RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2021/Issue 51 December 21, 2021

Manchin Says 'No' on Build Back Better

With Midterms Looming, Democrats Face Challenge of Saving Biden's Social and Climate Agenda

By K Kaufmann

Sen. Joe Manchin (D-W.Va.) | *Fox News*

Work on the Democrats' $2 trillion Build Back Better Act came to a screeching halt Sunday morning as Sen. Joe Manchin (D-W.Va.) stated unequivocally that he could not vote for the bill in its current form.

"I have always said if I can't go home and explain it to the people of West Virginia, I can't vote for it," Manchin said on "Fox News Sunday." "And I cannot vote to continue with this piece of legislation. I just can't. … This is a no."

President Joe Biden "has worked diligently; he's been wonderful to work with," Manchin said of his negotiations with the White House. But he said the government should focus on inflation and the new surge in COVID-19 cases, driven by the fast-spreading Omicron variant.

White House Press Secretary Jen Psaki said the administration was blindsided, labeling Manchin's statements "a sudden and inexplicable reversal in his position and a breach of his commitments to the president and the Ssenator's colleagues in the House and Senate."

Manchin had repeatedly told Biden he was committed to working on the bill, Psaki *said*. "On Dec. 14, Sen. Manchin came to the White House and submitted — to the president, in person, directly — a written outline for a Build Back Better bill that was the same size and scope as the fresident's framework and covered many of the same priorities. While that framework was missing key priorities, we believed it could lead to a compromise acceptable to all. Sen. Manchin promised to continue conversations in the days ahead and to work

Continued on page 4

FERC Orders End to Static Tx Line Ratings

New Docket Opened to Consider Dynamic Line Ratings

By Rich Heidorn Jr.

FERC on Thursday ordered transmission providers to end the use of static line ratings in evaluating near-term transmission service, a move the commission said will improve accuracy and transparency and increase utilization of the grid (*RM20-16, Order 881*).

The order requires transmission providers to employ ambient-adjusted ratings (AARs) for short-term transmission requests — 10 days or less — for all lines that are impacted by air temperature. Seasonal ratings will be required for long-term service.

The commission said the current practice — in which line ratings are typically based on conservative assumptions about worst-case, long-term air temperature and other weather conditions — has caused underutilization of available transmission capacity.

"This is a pretty big deal," Chairman Richard Glick said at the commission's open meeting. "We've spent a lot of time over the last several months talking about the need for substantial investments in new transmission capacity, and there is a significant need for these investments. But at the same time, we need to squeeze more out of the existing grid."

FERC opened the docket with a Notice of Proposed Rulemaking last year. (See *FERC Proposes Requiring Variable Tx Line Ratings*.)

The final rule did not mandate the use of dynamic line ratings (DLRs), which the commission said should be more accurate than AARs by incorporating not only forecasted

Continued on page 5

PUC Forges Ahead with ERCOT Market Redesign

Stakeholder, Public Input Limited in Market Blueprint

Sierra Club members display 3,500 petitions from Texans requesting an electric grid that works for their community. | *Eric Goff*

By Tom Kleckner

The Texas Public Utility Commission on Thursday pushed ahead with staff's proposal to redesign the ERCOT market in a two-phase approach that Chairman Peter Lake said marked a generational change.

In a 35-minute discussion, the commissioners did not address the 54 stakeholder comments it received on the Dec. 6 *strawman* proposal, sticking instead to language in staff's original memo. (See *PUC Narrows Options*

Continued on page 14

Also in this issue:

10837 Deborah Drive ▣ Potomac, MD 20854 ▣ (301) 299-0375 ▣ info@rtoinsider.com

▣ rtoinsider.com ▣

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

In this week's issue

Stakeholder Soapbox

Low-cost, Reliable Power Service Depends on Large-scale Tx

By Barbara Tyran

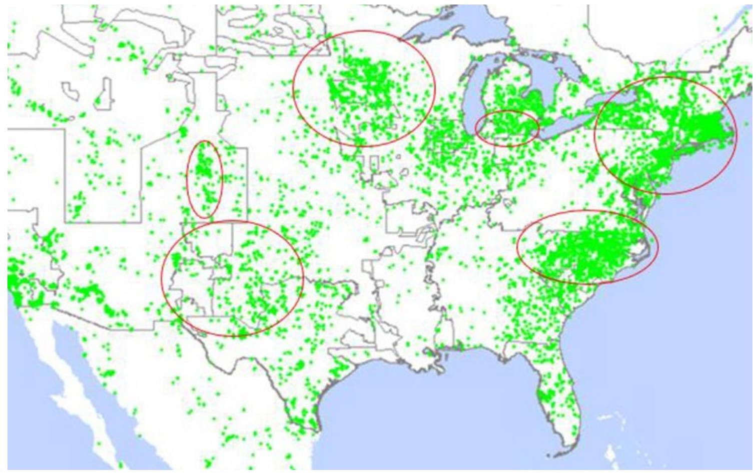
Barbara Tyran | *American Council on Renewable Energy*

As the frequency and severity of extreme weather events continue to increase and the clean energy transformation accelerates, grid operators and regulators across the country are faced with difficult decisions on how to ensure cost-effective, reliable service.

Two new studies illustrate the value of interregional transmission in solving an important part of this challenge. Their commonality reinforces the significance of their findings: We have the opportunity today to "read postcards from the future."

The first, *Potential Customer Benefits of Interregional Transmission*, submitted by GE International to the American Council on Renewable Energy (ACORE), points to three geographic areas today with greater than 70% renewable penetration: California, Denmark and the Southwest Power Pool (SPP). The report posits that the entire U.S. will have 20 to 50% renewable energy penetration by 2035. We can learn valuable lessons about load management and system operations from the areas with higher renewable energy penetration now. The report recommends examining the value of regionalization that has been validated for SPP, California and Denmark in an overall assessment for the broader U.S.

The second report, *Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights on When There is a Loss of Generation*, highlights the asset value of the U.S. transmission system: 600,000 miles, of which 240,000 miles is intraregional and interregional high-voltage transmission. The report, written by Grid Strategies, describes the performance of the grid during several recent examples of extreme weather, including the 2021 Texas power outage, the 2021 California heat wave, the January 2019 Polar Vortex, and the 2017-2018 Bomb Cyclone. The analysis illustrates the benefits of interregional transmission access, which can serve as a "lifeline" during periods of interruption. As documented in other studies, including a *FERC-NERC investigation*, the localized nature of extreme weather underscores the important role of interregional cooperation and access to new electricity supplies. As an example, each additional gigawatt of transmission capacity connecting ERCOT with neighboring states in the Southeast *could have saved $1 billion in damages and provided energy to 200,000 homes during February's winter storm*.

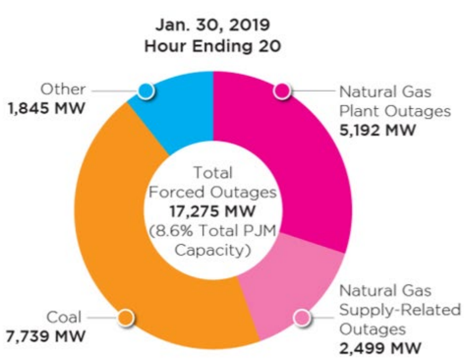


Operating and planned wind and solar projects as of 2020. The ovals represent areas of high wind and solar siting along interregional interfaces, which could potentially benefit from greater interregional transfer capacity. | *ABB Hitachi*

The "postcard from the future" in both reports aligns around the utilization of today's best practices to guide future energy planning efforts. Because decarbonization mandates will likely continue/increase — as will extreme weather events — geographic regions with higher renewable energy penetration provide a window into how to operate future power systems reliably and affordably in the new paradigm. As pointed out in the GE report, resilience is based on three types of reliability: 1) adequacy (fuel diversity); 2) operations (flexibility); and 3) stability (grid strength). We can begin to address these three attributes today to achieve resilient decarbonization. The report concludes, based on contemporary experience, that interregional transmission access ("greater regionalization") is the most cost-effective mechanism for achieving resilience in a world with higher renewable energy penetration.

Today's experience also reveals that it is difficult to accurately evaluate consumer benefits on a regional basis and that guidance must be established at the national level in order to be fully effective.

We can glean important information today from those geographic areas with higher renewable energy penetration that will help prepare us for a seemingly inevitable path ahead. Let's study those examples now so that we arrive together in 2035 with empirical knowledge and confidence in our power system. Reading "postcards from the future" is smart and highly useful. ■



Forced outages in PJM during the 2019 polar vortex | *PJM*

Barbara Tyran is the director of the American Council on Renewable Energy's Macro Grid Initiative, which seeks to expand and upgrade the nation's transmission network to deliver job growth and economic development, a cleaner environment and lower costs for consumers.

FERC/Federal News

Manchin Says 'No' on Build Back Better

With Midterms Looming, Democrats Face Challenge of Saving Biden's Social and Climate Agenda

Continued from page 1

with us to reach that common ground."

In his own *statement*, released following his appearance on Fox, Manchin said that the bill represented efforts by Democrats to "dramatically reshape our society in a way that leaves our country even more vulnerable to the threats we face."

He also reiterated his longstanding argument that U.S. energy policy should be driven by innovation and markets, rather than regulation.

"If enacted, the bill will also risk the reliability of our electric grid and increase our dependence of foreign supply chains. The energy transition my colleagues seek is already well under way in the United States of America," he said. "We have invested billions of dollars into clean energy technologies so we can continue to lead the world in reducing emissions through innovation. But to do so at a rate that is faster than technology or the markets allow will have catastrophic consequences for the American people like we have seen in both Texas and California in the last two years."

'This is not Over'

Clean energy advocates have lobbied hard for the bill, which contains $555 billion in funding for renewable energy tax credits and other programs aimed at achieving Biden's goals of decarbonizing the U.S. electric grid by 2035 and cutting the nation's carbon emissions to net zero by 2050. Supporters pledged to continue their efforts despite Manchin's announcement.

Speaking on CNN's "State of the Nation," Sen. Bernie Sanders (I-Vt.) said Manchin is "going to have to tell the people in West Virginia why he's rejecting what the scientists of the world are telling us, that we have to act boldly and transform our energy system to protect future generations from the devastation of climate change."

Sanders also called for Democrats to "bring a strong bill to the Senate as soon as we can and let Mr. Manchin explain to the people of West Virginia why he doesn't have the guts to stand up to powerful special interests."

"This is not over," said Gregory Wetstone, CEO of the American Council on Renewable Energy. "The clean energy tax platform and grid infrastructure provisions in the Build Back Better Act are our last, best chance to tackle climate change. We will be working with Congress to find a way forward and deliver the clean energy future Americans want and deserve. Failure is not an option."

Erin Duncan, vice president of congressional affairs for the Solar Energy Industries Association, also signaled the organization's determination to keep fighting for the bill.

"There have been many twists and turns in this legislation, but the need for jobs, particularly domestic manufacturing jobs, that help address the climate crisis is unrelenting," she said. "This is not the end of the road. We will continue to advocate aggressively for policies that deliver jobs and clean energy to every state across America."

The debate also exploded on Twitter, where Robert Reich, who served as secretary of Labor for former President Bill Clinton, said Congress's adjournment at 4 a.m. Saturday ended any hope for passing Build Back Better this year. "Biden's agenda is now at the mercy of the midterm election year," Reich said.

Calling Manchin "the new Mitch McConnell," Rep. Jamaal Bowman (D-N.Y.) questioned whether Manchin's opposition to the bill was influenced by special interests. "When you say you're a no on Build Back Better — is it you? Or is it the special interest that powers you?" Bowman tweeted. "I'm inviting you to my district to see just how badly we need this bill. Will you tell my community 'No' to our face?"

On the other side of the aisle, Rep. Dan Crenshaw (R-Texas) was jubilant, tweeting that Manchin's no means that "America has dodged a serious bullet. BBB is dead. Merry Christmas!"

ClearView Partners, a D.C.-based research firm, anticipates the new year could bring a revised Build Back Better Act (BBBA) with trimmed down energy spending.

"Democrats could face a Hobson's Choice on a next bill (i.e., a significantly smaller bill or nothing at all)," ClearView said in a note to clients. "A future draft therefore would seem unlikely to retain the breadth and depth of clean energy spending in the House-passed BBBA. … We would not yet bet against long-term green power tax credit extensions in some form, albeit for shorter durations and/or with less generous provisions."

Keeping Coal in the Picture

As chair of the Senate Energy and Natural Resource Committee and one of two critical swing votes in the evenly divided Senate, Manchin, along with Sen. Kyrsten Sinema (D-Ariz.), has had an outsized ability to shape key legislation, especially anything related to energy policy.

His opposition had already cut key provisions from the bill, most prominently Biden's Clean Electricity Performance Program, which would have provided incentives for utilities to accelerate their switch to carbon-free power.

Manchin describes himself as a "conservative Democrat," but his opposition to aggressive clean energy programs reflects his strong ties to the coal industry in his home state of West Virginia. He earns hundreds of thousands of dollars annually from Enersystems, the coal company he started, which is now run by his son, Joseph Manchin IV.

Manchin has long maintained the family business does not constitute a conflict of interest because he put his investments in a blind trust.

But *The Washington Post* *reported* last week that his most recent financial disclosure showed the company paid him $492,000 in interest, dividends and other income in 2020 and was worth between $1 million and $5 million. The blind trust Manchin created with $350,000 in cash in 2012 generated no more than $15,000 last year, the *Post* reported.

Manchin regularly speaks in favor of bipartisan legislation, especially when it contains dollars for his home state of West Virginia and the coal industry. For example, the $1.2 trillion bipartisan infrastructure bill, which he helped shepherd through the Senate, includes billions for the development and deployment of carbon capture, storage and sequestration projects.

Similarly, on Thursday, Manchin and Sen. John Barrasso (R-Wyo.), ranking member on the Energy and Natural Resources Committee, introduced a bill that would establish a program to provide federal dollars for building advanced nuclear reactors and related supply chain facilities on or near retired coal plants.

"Advanced nuclear technologies provide an opportunity to repurpose shuttered coal and fossil generating plants," Manchin said in the press announcement of the bill. Such projects "could bring new high-paying jobs and economic opportunities to communities throughout West Virginia and the nation while expanding our domestic nuclear supply chain." ■

FERC/Federal News

FERC Orders End to Static Tx Line Ratings

New Docket Opened to Consider Dynamic Line Ratings

Continued from page 1

temperatures, but also other weather conditions such as wind, cloud cover, solar irradiance intensity, precipitation, and line conditions such as tension or sag. DLRs also can provide situational awareness, alerting operators if a line is over its capacity.

But the order does require that organized market operators allow transmission owners that would like to use DLRs the ability to do so. FERC also ordered RTOs and ISOs to create systems and procedures to allow transmission owners to electronically update transmission line readings at least hourly.

The order also rejected the NOPR's proposal to "stagger" implementation of AARs on historically congested lines first, followed by all lines. The order requires transmission providers to submit compliance filings within 120 days of the rule's publication in the *Federal Register* and to implement the rules within three years after that.

Worst-case Assumption

In a *presentation* to the commission, Dillon Kolkmann of the Office of Energy Policy and Innovation, said that transmission line ratings are often based on worst-case assumptions, for example, a hot summer day. "Atmosphere and weather conditions vary day to day and hour to hour. But seasonal or static ratings are typically updated only when equipment is changed or weather assumptions are revised," he said.

As a result, such ratings often result in less transfer capability than the system can actually provide, resulting in unnecessary congestion costs, curtailments and redispatch orders.

Kolkmann said seasonal and static ratings may also overstate near-term transfer capability, creating reliability risks.

Glick said the evidence gathered to date was insufficient to determine "the incremental benefits, costs and risks associated with dynamic line ratings." The commission opened a new proceeding (AD22-5) to build the evidentiary record further.

Commissioner Allison Clements said she hoped that new rules also would result in more accurate signals about where investments in new transmission facilities are needed.

"I want to stress that this rule is not [the end of] efforts to improve existing system efficiency, but instead represents an important first step," she said. "The record in this proceeding does demonstrate that dynamic line ratings may provide even more accurate line ratings than ambient adjusted ratings, and therefore even greater reliability and economic benefits to consumers. In my mind, these are benefits we can't afford to leave on the table."

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*

How Much More?

LineVision Inc., which provides transmission technology for AARs and DLR, claims its solutions can "unlock up to 40% additional capacity."

The Electric Power Research Institute said that DLR is more costly than AARs because it requires "placing sensors in remote locations, ensuring the cyber security of sensors, and various additional costs."

AARs are widely used in PJM. The RTO told the commission that AARs provide "significant operational value [and] allows for the realization of additional incremental capability on the system."

PJM is conducting DLR pilot programs with PPL and AEP. In a study of a hypothetical installation on one of its most congested lines, PJM said DLRs could provide a payback of the estimated $500,000 equipment installation cost in two months through reduced congestion payments.

In its comments, the Electric Power Supply Association was generally supportive of moving to DLR but warned it "could have some unintended impacts with respect to day-ahead and real-time price convergence.

"While such an impact ultimately may not be negative or significant, it is nonetheless important to ensure that the RTOs consider the issue," EPSA said.

ITC Holdings told the commission in April that "AARs should not be seen as a panacea to the needs of the transmission system."

The company said it agreed with the Organization of MISO States (OMS) that AARs "should not be implemented on facilities where it is not economic or reliable to do so.

"A collaborative approach among stakeholders will allow the identification of the facilities that will provide the most benefit to electric customers from the use of AARs," ITC said. "This is of particular importance in MISO where the Transmission Owners have worked over more than the past 18 months to develop an AAR conceptual framework to evaluate candidate facilities and begin the process of program development." ■

FERC/Federal News

FERC Questions Ratepayer Funding of Trade Association Dues

By Amanda Durish Cook

FERC opened a Notice of Inquiry on Thursday over the recovery of trade association dues in utility rates, with commissioners questioning whether customers should pay for groups that seek policies that may be contrary to consumers' interests.

The NOI asks what portions of utilities' dues paid to industry, civic and political associations are suitable for rate recovery (*RM22-5*).

The inquiry is a response to a petition filed by the Center for Biological Diversity, a conservation nonprofit that argued that association dues should be presumed to be non-recoverable through rates. Utilities should shoulder the burden of proving that such expenses should be recoverable, the group said. The group also sued the Tennessee Valley Authority over the issue in September. (See *TVA Sued Over Contributions to Trade Groups*.)

Under current FERC accounting rules, regulated utilities are allowed to recoup association dues, subtracting disclosed spending on IRS-defined lobbying activities.

FERC Chairman Richard Glick | *© RTO Insider LLC*

FERC Chairman Richard Glick said the NOI will help FERC decide whether to modify its accounting and recordkeeping requirements.

"It appears that trade associations might not provide the utility company members with a sufficient level of detail as to which portion of a trade association's dues should be recoverable and which should not, making it difficult for the commission to assess whether utilities are being excessively compensated by ratepayers or not," Glick said at FERC's open meeting.

FERC Commissioner Allison Clements | *© RTO Insider LLC*

Commissioner Allison Clements said the inquiry "in no way impinges on regulated utilities' ability to advocate for any issue of interest.

"Regulated entities have every right to engage in outreach to influence public opinion on political issues; however, they do not have the right to pass through the cost of their outreach to the customer," she said.

"At the minimum, it is a good housekeeping exercise to ensure that customers are not inappropriately left footing the bill for their electricity provider's political aims, simply because they were taken on a by trade association instead of a regulated entity itself."

Commissioner Mark Christie agreed that the NOI "is not a constitutional threat."

"I don't see it as threatening any corporations or trade associations' speech rights," he said.

FERC Commissioner Mark Christie | *© RTO Insider LLC*

"The question here is not about the First Amendment; it's about who pays for the expenses associated with speech."

Christie pointed out that while state-regulated monopolies "may invest voluntarily," their captive customers cannot buy voluntarily.

Christie said that FERC uses formula rates, a "very different system than in states where a utility comes in and has … the burden of proving that any expenditure is prudent."

He added that he hadn't prejudged any answer to whether FERC's formula rate format is transparent enough. "It may be that the rules are fine. And maybe no changes are needed. But I don't see a problem at all with putting this out for comment."

Christie added that FERC should probably also consider whether its precedents on charitable and civic contributions should be codified. "I do not think that charitable and civic contributions by a state-granted monopoly should be recoverable from customers, period. That should not be allowed at all," he said.

FERC Commissioner James Danly said he was dissenting on the NOI and would issue a later statement. He did not explain his opposition during the open meeting. ■

FERC/Federal News

FERC Ups Hydro Dam Inspection and Safety Requirements

No More Single Consultants; Rule Calls for Expert Teams to Perform Critical Inspections

By K Kaufmann

FERC on Thursday approved a rule to improve hydro dam safety by instituting a two-tier inspection program and requiring such inspections to be performed by teams with site-specific expertise, rather than a single independent consultant.

Additional provisions in the rule (*RM20-9-000*) will also codify a 2012 requirement that dam owners develop and file with FERC a Dam Safety Program, as well as report any public safety incidents, including rescues, related to project operations. The rule passed unanimously, with newly installed Commissioner Willie Phillips not voting. It will take effect 90 days after publication in the Federal Register.

