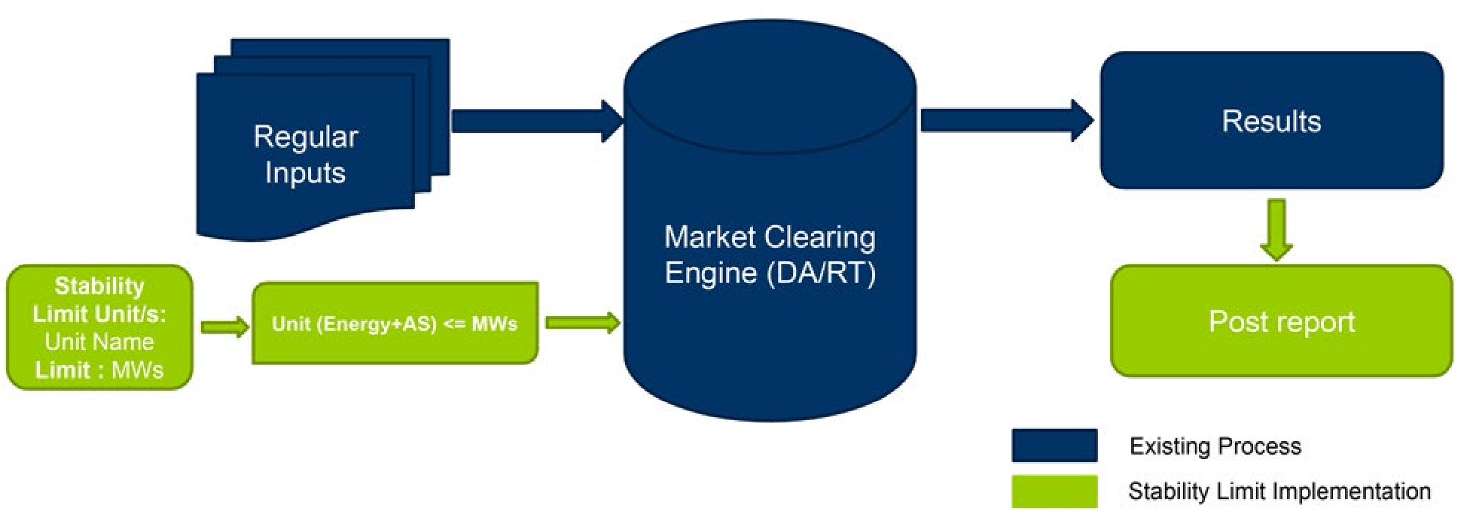
Manual 29 Revisions

Natasha Holter, manager of PJM's market settlement operations, *provided* a first read of revisions to *Manual 29: Billing* as part of the periodic review.

Holter said there were no "substantive changes" in the manual language and mostly included updates to terminology and reference materials.

Several new subsections were added to the manual, Holter said, including one called "Billing Notifications" that features language providing guidance on how to obtain notifications for billing statements. Another subsection, "Billing Adjustments," added language to describe what a billing adjustment is and how to identify one.

Stakeholders will be asked to endorse the revisions at the May MIC meeting. ■



PJM's proposed stability limits modeling and market clearing process. | *PJM*

SPP News

SPP to Phase out WEIS as New Market Offerings Expand

WEIS Members Will Eventually Join RTO West or Markets+ Program

By Hudson Sangree and Tom Kleckner

SPP said Wednesday it plans to eventually close its Western Energy Imbalance Service (WEIS) after current members join either its expanded RTO West or its Markets+ program, now under development, that will offer a bundle of RTO-like services.

"We don't intend to have three different offerings in the West," Kara Fornstrom, SPP director of state regulatory policy and a staff member working on Markets+ design, said in a briefing for the Western Interstate Energy Board.

The webinar gave Western utility regulators the chance to ask questions about the Markets+ program. Fornstrom made her comments while answering a question from Colorado Public Utilities Commission Chair Eric Blank.

"I just realized this a few days ago, that the WEIS market, the energy imbalance market, is at some point in the future going to sunset as entities join the RTO and the Markets+ day-ahead," Blank said.

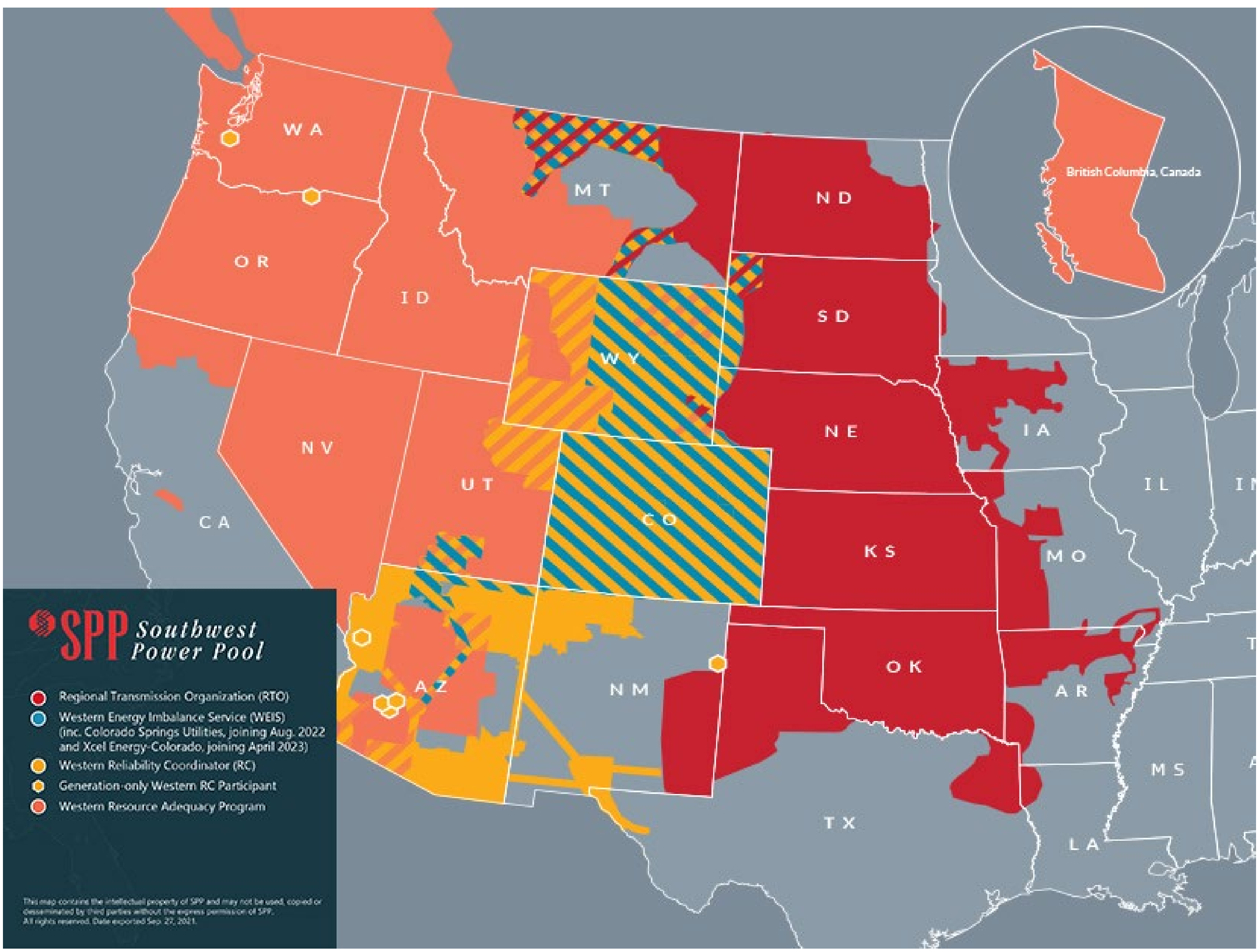
"I was just surprised that WEIS is going away," he added.

Blank asked if Markets+ would also "sunset" or would be a "permanent option."

Fornstrom said most of the WEIS's current members "will have moved already to the RTO expansion … before Markets+ launches, so the WEIS will have shrunk before we get to Markets+, and the remaining entities in WEIS that we have today have expressed their interest … to go to Markets+ rather than just the [WEIS's] real-time service.

The move is "based on [WEIS members'] interest level on adding the [Markets+] day-ahead service," she said.

Markets+ will be a "long-term durable solution" in the West, Fornstrom said.



SPP plans a range of services in the Western Interconnection to compete with CAISO. | *SPP*

Later, Joe Fina, a stakeholder member of the Markets+ design team and assistant general counsel at the Snohomish County Public Utility District, said: "The WEIS will be replaced by Markets+."

And SPP spokeswoman Meghan Sever said in an email to *RTO Insider* that it is "SPP's intention to only provide one market offering in the West in order to provide maximum benefits for Western utilities. Current WEIS participants will have the option to join the RTO or participate in Markets+. Until then, SPP remains fully committed to continue providing Western reliability coordination and operating the WEIS market."

Toe-to-toe with CAISO

SPP launched the WEIS, a real-time interstate trading market, in January 2021, making it the first RTO with energy markets in both the Eastern and Western interconnections. It intended for the WEIS to compete with CAISO's larger and well-established Western Energy Imbalance Market (WEIM).

SPP has had some success competing with CAISO. In January, three Colorado utilities that had planned to join the WEIM instead decided to join the WEIS. Public Service Company of Colorado, Platte River Power Authority and Black Hills Colorado Electric followed Colorado Springs Utilities in switching allegiance from CAISO to SPP. (See *Colorado Utilities Choose WEIS over WEIM*.)

The WEIS, however, has gained fewer members than the WEIM, which was launched in 2014.

CAISO's imbalance market has attracted 22 current or planned *participants*, including major utilities such as Arizona Public Service and NV Energy, while the huge Bonneville Power Administration is scheduled to go live next month. The WEIM has produced $1.93 billion in economic benefits for its members in the past eight years and is expected to cross the $2 billion mark with its next quarterly report. (See *Western EIM Nears $2B in Total Benefits*.)

With the addition of the Colorado utilities, WEIS has 14 current or future members including Deseret Power Electric Cooperative, the Municipal Energy Agency of Nebraska, Tri-State Generation and Transmission Association, Guzman Energy and the Western Area Power Administration's Upper Great Plains West and Rocky Mountain regions and its Colorado River Storage Projects.

CAISO has been working to develop an extended day-ahead market (EDAM) as an additional offering to the WEIM, a real-time interstate market that was the first of its kind. CAISO also provides reliability coordination services through its RC West to most of the Western Interconnection.

The ISO, however, is limited by its one-state governance from becoming a Western RTO.

SPP also offers RC services in the West and is administrator for the Western Power Pool's Western Resource Adequacy Program (WRAP). Once fully implemented, the WRAP will help Western balancing authorities respond to potential generation shortages during critical hours as the region addresses the retirement of thermal resources and its growing reliance on variable renewable resources. (See *NWPP Rebrands as Western Power Pool*.)

Unlike CAISO, SPP can offer full RTO membership to Western entities. It intends to expand its RTO footprint and develop a Western market system that is fully integrated with its existing market system.

The Markets+ program is aimed at utilities that do not want to join an RTO but need a range of services normally provided by an RTO, including day-ahead and real-time unit commitment and dispatch. SPP says Markets+ will provide easy transmission service across the footprint and set the stage for the reliable integration of renewable energy's growth.

SPP presented the Markets+ model to interested participants during a virtual meeting in December and plans to hold in-person forums throughout the West. The RTO is gathering information from interested parties, including WRAP participants, as part of an extensive process leading up to the program's launch. Wednesday's WIEB briefing on program governance and other matters was part of that process. ■

SPP News

Now, the Hard Part: MISO, SPP Tackle JTIQ Cost Allocation

By Rich Heidorn Jr.

SPP and MISO began gathering stakeholder feedback Friday on ways they can pass the hat for the projected $1.65 billion in transmission projects that resulted from their joint targeted interconnection queue (JTIQ) study.

RTO officials began their *meeting* by acknowledging uncertainties over how much additional generation could be connected as a result of the new transmission, comprising *seven projects* that are projected to resolve 48 reliability constraints and deliver about $724 million in adjusted production costs savings to MISO and $247 million to SPP.

While MISO's model estimated a total of 28 GW (10.5 GW in SPP and 17.5 GW in MISO), SPP's model estimated almost twice as much benefit, a total of 53 GW (11.1 GW in SPP and 41.9 GW in MISO).