The new requirements are based on recommendations from an analysis of the February 2017 incident in which California's Oroville Dam, the tallest dam in the nation, saw major damage to its primary spillway and the first activation of its auxiliary spillway. About 180,000 people were forced to evacuate the surrounding area. Emergency response and repairs cost more than $1.1 billion, said a *recent report* from the Congressional Research Service.

Citing that report, FERC Chair Richard Glick said that the U.S. has 90,000 dams, 15% of which are classified as "high hazard potential," meaning that any failure of the dam could result in loss of life. In addition, half the dams are more than 50 years old and could require upgrades costing an estimated $20 billion, Glick said.

FERC has jurisdiction over more than 2,500 hydro projects, said a *Hydropower Primer* the commission released in 2017. Following the Oroville incident, FERC convened its own review panel to suggest potential changes to its Dam Safety Program. A notice of proposed rulemaking (*RM20-9*) was issued in July 2020. (See *FERC Proposes Tougher Hydro Safety Rules*.)

Oroville Dam on Feb. 17, 2017 | *California Department of Water Resources*

David Capka, director of the Division of Dam Safety and Inspections in the Office of Energy Projects, said the final rule contains some "clarifying edits" made in response to comments received from stakeholders, including dam owners, other federal agencies and trade associations. But otherwise, it is essentially the same as the 2020 NOPR, he said.

Two-tier System

Prior to the vote, Tara DiJohn, attorney-advisor in FERC's Office of General Counsel, provided more detail on the four "overarching objectives" of the rule.

All hydro projects under FERC's jurisdiction will still be subject to the commission's inspection rules, as spelled out in regulations known as *Part 12D*, which require inspections every five years. But, DiJohn said, under the two-tier system, "the required scope of the inspection will alternate between a periodic inspection and a comprehensive inspection."

Periodic inspections will focus on "the performance of the project over the previous five years," she said. "It includes a field inspection or review of project operations, an in-depth review of monitoring data trends and behavior, and an evaluation of whether any potential failure modes are occurring."

Comprehensive assessments will build on the periodic reviews "with a deep dive into every aspect of a project, including a detailed review of the design basis, analysis of records and construction history, and evaluation of spillway adequacy [and] potential failure modes analysis and risk analysis," she said.

Commissioner Allison Clements raised concerns about the cost of the new inspections. "If we're going to strengthen safety, we have to balance the benefits of more stringent requirements with the cost burden to the regulated [projects], including the smaller entities that may have fewer resources," she said.

The two-tier system is intended to help offset the cost of inspections, DiJohn said, with the periodic inspections being "less burdensome." With smaller, less complex projects, licensees can also propose a single independent consultant to perform the inspection, she said.

Ultimate damage at the Oroville service spillway | *California Department of Water Resources*

First Line of Defense

The second major provision modifies who performs the Part 12D inspections. "Instead of focusing on the individual independent consultants, we will focus on the qualifications of the independent consultant teams," DiJohn said.

"We have a lot of very large and very complex projects, and requiring one person to be responsible to review all the features of those projects is a lot to ask," she said. "To have the right expertise, we want to ensure that licensees look at teams to do that."

While first required in 2012, the Dam Safety Programs codified in the new rule will "formalize licensees' policies and procedures related to organizational oversight and responsibilities, internal communication, resource allocation and continuous improvement," DiJohn said. "A proactive, conscientious licensee is the first line of defense against potential dam safety issues."

Finally, the rule expands requirements for reporting on public safety incidents at or near dams, DiJohn said, adding rescues to the list of incidents to be reported, along with serious injuries and deaths.

Calling dam safety "one of our most important jobs," Glick said the new rule was "a step in the right direction ... [but] not the end of our efforts to protect the public." The commission is planning a staff-led technical conference, possibly in April, Glick said, examining financial assurance measures for hydropower projects to ensure than licensees have sufficient financial resources for dam maintenance and repair as needed for public safety. ■

CAISO/West News

CPUC Levies $550M on Edison for Wildfires

Approves Utility's $1.2B Storage Project for Grid Reliability

By Hudson Sangree

Investigators found that Southern California Edison power lines sparked the Thomas Fire, which killed two people in December 2017 and led to a mud flow that killed 21 more. | *U.S. Forest Service*

The California Public Utilities Commission on Thursday took steps to address two of the state's major grid problems, resource adequacy and wildfires, by approving Southern California Edison's request for a $1.2 billion storage project and slapping the utility with a half-billion dollars in penalties for blazes sparked by its equipment.

The decisions, reached in quick succession, came during the CPUC's final meeting of 2021 and the last meeting for retiring President Marybel Batjer and Commissioner Martha Guzman Aceves, who is leaving for a top post at EPA.

The *storage project*, meant to improve summer reliability, would connect 535.7 MW of batteries at three SCE substations at an estimated cost of $1.226 billon. SCE said it will operate the storage resources as local distribution assets, not connected to CAISO, for five years. It will then transition the projects to "resources that participate in the wholesale market … [and] proceed through the interconnection process like any other customer."

More than a dozen entities — including the CPUC's Public Advocates Office, the Solar Energy Industries Association and the California Energy Storage Alliance — protested, challenging the cost of the project, its intended use and SCE's interconnection plans.

The CPUC said it was not swayed by the objections and believed the project qualified under its prior procurement orders and Gov. Gavin Newsom's emergency proclamation in July requiring the connection of additional resources to meet projected shortfalls by next summer. The five commissioners voted unanimously to approve it.

"We are facing a large gap in the amount of resources we have to ensure the reliability of our current grid in the face of the more extreme, climate-driven weather events that we saw earlier this summer and [that] we witnessed last summer," Batjer said, referring to the derating in July of transmission lines linking the Pacific Northwest to California caused by a massive wildfire and the rolling blackouts of August 2020 in a severe Western heat wave.

"In this case, Edison has been able to leverage its unique position as an IOU and distribution operator to move forward with a shovel-ready project that can respond to our emergency procurement needs," she said.

The project is expected to come online by Aug. 1, 2022, in time to meet summer reliability needs.

Wildfire Penalties

The CPUC next voted 4-1 to approve a *settlement* with SCE over the major fires of 2017/18 ignited by its equipment. The Thomas, Woolsey, Liberty, Meyers and Rye fires collectively killed at least five people, destroyed more than 2,700 structures and burned more than 385,000 acres.

Of the five blazes, the Thomas and Woolsey fires were by far the largest and most destructive.

The Thomas fire, which began in December 2017, was the biggest wildfire in state history at the time at 282,000 acres. It was surpassed by much larger fires, including two of approximately 1 million acres, in recent years.

The fire in Santa Barbara and Ventura counties killed two people and destroyed more than 1,000 homes. Subsequent flooding and debris flows in the burn-scar area later killed 21 residents and destroyed more than 100 homes. Without admitting liability, SCE settled with insurers for nearly $1.2 billion last year.

The Woolsey fire started in November 2018, killed three people, destroyed more than 1,600 homes and led to the evacuation of almost 300,000 residents in Los Angeles and Ventura counties.

The CPUC used its new, controversial procedure called an administrative consent order (ACO) to settle with SCE. The expedited process reduces the time it takes the commission to hold utilities accountable for safety violations in an era of regular, catastrophic wildfires. Other *enforcement* proceedings, such as the commission's order instituting investigation, can take years to complete.

It was the second time the CPUC has used an ACO to settle with a utility blamed for starting wildfires. Earlier this month it approved a $125 million settlement with Pacific Gas and Electric over the 2019 Kincade Fire in Northern California's wine country.

Commissioners *voted* 3-2 to approve the *agreement* between PG&E and the CPUC's Safety and Enforcement Division that levied $40 million in fines and denied the utility $85 million in cost recovery for removing abandoned transmission lines. (See *CPUC Assesses PG&E $125M for Kincade Fire*.)

They voted 4-1 to approve Thursday's settlement with SCE. Commissioner Genevieve Shiroma, who voted "no" previously, said she was satisfied the process had led to a better result with SCE than with PG&E. Commissioner Darcie Houck, who also voted against the PG&E settlement said she believed the ACO process lacked transparency and the opportunity for public participation, especially involving fires of such magnitude.

"I agree that this can be a flexible and useful tool that allows us to resolve things in a streamlined and efficient way where we are dealing with only penalties and not the extreme catastrophic events at issue here," Houck said. ■

CAISO Proposes Paying Storage Differently

New Rules Would Address State's Reliance on Batteries for Reliability

By Hudson Sangree

CAISO issued a *straw proposal* Dec. 9 that seeks to address the state's dependence on energy storage for meeting summer evening peaks by paying batteries to stay charged during the day in readiness for when they are needed most.

Avoiding energy emergencies like those in the past two summers requires batteries to be ready to discharge during heat waves in the hours after the sun sets and solar goes offline, CAISO said. But requiring storage resources to maintain a state of charge means they cannot take advantage of other financial opportunities during the day, it said.

"A principal concern raised by the storage community is a lack of compensation during critical periods when the ISO must retain state of charge on limited energy storage devices, which may preclude their active participation in the real-time markets," the proposal says. "The existing bid cost recovery rules, which are designed based on traditional energy generation resources, do not consider energy storage charging and discharging cycles."

A main objective of CAISO's energy storage enhancements stakeholder *initiative* is to develop a "set of solutions to enhance the optimization of storage resources and to allow additional flexibility for storage operators to manage state of charge in the real-time markets," the straw proposal says. "The ISO proposes a new model, called the energy storage resource (ESR) model, which is unique from existing models because bids are predicated on state of charge values, rather than a dispatch instruction for power."

The ESR model would require scheduling coordinators to "submit bids in terms of incremental state of charge instead of traditional bids submitted in terms of incremental energy," in recognition that a resource's costs to charge and discharge are different based on its state of charge, it says.

"Specifically, the energy storage resource model will allow storage resources to offer lower prices to provide energy when a battery has a nearly full state of charge and higher prices when it is nearly depleted," it says. "This new model would be employed in the ISO's market software for both the day-ahead and real-time markets and could be used by participants in the energy imbalance market."

Before last summer, FERC approved a temporary two-year measure by CAISO to require batteries to maintain a minimum state of charge on days with insufficient supply to meet demand. The proposed changes are intended as long-term market rules.

Another part of the proposal involves paying storage resources for exceptional dispatch by compensating them "at the difference between the prevailing price during the exceptional dispatch and the reference interval discharge price. The reference interval discharge price will be the period when the storage resource actually discharges and sells energy."

NextEra Energy is developing 2.4 GW of battery storage in California for deployment in 2023-2024. | *NextEra Energy Resources*

Batteries Proliferate

The proposed new rules reflect the state's growing reliance on batteries to maintain reliability.

CAISO will have 2,500 MW of four-hour lithium-ion battery storage connected to its grid by the end of this year, CEO Elliot Mainzer told the Western Energy Imbalance Market's Governing Body on Wednesday. He called 2021 the "advent of the bulk storage fleet on the California grid."

"I believe that is the highest concentration of lithium-ion battery storage in the world and testament to years of policy support and procurement efforts by state officials," he said.

Most of the battery resources were connected in response to the rolling blackouts of August 2020, when the state's vulnerabilities to outages during severe Western heat waves became clear. The state's increasing reliance on solar and wind power, without sufficient storage, was partly to blame for the energy emergencies. (See *CAISO Sees 'Explosive' Growth in Storage in July*.)

The energy storage enhancements stakeholder initiative, which began in May, focuses on market reforms to bring massive amounts of utility-scale storage into CAISO's system to back up the solar and wind power needed for California's transition to 100% clean energy by 2045, as well as to meet local capacity requirements. (See *CAISO Readies for Storage Scale-up*.)

The separate energy storage and distributed energy resources (ESDER) stakeholder initiative began five years ago and proposed numerous changes in four phases. FERC approved the fourth phase in October; it included market power mitigation measures for storage resources and biddable state-of-charge parameters. (See *FERC Accepts Latest CAISO Storage, DER Rules*.)

CAISO expects to add at least another 1,000 to 2,000 MW of storage in 2022-2024, most of it in lithium-ion batteries with four-hour discharging capacity.

Summer reliability issues will likely continue through 2024, as natural gas plants close and the state's last nuclear generator, Pacific Gas and Electric's Diablo Canyon power plant, begins shutting down, CAISO has said. State energy planners hope a large-scale buildout of solar, wind and batteries will compensate. ■

CAISO/West News

Court Overturns FERC on CAISO CPM Rates

DC Circuit Says FERC Inappropriately Based its Decision on Prior Ruling

By Hudson Sangree

The D.C. Circuit Court of Appeals on Friday overturned a 2020 FERC ruling that approved CAISO's decision to award a 20% adder to above-cap bids for resources needed for grid reliability, saying FERC's decision "was not the product of reasoned decision-making." (*20-1388*).

The case involved CAISO's capacity procurement mechanism (CPM), which lets the ISO purchase electricity needed to maintain grid reliability in extraordinary circumstances. It was based on a challenge by the California Public Utilities Commission, which claimed that CAISO and FERC had erred by awarding the adder to CPM resources that exceeded CAISO's soft-offer cap reference bid of $6.31/kW-month.

CAISO and FERC had previously approved a 20% adder for resources that bid under the ISO's soft-offer cap, saying the adder would cover going-forward costs such as maintenance and upgrades. FERC relied on its prior decision to also approve the 20% adder for resources that sought compensation above the soft-offer cap by applying for a higher rate from FERC.

The D.C. Circuit said FERC had relied on its own precedent regarding the soft-offer cap without considering the differences in the two cases.

"The commission relied chiefly on its 2015 CPM Order approving the soft-offer cap, which includes a 20% adder," the court said. "The commission inferred from its 2015 order that applying the same adder to above-cap CPM bids would be just and reasonable."

That was a mistake, the court said.

FERC "may attach precedential, and even controlling weight to principles developed in one proceeding and then apply them under appropriate circumstances in a [precedential] manner," the court said. "But application of precedent is warranted only if the factual composition of the case to which the principle is being applied bears something more than a modicum of similarity to the case from which the principle derives."

"Here … the commission failed to grapple with the distinction between bids submitted below or above the soft-offer cap, resulting in the commission's reliance on precedent without recognition of the substantial differences between the two cases," it said.

With the below soft-offer cap bids, "CAISO reasoned that the 20% adder would allow resources with costs higher than the reference resource to recover their going-forward costs and additional fixed costs, as well as providing investment incentives," the court said. "In the event that the soft-offer cap does not allow a resource to recover its going-forward costs, that resource can submit a cost-justified filing to the commission for a higher rate."

Providing the adder to above-cap bidders, however, "effectively renders the compensation formula uncapped; the greater a facility's going-forward costs, the more it stands to recover through its cost-justified bid. This uncapped recovery stands in stark contrast to the soft-offer cap, which is meant to cap maximum bids evenly in order to facilitate competition among resources."

Without reference to its precedent regarding soft-offer cap bids, "the commission's order has little else, if anything, to support it," the court said.

The court vacated FERC's order and remanded the case for further proceedings consistent with its order. ■

A transmission line crosses the Sacramento Valley in Northern California. | *© RTO Insider LLC*

CAISO Board Elects New Leader

Approves Technology Upgrades for Market Transactions

At Friday's CAISO Board of Governors meeting, clockwise from top left, CEO Elliot Mainzer; former Chair Angelina Galiteva; Governor Jan Schori, General Counsel Roger Collanton; Director of Financial Planning and Procurement April Gordon; Governor Severin Borenstein; new Chair Ashutosh Bhagwat; and Vice Chair Mary Leslie (center). | *ISO-NE*

By Hudson Sangree

In its last meeting of 2021 on Friday, the vCAISO Board of Governors elected a new chair and vice chair and voted to fund new technology to settle billions of dollars in yearly market transactions.

The five board members continued their policy of rotating leaders annually, electing Vice Chair Ashutosh Bhagwat as chair and naming Governor Mary Leslie to take his place as vice chair.

Bhagwat, a law professor at the University of California, Davis, who has served on the board since 2011, took over the top spot from Angelina Galiteva, whom colleagues praised for her leadership in difficult times. The first woman to chair the CAISO board, her term included the pandemic, the state's struggle to prevent summer blackouts and a changeover in CEOs.

"You are the perfect chair to have led this effort because I think you brought a really nice warmth and understanding and vision to being chair, and I think it's served us really well," Leslie told her.

Galiteva responded, "Well, thank you. It was a pleasure to be the first woman chair. It was about time we had a woman chair at the ISO, and now we'll have many more. It's wonderful to see that now women are the majority on the board, which is also a first, so it has been it has been a very good period."

Bhagwat lauded Galiteva for her work as an ambassador between the CAISO board and the Western energy community and asked her to continue with those efforts.

Accepting his new role, Bhagwat said, "I appreciate the confidence you're showing in me, and I hope to live up to it."

Settlement Upgrades

CAISO management requested a $15.6 million upgrade to CAISO's settlement system, which handles billions of dollars in transactions annually and will likely handle more in the coming years as CAISO expands its Western Energy Imbalance Market.

"Every week, the ISO settles between $60 [million] and $219 million dollars of market transactions, and in 2020 that totaled $11.4 billion dollars," Vice President for System Operations Dede Subakti and CFO Ryan Seghesio said in a memo to the board. "In order to achieve this, the ISO settlement team must process between 18 and 51 trade dates each week, as mandated by our tariff. This results in roughly 31,000 system files being published to 585 market participants weekly."

The current system is aging, they said.

"It [now] takes between three and seven hours of work to process each trade date, leaving very little room for error," they wrote. "As a result, the ISO is sometimes challenged to meet the tariff-defined statement publishing deadlines."

"As we look toward a future with more market participants, new customer types, new market products and an expanded ISO footprint, it is time to address the shortcomings in the current settlement system," they said. "Failing to do so would be too risky to the ISO and our stakeholders."

The board unanimously approved the request. ■

CAISO/West News

CAISO Re-evaluates WEIM Resource Sufficiency Test

By Hudson Sangree

The Western Energy Imbalance Market Governing Body met twice last week, once by itself and once in a joint session with the CAISO Board of Governors, receiving briefings in both meetings on potential changes to the interstate market's resource sufficiency test, which is being re-examined in a stakeholder initiative.

The test is meant to ensure that each WEIM participant enters a trading hour with enough capacity and ramping capability to supply its own needs and to prevent participants from "leaning" on the market to meet internal demand.

Participants raised objections to the test, including the recent addition of components that account for the unpredictability of weather-dependent resources such as solar and wind generation, transmission outages and other variables. Some contended the "uncertainty" components skewed results and led to periodic test *failures*, including by CAISO during intervals last summer.

A revised final draft *proposal* in the resource sufficiency evaluation (RSE) enhancements stakeholder initiative was released Thursday, when the board and governing body met in *joint session*. CAISO Vice President of Market Policy and Performance Anna McKenna provided a briefing on the proposed changes, as she had done in the governing body's regular meeting Wednesday.

Stakeholders had four areas of concern over test accuracy, McKenna said.

"The first category is with regards to the measurement of uncertainty used in the capacity test," she said. "After hearing more concerns about the current measurements that we use to capture uncertainty and the adders that we've put into the test, we are now considering suspending … uncertainty in the tests."

Participants also raised concerns around demand response resources, capacity counting rules and consideration of load conformance.

CAISO planners had proposed increasing penalties for including demand response resources in the sufficiency test that do not materialize, but they now recommend shelving that plan because the penalties could have a "detrimental impact on how (participants) use demand response," McKenna said.

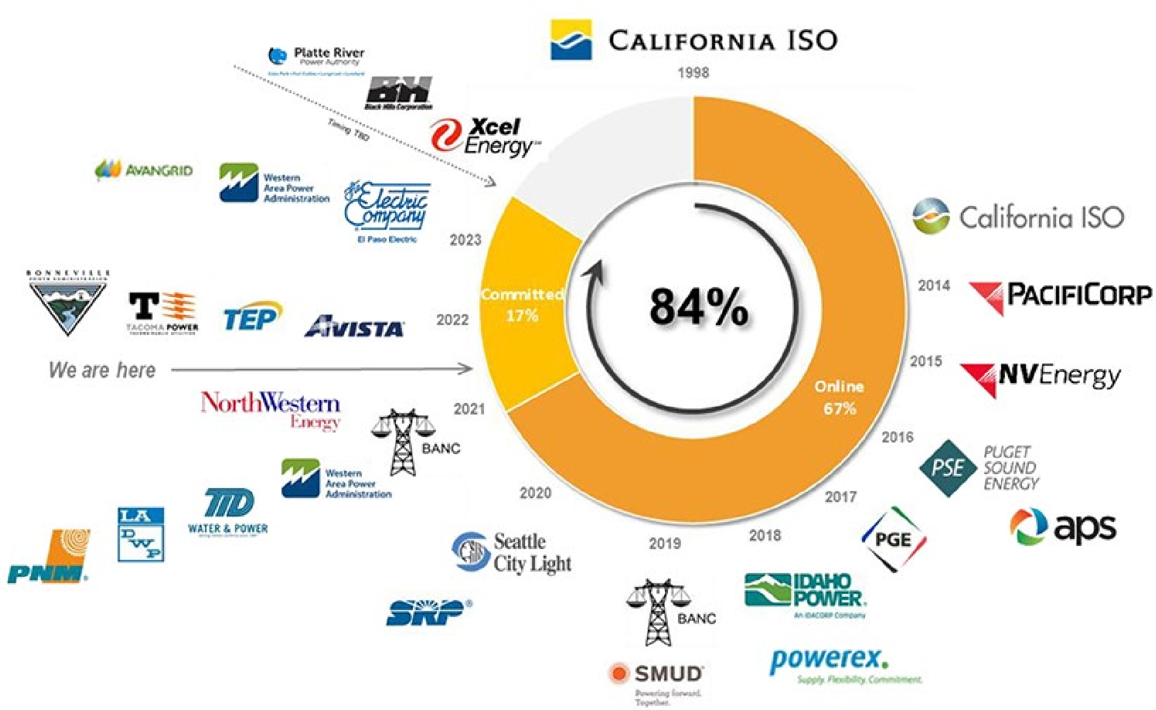
A third category of stakeholder concerns involved CAISO's proposed rules for counting resources toward the sufficiency test. CAISO still intends to enhance the counting criteria "so that the resources that are used to count to meet the test … can better reflect their actual reliability," McKenna said.