Andy Witmeier, director of resource utilization for MISO, said the discrepancies may have resulted from how SPP's model dispatched MISO generation to serve MISO load and the impacts on loop flow.

To simplify the cost allocation, the RTOs said they *settled* on using each RTO's model for its own generation: 11.1 GW in SPP and 17.5 GW in MISO, for a total of 28.6 GW.

"MISO knows how they dispatch their generation … and similar for SPP," Witmeier said. "Let's just use the SPP number based on how they're serving their own load with their generation to try … and remove some ambiguities."

In an example offered by the RTOs, generator interconnection requests with a 5% or greater DFAX (solution-based distribution factor) impact on the JTIQ portfolio could pay a charge of $35,000/MW. So, a 270-MW generator

Five of the proposed JITQ projects touch MISO's Dakotas, Minnesota and Iowa footprint. | *MISO, SPP*

SPP News

Model	SPP Generation Enabled	MISO Generation Enabled	Total Generation Enabled
MISO Model	10.5 GW	17.5 GW	28 GW
SPP Model	11.1 GW	41.9 GW	53 GW

To simplify cost allocation discussions, MISO and SPP said they will use SPP's model for SPP's generation and MISO's for MISO: 11.1 GW of generation in SPP and 17.5 GW in MISO for a total of 28.6 GW. | *MISO*

with a 10% DFAX impact would pay $945,000 (27 MW x $35,000).

Rafik Halim of National Grid Renewables asked the RTOs to share the details of their modeling. "There needs to be a study that's transparent" before decisions are made, he said.

Stakeholder-driven Methodology Sought

Neil Robertson, SPP's coordinator of system planning, emphasized that the per-megawatt charge and DFAX threshold were used to illustrate the concept and not a firm proposal, saying the RTOs seek a "stakeholder-interactive approach" to developing the methodology.

"SPP and MISO did not intend to come up with a fully developed methodology and then simply ask for stakeholder input," he said. "We want to take stakeholder input on key concepts and use them as building blocks to build out this methodology."

"We are not naive enough to think we have all the answers," added David Kelley, director of seams and tariff services for SPP.

The actual cost multiplier will be designed to

SPP's Neil Robertson at the Gulf Coast Power Association's MISO South/SPP Conference in New Orleans. | *© RTO Insider LLC*

collect all of the costs of the portfolio "while, at the same time, fully utilizing the capacity, not underselling or overselling the capacity that we are creating," Robertson said. Whatever the methodology, "prior to executing a GIA [generator interconnection agreement], you would know what the JTIQ charge would be, just like you would know any of the other upgrades involved in the generation interconnection process."

Robertson said RTO officials are seeking a balance between a subscription-based model and one in which load would initially pay for the projects and generation would reimburse as it interconnects. Such a balance could involve the requirement of a "critical mass" of generator agreements: for example, 50% of total JTIQ portfolio funding agreed to by GI customers in signed GIAs. Funding for the other 50% could come from local transmission owners or be regionally funded and later reimbursed as additional generators sign up.

Steve Gaw of the Advanced Power Alliance, which represents wind, solar, and energy storage companies, expressed concern that the critical mass approach could delay interconnections of projects already in an open study.

Robertson acknowledged that while the model could mitigate risk to "any particular segment of the stakeholder base," it could also "increase the uncertainty" for some generators.

Brenda Prokop of LS Power said she agreed with the concept of a critical mass. "I think it's pretty necessary to set some kind of threshold for proceeding with projects."

But she said MISO and SPP should not "assume that the JTIQ projects would be reserved for local TOs and eligible to be funded by them" because not all of the projects would be in states that permit TOs a right of first refusal (ROFR). The projects would be built in Minnesota, North Dakota and South Dakota, which all have ROFR laws, as well as in Nebraska and Kansas.

Antoine Lucas, SPP's vice president of engi-

MISO's Andy Witmeier speaks at the Gulf Coast Power Association's MISO South/SPP Conference in March. | *© RTO Insider LLC*

neering, closed the meeting by acknowledging that the two RTOs had forgone the "certainty" of their existing cost allocation processes in seeking an "*ad hoc*" methodology for JTIQ.

"But we felt like it was worth it to have the flexibility to be able to craft a mechanism customized to fit the specific projects and specific circumstances that we would see from the JTIQ," he said.

Next Steps

The seven projects have a projected cost of $1.65 billion, but the JTIQ cost allocation likely won't apply to two of the projects, which MISO has included in its tranche of long-range transmission projects. (See *MISO, SPP Finalize JTIQ Results with MISO Tx Duplicates*.)

MISO and SPP hope to submit their cost allocation formula to FERC by the end of this year, with RTO approvals of the JTIQ projects by the second quarter of 2023.

Additional joint stakeholder meetings are tentatively scheduled for 10 a.m. to 12 p.m. CT on May 20, June 27 and July 29. Comments may be sent to *GI-AFS@misoenergy.org* and *interregional-relations@spp.org*. ■

SPP News

SPP Markets and Operations Policy Committee Briefs

APA's Steve Gaw (left) makes a point as Western Farmers' Matt Caves waits his turn. | © RTO Insider LLC

Counterflow Optimization Still an Issue Without a Solution

DALLAS — SPP stakeholders last week rejected a working group's recommendation to stick with the status quo when it comes to adding counterflow optimization to the congestion-hedging process — three months after agreeing with staff to leave the market construct untouched.

The Market Working Group brought the recommendation to the Markets and Operations Policy Committee after more than a year's worth of meetings and educational sessions and drafting a policy paper. However, it fell just short of the committee's two-thirds approval threshold at 65.6%.

The measure will still go before the Board of Directors on April 26 for its consideration.

"If the board basically directs us to keep working on this, that's what we'll have to do," SPP COO Lanny Nickell said during the April 11 discussion. "MOPC doesn't have an official position because we didn't approve the status quo motion. It simply sends a signal to the board that keeping the status quo is not a popular option."

"Hopefully, it'll be back to MOPC in July," MOPC Chair Denise Buffington, of Evergy, told the Strategic Planning Committee on Wednesday. "A lot of work went into that."

The proposal to add counterflow optimization — limited to excess auction revenue — to SPP's market mechanism that hedges load against congestion charges has been an issue with no solution since its approval by the board in 2019. The Holistic Integrated Tariff Team's (HITT) direction, which would essentially keep system transmission flows between two points balanced, was meant to address concerns about how congestion rights instruments are awarded and the current process's efficiency. (See *SPP SPC Takes on Congestion Hedging Issues*.)

Staff and the MWG have been unable to reach consensus on the recommendation. The MWG voted in 2020 to keep the current market construct. Although they acknowledged that counterflow optimization would benefit load-serving entities, staff have also recommended keeping the current construct, noting some market participants want to review the transmission service process for efficiencies.

The RTO's Marketing Monitoring Unit has said the proposal doesn't give participants a say in the amount of counterflow they receive and there is no way for them to avoid being affected by optimization even when they opt-out. It says auction participants will adapt to the market changes, which will affect auction revenue.

The SPC in January agreed with staff and stakeholders to put the issue on hold and allow for a "cooling-off" period. (See "Counterflow Optimization on Hold," *SPP Lays Out its Western Expansion Strategic Plan*.)


Bill Grant, SPS, at his last MOPC meeting before retiring. | © *RTO Insider LLC*

"We've been talking about this for four or five years," Southwestern Public Service's (SPS) Bill Grant said. "What we've run into is that a lot of companies are currently happy with their total end results on hedging, mainly because of the annual uplift that takes place once a year. That's why there's reluctance to make a change."

The Advanced Power Alliance's Steve Gaw said the congestion-hedging problem is not fixed and will hinder stakeholders' efforts to export power from wind-rich regions.

"This remains a substantial obstacle for accomplishing that. Until that is fixed, we'll continue to have this wall as far as the opportunities exist for this transaction in SPP," he said.

"This is bad policy of doing nothing, which lead to those exports not happening," American Electric Power's Jim Jacoby said. "Everyone complains about all the wind congestion happening in SPP. We need some way to export this stuff."

A study by SPP found that market participants' hedging positions will change in coming years thanks to new topology, HITT initiatives and the changing generation mix. The study indicated a net positive value for all LSEs with counterflow optimization.

"At the risk of sounding like Yogi Berra," Golden Spread Electric Cooperative's Mike Wise said, referring to the baseball Hall of Famer known for his *misuse of the English language*, "we are where we are, although we're not where we are going to be.

"I'm torn, because our organization doesn't want to make any changes. We're comfortable with our hedging position," Wise said. "From the perspective of SPP, it's looking at the bigger picture. We are probably going to see a different set of circumstances going forward. It will likely be that many of us who enjoy the current paradigm won't enjoy it in the future."

Staff Reducing Interconnection Queue's Backlog

Staff told MOPC that they are on track to eliminate the backlog in SPP's interconnection

SPP News

queue in two years, having reduced the current queue's number of active interconnection requests from 651, totaling 119.9 GW, to 481, totaling 90.3 GW, as of March.

SPP's Juliano Freitas said the new three-phase interconnection study process, approved by FERC in 2019, kickstarted the mitigation effort. (See *FERC OKs New SPP Interconnection Process*.)

Since then, staff have also received stakeholder approval to reduce the number of models required per study, combine 16 study groups into five and incorporate more realistic generation dispatch assumptions. They have also eliminated a special studies backlog, redesigned vendor contracts to streamline the process, and accelerated procedures to reduce wait times and clear a path for the consolidated planning process.

At the same time, SPP has been able to add 24.9 GW of generation over the last five years and execute 121 generator interconnection agreements (GIAs).

Freitas said that historically, 60 to 65% of interconnection requests are withdrawn, but the three-phase study process has helped filter out those requests that will not result in a GIA.

Jarred Cooley, SPS | © RTO Insider LLC

"Restudies add time to the process," he said. "That's why I'm confident we will mitigate the backlog."

SPS' Jarred Cooley was among several MOPC members complimenting SPP's progress, but he also said SPS was concerned with the fuel-dispatch changes that he said should have been brought to the committee as a policy issue.

"No analysis was done to warn the TWG [Transmission Working Group] of how these changes will impact the SPP region," Cooley said.

Arash Ghodsian, a former MISO staffer who is now senior director of transmission and policy at EDF Renewables, said, "No one anticipated the size of the queues to grow like this. This is a change that's needed."

Tx Planning Changes Pass

The committee endorsed working groups' recommendations to re-baseline the 2022 Integrated Transmission Planning (ITP) assessment and to modify the 2022 20-year assessment's scope.

The TWG and the Economic Studies Working Group (ESWG) said approving several waivers and revising the 2022 ITP would allow staff to perform a reliability-only assessment this year and full assessments for the 2023 and 2024 ITPs.

MOPC unanimously endorsed the proposal, with one abstention, after having asked the groups in January to bring a more fully developed plan to the April meeting. ESWG Chair Alan Myers, with ITC Holdings, said all ITP assessments are on track and that a 345-kV, 150-mile double-circuit project's re-evaluation in West Texas will be completed by the June MOPC meeting. (See *SPP Markets and Operations Policy Committee Briefs: Jan. 10-11, 2022*.)

The two working groups also recommended the 20-year assessment's scope be modified to include more aggressive emissions-reduction futures that include a 93 to 95% reduction target in 2042 from 2017 levels. Staff identified a software limitation that would not allow the target to be met without modifying the scope.

Oklahoma Gas & Electric's Usha Turner noted that one model showed emissions rising because it was unable to account for energy storage, resulting in additional thermal resources being dispatched.

"Modeling storage has been tricky the last few years," Myers said.

The ESWG and TWG's request passed with 99% approval.

The committee also:

- endorsed the annual 2022 SPP Transmission Expansion Plan (STEP) *report*. Staff have issued 94 notifications to construct (NTCs) valued at $894 million since the last STEP report, a period covering January 2021 through March 2022. Twelve upgrades valued at $38 million have been withdrawn, and 38 upgrades, valued at $162 million, have been completed. SPP is currently tracking $2.77 billion of upgrades.
- approved suspension of a 115-kV project related to an industrial load in Nebraska while staff conduct a restudy to determine appropriate changes to the NTC, its possible withdrawal or whether an alternative project can be found. A $6.3 million increase to relocate a 345/115-kV substation helped push the project's costs from $43.4 million to $53.8 million, a 24% increase beyond the baseline's 20% plus-minus threshold. Staff said they were optimistic they can reach Nebraska Public Power District's request to complete the restudy by July and avoid further cost increases.