The fourth category of concerns involves "how conformance of load forecast, which is done by our operators, can trigger EIM transfers to meet the [resource sufficiency] test," McKenna said. CAISO continues to believe that understanding and adjusting for the impact of load forecast is important, but additional analyses showed complexities that deserve further testing and evaluation, she said.

"So, we're proposing to take that additional time with regard to this one item," McKenna said.

CAISO already had extended its timeline for the RSE initiative to take stakeholder comments into consideration and now plans to submit a final proposal to the board and governing body in a joint meeting Feb. 9.

Thursday's joint meeting was the first to be held under new governance rules adopted by the CAISO and WEIM in August. The vote on the sufficiency test will among the first joint decisions under the new rules. (See *CAISO Agrees to Share More Power with EIM*.)



A graph shows the timeline of entities joining the WEIM since it started in 2014. | *CAISO*

A meeting on the latest draft RSE draft proposal is scheduled for today, with stakeholder comments due Jan. 10.

The WEIM now has 15 participants with seven more scheduled to join in the next two years, eventually accounting for more than 80% of load in the Western interconnection. Participants have amassed more than $1.7 billion in benefits since the market started in 2014 by buying and selling excess power across state lines.

CAISO is undertaking a major effort this to year to expand the real-time market to a day-ahead market (EDAM), further increasing cooperation among the West's 37 balancing authorities. ■

ERCOT News

ERCOT In-person Meetings Delayed to February

ERCOT has pushed back the resumption of in-person stakeholder meetings from January to February, the grid operator said Dec. 14.

The grid operator had expected to resume face-to-face meetings next month with the Jan. 26 Technical Advisory Committee. It told market participants the meeting will now revert back to a virtual format. Staff will provide another update in January to "manage expectations."

The postponement was caused by a delayed transition to ERCOT's new headquarters facility, which was approved by the Board of Directors in 2020. The 37,000-square-foot facility was expected to be ready in January.

Stakeholder meetings will continue to be conducted virtually, as they have been for almost two years now. ■

— Tom Kleckner

ERCOT's new office facilities in Austin won't be ready until at least February. | *ERCOT*

ERCOT News

PUC Forges Ahead with ERCOT Market Redesign

Stakeholder, Public Input Limited in Market Blueprint

Continued from page 1

for ERCOT Market Redesign.)

"In prior years, any single one of these changes would have been considered significant," Lake said. "Taken together, they are a generational shift in the Texas electricity market."

The commissioners agreed to adopt the strawman as its market redesign blueprint and ordered ERCOT to take the proposal's Phase 1 blueprint and file a comprehensive implementation report by Jan. 10. They also directed the grid operator to prepare nodal protocol revision requests for their approval, potentially sidelining its stakeholder process.

Phase 1 involves modifying the operating reserve demand curve (ORDC); allowing for "more targeted response" to increase the use of load resources; revising emergency response service; and adding new ancillary service products.

The PUC ordered ERCOT to make the ORDC changes effective Jan. 1. The modifications include setting the curve's minimum contingency level to 3,000 MW and eventually decoupling the systemwide offer cap and the value of lost load, now set at $5,000/MWh.

The commission earlier this month lowered the high systemwide offer cap to $5,000/MWh. (See *Texas PUC Pushes 44% Reduction in ERCOT Offer Cap*.)

Lake also asked commission staff to work with ERCOT in "crystalizing" the major "abstract" concepts of Phase 2. He said the staffs should focus on the backstop reliability service proposal first and then the load-side reliability mechanism he has been promoting since October.

As proposed, a new ancillary service would "backstop" to meet specific needs not met by the real-time and AS markets. The load-side mechanism would obligate load-serving entities (retail electric providers, cooperatives and municipalities) to procure commitments for enough capacity to meet future forecasted demand and a dispatchable energy credits program requiring LSEs to obtain sufficient dispatchable capacity to meet future net peak load.

ERCOT's Kenan Ögelman, vice president of commercial operations, told the PUC that ERCOT staff would target a Feb. 15 deadline to file a report with the inputs, specifications, quantification and relevant metrics necessary to design and build each of the Phase 2 proposals.

Orders codifying the PUC's direction had yet to be filed as of Monday afternoon.

Criticism

The PUC did not discuss the cost impact of its proposals, which some energy experts anticipate will only further increase *customer bills that have been rising*. Commissioners Jimmy Glotfelty and Will McAdams pushed back, calling for more analysis of the Phase 2 options before they could offer their support.

"I'm not sitting here and saying that I support [phase 2] 100%, because I don't know," Glotfelty said. "To me the vast majority of that is dependent upon an analytical model-based analysis."

Alison Silverstein, a former PUC and FERC staffer, said in a fiery response to *RTO Insider* that she was "deeply disappointed" by the commission's actions. She said the commissioners should have called for "much more" analysis of both phases' reliability, market and cost impacts and should include better stakeholder and public input going forward.

"Today the commission voted to implement many Phase 1 measures that will have interacting effects on resource and system operating capabilities and costs, without any clear analy-

PUC Chair Peter Lake (2nd from right) explains his thoughts on the ERCOT market redesign. | *Texas Admin Monitor*

ERCOT News

sis of whether and how it will all work together or what it could cost Texas electric customers," Silverstein said. "We don't know whether all these measures will collectively help or hurt day-to-day resource availability and reliability, and there has been zero calculation of how much additional money they will suck out of Texas electric customers' wallets.

"I'm willing to pay more for better reliability, as are many Texans, but it's the commission's responsibility to make sure that we get what we pay for. Today, the PUC abdicated that responsibility," Silverstein said.

Consultant Doug Lewin of Stoic Energy, who live tweeted the open meeting, said that although there will be a cost analysis on the load-side reliability mechanism and the backstop reliability service, "it still seems to me like they're missing an integrative look at system needs."

"How big should the backstop reliability service be? What are we basing that on: a detailed, transparent analysis?" he said in an email to *RTO Insider*.

Both Lewin and Silverstein said the FERC-NERC investigation of the February winter storm's devasting power outages in Texas and elsewhere was largely ignored by the PUC. The report laid the blame for the nation's largest controlled load shed at the foot of the natural gas industry and listed 28 recommendations to prevent a reoccurrence. (See *FERC, NERC Release Final Texas Storm Report*.)

"There was a lot of discussion at the legislature and in the press about how the 2011 recommendations were largely ignored," Lewin said. "How seriously are we taking this more recent set of recommendations?"

ERCOT said in a statement that the PUC's proposals "will require a lot of coordination among all the market participants and market experts," calling them "the most significant and important changes … since [the market's] migration to a competitive market almost a quarter century ago."

"ERCOT is glad to be able to assist the PUC in this effort and will continue to work closely with the agency to meet the aggressive timeline," a spokesperson said.

"It is unprecedented to make so many substantive, market and cost changes with such minimal regulatory process and public and stakeholder input," Silverstein said. "The pace and scope of the PUC's decisions today may pass legal standards for Texas administrative law practice, but it violates sensible practices for sound public policy and public-interest decision-making."

Public Protests Heard

The PUC allowed nearly 50 minutes for comments from 22 citizens attending the meeting as part of a Fix the Grid rally organized by the Sierra Club, Public Citizen and Texas Campaign for the Environment. The groups asked the PUC to prioritize public input in their decision-making and consider "people-first solutions."

To make their point, the group's members held up a symbolic power line decorated with 350 icicles, each representing the names of 10 people asking the commission to weatherize the Texas grid to "protect and benefit the people of Texas, rather than the profits of Texas energy companies."

The wide range of comments, some in Spanish and responded to by bilingual Commissioner Lori Cobos, called for energy efficiency and demand response measures that decrease energy consumption. One speaker tearfully recounted her granddaughter being forced to go without power for 60 hours and then another 30 without water.

"You need to start being accountable to the people of Texas," another person said.

Emma Pabst, a representative for the Sierra Club's Beyond Coal Campaign, called for an energy grid "that works first and foremost for our communities."

"The fossil fuel industry left us to die during the [February] freeze," Pabst said. "Natural gas made $11 billion, while we were left to die in our homes."

Go-ahead for San Antonio Tx Project

The commission also approved CPS Energy's request to build a double-circuit 138-kV transmission line outside San Antonio. The project, which will cost between $37 million and $57 million for about 6 miles of a scenic loop and substation facilities, was the subject of an administrative law judge's hearing and public comments before the PUC (*51203*).

In other action during the open meeting, the commission:

- adopted rules simplifying the maximum provider of last resort (POLR) rate formula and limiting price volatility from real-time settlement point prices adversely affecting residential, and small and medium commercial customers transitioning to POLR service (*51830*); and
- signed off on ERCOT rule changes endorsed by its Board of Directors and Technical Advisory Committee (*52307*). ■

ERCOT News

Jones Working to Restore Confidence in ERCOT

Interim ERCOT CEO's Listening Tour Crisscrosses the State

By Tom Kleckner

DALLAS — Brad Jones, ERCOT's interim CEO, opened his conversation Friday with the Dallas Friday Club as he always does on what he calls his Listening Tour: stepping away from the podium and eschewing the use of a mic. The better to wander the stage and connect with his audience.

"This will take about two and a half hours," Jones said, drawing a few laughs.

His story began on Feb. 15 during a winter storm, "one you've never seen and one your grandparents never saw." Jones, retired from the electric industry at the time, says he was on his couch and watching television coverage of the winter storm disaster that left millions without power and caused human and financial suffering.

"Things have changed for me, haven't they?" Jones said in a quick aside.

"Were you in Texas?" asked a voice from the back of the room.

"Yes."

"Did you have power?"

"Electricity, but no water."

It's that mixture of charm, humor and candor that serves Jones well as he explains to Texans what happened to the grid during the storm and why it won't happen again. Several members of the public affairs organization exchanged smirks as Jones began his comments. An hour later, most everyone in the room was listening in rapt attention.

Jones admitted to ERCOT's poor communication during the storm, when "each piece of the market was telling different stories." He said the subfreezing temperatures shut down almost 50 GW of the grid operator's capacity — more than the 48-GW demand peaks CAISO sees on its hottest days, he said — and left the grid within about 10 minutes or so of a black start situation when generators automatically shut down.

"Things would have been much more difficult to manage," Jones said.

He explained the lack of interconnections with neighboring RTOs wouldn't have helped much, as they were experiencing the same emergency conditions. That led into an explanation of why ERCOT, "an island to itself," is exempt from FERC jurisdiction.

When Jones began taking questions from the audience, he was asked how Texas can again say it has the best grid in the nation. He said his flippant answer is that New York has had three blackouts and California two while the Lone Star State has not had one.

"The real answer is simple," he said. "We have to show the country we've changed the way we operate."

Jones mentioned the RACE acronym he uses to denote "reliable, affordable, clean electricity." Until the February storm, he said, RACE had been turned into CARE.

"For 20 years, we let the market dictate what we need for reliability," Jones said. "We need to move reliability back to the front. That will be how we change."

Jones handled every following question with similar ease. When the luncheon concluded, he took time to visit with the diners that stayed behind before doing on-camera interviews with the local media.

Asked if he is the perfect spokesman for this role as the communicator in chief, Jones laughed loudly.

"It's an extremely important role," he said. "The reason I came back to ERCOT after the winter storm was so ERCOT can begin to restore confidence among Texans in what it does."

Jones served as ERCOT's COO before leaving to take the top job at NYISO. He has watched the industry from afar since abruptly leaving New York for personal reasons in 2018. (See *Brad Jones out at NYISO*.)

The Brad Jones Listening Tour continues. Dallas was the 13th stop, with four more on the schedule. That is expected to change, however. Jones has yet to come across a city council or town hall that he won't attend.

Contrast that with Texas Gov. Greg Abbott, who has *guaranteed* the grid will not fail this winter. While Jones has been crisscrossing the state, Abbott held a closed-door meeting Thursday with "Texas energy providers" to discuss the grid's reliability and "preparedness ahead of the winter season."

The governor's office said in a *statement* that Abbott and "energy leaders" discussed actions already taken and improvements made by both the providers and the state, including updated winter preparedness plans, meetings with plant managers and "winterization of all components of the power grid."

The office also said several providers "discussed their efforts to ensure that natural gas supply is available this winter to fuel power plants, including on-site storage of natural gas and designation of natural gas facilities as critical to ensure they maintain power during energy emergencies."

NRG Energy, Vistra, Calpine and several pipeline companies were among those *involved* in the meeting.

434 MW Back for Late Winter

ERCOT will have an additional 434 MW of gas-fired capacity to play with before this winter is over, thanks to a pair of decisions related to retired power plants.

Vistra *told* the grid operator on Friday it is bringing its 69-MW Wharton County Generation facility out of retirement and making it operational as of Feb. 4. The plant, located southwest of Houston, was decommissioned and retired last December after a forced outage. (See "Luminant, 1 Other File NSOs with ERCOT," *Vistra to Shut down Another Texas Coal Plant*.)

ERCOT and CenterPoint Energy, the interconnecting transmission service provider, may delay the proposed return date if any studies, testing, metering or facility upgrades are necessary.

NRG *notified* ERCOT on Dec. 14 that Gregory Power Partners — a three-unit, 365-MW facility near Corpus Christi currently under seasonal mothball status — will change the start date of the operating period from May 1 to Jan. 1.

The plant was shut down in late 2016 when its cogeneration partner, Sherwin Alumina, filed for bankruptcy and ceased operations. NRG returned it to seasonal operations in 2019. (See *ERCOT Approves Seasonal Plan for NRG Cogen Units*.)

The announcements will help make up for the loss of almost 500 MW of capacity following recent suspension-of-operations notifications filed by the cities of *Austin* and *Garland* for aging gas-fired generators. ERCOT approved the notices earlier this month. (See "500 MW to Depart Market," *ERCOT Briefs: Week of Nov. 1, 2021*.)

The 405-MW Austin unit will be available through the winter before being retired. ■

ISO-NE News

IPPs See Danger in Swift Move from Gas and Coal

CEOs Give Stark Outlook for New England Winter

By Jennifer Delony and Rich Heidorn Jr.

Independent power producers warned Dec. 13 that policymakers are risking reliability by attempting to transition too quickly from gas and coal — and they said the consequences could be felt in New England this winter.

"We really shouldn't just … pave the ground with solar panels and then deal with the consequences after you've shut down all of your gas projects, like we saw in California," Gary Lambert, CEO of Competitive Power Ventures, said during a panel discussion at the New England Power Generators Association's (NEPGA) New England Energy Summit in Boston. "We have to … have a market that compensates us appropriately to keep the reliability resources around."

Sarah Wright, founder and managing partner of *Hull Street Energy*, a mid-market private equity firm, said it is "premature" to focus on retiring thermal generation. "You see it in California — the effects of this fictitious narrative that says, 'All we need to do is install solar panels and batteries and we'll be fine.' That is a nice political story, but it's not actually true," she said.

Himanshu Saxena, CEO of *Starwood Energy Group*, noted that renewables only comprise about 20% of the 1,000 GW of installed capacity in the U.S., with coal and gas representing about 600 GW.

"In the best of times, this country installed 20 GW of renewables on an annual basis. So if the best of times continued, it will take 30 years to replace [thermal generation], and this is not even [considering the lower] capacity factor" of renewables, he said. "Everybody has to be realistic about how fast this change is going to happen."

When Curt Morgan became CEO of Vistra in 2016, he said the company's generation was more than 70% coal. "And investors that we had were pretty comfortable with it," he said.

After studying the subject, Morgan said, he and the board of directors concluded that climate change was real and they needed to change the company's trajectory. It has *pledged* to reduce its carbon emissions by 60% from 2010 levels by 2030.

"Maybe that sounds simple to everybody in this room. But that was a huge thing for our board to accept and understand with over 70% coal [generation]. And so that put us on a path of not denying, but actually participating" in the transition away from fossil fuels.

"We're the kind of company that policymakers should want, because we're doing the responsible thing. We're helping the three pillars: reliability, affordability … and [reducing] emissions," Morgan said. "But it's going to take us some time to do this transition. And we can't sacrifice one of those three pillars to get there. And so I tell policymakers this all the time: 'We're not the guys that you ought to be throwing darts at. We're the ones that you ought to be supporting, because we are going to be the ones that will help this transition."

Cash Flow, Financing Challenges

Saxena said cash flows for gas and coal assets have become less predictable because of volatility in capacity prices, making it harder to raise debt or equity to fund the plants.

"You take something to market … if you have any green halo on it, you're trading at 20 to 40 times EBITDA [earnings before interest, taxes, depreciation and amortization]," he said. "But the capital market community hates coal. So getting everything from insurance for that asset to getting refinancing done is really, really hard."

Lambert said the influx of zero-cost resources could make it increasingly difficult to keep thermal plants operating. "So then you'll see a bunch of shutdowns. And we'll go back to RMRs [reliability-must-run contracts], and that's the world that we don't want to go back to, 2003-2005; everything was being run on cost-based RMRs."

Morgan said his normal optimism is being tested. "I am always a positive person, but I am very concerned that in the next 10 years, it's going to be a bumpy ride, because we're relying more and more on government intervention to get our rents.

"PJM did a study that said that, with 50% penetration of renewables, they need a 70% reserve margin. Yet we've got people wanting to … literally drive assets out of the market. When I talk to regulators, reliability doesn't even come out of their mouth. I have to raise it.

ISO-NE Board Chair Cheryl LaFleur (left) moderates a session during the New England Energy Summit in Boston with (second from left to right) Competitive Power Ventures CEO Gary Lambert; Starwood Energy Group CEO Himanshu Saxena; Sarah Wright, Hull Street Energy; and Vistra CEO Curt Morgan. | *New England Power Generators Association*

ISO-NE News

It's all about emissions.

"When you allow those things to come out of balance — reliability, affordability and emissions — you're going to have California, which was driven by a lack of reliability, and Texas, which was driven by too much emphasis on affordability and a lack of focus on the fact that … intermittent resources" create new reliability challenges.

Morgan said the U.S. may need to adopt Australia's solution of two markets: one for new renewables, and a residual market for dispatchable fossil fuel generators. "I'd hate to see us go there. But I don't know how [else] we get there," he said. "The markets are just not functional right now. … The ISOs have knuckled under to political pressure. And they're not speaking what they believe. I think they're saying what the politicians want to hear. And that's dangerous, because … they're the ones that are going to make sure whether this thing works or not. So we need them to speak up about their grids. And I'm concerned that they are not doing that."

Increasing Gas Prices, Availability Concerns

In the short term, the speakers said, the increasing price of natural gas and its limited availability are a threat to New England's energy security.

"So far, it has been a warm winter, and we may skirt through, but prices are certainly projected to be very high in the region," Lambert said. New England would benefit from a new pipeline that could bring in cheaper gas from outside the region, "but that's very, very difficult, if not impossible, to get done."

The increasing globalization of natural gas prices through LNG also is a concern, Wright said. "Algonquin [Gas Transmission Pipeline] prices are high right now because we think it's going to be cold in China," she said. "That's mind-blowing after decades of focusing on gas as a very local matter."

Saxena said that although his company has firm gas transport agreements for many of its New England assets, "it's not 100%. And [additional] firm transport is just not available. … There is no price at which you can buy firm gas in this market."

ERCOT failed during the February winter storm "not because the generation wasn't there; it failed because gas wasn't there," he said. "New England is going to have the same issue."

Constraints in gas supply in the region will become more challenging as New England states push more renewable resources onto the grid, Morgan said.

"I think New England is the next region to be at risk [of a major blackout] with a lot of focus on offshore wind and a bitter hatred toward gas," he said. "I know that we've got some challenged gas assets that really are going to be needed for reliability reasons, given the intermittency of all the offshore wind coming." ■

"The markets are just not functional right now. … The ISOs have knuckled under to political pressure. And they're not speaking what they believe. I think they're saying what the politicians want to hear."