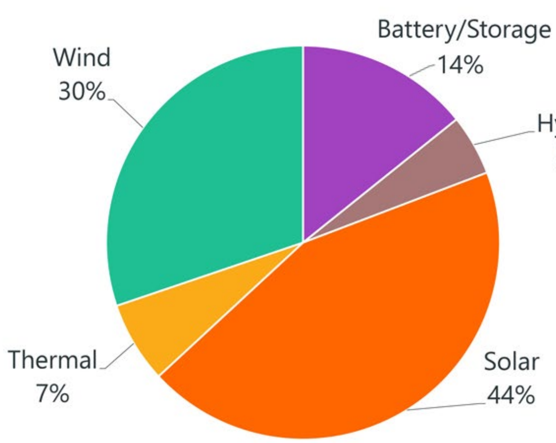
MOPC Honors Retiring Bill Grant

SPP staff and stakeholders paid tribute to SPS' Grant, who is retiring June 1 after 40 years with SPS parent company Xcel Energy. He has spent 16 of those years serving on MOPC and other stakeholder groups.

"I don't know how you did it," SPP's Nickell told Grant, one of the RTO's more vocal and colorful stakeholders who was involved in half a dozen groups last year. "I will always appreciate Bill's candor, his straightforwardness. … He would call just to tell me how things would work. He would try to help me understand and how I could make things better at SPP.

"I always appreciated your willingness to improve our processes, once we addressed your concerns," Nickell said to knowing smiles in the room. Members then gave Grant a standing ovation.

GEN TYPE	Requests	GW Capacity
Battery / Storage	111	12.85 GW
Hybrid	21	4.49 GW
Solar	190	39.6 GW
Thermal	37	6.03 GW
Wind	122	27.3 GW
TOTAL	**481**	**90.3 GW**



Renewables and storage dominate SPP's reduced GI queue. | *SPP*

SPP News

"One thing I'll miss is the relationships," he said, appearing to choke up with emotion. "Don't take them for granted."

Grant is retiring as vice president of rates and regulatory affairs to Jasper, Texas. He plans to do some consulting but also take advantage of two nearby lakes and enjoy spending time with his 11 grandchildren. Asked if he enjoys fishing, Grant said he has bought a triton boat. He also has a fully stocked pond on his property.

Cooley, SPS' director of strategic planning, has replaced Grant on MOPC.

Order 2222 Compliance Work 'Highly Complex'

Michael Desselle, SPP's chief compliance and administrative officer, told stakeholders it could cost as much as $1 million and take as many as 18 months to implement compliance measures with FERC Order 2222. The 2020 order directed RTOs and ISOs to open their markets to distributed energy resource aggregations. (See *FERC Opens RTO Markets to DER Aggregation*.)

Desselle said the "highly complex effort" to change tools, process and procedures, involving 10 different sections of the RTO's tariff, could be completed by the third quarter of 2025. That assumes FERC approves SPP's *compliance filing* by the end of the year.

"All we can do is estimate what it takes for us … to get [changes] in place, for our system alone," Desselle said.

SPP has estimated it will take almost 16,000 hours to complete the process, he said, "but only if the staff has nothing else to work on."

Surplus Interconnection Service Change Remanded

The committee remanded back to the MWG and Operating Reliability Working Group a revision request (*RR451*) that would create pooled surplus interconnection service for existing generators with multiple interconnection agreements and a shared point of interconnection. The measure fell percentage points short of MOPC's two-thirds approval.

Members pushed back over whether staff could reliably manage the process during a discussion that devolved into the intricacies of Robert's Rules of Order. The measure passed three stakeholder group ballots with only one opposing vote and nine abstentions, primarily over cost concerns.

SPP estimates it will cost $20,000 to $60,000 to implement RR451's changes and almost $200,000 annually to administer the GI service, which was mandated by FERC Order 845.

The tariff currently allows surplus service to be associated with only one existing generator's interconnection service. Staff said allowing generators to pool their GIAs and offer the service could enable more cost-effective surplus generation to enter the market.

MOPC did approve *RR465* by an 83.3-16.7 margin after it was pulled from the consent agenda. It allows transmission facilities constructed to facilitate generator interconnections to be treated on a consistent cost basis with other transmission facilities if the transmission owner self-funds the work.

Some grid operators have already implemented similar measures that give TOs the option to provide the initial funding for upgrades and the ability to earn a return on the facilities. A recent PJM proposal was modeled on a FERC-approved order in MISO following a 2018 ruling by the D.C. Circuit Court of Appeals. (See *MISO Gauging Aftershocks of TO Self-fund Order*.)

"If this goes forward, we will be involved in litigation because other cases are outstanding," APA's Gaw warned.

The unanimously approved consent agenda include eight other RRs, removal of a remedial action scheme on the SPS system, and approval of a re-evaluated OG&E-sponsored upgrade to add a new 345/161-kV substation and transformer.

- *RR419*: provides a market power framework for storage resources operating as transmission assets, requiring they follow SPP directions at all times while allowing for technical issues.
- *RR455*: requires a generation interconnection customer to correct all reliability problems found in the electromagnetic transient study before injecting power into the transmission system.
- *RR482*: updates the ITP manual to reduce redundant stakeholder review of capacity additions for inclusion in the economic models.
- *RR485*: modifies the ITP manual to be consistent with current IRS regulations that define a wind unit's production tax credits (PTCs) as based on the construction start date. The change also allows for PTCs to be awarded to solar facilities, in accordance with IRS specifications.
- *RR486*: updates the Integrated Marketplace protocols by removing outdated network and commercial model timelines and condensing about 17 pages of Network and Commercial Model Update Timelines tables to one page.
- *RR487*: clarifies the Integrated Marketplace protocols over when an outage commitment status necessitates an outage scheduling tool (CROW) submission and when a CROW submission necessitates an outage commitment status.
- *RR488*: adds two functions necessary to settle the real-time combined interest resource adjustment amount — the real-time ramp capability nonperformance amount, and the real-time ramp capability nonperformance distribution amount.
- *RR490*: adds a new tariff section on transmission line ratings, detailing their development and usage, to comply with FERC Order 881. ■

— Tom Kleckner

MOPC holds its first in-person meeting since January 2020. | © *RTO Insider LLC*

SPP Strategic Planning Committee Briefs

Staff Say Markets+ Design on Track for Completion in 2023

DALLAS — SPP staff last week said the RTO's *Markets+* day-ahead offering in the Western Interconnection is on track to be completed by the end of the year.

Bruce Rew, SPP senior vice president of operations, said the market's development is going "really well," with Western parties leading the three design teams (governance, market products and price formation, and transmission availability). Their first in-person meeting last month drew a capacity crowd, with almost the entire interconnection represented, he said.

A second in-person market-development meeting is scheduled June 1-2 at Tri-State Generation and Transmission Association's headquarters in Westminster, Colo.

SPP last week told the Western Interstate Energy Board that it will eventually close its Western Energy Imbalance Service (*WEIS*) market after its seven current members join either the Markets+ program or its expanded *RTO West*. (See related story, *SPP to Phase Out WEIS as New Market Offerings Expand*.)

Obstacles remain, however. During Wednesday's Strategic Planning Committee meeting, committee Chair and Director Mark Crisson brought up a panel discussion during the SPC's retreat earlier this year. He noted participants anticipate CAISO, SPP's competitor in offering RTO membership in the West, will correct its governance problems and pose a challenge for the RTO.

Other participants, while "generally supportive," Crisson said, questioned whether SPP's staff are spread too thin and that the membership is getting too big, potentially damaging the RTO's stakeholder-driven culture.

Southwestern Public Service's Bill Grant expressed his concern that some Western entities don't want to give up their balancing authorities, which he said will create huge software costs.

"Now we have to curate a market model that has 34 different [balancing authorities]," he said. "It's an EIS market on steroids, rather than a market with day-ahead dispatch. I believe it's going to increase the cost for us to perform this service."

Crisson, who spent nearly 30 years with Tacoma Public Utilities, said some entities may not understand the benefits of centralized dispatch and suggested it might be a "little bit of RTO paranoia" dating back to the 2001 energy crisis.

"There's a lot of concern about FERC regulation," Crisson said. "A lot of people remember that exercise."

SPC Chair Mark Crisson (right) and SVP of Operations Bruce Rew listen to a report. | *© RTO Insider LLC*

SPC Endorses Value of Tx Report

SPP's updated value of transmission *study* has quantified $27.2 billion in net present value (NPV) of benefits over the next 40 years from $3.35 billion in members' installed transmission from 2015 to 2019, staff said.

The study's 5.24:1 benefit-to-cost ratio is an increase from SPP's first transmission-value study in 2016, which had a 3.5:1 ratio. That analysis found more than $16.6 billion in NPV of project benefits installed from 2012 to 2014. Casey Cathey, SPP's director of system planning, said The Brattle Group called the first study "a path-breaking effort."

The newer study refined the first one by analyzing five years of transmission projects instead of three, simulating 57 days of production instead of 38, excluding the benefits of reduced planning margins, and capturing the incremental capacity from transmission rebuilds and transformer upgrades.

"This is probably the most accurate study you can perform," Cathey said.

The 2021 study does not quantify other benefits such as improved use of transmission corridors and storm hardening. The latter issue has gained importance with SPP following the first load sheds in the RTO's 80-year history during the February 2021 winter storm.

"The value of resiliency is so critical, especially after this winter event," COO Lanny Nickell said, "and it will be helpful to you all when customers are expressing doubts about the benefits of proposed upgrades. How much more load would have been shed had we not had that transmission?"

Members generally agreed, noting they're now having those conversations about the transmission's value.

"We got beat up in the commissions," Oklahoma Gas & Electric's Usha Turner said.

"I'm proud of what we've accomplished at SPP," Grant said. "We've added all this transmission, and we've done it in such a way that the total bill to customers is below the rate of inflation. The total cost to customers has not dropped, but still, we've increased reliability and increased deliverability. That's a win."

SPP News

Casey Cathey, SPP | © *RTO Insider LLC*

The SPC also endorsed staff's annual member value update, which indicates members enjoy $3.25 billion in annual savings and benefits and a 22:1 return on investment. SPP's market operations account for the bulk of those savings, yielding $1.42 billion.

Staff used both quantitative and qualitative estimated values of various areas of the grid operator's services to calculate the value provided to members through improved reliability, increased efficiencies and economics, consolidated functions, and improved environmental, public policy and local economic impacts.

A year ago, members were gaining $2.7 billion in savings and an 18:1 return on investment.

Mike Ross, senior vice president for external affairs and stakeholder relations, said the improved benefit metrics have primarily been driven by increased fuel costs and escalated LMPs. He warned the savings increase may only be a blip.

"We tried to err on the side of being cautious," Ross said.

SPP Lays out Comprehensive Roadmap

SPC members endorsed staff's recommendation to develop a schedule and details for a comprehensive roadmap process that will be part of SPP's broader effort to develop strategic services such as data-management solutions, re-engineered and streamlined stakeholder processes, and defining tracking and reporting on metrics.

Board approval later this month will allow staff to move forward with instituting the process and balancing ongoing work against the approved schedule.

Staff told the Markets and Operations Policy Committee that the roadmap is intended to show stakeholders everything that's on the RTO's plate and to solicit their help with prioritizing the initiatives. MOPC declined to act on the roadmap over concerns of costs associated with staff and consultants.

"Resource management is a crucial element that we haven't figured out," Nickell said. "That is an issue, and we are very aware of the concerns around that."

"This has been a heavy lift. I do worry about maintaining it," American Electric Power's Richard Ross said.

The comprehensive roadmap is intended to develop a "proactive, transparent and collaborative annual and ongoing process" that balances SPP's portfolio of work and managing resource constraints. Staff hopes to identify the greatest needs for improvement over a five-year timeframe and create alignment with and direct input for initiatives into the RTO's strategic planning, budgeting, and project management processes.

Ad Hoc Group to Look at Cryptos

The committee agreed to form an ad hoc group to determine how best to address flexible loads like data centers that generate Bitcoin and other cryptocurrencies and are popping up on electric grids all over the country.