—Vistra CEO Curt Morgan

ISO-NE News

NEPOOL Reliability Committee Briefs

Bay State Wind Project Wins OK for Larger Turbines

The NEPOOL Reliability Committee on Dec. 14 approved the Bay State Wind project's request to increase its capacity by 40 MW, reflecting a move to larger turbines.

The committee found no negative reliability impacts resulting from Bay State's proposed array of 80 11-MW turbines south of Martha's Vineyard, Mass. The project, a joint venture of Ørsted and Eversource Energy, is scheduled to reach commercial service in May 2026.

The committee also signed off on transmission applications for the project including:

installation of two 140-MVAr synchronous condensers connected via 345/24-kV transformers;

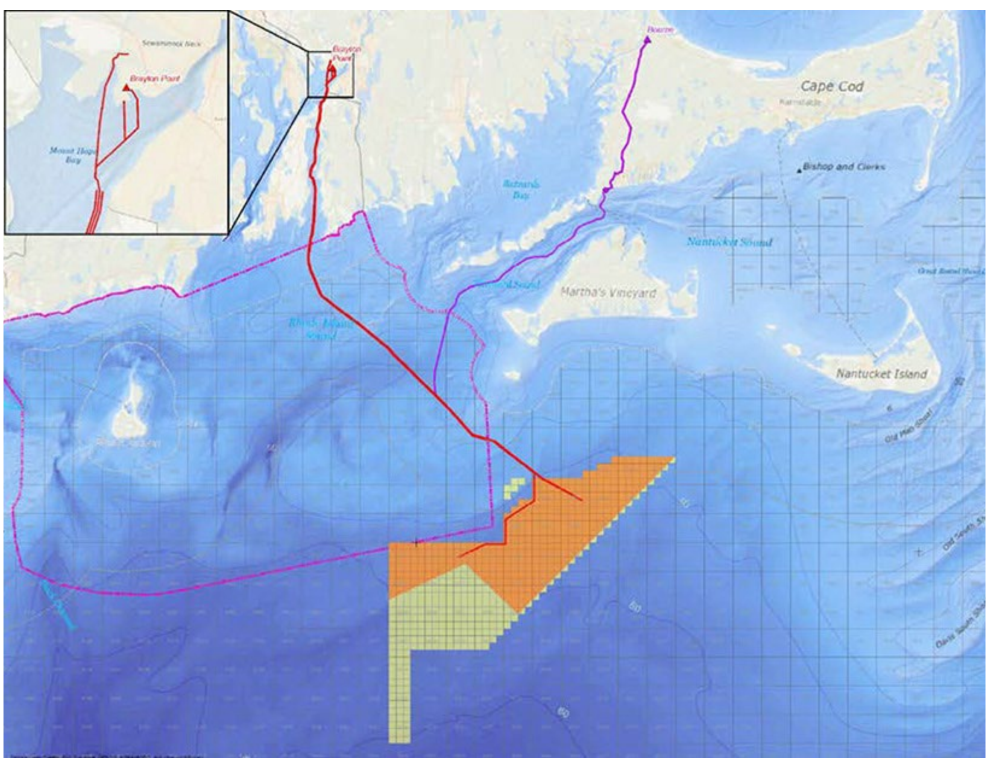
- construction of a 345/275-kV onshore substation;
- installation and interconnection of two 275-kV submarine, landfall and land cable circuits;
- installation of two 275/66-kV off-shore substations;

installation and interconnection of two 345-kV buried land cable circuits interconnecting at the Brayton Point 345-kV and Bay State Wind 345/275-kV onshore substations.

Order 2222 Compliance, Procedure Changes Approved

The committee also approved:

- changes to Planning Procedure 10 (Planning Procedure to Support the Forward Capacity Market), including conforming changes for ER21-640, related to qualification of non-commercial resources in annual reconfiguration auctions, and ER19-343, related to the modeling of peaking generation in reliability reviews;
- tariff revisions regarding auditing and installed capacity requirements as part of ISO-NE's compliance with FERC Order 2222, which allows aggregations of distributed energy resources to participate in the RTO's markets; the compliance filing is due Feb. 2, 2022;
- changes to Operating Procedure 16K (Transmission System Data – Submission of Short Circuit Data), part of a biennial review with minor updates to process flow diagram; and
- changes to Operating Procedure 3 (Transmission Outage Scheduling), part of biennial review with minor edits and grammatical revisions.



The Bay State Wind project will include 80 11-MW turbines south of Martha's Vineyard, Mass. | *Ørsted, Eversource Energy*

Other Projects

The committee also determined no negative reliability impacts from the following projects:

- installation of a 200MW/400-MWh battery storage project in Milford, Conn., which will interconnect to a new 345-kV breaker position at the East Devon substation (Able Grid Infrastructure Holdings, Eversource Energy and United Illuminating);
- installation of a 20-MW solar PV facility in Leeds, Maine, interconnecting to the Leeds Substation (Central Maine Power on behalf of Walden Solar Maine);
- installation of a 4-MW solar PV facility in Putnam, Conn., interconnecting to the Tracy 14M Substation (Eversource Energy on behalf of Glenvale Solar); and
- a generation group study for a 35.4-MW distributed energy resources project in the Winslow/County Road area and a 29.8-MW DER project in the Lakewood area of Maine. The generation clusters represent 20 DER facilities that would interconnect into Central Maine Power's sub-transmission and distribution systems.

The committee approved the following cost allocations for pool transmission facilities:

- $64.7 million of transmission upgrade costs for work associated with 115-kV and 230-kV wood structure replacement projects in Massachusetts, Connecticut and New Hampshire (Eversource);
- $186.3 million for 345-kV structure replacement projects in Massachusetts, Connecticut and New Hampshire (Eversource);
- $23.9 million for replacement of wood structures on the 1261/1598 115-kV line (Eversource).

Stein Re-elected Vice Chair

The committee re-elected Robert Stein, a consultant who represents H.Q. Energy Services, as vice chair for 2022. There were no other candidates. ■

— Rich Heidorn Jr.

MISO News

FERC Accepts MISO-SPP Congestion Charge Solution

Commission Orders Refunds to AEP, City of Prescott

By Amanda Durish Cook

FERC said Thursday that MISO and SPP can use a predictive flow factor process to offset overlapping congestion charges between the RTOs on pseudo-tied loads and resources (*EL17-89, et al.*).

However, the commission said the grid operators are not off the hook in refunding past excessive congestion charges.

FERC said the organizations can use the new process, which entails using forecasted rather than historical data, to determine the relief necessary on a market-to-market (M2M) flowgate. MISO and SPP said a predictive process will allow them to provide more precise redispatch relief on constraints.

The RTOs pledged to use the process in the first couple of intervals after an M2M event begins. The update to their joint operating agreement will become effective at the end of March 2022, when the RTOs will complete software design and testing.

FERC agreed that the solution would dramatically cut or reduce the duplicative charges.

The commission said in late 2019 that it would investigate overlapping congestion charges between the grid operators after complaints from American Electric Power (AEP) subsidiary Southwestern Electric Power Co. and the city of Prescott, Ark. FERC has since held a technical conference on the matter, ruling that MISO and SPP must correct the problem and rejecting challenges from the RTOs. (See *FERC Upholds Decision on MISO-SPP Overlapping Charges*.)

AEP and Prescott argued that it won't be clear for months whether the new process is a sufficient solution and asked FERC that its acceptance be conditional. The commission responded that the predictive flow factor remedy should represent an improvement over the RTOs' "uniquely excessive" congestion charges, reminding AEP and Prescott that "the RTOs cannot provide perfectly calibrated redispatch to match the exact congestion relief required."

However, FERC ordered the grid operators to submit three annual joint informational reports through early 2025 to describe whether the solution works in practice and to list any post-implementation challenges.

FERC: Refunds in Order

FERC set hearing and settlement judge procedures to establish appropriate refunds due to AEP and Prescott.

The RTOs had said the refunds would be too onerous to calculate. They said the calculations would be tantamount to re-running the market and asked FERC to exercise its discretion in not ordering the refunds.

MISO and SPP said that "by only correcting the relief amount during any given interval, without taking into account the many variables that occur during real-time operations, the results of the calculations would be, at best, an unverifiable estimation."

FERC countered, "We believe that providing recovery to AEP and Prescott for the unjust and unreasonable overlapping congestion charges they incurred during the refund period outweighs the RTOs' concern that calculating refunds for AEP and Prescott would be burdensome and lead to unverifiable estimates."

Before proposing their solution, MISO and SPP had argued that though duplicative congestion charges are possible for their pseudo-tie transactions, mechanisms such as virtual transactions, financial transmission rights and firm flow entitlements counteract double charging.

MISO maintained that congestion charges on the RTOs' pseudo-tied generation don't require special tariff remedies similar to the measures it took to correct double charging with PJM. MISO said it did not experience near the pricing impacts that it used to with PJM transactions. ■

Line work in AEP's Southwestern Electric Power Co. territory | *SWEPCO*

MISO News

FERC Grants Comment Extension for MISO Capacity Filing

By Amanda Durish Cook

FERC has granted stakeholders a 24-day extension until Jan. 14 to file comments on MISO's plan to redefine its capacity market during the 2023-24 planning year. Interested parties originally had until today to comment.

MISO has requested commission approval to conduct four seasonal capacity auctions, with separate reserve margins and using a seasonal accreditation based on a generating unit's past performance during tight conditions (ER22-495).

The grid operator has also *filed* separately to create a minimum capacity obligation, where a MISO load-serving entity must demonstrate that at least 50% of the capacity required to meet their peak load is secured ahead of the voluntary capacity auction (ER22-496).

The RTO originally intended that a minimum capacity rule would be part of the seasonal auction design, but stakeholders said including the rule could risk FERC's rejection of the entire capacity design.

The grid operator made both filings on Nov. 30 despite stakeholder discomfort with the design's capacity accreditation and minimum capacity requirement components. They asked MISO to only file the seasonal auction and do further work on the availability-based accreditation before sending it to FERC. (See *Last-minute Unease over MISO's Seasonal Accreditation*.)

Entergy asked for more time to comment on the seasonal auction and accreditation and a coalition of clean energy groups asked for an extension of the minimum capacity obligation. Both said the filings were too long and complex to digest and file comments before the holidays.

"The MISO region is experiencing significant shifts in generation resource retirement, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins," the RTO explained in its *filing*.

Organization of MISO States President Julie Fedorchak said the current annual reserve margins and accreditation have clearly become inadequate.

"The dynamics of the system are far, far different today," she said during MISO's December Board Week.

MISO's Richard Doying said the new accreditation is necessary because it no longer relies on a forced outage rate for generators, but on a question of "were you there when we needed you?"

"We're trusting that we're setting ourselves up for the situation that's on the doorstep," MISO Executive Director of Market Development and Design Scott Wright said during a special November workshop to discuss the filing with stakeholders.

MISO made two late additions to its seasonal proposal in November. It will now factor in when generation owners make facility upgrades that stand to increase their capacity accreditation. In those cases, the RTO said it will reflect the generators' increased capability in accreditation values.

The grid operator also said its zones can seasonally clear beyond its annual $257/MW-day cost of new entry (CONE). It said some seasons could clear in near-shortage conditions, making a clearing price of up to $1,000/MW-day appropriate.

Under MISO's current planning resource auction setup, the maximum clearing price is set at CONE, which is calculated by dividing the new generator costs over 365 days. Now, CONE will be divided by a season's days.

MISO said multiple seasons could possibly clear in near-shortage conditions, stacking revenues in excess of the annual CONE value. Should that happen, staff would retroactively reduce the clearing prices. Because the adjusted prices could create revenue sufficiency problems for generators MISO has proposed issuing make-whole payments in those instances.

Stakeholders have asked the RTO to first estimate the impacts of the auction's greater offer cap. Some said pivotal suppliers in certain zones could manipulate an auction by making higher offers.

Staff has said suppliers are still bound to the Independent Market Monitor's conduct thresholds and their own facility-specific reference levels. ■

Work at an Xcel Energy nuclear power station | *Xcel Energy*

MISO News

FERC Sits Out One Grand Gulf Tax Dispute

By Amanda Durish Cook

FERC told the Louisiana Public Service Commission Thursday that it would not appoint a discovery master or settlement judge in an ongoing dispute over Entergy's decommissioning deduction for its Grand Gulf Nuclear Station.

The PSC is attempting to compel Entergy subsidiary System Energy Resources, Inc. (SERI) to hand over accounting information and discussion notes with the IRS and understand the sudden decision to forgo a deduction it has enjoyed and renewed for 17 years (*ER21-142*).

However, the tax clash will continue to play out in another FERC docket.

The federal commission said in its order that state regulators were raising their arguments under an informal challenge as an interested party and that they needed a more formal channel for those measures.

The PSC filed the information request through a 2020 amendment to SERI's formula rate protocols that allows interested parties to request information and submit informal challenges to unit power sales agreements. The commission claimed it needed to better understand Grand Gulf's 2020 formula rate inputs.

SERI owns 90% of the 1,400-MW Grand Gulf plant in Port Gibson, Miss., and sells the plant's output under a FERC-regulated wholesale rate to Entergy's Arkansas, Mississippi, Louisiana and New Orleans subsidiaries. It's taken a tax deduction since 2003 for future costs of shuttering the plant.

The Louisiana commission alleges SERI's Grand Gulf power sales agreements contain "millions of dollars of unjust and unreasonable charges" because it didn't reflect the decommissioning tax benefit in its rates. The PSC has accused Entergy of collecting money from ratepayers for taxes that were never paid.

The Louisiana commission and Entergy are involved in a separate docket before FERC over whether the utility violated filed rate doctrine by neglecting to include the decommissioning deduction as a rate base offset. The federal commission this year set that case for settlement hearings to determine customer refunds (*ER21-748*).

SERI relinquished its decommissioning deduction in 2020 following an IRS Notice of Proposed Adjustment that disallowed more than $1 billion of the deduction. The subsidiary quickly accepted the settlement and Entergy said it's the net operating loss carryforwards would absorb the adjustment's costs.

The Grand Gulf plant has been criticized in recent years for its persistent *unplanned outages*. Earlier this year, the PSC was joined by the Arkansas Public Service Commission and the New Orleans City Council in a FERC complaint over the plant's malfunctions and performance issues. The trio *argued* that Entergy should refund customers the $800 million spent on *upgrades* to the plant in 2012. They also said Entergy should refund its customers the $361 million in power purchases it has had to make when the station was unavailable since the upgrade.

The Louisiana PSC has registered other grievances about Grand Gulf rates, arguing that SERI's return on equity was overstated. (See *FERC Rebuffs Challenges to Grand Gulf Ruling*.) ■

Grand Gulf nuclear station | *Entergy*

MISO News

MISO-SPP M2M Settlements Exceed $200M

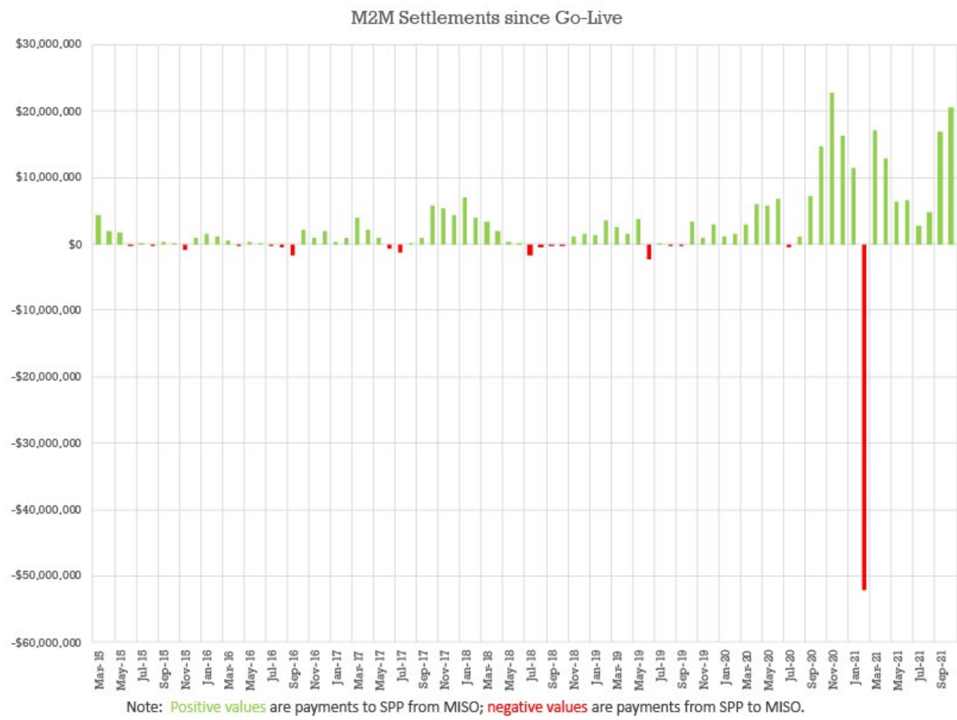
By Tom Kleckner

SPP's market-to-market (M2M) settlements with MISO exceeded $20 million in October for the second time in 12 months, staff told the Seams Advisory Group Wednesday.

The $20.59 million in settlements, which accrued in SPP's favor, pushed the M2M payments due to SPP to $203.87 million since the grid operators began the process in March 2015.

Permanent and temporary flowgates were binding for more than 1,875 hours in October. Outages and power swings from nearby wind increased shadow prices. The grid operators exchange settlements for redispatch based on the non-monitoring RTO's market flow in relation to firm-flow entitlements.

M2M settlements hit a record $51.49 million, in MISO's favor, in February, thanks to February's winter storm. Settlements have accrued to SPP during the eight months since February and for 23 of the last 25 months.



Market-to-market settlements have exceeded $200 million in SPP's favor. | *SPP*

New SAG Members

The group welcomed new members Luke Haner of Omaha Public Power District and Brenda Prokop of ITC Great Plains to their first meeting.

The SAG still has three open seats that it plans to fill next year. With a membership normally dominated by transmission owners, the group hopes to diversify by targeting larger retail customers and generation developers when it seeks applications after Jan. 1.

Rate Pancaking Issues

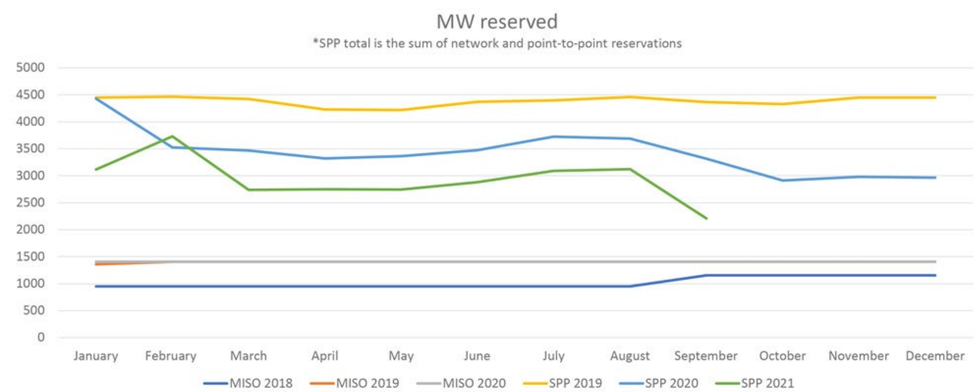
The Seams Liaison Committee's (SLC) Pancaking Working Group met briefly Wednesday to review survey results of *stakeholders' pancaking issues* and its *information request* of SPP and MISO.

Only five of 20 respondents to the stakeholder survey said their companies have experienced a failed cross-seam transaction, transmission project or interconnection project because of rate pancaking issues. Twelve said rate pancaking is a factor when seeking long-term generation commitments and half said the same for siting or accessing generation in a particular location.

Stakeholders said reservations timing is not consistent between the RTOs. SPP charges for all use of its transmission system, including unreserved use, while MISO only bills for network services taken, not reserved, at the time of the monthly system peak. MISO bills for transmission service each month based on actual usage at the zonal coincident peak, but SPP uses a 12-month rolling average.

The RTOs told the working group that 59 load-serving entities have transactions across the seam. MISO has three active point-to-point (PTP) service requests across the seam and SPP had 75 network service and PTP requests.

Marcus Hawkins, the Organization of MISO States' executive director, said he has not yet sifted through all the data, leading to group to plan another meeting in January to take a deeper dive. The working group plans to present its findings to the SLC in February. ■



Point-to-point reservations across the seam | *Organization of MISO States*

NYISO News

NYPSC OKs Exelon Spinoff of 4 Upstate Reactors

By Michael Kuser

New York regulators on Thursday approved Exelon's plan to split its regulated transmission and distribution business and merchant nuclear power generation into two separate publicly traded companies (Case No. *21-E-0130*).

The Public Service Commission accepted a joint proposal by Exelon staff of the Department of Public Service, the state Attorney General, the Alliance for a Green Economy and the Long Island Power Authority for four upstate nuclear power plants to be spun off by Exelon.

The spinoff, Exelon Generation, will become part of a new, independent, publicly traded entity that owns the two-unit 1,918-MW Nine Mile Point nuclear power plants in Scriba, Oswego County; the 579-MW R.E. Ginna nuclear power plant in Ontario, Wayne County; and the 842-MW James A. FitzPatrick nuclear power plant, also in Scriba.

The New York Public Service Commission held its regular monthly session in hybrid fashion Dec. 16, meeting both in person and via videoconference. | *NYDPS*

NYPSC Chair Rory M. Christian | *NYDPS*

"Getting all the parties from disparate sides to sit at the table together to agree on this shows how significant their goals were of supporting the interests of New York," PSC Chair Rory M. Christian said. "The simple fact that we're going to be able to decommission these plants in 20 years, rather than the recommended 60, is a huge accomplishment. The financial protections you accomplished and achieved through these negotiations are just as significant."

FERC in August approved the corporate transfer proposal, determining the transaction to be "consistent with the public interest" (*EC21-57*). (See *FERC Sanctions Exelon's Plan to Split Utility, Generation Businesses*.)

The current operating licenses expire in 2029 for Ginna and Nine Mile Point 1, 2034 for FitzPatrick and 2046 for Nine Mile Point 2. The Nuclear Regulatory Commission (NRC) and the PSC required funds be set aside for the decommissioning of the facilities and the restoration of the sites.

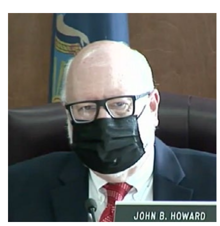
Operational Details

A lot of these issues were not as contentious as others for the parties, so working with the collaborative process seems to have worked here, Commissioner Diane X. Burman said.

NYPSC Commissioner Diane X. Burman | *NYDPS*

Exelon has an "extraordinary obligation" to the state of New York, considering the more than $7 billion in ratepayer money that supports the four units and without which these plants would have ceased operation some time ago, Commissioner John B. Howard said.

"Second of all, the parent of this company, it should be pointed out, has had serious corruption allegations in the state of Illinois, and those are being pursued by various law enforcement and prosecutorial entities in that state and with the federal government. So that was the background by which we started this case," Howard said.



NYPSC Commissioner John B. Howard | *NYDPS*

Exelon also has proven itself devoted to focusing on safety and reliability, Howard said.

In addition, the nuclear plants represent "a huge chunk of the overall central New York economy" and the people working at the facilities are "maybe the highest-paid and best-benefited workers in the region," he said.

Under the approved proposal, Exelon and Exelon Generation agreed to the following:

- Continuation of emergency operation facilities in New York;
- Depositing an additional $15 million in the remedial trust fund for Nine Mile Point Unit 2 and maintaining a minimum trust fund balance of $144 million per unit — or $576 million in total across the four units;
- Provide a 20-year projected backstop timeline for decommissioning following the end of licensed term rather than the 60 years allowed by the Nuclear Regulatory Commission;
- Acknowledgment of New York State's 10 millirem clean up guidance standard for residual radiation, rather than the NRC 25 millirem standard;
- Annual decommissioning trust fund reporting rather than the 2-year summary level reporting to NRC, and twice-a-year reports during decommissioning; and
- Provide an 18-month advance notice of shut down rather than the 12-month NYISO requirement.

Proposal supporters included the affected counties, the New York State Building and Construction Trades Council and the International Brotherhood of Electrical Workers, Local 97, representing approximately 4,700 electrical workers across upstate New York. ■

NYISO ICAP/MIWG Briefs

NYISO Monitor: Q3 Energy Prices Up Sharply Y-o-Y

NYISO energy markets performed competitively in the third quarter of 2021, with all-in prices ranging from $38/MWh to $117/MWh, up 62% to 94% from 2020 in all regions except New York City, which saw a decrease of 16%, the Market Monitoring Unit said Dec. 14.

"So there was quite a large spread, with particularly high prices in Long Island," said Pallas LeeVanSchaick of Potomac Economics as he presented the quarterly report on the ISO's electricity markets to the Installed Capacity/Market Issues Working Group.

Energy prices rose 68% to 124% primarily because of higher gas prices, which rose 110% to 139% across the system. The exception was New York City, which saw a decrease driven by lower capacity prices resulting from a lower locational capacity requirement, he said.

Nuclear output fell by an average of 820 MW/hour following the retirement of Indian Point 3.

Both 345-kV lines from upstate New York to Long Island were out of service for more than half of the days during the quarter, LeeVanSchaick said, which led to some "pretty extraordinary conditions on Long Island, very tight, with very volatile pricing."

He said the loss of the lines resulted in several "inefficiencies" including:

- Lack of reserve shortage pricing during Long Island capacity deficiencies;
- Understated reserve requirements in the day-ahead and real-time markets;
- Inflexible generator scheduling related to gas-balancing charges; and
- Over-accreditation of capacity for some conventional Long Island generation.

NYISO was able to substantially reduce the use of out-of-market dispatch to manage congestion on Long Island because they started modeling two 69-kV facilities, which were constrained on more than 80% of the days in the quarter, LeeVanSchaick said.

Despite several heat waves, load exceeded 30 GW on just one day, and transmission owners activated utility demand response on 10 days, mostly for peak-shaving.

NYISO applied supplemental resource evaluation (SRE) — a determination of the least-cost selection of additional generators to be committed — for statewide capacity needs on three days. Some of those SREs probably would not be necessary if there was more consideration of the utility DR deployments that are going to be called before the ISO makes the decisions, LeeVanSchaick said.

A tanker pushes through ice, outbound from Charlottetown, Prince Edward Island. | *Canadian Coast Guard*

The Monitor identified several categories of conventional generating capacity that may receive excessive accreditation under the current rules, which he said should be evaluated further.

"We do also still observe large quantities of out-of-merit commitment for operating reserve requirements that are not adequately reflecting the day-ahead and real-time markets ... both at the larger level as well as in more localized areas," he said.

Reserve Enhancements for Constrained Areas

Pallavi Jain, energy market design specialist, presented a study evaluating the feasibility of dynamically scheduling reserves in the security constrained unit commitment (SCUC), real-time commitment (RTC) and real-time dispatch (RTD) intervals

"We're looking at dynamically scheduling reserves because the current static modeling of reserves and the associated requirements may not optimally reflect the varying needs of the grid to respond to operating conditions," Jain said.

Based on all the mathematical formulations and the prototype, the ISO has determined that it is feasible to set dynamic reserve requirements based on the single largest contingency systemwide and using the available transmission headroom. However, this concept would need to be further developed and its applications to all reserve areas would need to be evaluated, Jain said.

The ISO made several recommendations, such as considering revising the approach for the determination of the single largest contingency from the current static requirement to a more dynamic methodology; applying the dynamic reserves approach to all reserve areas; and keeping the methodology consistent between the day-ahead and real-time markets to the extent practical.

Senior Manager Tariq N. Niazi presented a consumer impact analysis of the reserve enhancements for constrained areas, which looked at four scenarios based on conditions on Aug. 5, 2021, a hot summer day.

NYISO News

In three of the scenarios LBMPs decreased between $0.60/MWh and $2.60/MWh in different load zones and reserve clearing prices increased by less than $0.10/MWh in the reserve areas. A fourth scenario found an insignificant change in prices.

The ISO will continue working on the prototype in hopes of completing a market design proposal by December 2022 and implementation in 2025.

Coordinating Tx and Distribution

NYISO also *updated* stakeholders on a project to ensure coordination between transmission system operators (TSOs) and distribution system operators (DSOs) in compliance with FERC Order 2222.

The project will ensure that NYISO and the New York transmission operators have the communication protocols and procedures in place to maintain reliability as DER penetration increases, said Michael Ferrari, market design specialist in new resource integration. (See *NYISO Updates Grid in Transition Work and Plan for 2022*.)

The ISO has been working with the applicable member systems individually to identify transmission nodes, with those identified in the New York Control Area now totaling 115.

Transmission nodes are electrically similar facilities to which individual DER may aggregate as a DER coordinating entity aggregation (DCEA), represented by a single point identifier (PTID).

A transmission node might comprise several load nodes, which provide the most detail for NYISO system modeling and are associated with distribution stepdown transformers at facilities below the transmission level NYISO currently secures.

NYISO will present the list of transmission nodes at an ICAP meeting early in the first quarter of 2022.

NYISO and the investor-owned utilities in the state have created a framework to prohibit resources participating through an aggregator from receiving compensation for the same services as part of another program. The ISO's Order No. 2222 compliance filing proposes to require aggregators make attestations that its DERs are not providing the same service(s) in a retail market or program.

To prevent double counting, NYISO is collaborating with the utilities to develop a document identifying retail market services that conflict with wholesale market services.

This project and current coordination efforts will continue in 2022 with a focus on facility enrollment; metering and communications infrastructure and configurations; and NYISO administrative and operational manuals, an aggregation program manual, and supporting modifications to existing manuals, Ferrari said.

One stakeholder expressed concern that the ISO was working only with the utilities on DER participation and not with aggregators, saying the one-sided approach is a missed opportunity to encourage DER participation.

The ISO responded that any utility denying participation to DER must provide detailed data to back up its rationale and lay out steps the utility will take to improve market access in that specific case.

Prohibiting Critical Infrastructure Load from DR Programs

Responding to *NERC* and *FERC* guidance, NYISO is *proposing* to prohibit market participants from enrolling critical infrastructure load in its demand response programs. (See *Grid Faces Multiple Risks in Winter Months, NERC Warns*.)

Critical infrastructure is load needed to deliver natural gas, fuel oil, and other fuels used to supply generation, and load otherwise likely to impact the supply of fuels to generators serving the New York Control Area, said Francesco Biancardi, market design specialist. It includes natural gas compressors, LNG storage facilities, fuel oil suppliers, refineries and control centers.

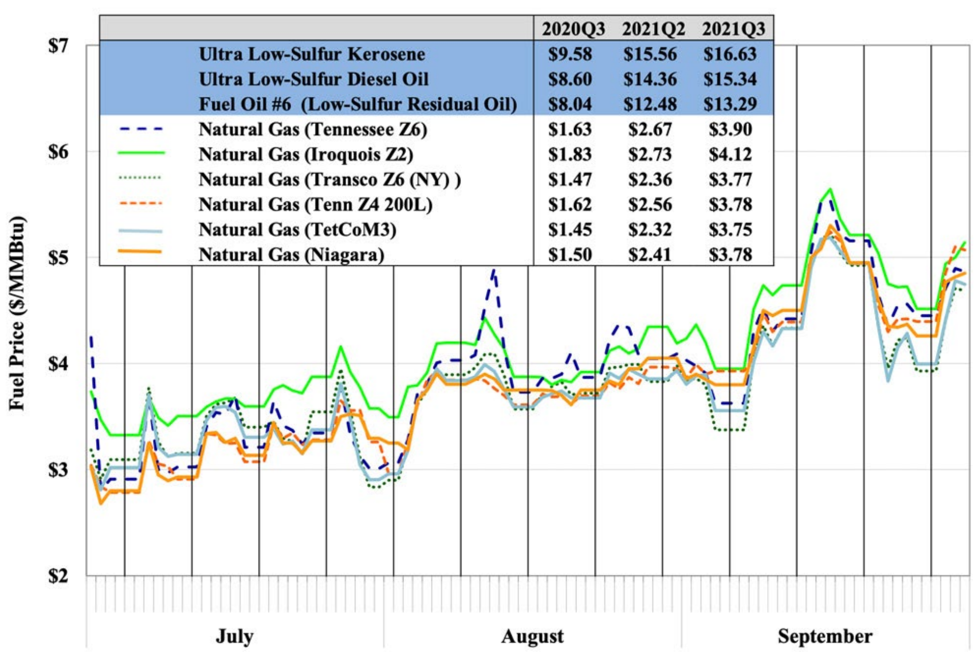
NERC on Oct. 6 submitted a Standard Authorization *Request* to address extreme cold weather grid operations, preparedness and coordination. Recommendation No. 8 states that "balancing authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response."

In January 2021, approximately 1,071 kW of curtailment capability was offered by special case resources (SCRs) that include critical infrastructure load, according to an ISO survey of DR providers. About 175 kW of such curtailment capability was offered in July 2021.

While the total kW of demand response load is small as compared to total system MW, it is possible that curtailment of a small amount of critical infrastructure load could have a material impact on generator availability, Biancardi said. For example, curtailment of a few kW of natural gas compressor station load could cause an outage of many MW of generation, Biancardi said.

The ISO is working toward implementation before Winter 2022/23. ■

— Michael Kuser



Third quarter 2021 natural gas and fuel oil prices in the New York Control Area | *Potomac Economics*

New York Issues 10 GW Solar Roadmap for 2030

By Michael Kuser

New York officials on Friday *announced* the release of a *roadmap* outlining expanded programs to achieve 10 GW of distributed solar in the state by 2030 (Case No. *21-E-0629*).

The state defines distributed solar as projects under 5 MW, including rooftop installations and community solar projects. The new framework builds on New York's solar energy progress so far, with installed distributed solar and projects under development already totaling 95% of the current state goal of 6 GW by 2025.

"Strengthening our commitment to solar energy will help build healthier, more resilient communities while catalyzing quality, good paying new jobs in this thriving sector of our clean energy economy," Governor Kathy Hochul said in a statement.

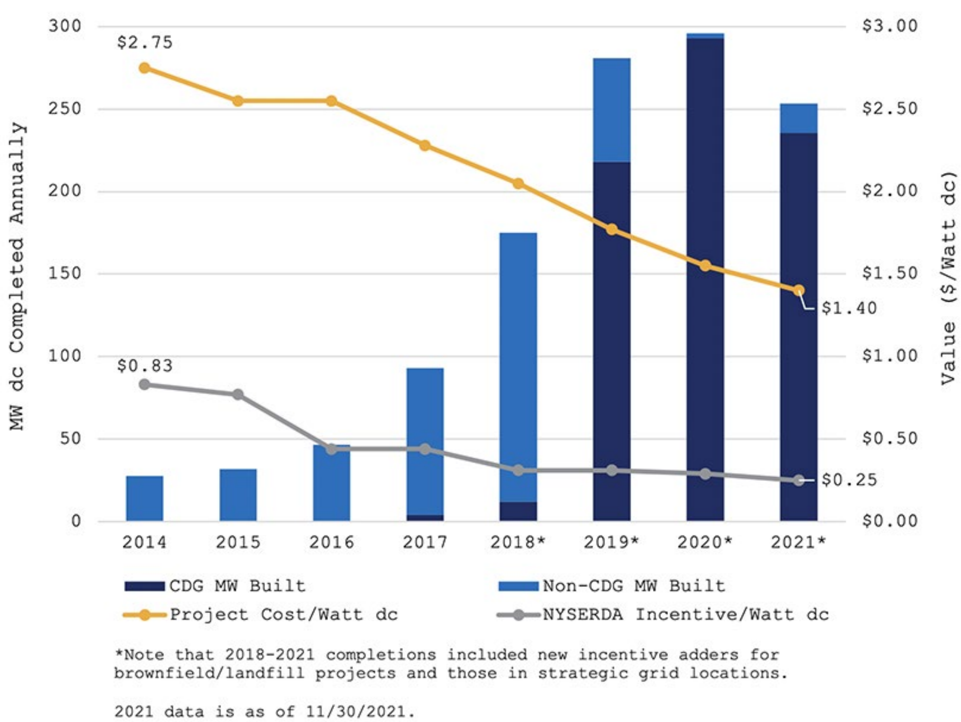
The New York State Energy Research and Development Authority (NYSERDA) and the Department of Public Service (DPS) submitted the roadmap to the Public Service Commission for public comment.

The expanded *NY-Sun* initiative aims to incent the construction of at least 1,600 MW of new solar capacity to benefit disadvantaged communities and low-to-moderate income New Yorkers, and proposes that at least 450 MW be built in Con Edison's service territory covering New York City and parts of Westchester, increasing installed solar capacity there to more than 1 GW by the end of the decade. NYSERDA also proposes that at least 560 MW be advanced through the Long Island Power Authority.

The proposal would require workers associated with projects supported by NY-Sun that are greater than 1 MW be paid the applicable prevailing wage, although projects that submitted their initial utility interconnection application prior to the Dec. 17 filing of the roadmap would be exempt from that requirement.

NYSERDA and the DPS estimated that the new solar push would direct $600 million in investments toward disadvantaged communities, with the Climate Leadership and Community Protection Act (CLCPA) mandating that at least 35% of the benefits from the state's renewable energy spending go to such communities.

The proposal estimates that the solar program expansion will spur $4.4 billion in private investment and create 6,000 additional solar jobs across the state.



Annual C/I distributed solar development under the program has grown substantially over time despite declining incentive levels, with two-thirds of the total 1,232 MW of C/I distributed solar capacity completed in 2019-21. Most of these completed projects were structured as CDG, as shown here. | *NYSERDA*

A *study* commissioned by the New York Climate Action Council's Just Transition Working Group last month predicted that the state's clean energy sector will add at least 211,000 jobs this decade and nearly 350,000 by mid-century, and that 10 new jobs will be created for every job displaced through 2030 by the state's transition away from fossil fuels. (See *NY Predicts 200K+ New Clean Energy Jobs by 2030*.)

Questions and Answers

To ensure funding for the incremental 4 GW target, NYSERDA proposes ratepayer collections of nearly $1.5 billion through 2032. The cost of up-front incentives would be distributed across utilities proportional to load via a Clean Energy Fund surcharge.

Funding would not require new processes or ongoing settlements between utilities or NYSERDA. NYSERDA's cashflow analysis has been updated to reflect the projected expenditure forecast of the $1.47 billion.

"Assuming collections occur over the 11-year period of 2022-32, the average levelized ratepayer bill impact is 0.79%," the roadmap said. "The levelized impact on residential bills would be $0.71 per month. Expenditures, collections, and ratepayer impact are forecasted to peak in 2024. The 2024 bill impact is calculated at 1.07%, with an average 2024 statewide residential bill impact of $0.92 per month."

The Public Service Commission on Thursday *approved* NYSERDA's 2022 Clean Energy Standard compliance period administrative budget in the amount of $30.2 million, up from $28.4 million this year (Case No. *15-E-0302*).

PSC Commissioner Diane X. Burman, one of two Republicans on the seven-member commission, said that while it's reasonable that the NYSERDA team must grow as the workload continues to grow, the commission needs to engage in more discussion about how the state will deal with legislation that creates significant cost drivers.

"I believe very strongly that we should look at the proper resources, staff resources across the board," Burman said. "I'm tired of it just being NYSERDA who we're looking at ... I'm left with blanks."

Under the same CES proceeding, nuclear energy advocacy group New York Energy and

NYISO News

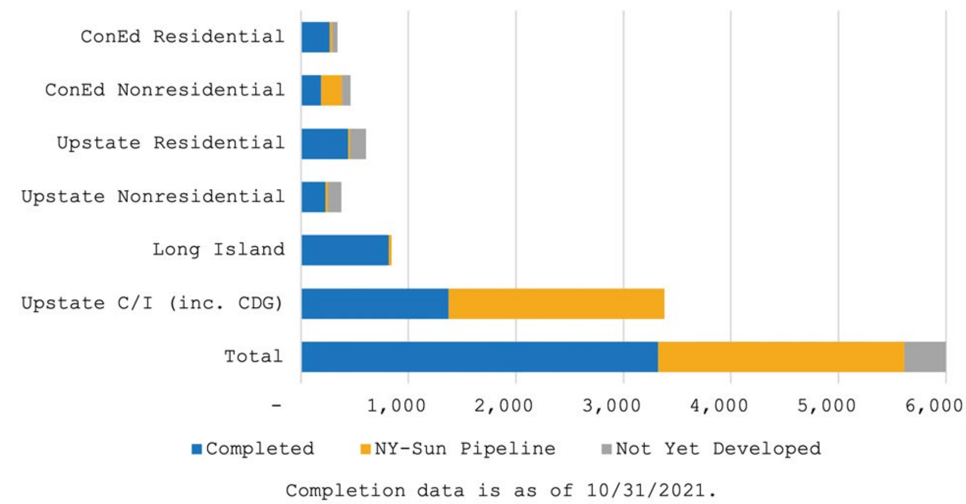
Climate Advocates on Dec. 7 submitted to the PSC a *query* regarding differences between NYSERDA's analysis of the steps needed to meet CLCPA goals and analysis of the same subject by NYISO.

The letter signed by Leonard Rodberg referred specifically to a *presentation* of clean energy integration scenarios and analysis provided by NYSERDA and consultancy Energy and Environmental Economics (E3) at the Oct. 1 meeting of the Climate Action Council, and to the *Climate Change Impact Phase II* study conducted by Analysis Group on behalf of NYISO in September 2020. (See *New Analysis Sets Low-carbon Focus for NY Climate Plan*.)

"In our view, both analyses reveal an unrealistic buildout of intermittent, low-energy-density, low-capacity factor sources and related infrastructure that warrants the consideration of alternatives if New York hopes to meet its climate goals," Rodberg said. "We also recommend better coordination between agencies involved in crafting energy policy and entities charged with maintaining the reliability of New York's electric grid."

Rodberg said in the letter that since Oct. 1 he had written three times to Carl Mas, NYSERDA's director of energy and environmental analysis, and received no reply to his questions.