Nickell cited the uncertainty around the size and nature of the loads in suggesting the SPC own the issue. Bitcoin miners say they can quickly shut down their operations should the energy be needed elsewhere or operate during off-peak hours.

"Do we really want to be funding transmission improvements for temporary loads?" Nickell asked, rhetorically. He suggested the ad hoc group focus on transmission issues and cost allocation, recognizing that the SPC may want to take a broader look.

The Regional State Committee (RSC), comprising state regulators with authority over regional transmission rates, is expected to eventually be involved.

"I don't understand how the RSC can't be involved in this. At the end of the day, this is regional load," Grant said. "If we don't come up with a concise way to deal with this or [the RSC] doesn't agree with it, they'll go to their individual commissions."

"We saw a similar phenomenon in the Northwest 15 to 20 years ago with load centers," Crisson said. "Most utilities took the same approach, requiring them to pay for any substation and transmission upgrades, which cooled their enthusiasm considerably."

The group will report back to the SPC during the committee's July meeting. ■

— Tom Kleckner

Company Briefs

Cleco to Invest in Carbon Sequestration Project

Cleco last week said it will invest $900 million in its Diamond Vault carbon sequestration project that will capture and store 95% of the carbon emitted from its Rapides Parish plant.

Cleco, a monopoly regulated by the Louisiana Public Service Commission, will store the emissions in a geological formation under the Madison-3 plant at the Brame Energy Center in central Louisiana. The coal-fired plant emits the largest amount of carbon dioxide of any plant in the state (4 million tons per year).

The project is expected to take six years to complete.

More: *Lafayette Daily Advertiser*

Envision to Build EV Battery Plant in Kentucky

Japan-based Envision AESC last week said it plans to build a $2 billion, 3 million-square-foot plant on a 512-acre site recently added to the Kentucky Transpark industrial park.

Envision, which is one of the world's largest producers of batteries for EVs, will take on the second-largest economic development project in state history.

The plant — slated to open in 2025 but not hit full capacity until 2027 — is expected to produce 300,000 batteries annually.

More: *Bowling Green Daily News*

EPRI Elects New Chairs, Board Members

The Electric Power Research Institute (EPRI) last week announced the election results of its board of directors, effective immediately.

For the second consecutive year, Stanley Connally, Jr., Southern Company's executive vice president of operations, and chairman, president and CEO of its Southern Company Services subsidiary, has been appointed chair of EPRI's Board of Directors. His second term runs through April 2023. Maria Pope, president and CEO of Portland General Electric, will become first vice chair, while Lisa Barton, executive vice president and chief operating officer of American Electric Power, will be the new second vice chair.

Three additional directors were also elected by the board: Matthew Ketschke, president of Consolidated Edison of New York; John Larsen, chair, president and CEO of Alliant Energy; and Brian Savoy, executive vice president and chief strategy and commercial officer of Duke Energy.

More: *EPRI*

Kelly to Join LineVision Advisory Board

LineVision last week announced that Chris Kelly, the former COO of National Grid, will join the company's advisory board.

Kelly worked with National Grid for more than 20 years in a variety of roles.

More: *LineVision*

Lawsuit Accuses BGE of Racial Discrimination

Seven former Baltimore Gas & Electric workers last week filed a lawsuit against the utility and parent company Exelon Corp. for allegedly perpetuating a culture of racism where African American employees regularly endured racial slurs, discrimination and at least one instructor who tied nooses in front of them.

The complaint cites several examples over more than a decade of Black employees facing retaliation for reporting bigoted outbursts to supervisors and highlights the colleague who allegedly tied nooses and discussed lynchings in front of African American trainees. The instructor was later fired after a terminated employee posted photos on social media.

In a statement, BGE acknowledged "offensive photos taken of a former training instructor inappropriately holding up a noose during a ropes and rigging training session." The company said it "condemns hatred, discrimination and violence in any form and is committed to building a more diverse, equitable, safe and inclusive culture, both in our company and in the communities we serve."

More: *The Baltimore Sun*

Musk Says Tesla Cybertruck to Start Production in 2023

Tesla CEO Elon Musk last week announced that the company will start production of its new Cybertruck at its Giga Texas manufacturing facility in Austin in 2023. Musk made the announcement during the $1.1 billion facility's grand opening.

The electric truck was originally slated to hit the market in 2021 but has been delayed due to a lack of parts, Musk said.

More: *Houston Chronicle*

Federal Briefs

Ex-EPA Chief Pruitt to Run for Senate in Oklahoma

Scott Pruitt, who led the EPA until resigning amid a series of ethics scandals in 2018, last week announced he is launching a Senate bid in Oklahoma.

Pruitt is running to fill the unexpired term of Sen. James M. Inhofe (R), who announced in February that he will step down next year. Inhofe handily won reelection in 2020, meaning that whoever wins the November special election for his seat will serve until 2027.

Before being tapped by President Donald Trump to lead the EPA, Pruitt was Oklahoma attorney general from 2011 to 2017 and served in the state Senate for eight years. He also pursued an unsuccessful U.S. House bid in 2001. He resigned from the EPA in 2018 amid controversies over lavish spending, ethical lapses and management decisions.

More: *The Washington Post*

Former Solar Executive Sentenced to Prison over Fraud

Robert A. Karmann, a former chief financial officer for DC Solar, which sold mobile solar generator units mounted on trailers, was sentenced to six years in prison and ordered to pay $624 million in restitution for taking part in a fraud scheme.

The company said the generators would be able to provide emergency power for cellphone companies or provide lighting at sporting and other events. Executives told investors they could benefit from federal tax credits by buying the generators and leasing them back to DC Solar, which would then provide them to other companies for their use, prosecutors said.

The generators never provided much income, and prosecutors say the company ran a Ponzi scheme in which early investors were paid with funds from later investors. The company eventually stopped building the generators, and prosecutors say a least half the company's claimed 17,000 generators didn't exist.

More: *The Associated Press*

Wind Output Tops Coal, Nuclear for First Time

Wind power produced more electricity than coal or nuclear plants for the first time on March 29, according to the U.S. Energy Information Administration.

Wind produced 2,017 GWh, behind only natural gas, according to the EIA's Hourly Electric Grid Monitor. Wind has surpassed coal or nuclear electricity generation separately on other days earlier this year, but it had not surpassed both sources on a single day.