One question concerned NYSERDA's estimate of up to 126,047 GWh annual solar generation by 2050, which Rodberg said corresponds to a capacity factor of "almost 22%. However, the capacity factor of solar PV in New York is poor, only 14% for fixed panel and only 20% for tracking panels. How does NYSERDA explain this discrepancy? ... Did NYSERDA inadvertently use capacity factor data for a different state?"



An overview of the progress made toward the 6 GW target, by development phase, market sector, and region. Most of the progress to date has been in the Upstate region for C/I onsite and community solar projects. | *NYSERDA*

In response, NYSERDA told RTO Insider that it has provided an "unprecedented" level of transparency around the Integration Analysis presented to the Climate Action Council, with the most up-to-date inputs and key drivers published on the *CAC resource website*. The analysis team has conducted an in-depth study of the performance and cost of solar-PV technology specific to New York, the agency said.

NYSERDA said the state's solar PV capacity factors range from 13 to 21%, depending on the NYISO Zone (based on variation in solar irradiance by geography) and installation configuration, with large utility-scale tracking projects able to harness more power than fixed roof-mounted systems. ■

PJM News

PJM Releases Energy Transition Study

RTO Begins Multiyear Stakeholder Effort

By Michael Yoder

PJM kicked off what it said will be a multiyear initiative on the increasing integration of renewables Wednesday with the release of a study on the transformation of generation.

The paper, *Energy Transition in PJM: Frameworks for Analysis*, includes the RTO's preliminary five-year strategy built on three pillars: facilitating state and federal decarbonization policies, planning for the grid of the future and fostering innovation for the transition.

PJM told the Markets and Reliability Committee the study is designed to help the RTO identify gaps and opportunities in the current market construct and provide insights into the future of market design, transmission planning and system operations.

"As the generation mix continues to rapidly evolve in PJM, we must be ready to maintain the reliable, cost-effective delivery of electricity at all times," said CEO Manu Asthana. "This study represents an important step in understanding how PJM can best work to facilitate the energy transition and make the grid of the future possible."

Study Overview

Emanuel Bernabeu, director of PJM's Applied Innovation and Analytics department, presented a high-level overview of the study, saying PJM believes it can "play a major role" in facilitating the decarbonization transition through reliability and cost-efficiency measures.

PJM is also working on defining what the grid of the future will be and how it will be operated, Bernabeu said, and fostering innovation both internally at the RTO and within the stakeholder community.

"These are pretty heavy pillars, so it does require a strong foundation," Bernabeu said.

The first phase of the study was not meant for PJM to propose solutions, Bernabeu said, but to inform stakeholders on broad issues and initiate a discussion to "put some light" on areas that need focus.

Bernabeu called the paper a "living study" because the assumptions that went into the work will continue to be refined as PJM continues to look for opportunities to improve market designs, operations and planning.

The study considers three scenarios in which an increasing amount of energy is served by renewable generation. The "base" scenario included 10% of the annual energy in the PJM footprint coming from renewable generation, while the "policy" and "accelerated" scenarios had renewables representing 22% and 50% of the annual energy, respectively.

In the accelerated scenario, up to 70% of the dispatch was considered carbon-free when combined with nuclear generation. The accelerated scenario includes 29 GW of offshore wind, 36 GW of onshore wind and 55 GW of solar.

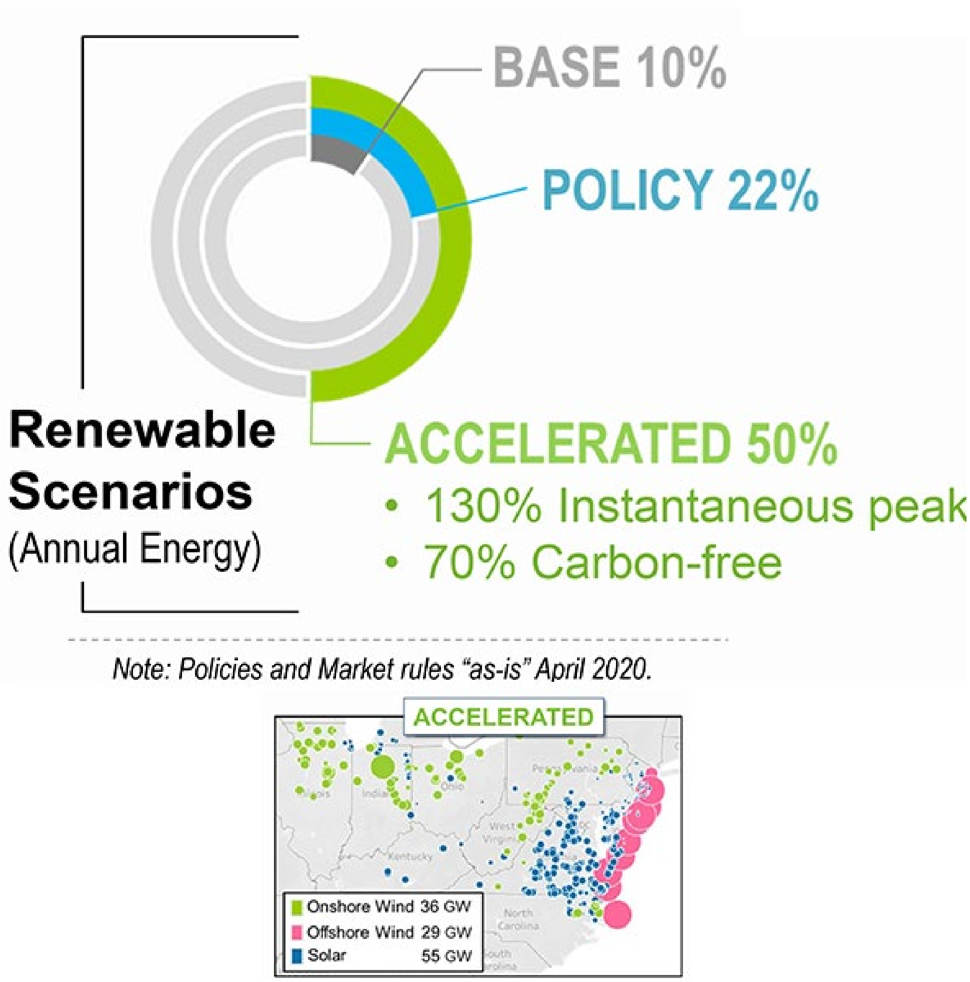
As of 2020, renewables represented 6% of PJM's annual energy, a total of more than 40% carbon-free including nuclear.

Bernabeu acknowledged that annual energy is "not the most intuitive metric." In the accelerated scenario, he said, there are periods of time when PJM is serving 130% of the load with renewables — with any generation over the 100% mark exported to other regions.

PJM studied the resource adequacy of the three scenarios and simulated an entire year of the energy market with an hourly resolution to see how the renewable resources will operate.

Bernabeu said the study's initial findings suggested five key focus areas for PJM's stakeholder community, including correctly calculating the capacity contribution of generators. He said transmission systems with increased variable resources will require "new approaches" to assess the reliability value of each resource and the overall system.

The study determined the need for "operational flexibility" to address the uncertainty of



PJM renewable scenarios studied in its energy transition report | *PJM*

PJM News

variable resources, Bernabeu said, including lower capacity factors for thermal resources and average locational marginal pricing (LMP) decreases of as much as 26%.

The report says thermal generators provide "essential reliability services," and an adequate supply will be needed until a substitute is "deployed at scale." Bernabeu said PJM and stakeholders should ensure market structures provide the necessary incentives to maintain the generation for reliability.

He said expected increases in congestion, renewable curtailments and interchange with other regions "suggest opportunities for strategic regional transmission expansion."

Reliability standards also must evolve, PJM said. The development of PJM's markets, operations and transmission planning must be accompanied by the "advancement of comparable reliability requirements across interdependent infrastructure," Bernabeu said. "Reliability cannot be achieved in a vacuum."

Work on the study is expected to continue through 2022 with an updated report coming around the end of the first quarter of next year. "This study is not meant to be done and collect dust in your desk," Bernabeu said.

Stakeholder Questions

Bernabeu was asked about the modeling done in neighboring RTOs and ISOs and the assumptions that were used. Wind projects in *MISO* were highlighted as an example of potential impacts on generation in PJM.

Bernabeu said the export and interchange numbers in the first version of the study were based on modeling neighboring regions maintaining the status quo with transmission and generation.

"The models tend to be extremely detailed inside PJM, and then the accuracy tends to degrade the further you move away from the footprint," Bernabeu said.

Another stakeholder asked what PJM believes is an adequate supply of thermal generation.

Bernabeu said the first round of the study stopped short of making definitive quantitative assessments. He said there's not a definitive quantity of supply for adequacy, so sensitivity analysis is going to continue to seek answers.

Emanuel Bernabeu, PJM | © *RTO Insider LLC*

The most important aspect of the thermal focus area is how to incentivize behavior to maintain "essential reliability services," he said.

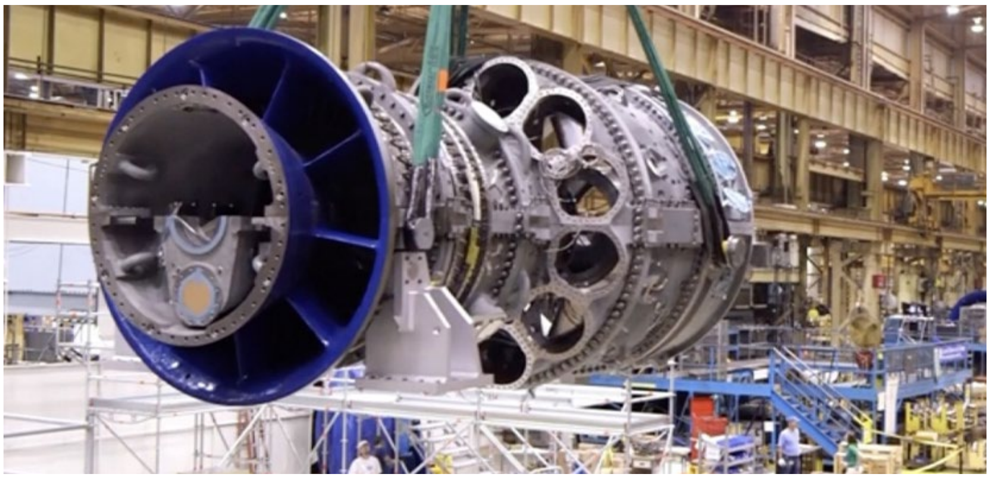
"What is adequate? We haven't found an answer yet," Bernabeu said. ■

PJM News

FERC Accepts PJM Black Start Tariff Revisions

FERC on Thursday accepted PJM tariff changes covering non-rate provisions for black start service, including commitment and termination periods, as well as outage and substitution restrictions (*ER21-1635-002*).

The letter order directed a further compliance filing within 30 days to make agreed-upon revisions to an initial compliance filing that set forth details concerning the formulaic capital recovery factor (CRF) that the commission found essential to the rates, terms and conditions of black start service.



7HA gas turbine | *GE Power*

PJM Market Monitor Joe Bowring in April said the CRF table was originally created in 2007 and included incorrect assumptions. Black start unit owners and other stakeholders asserted that any changes to the CRF table should only be applied prospectively, and any rates currently in place should remain changed. (See *PJM to File Black Start Proposal Without Members' Endorsement*.)

In October, PJM filed reply comments agreeing with the Market Monitor, explaining that the CRF formula used prior to June 6, assumed a 100-MW combustion turbine plant with a $1,000,000 capital investment. The RTO agreed that the formula no longer uses those assumptions and asked to remove the references to the assumed type of unit. ■

— Michael Kuser

PJM MRC/MC Briefs

Markets and Reliability Committee

Synchronous Reserve Endorsed

Stakeholders at Wednesday's Markets and Reliability Committee meeting endorsed a PJM proposal to improve the deployment of synchronized reserves during a spin event.

The proposal, which was developed from discussions in the Synchronized Reserve Deployment Task Force (SRDTF) and endorsed at the November Operating Committee meeting, received a sector-weighted vote of 3.77 (75.4%), surpassing the necessary 3.335 threshold for endorsement. (See "Synchronous Reserve Endorsed," *PJM Operating Committee Briefs: Nov. 4, 2021*.)

Ilyana Dropkin, an engineer in PJM's performance compliance department, *reviewed* the proposed solution and corresponding *tariff* and Operating Agreement revisions addressing synchronous reserve deployment.

Synchronized reserve events are emergency procedures triggered by PJM to maintain grid reliability in accordance with NERC's Resource and Demand Balancing (BAL) standards. The RTO invokes those procedures under conditions such as the simultaneous loss of multiple generating units or a sudden influx of load.

The SRDTF examined ways to secure controlled deployment of synchronized reserves throughout emergency events by using tools such as real-time security-constrained economic dispatch (RT SCED) to maintain consistent pricing and dispatch signals. Dropkin said the goal was to ensure BAL compliance during the recovery process and maintain a reliable transition in and out of emergency events and to define clear rules and expectations that address how PJM operators approve RT SCED cases around a synchronized reserve event.

PJM's proposal creates an intelligent reserve deployment (IRD), a 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 takes the megawatts of the largest generator contingency and adds 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.

| National Renewable Energy Laboratory

Some of the significant changes over the status quo in the proposal include updating the economic basepoints to replace all-call instructions, Dropkin said, along with having active constraints controlled by IRD so that deployed resources don't have negative impacts on the constraints.

PJM is looking at a phased approach for IRD, with an initial phase of six to 12 months beginning as soon as March.

IRD updates will be provided at OC meetings beginning next year, including a review of performance metrics and solicitation of feedback and a finalized deployment approach and adjustment for upcoming reserve market changes.

"IRD is an out-of-the-box solution that seamlessly integrates into PJM's existing dispatch applications," Dropkin said.

Mike Bryson, PJM | © *RTO Insider LLC*

Mike Bryson, PJM senior vice president of operations, said the RTO has always been focused on recovering reserves as quickly as possible "to be ready for the next bad thing to happen." Bryson said the proposal retains that focus for reliability issues.

Susan Bruce, PJM ICC | © *RTO Insider LLC*

Susan Bruce, counsel to the PJM Industrial Customer Coalition, said the ICC "continues to have concerns" with the proposal. Bruce previously brought up issues with the proposal at the November MRC meeting, saying IRD didn't appear to be the correct solution. (See "Synchronous Reserve Deployment Stakeholder Initiative," *PJM MRC/MC Briefs: Nov. 17, 2021*.)

"As PJM goes out to get reserves that we're going to call 'shortage,' I think it is problematic from our perspective and a just and reasonable rate perspective," Bruce said.

PJM Monitor Joe Bowring | © *RTO Insider LLC*

Market Monitor Joe Bowring said he believed the status quo was preferable to PJM's proposal because the IRD will result in "inefficiently high prices." Bowring

PJM News

said RTO load under IRD would continue to increase by the largest contingency megawatts even though "that's generally too big" and results in overresponse during spin events.

Sean Chang of Shell Energy said his company supported PJM's proposal because it "takes a step in the right direction."

The proposal will have a final endorsement vote at the January Members Committee meeting.

Regulation Market Senior Task Force Endorsed

A new senior task force aimed at examining PJM's current regulation market design was unanimously endorsed by stakeholders as discussions continue on how to advance a short-term solution to the undefined regulation mileage ratio calculation issue debated for several months.

Danielle Croop, PJM | © *RTO Insider LLC*

Danielle Croop, senior lead market design specialist at PJM, reviewed the *problem statement* and *issue charge* first presented at the November MRC meeting. (See "Undefined Regulation Mileage Ratio Calculation," *PJM MRC/MC Briefs: Nov. 17, 2021*.)

Croop said the language in both documents was similar to language that created the former *Regulation Market Issues Senior Task Force* that last met in 2017. Stakeholders at the June 2017 MRC meeting agreed on a proposal developed in the task force that changed compensation in the regulation market. (See *PJM Regulation Compensation Changes Cleared over Opposition*.) The proposal was ultimately rejected by FERC. (See *FERC Rejects PJM Regulation Plan, Calls Tech Conference*.)

The proposal to look at the regulation market design came in response to stakeholder feedback at the October MRC meeting after stakeholders rejected two different proposals to change the undefined regulation mileage ratio calculation in *Manual 28* and the *tariff*. (See "Regulation Mileage Ratio Fails," *PJM MRC/MC Briefs: Oct. 20, 2021*.)

Regulation mileage measures the amount of movement the regulation control signal requests of a resource; it is calculated for the duration of the operating hour for each regulation control signal.

PJM's performance-based regulation market splits the dispatch signal in two: RegA for slower-moving, longer-running units; and RegD for faster-responding units that operate for shorter periods, including batteries. If a signal is "pegged" high or low for an entire operating hour, the corresponding mileage would be zero for that hour.

The RTO has witnessed an increase in the frequency and duration of RegA signal pegging, highlighting a potential problem in the regulation mileage ratio calculation. The RegA mileage can be set at zero for a given hour and create a divide-by-zero error in the calculation of the mileage ratio.

PJM proposed setting the RegA mileage floor at 0.1 instead of zero, which would provide a solution for the division ratio and still maintain market design objectives while having no impact on the regulation signal design, operations or regulation market clearing.

The Independent Market Monitor proposed a cap of 5.5 on the realized mileage ratio in all hours instead of 0.1, indicating the cap would eliminate the current undefined mileage ratio result that PJM is attempting to address.

Members said other larger issues with the regulation market needed review besides the undefined regulation mileage ratio calculation, and PJM said it supported a broader review through a new task force. (See "RTO to Propose Review of Regulation Market," *PJM MIC Briefs: Nov. 3, 2021*.)

Key work activities in the task force issue charge include regulation market education, evaluating the benefits factor curve and proscribed RegA/RegD commitment percentages, and proposing any modifications to the regulation market to address issues raised in the evaluation. Expected deliverables include potential modifications to the regulation market and changes to the tariff, OA and manuals resulting from the regulation market modifications.

Areas up for evaluation include signal design, performance scoring, regulation market clearing and regulation settlement.

Croop said the review is expected to take 12 months and would start sometime in the second or third quarter of 2022.

"This will really give us the opportunity to evaluate any operational or market components of the regulation market design," Croop said.

Adam Keech, PJM vice president of market design and economics, discussed the next steps the RTO was examining to resolve the undefined regulation mileage ratio calculation issue. Keech said PJM had a couple conversations with the Monitor since the November MRC meeting to find a compromise between the proposed RegA mileage floor values of 0.1 and 5.5, but did not come to a compromise.

Adam Keech, PJM | © *RTO Insider LLC*

"We're just coming at this issue from two different angles," Keech said. "It's just two different views on how to tackle this issue."

If a short-term solution cannot be determined and a divide-by-zero error in the calculation of the mileage ratio occurs, Keech said, PJM would make a Section 206 filing with FERC to propose a replacement rate for the specific occurrence of the undefined mileage ratio.

Paul Sotkiewicz, E-Cubed Policy Associates | © *RTO Insider LLC*

Paul Sotkiewicz of E-Cubed Policy Associates said he was interested in having discussions on market designs but didn't want to see a RegA mileage floor number "picked out of a hat" without justifying the chosen value.

"We're not prepared to support just any number just for the sake of getting a number in there," Sotkiewicz said.

Bowring said the current regulation market design is not working properly, and the undefined mileage ratio is "one symptom of it." He said a short-term fix would be the best outcome for now to solve for the problem while stakeholders discuss the broader issues.

"There is no magic to the exact number," Bowring said. "It's really up to the judgment of the participants to pick that number."

Tariff Revisions Rejected

Stakeholders rejected *proposed* revisions to *attachment DD* of the tariff endorsed by the Governing Document Enhancement and Clarification Subcommittee after being pulled from the consent agenda.

The committee voted against the revisions with a sector-weighted vote of 2.17 (43.4%), coming under the necessary 3.335 threshold for endorsement.

The revisions included removing section 6.2(c) of the attachment because FERC affirmed PJM's position that this section of the tariff was no longer applicable and encouraged the RTO to remove the provision as part of its next tariff clean-up filing.

In a complaint filed in June, Jackson Generation alleged that PJM violated section 6.2(c) of attachment DD by failing to file a report concerning the minimum offer price rule (MOPR) offer floor and other mitigation determinations made in connection with the Base Residual Auction for the 2022/23 delivery year within seven days of the deadline for the submission of sell offers into that auction (*EL21-82*).

FERC denied the complaint, saying the requirement to file a report detailing any determinations was "only applicable to the mitigation determinations that are 'identified in such sections as subject to the procedures of section 6.2(c),'" and that several provisions contained in the section "no longer state that they are subject to the procedures of section 6.2(c)."

The commission previously ruled in favor of Jackson Generation in a related filing in which the company challenged the rejection by PJM and the Monitor of its request to use an asset life of more than 20 years in calculating the plant's unit-specific exception to the MOPR. (See *PJM Must Consider Longer Asset Life for Generator*.)

Jeff Whitehead of Eastern Generation requested that the revisions be pulled from the consent agenda, saying that issues surrounding the unit-specific review process and the market seller offer cap (MSOC) for the upcoming BRA have created a desire among some stakeholders for more transparency in the process. (See *PJM Requests Rehearing of MSOC Change*.)

Whitehead said many of the negotiations on the unit-specific offer levels are "happening behind closed doors," and market participants of FERC don't have a "very clear view of exactly what the standards for review are."

Sotkiewicz made a motion to table the vote on the tariff revisions until the sunset of the Resource Adequacy Senior Task Force and discussions on the MOPR are complete. Sotkiewicz, who represents Jackson Generation, said the company continues to disagree with FERC's finding that section 6.2(c) was an "orphaned" part of the tariff and could be removed.

"The plain English is actually quite clear that there needs to be a report filed," Sotkiewicz said. "We need to shine some light on this."

The motion to table failed in a sector-weighted vote of 3.329 (66.5%), narrowly missing the necessary 3.335 threshold for endorsement.

Stu Bresler, PJM | © *RTO Insider LLC*

Stu Bresler, PJM's senior vice president of market services, said he appreciated the stakeholder discussion on the issue, adding the RTO will now examine next steps.

"I hear a very common desire for transparency in this area, so we will work towards that and figure out how to move ahead," Bresler said.

Solar-battery Hybrid Resources Endorsed

Stakeholders unanimously endorsed the proposed solution and corresponding *tariff* and Operating Agreement revisions to address market participation by solar-battery hybrid resources.

The proposal, which updates PJM's governing documents and manuals, was originally endorsed at the August Market Implementation Committee meeting with 99% stakeholder support before coming to the MRC. (See "Solar-Battery Hybrid Proposal Endorsed," *PJM MIC Briefs: Aug. 11, 2021*.)

Andrew Levitt, PJM | © *RTO Insider LLC*

Andrew Levitt, of PJM's market design and economics department, *reviewed* the RTO's solar-battery hybrid resources issue. Levitt said PJM conducted a prefiling meeting with FERC staff in September, and the commission made suggestions to reconfigure the language to increase its chances for approval. (See "Solar-battery Hybrid Resources," *PJM MRC/MC Briefs: Nov. 17, 2021*.)

One suggestion called for the term "hybrid resource" in the tariff to be structured as a largely independent resource-neutral category and not specifically about solar-battery resources.

Levitt said the proposal was intended to clarify energy and ancillary services market participation rules, including metering and telemetry and basic operational requirements, with the tens of gigawatts of solar-battery mixed technology facilities currently in the PJM queue.

PJM was hoping to present the exact tariff language presented at the November MRC meeting for a vote, Levitt said, but staff found some "minor clerical errors."

Levitt said the RTO hopes to go live with the new energy market model for hybrid resources in mid-2023.

A final vote on the proposal will take place at the January MC meeting.

Consent Agenda

As part of the consent agenda, the committee endorsed several revisions to:

- *Manual 6: Financial Transmission Rights*, conforming to the joint PJM-stakeholder proposal addressing auction revenue rights (ARR) and financial transmission rights (FTR) endorsed at the October MRC. The changes were initiated after the GreenHat Energy default in 2018, including a six-month review by an independent consultant and work done at the ARR/FTR Market Task Force. (See *Stakeholders Endorse PJM ARR/FTR Market Changes*.) Seven stakeholders abstained from the vote on the Manual 6 revisions.
- *Manual 10: Pre-Scheduling Operations* resulting from a periodic review. The revisions were endorsed at the November Operating Committee meeting. (See "Manual Changes Endorsed," *PJM Operating Committee Briefs: Nov. 4, 2021*.)
- *Manual 14B* revisions resulting from a biennial review. The revisions include the addition of a new section that features details about the incorporation of end-of-life needs in the Regional Transmission Expansion Plan, which were part of the tariff attachment M-3 discussions. (See "Manual Endorsements," *PJM PC/TEAC Briefs: Nov. 2, 2021*.)
- *Manual 14D: Generator Operational Requirements* resulting from a periodic review. The updates featured the addition of several new sections, including one describing eDART modeling requirements. (See "Manual Changes Endorsed," *PJM Operating Committee Briefs: Nov. 4, 2021*.)

Members Committee

Sector Selection Challenge Process

Sharon Midgley, Exelon | © *RTO Insider LLC*

Stakeholders questioned a proposal at Wednesday's Members Committee meeting seeking to change the way members can be challenged on their chosen sectors in PJM.

Sharon Midgley, Exelon's director of

PJM News

wholesale market development, *presented* proposed revisions to the sector challenge process in the OA during a first read.

The issue of sector challenges has been a source of discussion at the Stakeholder Process Forum for the last 18 months. In 2020, Exelon and FirstEnergy requested that PJM more actively police stakeholder selections after the disclosure that an LS Power affiliate was improperly voting in the RTO's senior committees. (See *Exelon, FE Ask PJM to Tighten Sector Selection Process*.)

Under current rules, Midgley said, "questionable" sector selections of an existing member may only be challenged one time per year, coming within 30 days of the Annual Meeting. Challenges to a new member's sector selection must be made within 30 days of the new member joining PJM.

In the last three years, Midgley said, PJM has required changes to the sector selections of 14 members, determining that a sector modification was warranted for 88% of challenges.

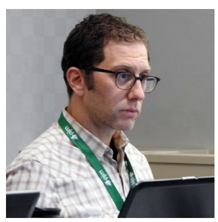
The proposed solution calls for revising Section 8.1.3 of the OA, saying any member may request that PJM review the qualification of another member to participate in a sector "if the basis for such challenged member's qualifications have not been subject to a sector challenge review in the prior 24 months, unless there is a material change in the challenged member's business interests with PJM."

The revised language also calls for removing the 30-day requirement from the Annual Meeting. Midgley said the requirement can be "challenging" for stakeholders to do "proper investigative work" on a sector challenge.

"We've got over 1,000 members, and sometimes just a simple email with their name doesn't really tell you much about the business that they're in or the interest they have in PJM," Midgley said.

Bruce said the ICC has "concerns" about the proposal, and that members make "personal" decisions about how they want to engage with PJM in the stakeholder process. He said PJM has done a lot of work in recent years on the "know-your-customer" efforts and has taken a "harder look" at sector selections for members.

Bruce said she worries that stakeholders' ability to use the challenge process at any time of the year could become a "way of affecting voting outcomes."



Steve Lieberman, AMP | © RTO Insider LLC

"I worry about the integrity of our voting and our stakeholder engagement if there's a threat that someone may be sector challenged before an important vote," Bruce said.

Steve Lieberman, assistant vice president of transmission and PJM affairs for American Municipal Power, said the OA changes read "like we have a solution in search of a problem." Lieberman would rather see changes focused on the appeals process to a sector challenge.

The committee will vote on the proposed changes at the January MC meeting.

Sector Elections

Stakeholders unanimously endorsed the *slate* of sector representatives for the 2021/22 Finance Committee and the 2022 sector whips.

The new Finance Committee members include: Susan Bruce, PJM Industrial Customer Coalition (End-use Customer); Jeff Whitehead, Eastern Generation (Generation Owner); Bruce Bleiweis, DC Energy (Other Supplier) and; Alex Stern, PSEG Services (Transmission Owner).

The 2022 sector whips include: Adrien Ford, Old Dominion Electric Cooperative (Electric Distributor); Greg Poulos, Consumer Advocates of the PJM States (End-use Customer); Michael Borgatti, Gabel Associates (Generation Owner); Brian Kauffman, Enel N.A. (Other Supplier); and Sharon Midgley, Exelon (Transmission Owner). ■

— Michael Yoder

PJM PC/RMC Briefs

Planning Committee

Interconnection Process Proposals

Members praised work done by PJM in the stakeholder process in the development of new rules for the interconnection process, as four proposals were brought to last week's Planning Committee meeting.

Jack Thomas, of PJM's Knowledge Management Center, *provided* a first read of the new interconnection process proposals from the work done at the Interconnection Process Reform Task Force.

An issue charge for work to be completed was approved at the April PC meeting, with task force meetings starting later that month. (See "Interconnection Process Reform Endorsed," *PJM PC/TEAC Briefs: April 6, 2021*.)

Key work activities include studies related to the interconnection process and costs related to network upgrades; improving and clarifying the use of interim agreements; the process for rules and requirements for new service requests; and ways to reduce the interconnection queue backlog.

Stakeholders also discussed how PJM will transition to a new interconnection process. Thomas said a separate slate of transition proposals is still being developed and will be presented for a first read at the January PC meeting.

PJM conducted a *poll* in November on the proposals, with a total of 625 companies responding, including 280 member companies. The PJM proposal received the highest level of support, with 83% of all responding stakeholders supporting the measure and 86% support from PJM members. The next most popular proposal was a joint effort from Open Road Renewables and Cypress Creek Renewables, which received 60% support from all stakeholders and 33% support from PJM members.

A proposal from RWE Renewables received 35% support from all stakeholders and 22% support from PJM members. Finally, Clearway Energy's proposal received 29% from stakeholders and 16% from members.

More than 90 design components were included in the matrix developed at the task force.

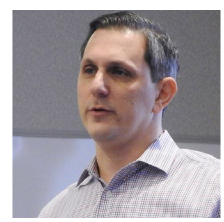
Thomas said details common to all four proposals included moving away from the concept of "first come, first served" projects in the queue to a "first ready, first served" concept. Thomas said the change will ensure projects that are ready to be built are prioritized instead of allowing speculative projects to fill the interconnection queue.

An 876-kW solar installation in Hopewell, N.J. | *Advanced Solar Products*

The proposals would add language that if a facility study isn't needed and no network upgrades are necessary for a project, then it could move to the final agreement stage early, speeding up the process. The study window for projects is also proposed to be scheduled for 710 days, or just under two years.

Three separate phases are being created to go through the interconnection process with different milestones attached to each phase. Thomas said at the end of each phase, there will be a decision point for customers to either continue with a project or abandon it and remove it from the queue.

Prior to proceeding to the final agreement, Thomas said, a customer will need to have all security deposit amounts submitted, 100% control of the building site, the attainment of all necessary state, county and local permits and the completion of all state jurisdictional interconnection requirements.



Jason Connell, PJM | *© RTO Insider LLC*

Jason Connell, director of infrastructure planning for PJM, said the RTO has spent most of the year putting together a proposal that is "workable" and "achieves a level of consensus" from the task force. Connell said PJM used an "enormous amount of feedback" from stakeholders to formulate the proposal.

"This moves the PJM interconnection process into a new stage where we can provide customers more cost certainty [and] timing certainty and make sure the projects that are ready to move ahead into construction and interconnection do so," Connell said.

Matthew Crosby of Cypress Creek thanked PJM for their leadership in the task force. Crosby said its proposal wit Open Road largely mirrored PJM's except for state jurisdictional issues. It would give interconnection customers "more flexibility," Crosby said, allowing project customers to post a security deposit and grant extension rights in the event of delays outside of the control of customers.

Iker Chocarro of RWE said there were five different issues his company wanted to "improve upon" in their proposal compared to PJM's.

PJM News

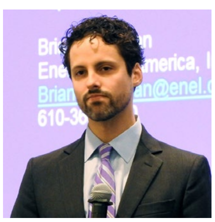
Those issues included:

- site control language alignment;
- affected-systems studies coordination;
- interconnection service agreement execution timeline;
- study methodology and coordination; and
- public policy and state agreement approach alignment.

Chocarro said RWE recognized that the last two items were likely out of scope from the issue charge, but he encouraged PJM to address and coordinate with stakeholders on those issues in the future.

Paul Sotkiewicz of E-Cubed Policy Associates said PJM did an "absolutely fabulous job" in running the stakeholder process in the task force and that their actions should serve as a "model going forward" as other issues are debated. He said its proposal "strikes the right balance" of where it needs to go in the future in the interconnection process.

"This has been a really good experience, and I hope the rest of PJM can replicate the process that's been done here," Sotkiewicz said.



Brian Kauffman, Enel X | © RTO Insider LLC

Brian Kauffman of Enel North America said PJM has "put a lot of work" into the stakeholder process on the interconnection process issue and "appreciated the time and energy" spent in the task force.

John Brodbeck, EDP Renewables | © RTO Insider LLC

John Brodbeck, senior manager of transmission at EDP Renewables North America, said he witnessed a "very level-headed and consistent effort" by PJM to improve the interconnection process and would like to see new rules implemented as soon as possible.

Alex Stern, PSEG | © RTO Insider LLC

Alex Stern, director of RTO strategy for PSEG Services, said he was "impressed" by the level of discussion that took place between stakeholders with diverse perspectives, as well as PJM, both in task force meetings and offline to develop proposals and reach consensus.

"I think we landed in a good spot, and I think you'll see a number of the transmission owners supportive of the PJM approach," Stern said.

Thomas said the process in the task force was difficult but ultimately fruitful.

"At the beginning we did start off polar opposites, and I think we've managed to get really close to the equator and get packages forward that everybody will be able to live with," Thomas said.

The committee will be asked to vote on the proposals at next month's PC meeting.

Generator Deliverability Proposal

Jonathan Kern, PJM | © RTO Insider LLC

Jonathan Kern of PJM's transmission planning department *provided* an update on a timeline for the development of a proposal to change the generator deliverability test.

Kern said PJM has agreed to conduct two sets of studies. The first is on the baseline in the 2026 Regional Transmission Expansion Plan summer, winter and light load assumptions, and the second is on an interconnection queue case using commercial probabilities to get an idea of the long-term implications of new rules.

All the work PJM is doing to provide transmission results and complete the studies is "customized," Kern said, with staff developing power flow models and completing an "extensive" revision to the in-house generator deliverability code. He said the in-house work has resulted in delays in the completion of the generator deliverability testing.

PJM is planning on providing a first read of the proposed generator deliverability changes at the Feb. 8 PC meeting.

"We have to make sure all the new rules are reasonable, both on an individual unit basis and collectively," Kern said.

Apex Clean Energy's Richard Seide asked if there will be any FERC filing involved in the process by PJM because of the potential for "significant changes" and impacts to customers.

Kern said that will come down to whether the changes will be considered planning assumption changes. He said typically in the past, PJM handled planning assumption changes through manual adjustments that didn't require any revisions to governing documents of FERC filings.

Kern said work currently being done in PC special sessions on capacity interconnection rights for effective load-carrying capability resources will also help to determine whether a FERC filing is needed or not.

"Depending on how that process works out, we may or may not have to make a filing," Kern said.

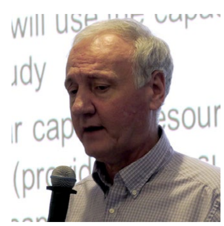
Sotkiewicz said the generator deliverability issue "dovetails with a lot of market and resource adequacy reliability issues." He said he can imagine scenarios in which capacity is being purchased that is not deliverable or could be backed down at PJM's direction because there's not enough transmission to deliver the energy on the system.

Sotkiewicz said there should be a more holistic discussion beyond the PC, possibly involving a joint meeting with the Market Implementation Committee.

"As we're having these discussions, it becomes more apparent that this is beyond a Planning Committee technical issue that we're dealing with," Sotkiewicz said.

Preliminary 2022 Load Forecast

PJM is anticipating "accelerated load growth" compared to last year's forecast as the 2022 load forecast is finalized this month, largely driven by the development of data centers in Virginia.



Tom Falin, PJM | © RTO Insider LLC

Tom Falin, director of resource adequacy planning for PJM, *reviewed* the preliminary 2022 load forecast results; the final results are expected by the end of the year. The long-term load forecast includes peak demand and energy forecasts for all zones, load deliverability areas and PJM over a 15-year forecast period.

The preliminary 15-year annualized load growth rate in the summer months for 2022 is estimated at 0.4%, Falin said, compared to 0.2% in the 2021 load forecast. However, 2025's rate is estimated to be 0.5% lower than in last year's model, driven by improvements in modeling.

Preliminary 15-year annualized load growth rates in the winter months for 2022 are esti-

PJM News

mated at 0.6%, compared to 0.2% in the 2021 load forecast. Falin said behind-the-meter solar growth in PJM reduces the load impact modeling for the summer months by about 0.3% per year.

Falin said the 2022 methodology changes in the forecast included enhancement to the sector models like residential, commercial and industrial customers to "better capture granularity." PJM specifically looked at industrial intensity, a measure of the electricity demand per unit output, and the industrial makeup of individual zones to have a better idea of the types of industry.

"A steel plant is going to be much more energy intensive than electronics manufacturing," Falin said.

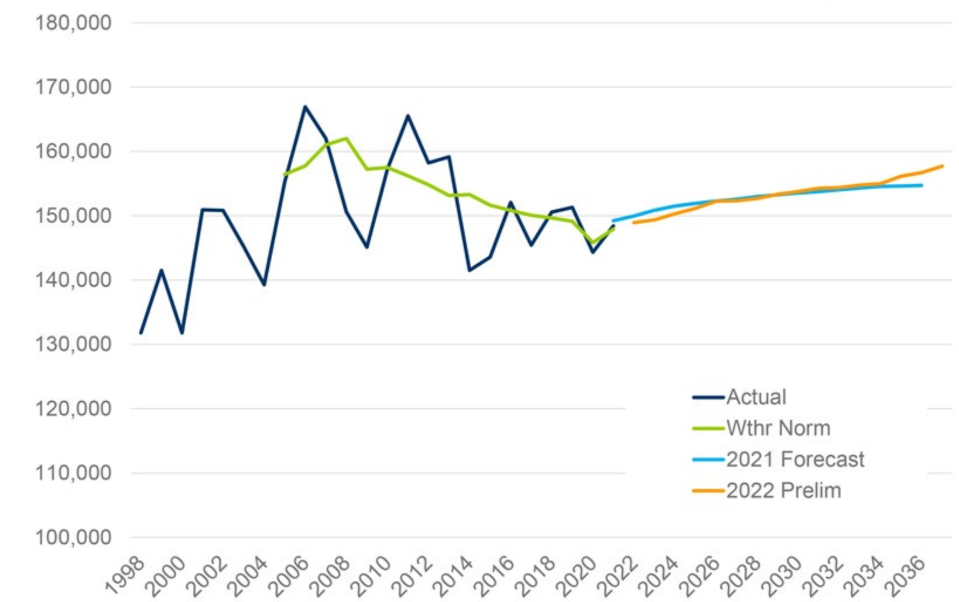
PJM also made improvements to better capture weather response in the summer and winter. Falin said the impact of the two modeling changes was "not great," and there were changes to the model in the last few years that had a larger impact.

Falin said the model parameters included a behind-the-meter solar and battery forecast for the first time. He said the amount forecasted was "extremely small," at 30 MW across the RTO, but PJM is "trying to get ahead of the game" as more storage comes online.

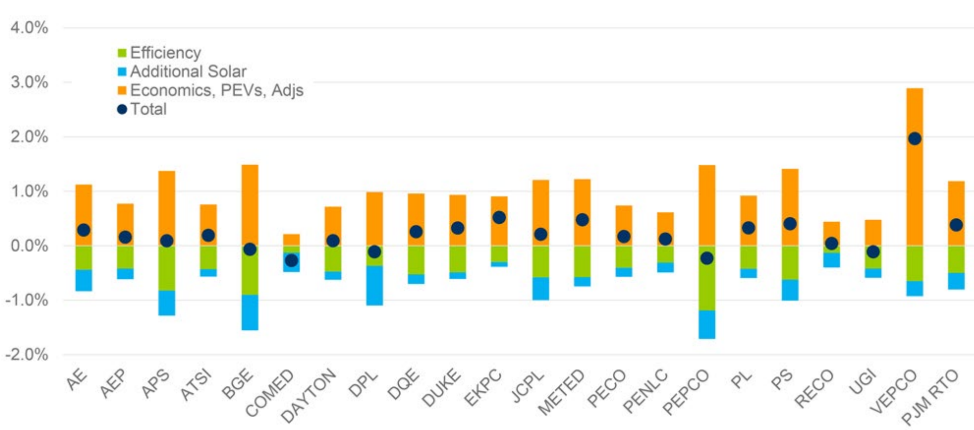
"That is something that could expand significantly in the future," Falin said.

In the forecast adjustment parameter for different transmission zones, PJM received information from Dominion about the addition of data centers in Northern Virginia. Falin said the planned data center projects could amount to as much as 2,800 MW of additional load by 2025.

"Past Dominion forecasts have underestimated the growth in data centers to some extent, so PJM has to be sure to capture that," Falin said.



PJM summer and winter forecast comparisons between 2021 and 2022. | *PJM*



Summer peak average annual growth (2022-2037) | *PJM*

Risk Management Committee

Bankruptcy Protections Issue Charge Endorsed

Stakeholders unanimously endorsed an issue charge at last week's Risk Management Committee meeting to examine changes to PJM's bankruptcy process with members.

Jess Troiano, senior counsel for PJM, *reviewed* the revised *problem statement* and *issue charge* addressing potential bankruptcy protection opportunities to be made in the tariff.

Troiano said PJM currently has several steps it can take regarding bankruptcies, including retaining all payments due as cash security for all obligations; suspending and/or terminating transmission service; and limiting, suspending and/or terminating market participation.