More: *EIA*

State Briefs

REGIONAL

Storms, Tornadoes Leave Many Without Power in Texas, Kentucky

Large thunderstorms accompanied by a tornado left tens of thousands of Texans without power on Tuesday.

Texas was still experiencing power outages on Wednesday afternoon, according to poweroutage.us, after severe weather swept through the central part of the state.

In Kentucky, nearly 57,000 people were without power late on Wednesday. As of 1:30 p.m. the next day, more than 10,000 people remained without power.

More: *Lexington Herald-Leader*, *USA Today*

ARKANSAS

Entergy, PSC Agree to Rate Increase

Entergy Arkansas and the Public Service Commission last month agreed to a 6.4% rate increase for the utility.

The average monthly bill for residential and business customers will go up about $6.80. Entergy said the increase was needed to offset the cost of rising natural gas prices.

More: *Arkansas Business*

FLORIDA

Walton County Board Approves Second Solar Energy Center

The Walton County Technical Review Committee last week approved the Pecan Tree Solar Energy Center.

Florida Power & Light's energy center is to consist of solar panels and a substation on 762 acres in the northwestern part of the county.

More: *The DeFuniak Herald*

IDAHO

Idaho Power to Pay $1M over Unpermitted Pollution at Dams

Idaho Power will pay more than $1 million in fines under a proposed settlement with the Department of Environmental Quality over unpermitted pollution at 15 hydroelectric facilities.

Last winter, the company self-reported pollution violations at multiple dams along the snake river and its tributaries. The sites named in court documents were: American Falls, Bliss, Cascade, C.J. Strike, Clear Lake, Upper and Lower Malad, Milner, Lower Salmon Falls, Upper Salmon Falls A and B, Shoshone Falls, Swan Falls, Thousand Springs and Twin Falls dams.

The pollution is related to oil and grease in power plant turbines, as well as fluctuations in water temperature and pH.

More: *Boise State Public Radio*

INDIANA

Tipton County OKs Short-term Solar Moratorium

The Tipton County Commission last week approved a moratorium on large-scale, commercial solar farms.

The moratorium will last six months or until the county approves a solar ordinance. The decision comes as ENGIE, a French utility company, is proposing a 1,874-acre solar farm southeast of Greentown.

More: *Kokomo Tribune*

KANSAS

Evacuation Orders Sent After Gas Plant Explosion

Immediate evacuation orders were in place for the city of Haven late last week following an explosion at the Haven Midstream gas plant.

The evacuations were originally lifted Thursday evening, but Reno County Emergency Management put the evacuations back in place due to concerns of additional explosions. County officials said after further inspection of the plant, they found 2,000 to 3,000 gallons of trapped liquid natural gas and that the relief valves were compromised, which could set off another explosion. Everyone within 1.5 miles of the facility had to evacuate.

Officials at the time said the evacuations could last up to 72 hours.

More: *WIBW*

LOUISIANA

EPA Investigates Environmental, Health Agencies for Discrimination

The EPA is investigating whether two state agencies discriminated against African American residents when they were involved in permitting decisions for two chemical plants and a grain terminal in St. John and St. James parishes.

The probe centers on actions taken by the Department of Environmental Quality and Health when the DEQ considered permits during the past two years for the Denka Performance Elastomers plant, the proposed Formosa Plastics Sunshine plant, and the proposed Greenfield Exports grain terminal. They come five months after EPA Administrator Michael Regan promised a crackdown on permitting decisions along Louisiana's chemical corridor.

The investigation of DEQ will review whether it administers its air pollution control program in ways that either have the intent or effect of subjecting individuals to racial discrimination, in violation of Title VI of the Civil Rights Act of 1964 and EPA's regulations. The investigation of the health department will include a review into whether it subjects African American residents of the parish to discrimination by failing to provide them, other state agencies and other communities with information about health threats from Denka and other nearby sources of pollution.

More: *Nola.com*

MICHIGAN

Detroit City Council Calls on DTE Energy to Pause Disconnections

The Detroit City Council last week passed a resolution, calling on DTE Energy to enact a one-year pause on electricity and gas shutoffs following disconnections during the COVID-19 pandemic.

The resolution cites findings that analyzed disconnections and found that DTE shut off accounts 208,000 times between April 2020 and December 2021. The investigation found that DTE's rate of shutoffs — disconnections as a proportion of customers — outpaced the six other state utilities that are owned by private investors and have their prices regulated by the state. DTE's residential rates were also the second highest in Michigan.

The resolution asks DTE to voluntarily begin a new moratorium on shutoffs "given the lasting economic impacts of the pandemic, thereby giving its customers some relief."

More: *ProPublica*

NORTH CAROLINA

Duke Energy Completes Solar Project

Duke Energy last week announced its 22.6-MW Stony Knoll Solar farm in Surry County has begun operations.

The project, owned and operated by Duke Energy Sustainable Solutions, is one of a half-dozen utility-scale solar projects totaling 270 MW awarded to Duke through renewable energy legislation passed in 2017.

More: *Winston-Salem Journal*

OREGON

Thousands in Portland Without Power After Rare Spring Snowstorm

More than 100,000 customers lost power on April 11 following a snowstorm across northwest Oregon and southwest Washington.

Portland General Electric reported more than 26,000 customers without power as of 7:20 p.m., with large clusters of outages in Southeast Portland, parts of North Portland and Beaverton. About 13,872 customers were without power in Multnomah County. Washington County had about 4,532 customers without power, and Clackamas accounted for about 2,034.

Pacific Power reported 183 customers without power in Oregon as of 7:20 p.m.

More: *The Oregonian*

TEXAS

Ector County Energy Center Seeks Bankruptcy Protection

Ector County Energy Center filed for Chapter 11 in U.S. Bankruptcy Court last week after it was unable to produce power during last year's historic winter storm.

Facing extensive litigation, including a $400 million lawsuit brought by customer Direct Energy Business Marketing, the company is looking sell its assets through bankruptcy. At the time of the storm, Ector had an agreement under which Direct Energy paid a monthly premium in exchange for the right to call on Ector to provide energy and various services. Ector has also been hit with more than 100 other lawsuits stemming from the storm.

Ector also owes $337.3 million on a first lien loan. It had about $5.4 million in cash on hand as of April 1.

More: *Reuters*