PJM has handled 15 bankruptcy proceedings in the last three years, Troiano said, with the RTO having to secure outside representation with its bankruptcy counsel to protect its interests. PJM hasn't suffered any "catastrophic loss" resulting from the bankruptcies, but its outside counsel and in-house staff identified areas in the tariff that the RTO can "fortify" to create stronger protections against future bankruptcies.

Some of the possible enhancements identified include:

- distinguishing between liquidation and reorganization in bankruptcies;
- requiring designation of PJM as a critical vendor upon bankruptcy filing;
- establishing an obligation to replenish collateral for post-petition activity;
- adding language with respect to priority interest in collateral; and
- strengthening recoupment language.

"We are not limited to these five, and we're not beholden to these five," Troiano said.

Work on the issue charge will begin at the January RMC meeting and is expected to take four months. ■

— Michael Yoder

SPP News

FERC Rules in Three SPP Disputes

By Tom Kleckner

FERC last week issued rulings in three SPP dockets, including Tenaska's complaint over a network upgrade cost assignment; a dispute between Nebraska Public Power District and Tri-State Generation and Transmission; and NorthWestern Energy's challenge of a qualifying facility.

Split Decision for Tenaska in SPP Complaint

FERC last week ordered SPP to restudy a Missouri wind project by Tenaska, which complained that the RTO erroneously assigned it about $66 million in network upgrade costs (*EL21-77*).

The commission's Dec. 16 order found that SPP appropriately applied its authority under its tariff to restudy the project after one or more higher-queued projects withdrew; corrected the omission of 4.5 GW of higher-queued generation; and used the network resource interconnection service (NRIS) standard to evaluate the project's effects on its system.

At the same time, FERC said SPP's use of 2019 transmission-planning models in the restudy was unduly discriminatory or preferential. It directed SPP to restudy the project within 60 days using the 2017 planning models and incorporate the 4.5 GW of missing generation. It directed SPP to make a compliance filing within 10 days of the restudy's completion.

Tenaska alleged that SPP mistakenly assigned the upgrade costs during a restudy of the Clear Creek Wind Project, a 242-MW facility that is interconnected to the Associated Electric Cooperative, Inc. (AECI) transmission system. It said the costs were assigned as part of SPP's affected system study (AFS) process and asked that they be rolled into regional transmission rates or that FERC set a hearing to determine their equitable allocation. (See *Tenaska Challenges SPP Tx Upgrade Costs*.)

Clear Creek became operational in May 2020.

The developer requested an NRIS study in 2017. AECI identified SPP and MISO as potential affected systems; MISO's AFS found no network upgrades were necessary to its system.

In August 2018, Tenaska requested that SPP conduct an AFS of the Clear Creek project. The RTO told Tenaska the project would be

| SEIA

queued between the 2016-002 and 2017-001 definitive interconnection system impact studies (DISIS) and that it would use the 2016 cluster's transfer case, reflecting capacity additions and associated network upgrades, as the base case. That transfer case used SPP's 2017 Integrated Transmission Planning (ITP) study models, as the basis for its regional transmission planning studies.

SPP's first AFS study identified $31.2 million in network upgrades it said were necessary to connect the project to the AECI system. The grid operator twice revised the study, in November 2018 and March 2019; the latter found approximately $33.5 million in network upgrades. FERC noted SPP only identified network upgrades to resolve constraints when modeling for energy resource interconnection service (ERIS).

After Tenaska began construction in 2019, it said it was told by SPP that the RTO intended to restudy the project because a higher-queued project had withdrawn from the interconnection queue. The RTO then told Tenaska in May 2020 that, because the initial studies' models were more than a year old, staff intended to conduct the affected system restudy using the 2019 ITP models.

The study identified $763 million in network upgrades to the AECI system and the need for NRIS network upgrades. SPP said it had inadvertently omitted 4.5 GW of higher-queued generation on the MISO transmission system in the project's first AFS and the DISIS 2016-002 cluster. The RTO deemed the initial AFS invalid and decided to use the 2019 ITP models for the restudy that lowered Tenaska's cost responsibility to $106.8 million. In February 2021, that amount was lowered again to $91 million.

In March 2021, SPP posted the most recent affected system restudy results, assigning about $99 million in network upgrades to Clear Creek, comprised of $34 million in ERIS network upgrade costs and $66 million in additional network upgrade costs necessary to provide NRIS identified in the affected system restudies.

Commissioner Alison Clements concurred with the order "only because it conforms to the standards and requirements currently applicable to SPP's affected system study process" and filed a separate statement.

She said the order demonstrates that reasonable efforts and good utility practice standards are "currently so lenient that neither SPP's delay of over a year in completing the restudy process … nor SPP's serious omission of 4.5

SPP News

GW from its initial studies rises to the level of a violation."

"I am sympathetic to the formidable challenges that overwhelmed regional interconnection queues cause for transmission owners, operators and interconnection customers," she wrote. "Our regulatory standards do not mean much, however, if they are lenient to the point of impotence. As the commission turns to addressing transmission and interconnection reforms in the coming months, the standards applicable to interconnection studies must be among the topics to receive the commission's attention and careful scrutiny."

NPPD Complaint Rejected

The commission also rejected a Nebraska Public Power District (NPDD) request that FERC find Tri-State Generation and Transmission's inclusion of certain costs in its 2021 annual transmission revenue requirement (ATRR) unjust and unreasonable (*EL21-100*).

FERC said NPPD did not demonstrate that Tri-State's inclusion of amounts related an agreement between the two SPP members seriously harmed the public interest.

NPPD in 2018 asked the commission to direct Tri-State to remove from its ATRR costs related to an earlier Western Nebraska Joint Transmission Agreement (NETS Agreement) between the two that governed the use of transmission facilities. Under the agreement, the party making greater use of the facilities was required to make an annual cost equalization payment to the other party.

The agreement originally had a 2020 termination date, which Tri-State agreed to extend to March 1, 2021, to allow for negotiations between the two and SPP. The cooperative made its final payment under the agreement to NPPD in February 2021.

In July, SPP posted Tri-State's update of its 2021 ATRR for the rate year beginning Sept. 1 and included an annual cost-equalization payment of more than $1.84 million. NPPD said the payment's inclusion led to unjust and unreasonable rates because the NETS agreement was terminated and Tri-State had made its last payment. It also alleged the cooperative was no longer incurring any costs under the agreement and that Tri-State refused to remove the payment from the annual update process.

FERC said it found the disputed cost component was included in 2017 settlement agreement between NPPD and Tri-State over SPP's placement of the Tri-State in NPPD's transmission zone. (See *FERC Rejects NPPD Objection to Tri-State Zonal Placement*.)

The commission said that under the agreement, NPDD had to demonstrate that the proposed modifications to the ATRR and underlying rates satisfy the "public interest" application of the just and reasonable standard. It said the utility had failed to do so.

FERC also found that NPPD agreed in the settlement to Tri-State's use of a formula rate based on the prior calendar year's financial data. It said that by arguing that the cooperative should not be permitted to include the annual cost equalization payment Tri-State made in 2020 in its 2021 ATRR, "NPPD is seeking to modify the nature of the formula rate and, thus, modify the settlement agreement."

"We find that NPPD, as a settling party, must make a showing sufficient to demonstrate that, without the proposed changes, the settlement agreement 'seriously harms the public interest,'" the commission wrote.

Tenaska's Clear Creek Wind Project in Missouri | *Tenaska*

NorthWestern Protest Denied

FERC denied NorthWestern Energy's protest of a solar developer's self-certification as a small power production qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA) of 1978 (*QF21-1213*).

Gallatin Power Partners in September filed a form self-certifying its Shields Valley Solar Facility, to be interconnected with the NorthWestern system in Montana, as a QF. It said the development would have a 160-MW nameplate capacity but would also incorporate a battery-storage system with an expected 80 MW capacity on the solar array's DC side, resulting in a maximum net AC power production capacity of 80 MW.

NorthWestern protested, arguing that the solar array and the storage systems were separate power-production facilities and that their capacities should be analyzed separately and then aggregated, resulting in a production capacity substantially larger than 80 MW. It based its argument on FERC's March *rehearing order* for Broadview Solar that restored longstanding commission precedent for determining QF eligibility and extending it to integrated battery energy storage. (See *FERC Reverses Ruling on Montana QF*.)

The commission determined that because the Shields Valley facility could only deliver a maximum of 80 MW of AC electricity to NorthWestern's system at any time, its production capacity "cannot and will not" exceed 80 MW. It said NorthWestern's protest relitigated the Broadview rehearing orders' capacity analysis and "effectively" requested that FERC overturn its findings and amounted to a "collateral attack" on those orders.

Commissioner James Danly concurred in part and dissented in part, saying as he did in the Broadview orders that "there is no net-output exception" to PURPA's production capacity threshold.

However, Danly also disagreed with NorthWestern's protest, noting batteries and other storage systems cannot be included when determining a facility's "power production capacity" because they "do not 'produce' power — they simply store it for later delivery." ■

Company Briefs

ACEG Names New Leadership

Americans for a Clean Energy Grid (ACEG) last week announced the election of its new Board President Patrick Hughes and Treasurer Christina Hayes.

Hughes is vice president of the National Electrical Manufacturers Association; Hayes is vice president for Federal Regulatory Affairs for Berkshire Hathaway Energy.

Hughes replaces former Board President Nina Plaushin.

More: *ACEG*

FirstEnergy Completes $1B Stock Sale to Blackstone

FirstEnergy last week completed the sale of $1 billion of stock to investment firm Blackstone. The deal will also give Blackstone a seat on the FirstEnergy board by next year.

FirstEnergy said it issued 25,588,535 shares of stock at $39.08 per share to BIP Securities, an affiliate of Blackstone. The sale provides FirstEnergy with $1 billion in capital and makes Blackstone the utility's fourth largest shareholder.

More: *Akron Beacon Journal*

Rivian to Build EV Plant in Georgia

Electric vehicle startup Rivian and the state of Georgia last week announced a deal to build a $5 billion manufacturing factory to construct vans.

Gov. Brian Kemp and Rivian officials are expected to hold a ceremony Thursday to outline plans, which would rank as one of the state's largest economic development projects. The project is said to be a multibillion-dollar investment that would produce 200,000 vehicles a year and employ 8,000 people at full production before 2030.

More: *The Atlanta Journal-Constitution*

Santee Cooper Names New President, CEO

The Santee Cooper Board of Directors last week approved the hiring of Jimmy Staton as the company's new president and CEO, effective March 1.

The board also approved naming deputy CEO Charlie Duckworth as acting president and CEO from Jan. 10 through Feb. 28 and extended his current contract as deputy CEO through July 9.

Current President and CEO Mark Bonsall will retire on Jan. 9.

More: *WLTX*

Shell Expands US Solar Footprint with Savion Acquisition

Shell New Energies U.S., a subsidiary of Royal Dutch Shell, last week said it will purchase Kansas City-based Savion from investment bank Macquarie's Green Investment Group.

Shell has been investing in solar projects, carbon capture and storage, and biofuels. It is planning to grow its global electric vehicle charging network to around 500,000 charge points by 2025 to support the expected rise of electric vehicles. Savion has more than 100 projects — representing 18 GW of solar and battery storage — under development in 26 states.

The acquisition is expected to close by the end of the year. Financial terms were not disclosed.

More: *Houston Chronicle*

Federal Briefs

Former Nuclear Plant Inspector Pleads Guilty to Falsifying Inspection Reports

Gregory Croon, a former senior resident inspector for the NRC, last week pleaded guilty to making false statements on inspection reports between 2016 and 2018 in regard to the North Anna Nuclear Power Station in Virginia.

Federal officials did not say whether there were any short-term or long-term safety concerns following the investigation, only that the false reports could have jeopardized the safety oversight of the plant.

Croon will be sentenced in March.

More: *WWBT*

United Power to Break Contract with Tri-State Generation

United Power, the largest electric cooperative in the Tri-State Generation and Transmission Association, last week filed notice with FERC of its intent to withdraw from the association, effective January 2024.

United Power, with 103,000 metered customers, is looking for flexibility in generating electricity locally and for the ability to adopt new initiatives. However, it must purchase 95% of its power from Tri-State according to its contract. The key to its departure will be the exit fee for not completing its contract, which runs until 2050. United believes the fee should be between $200 million and $300 million, while Tri-State has put the figure at $1.5 billion. FERC will rule on the method for setting the fee.

United follows two other co-ops that have left Tri-State; eight others have asked the association what it would cost them to exit their contracts.

More: *The Colorado Sun*

US Solar Industry to Grow 25% Less Than Expected in 2022

The U.S. solar industry will grow 25% less than previously forecast during 2022 due to supply chain constraints and rising raw material costs, said a report released last week by the Solar Energy Industries Association and Wood Mackenzie.

Costs rose across the utility, commercial and residential solar segments in the third quarter for a second straight quarter. In the utility and commercial segments, the year-over-year price increases were the highest since Wood Mackenzie began tracking the data in 2014.

In addition to supply chain issues, solar shipments have been disrupted after an anonymous group filed a petition with the U.S. Department of Commerce asking tariffs to be extended to Thailand, Malaysia and Vietnam. The petition was dismissed in November.

More: *CNBC*

State Briefs

REGIONAL

Storms from Colorado to Michigan Leave 510,000 Without Power

A powerful storm system swept through the central United States on Dec. 15 with high winds that left more than 510,000 customers without power. More than 36 million people from New Mexico to Michigan were under high-wind warnings, as gusts of up to 100 mph sent roofs flying and toppled tractor-trailers on highways from Colorado to Iowa.

More than 150,000 customers were without power in Wisconsin and Michigan early Dec. 16, said PowerOutage.US. Nearly 47,000 were without power in Iowa, while thousands more were in the dark in Illinois, Colorado, Nebraska, Missouri and Minnesota.

Evergy's outages map showed more 4,530 outages at 9 p.m. affecting 164,921 customers in Kansas and Missouri. At the peak, there were about 200,000 customers without power.

More: *The Washington Post*, *Kansas City Business Journal*, *Denver Post*

CALIFORNIA

USC Aims to be Carbon Neutral by 2025

The University of Southern California last week said it plans to be carbon neutral by 2025.

The university said new energy-efficient buildings, improvements to older structures, and the installation of more solar panels across campus are key to achieving its goal.

USC is on track to achieve the highest standard in green building when it completes the Dr. Allen and Charlotte Ginsburg Human-Centered Computation Hall in 2023. It will be the sixth LEED-certified building on campus.

More: *USC*

ILLINOIS

Former Rep. Eddie Acevedo Pleads Guilty to Tax Charge from ComEd Probe

Former Democratic state Rep. **Eddie Acevedo** pleaded guilty last week to a federal tax charge stemming from the ongoing federal probe into Commonwealth Edison's lobbying practices.

Acevedo entered a plea to one count of tax evasion. Preliminary sentencing guidelines call for up to a year in prison, although he could qualify for probation. Sentencing is scheduled for March 9. According to the agreement, Acevedo evaded $37,000 in taxes owed on income from his consulting business from 2015 to 2017.

Acevedo was the latest to be convicted as part of an investigation involving an alleged scheme by ComEd to bribe former House Speaker Michael Madigan to assist the utility with legislation.

More: *Chicago Tribune*

KANSAS

Reno County Bans Industrial Wind in Zoned Areas

The Reno County Commission last week voted unanimously to ban commercial wind development in all zoned areas of the county. The countywide moratorium will remain in place through mid-March.

A proposal to create a zoning overlay district was unanimously recommended by the County Planning Commission last month after the county commission signaled its desire to do so. However, the idea was tabled until Jan. 11 because it references a set of regulations the commission previously tabled and has yet to be finalized.

More: *The Hutchinson News*

KENTUCKY

Thousands Could be Without Electricity for Weeks

State officials warned residents that they could be without heat, water or electricity in frigid temperatures for weeks or longer due to the damage caused by recent tornadoes.

About 26,000 homes and businesses were without electricity, said PowerOutage.US. More than 10,000 homes and businesses had no water, while another 17,000 were under boil-water advisories.

"Our infrastructure is so damaged. We have no running water. Our water tower was lost. Our wastewater management was lost, and there's no natural gas to the city," said Mayfield Mayor Kathy Stewart O'Nan. "So, we have nothing to rely on there."

More: *The Associated Press*

MICHIGAN

Legislature Passes $1B Incentive Plan for 'Critical Industries'

The Legislature last week approved a $1.5 billion economic development proposal that it hopes will help the state land major projects such as a General Motors battery plant.

The six-bill plan would divert $1 billion into a new fund that could be used to recruit and retain "critical industries" like manufacturing. Chief among them is a $2.5 billion plan by General Motors and its battery-making partner, Ultium Cells, to build a third U.S. factory west of Lansing.

More: *Bridge Michigan*

MISSOURI

Ameren to Shutter Coal Plant 15 Years Earlier than Planned

Ameren last week said it will close its Rush Island coal-fired power plant in Jefferson County by 2024 — 15 years early — rather than install expensive pollution controls.

The announcement comes a decade after the U.S. filed suit against the company and more than four years after a federal judge found the utility had violated the Clean Air Act by boosting Rush Island's power output through "major modifications" while failing to obtain the necessary permits and install pollution controls.

Installing the equipment was estimated to cost up to $1 billion.

The coal plant, the newest among Ameren's four, wasn't scheduled to close until 2039.

More: *St. Louis Post-Dispatch*

NEBRASKA

Lancaster County Approves Permit for State's Largest Solar Farm

The Lancaster County Board last week approved a special permit that would allow construction of the $230 million Salt Creek solar project, which would be the largest solar installation in the state.

Last month, the county's planning commission granted the special permit after initially failing to pass it in October due to opposition from residents.

Developer Ranger Power said construction on the 3,000-acre project would likely begin within the next two years.

More: *KOLN*

NEW MEXICO

PRC Denies PNM's Application to Transfer Power Plant Ownership

The Public Regulation Commission last week unanimously voted to deny the Public Service Company of New Mexico's application to transfer its 13% ownership stake in the Four Corners Power Plant to Navajo Transitional Energy Company.

Commission Chairman Stephen Fischmann said more information is needed before it can approve the application. A prudency issue he referenced stems from a 2016 rate case when the PRC deferred a decision on whether investments made into the plant to keep it open were prudent. The matter was supposed to be addressed in a future rate case, but the rate case has not been filed and ratepayers are paying for those investments. He said the commission is open to PNM following up with that information, which he said should be available early next year.

More: *NM Political Report*

NEW YORK

MTA to Build All-electric Bus Depot in Queens

The Metropolitan Transportation Authority last week said it plans to build its first all-electric bus depot in Jamaica, Queens.

The agency will launch a search for contractors in March 2022 and expects construction to take about 4.5 years for the $400 million project. The depot will house around 60 electric buses.

The MTA aims to transition its 5,800-bus fleet to zero-emissions by 2040 but won't stop buying diesel-fuel-powered vehicles until 2028.

More: *AMNY*

OHIO

Cincinnati, Columbus Settle Civil Claims Related to Power Plant Bailout

Cincinnati and Columbus last week dismissed their state court claims against FirstEnergy and Energy Harbor for the companies' actions relating to House Bill 6, the nuclear and coal bailout law at the heart of a $60 million corruption case.

The dismissal does not include any admission of wrongdoing by FirstEnergy or Energy Harbor. The joint filing was made "with prejudice," meaning the cities cannot bring the same claims against the companies later.

"The dismissal was the result of negotiations with the defendants, the court's ruling in our favor, and the partial repeal of HB 6," Cincinnati Solicitor Andrew Garth said. "The city's claims were essentially resolved in December 2020 when the Franklin County Court of Common Pleas granted our motion to enjoin FirstEnergy and [Energy] Harbor from collecting the illegitimate fees that were authorized by House Bill 6."

More: *Energy News Network*

OREGON

Multnomah County to Phase Out Gas-powered Leaf Blowers

Multnomah County Commissioners last week passed a resolution that will phase out gas-powered leaf blowers at county facilities and create a work group to do the same thing countywide.

The resolution will require the county to transition from gas-powered to electric models. The county's landscaping contract says the transition to electric models will be complete by the end of the contract in 2025.

More: *Oregon Public Broadcasting*

TENNESSEE

Tusculum Planning Commission OKs Solar Farm Rezoning Request

The Tusculum Planning Commission last week voted 2-1 to approve a rezoning request by developers Silicon Ranch Corp. to build an 80-acre solar farm.

Power generated by the farm would be sold to Greeneville Light & Power System and fed into the grid.

A public hearing, tentatively scheduled for Jan. 24, will be held before the Tusculum Board of Mayor and Commissioners to consider approval of the project.

More: *The Greenville Sun*

VIRGINIA

Mountain Valley Pipeline Stream-crossing Permit Approved

The State Water Control Board last week voted 3-2 to approve a necessary stream-crossing permit for the Mountain Valley Pipeline.

According to Department of Environmental Quality figures, the project will temporarily impact 315 stream crossings and four acres of wetlands while permanently impacting two stream crossings and two acres of wetlands.

The project still needs stream-crossing authorizations from West Virginia's Department of Environmental Protection and the U.S. Army Corps of Engineers, as well as an approval from FERC allowing it to bore underneath waterways.

More: *Virginia Mercury*