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 26 June 29, 2021

Glick Says West Should 'Finish the Job' on RTO

FERC Technical Conference Examines Western Resource Adequacy

By Hudson Sangree, Jason York and Tom Kleckner

FERC Chairman Richard Glick | *FERC*

A FERC technical conference on Western resource adequacy began Wednesday with Chairman Richard Glick joining the chorus of those calling for the West to form one or more RTOs soon.

He cited last year's rolling blackouts in California, extreme heat waves in the West, and strained resources across the region. The West already had one serious heat wave in June and expects triple-digit temperatures this weekend from Tucson, Ariz., to Portland, Ore., he said.

"Portland's supposed to get to like 110 degrees in June," Glick said. "That's amazing to me, and we saw extremely hot weather in California and parts of the Desert Southwest last week. And so we know that climate change is with us, and it's going to present significantly increased challenges in terms of stress on the system."

(The National Weather Service said Portland hit a record high temperature of 112 degrees Fahrenheit on Sunday and forecast Monday's high at 114.)

NERC and WECC reported that areas of the West may not have the capacity to meet peak demand as soon as this summer, Glick said. (See *Summer Bringing 'Elevated Risk,' NERC Warns*.)

"I believe a regional transmission organization, or maybe a couple of regional transmission organizations, in the region would be a big part of the solution," Glick said.

Continued on page 14

CPUC Orders LSEs to Add 11.5 GW, but No Gas (p.13)

Biden, Manchin Push Bipartisan Infrastructure Plans

White House Announcement Overshadows Manchin's Energy Infrastructure Bill

By K Kaufmann

Sen. Joe Manchin (D-W.Va.) | *Senate ENR Committee*

Even as he took part in negotiations on the framework of the bipartisan infrastructure deal announced Thursday, Sen. Joe Manchin (D-W.Va.) also moved ahead with a 423-page "discussion draft" of infrastructure legislation encompassing energy, water, abandoned mine reclamation and wildfire management.

Introduced at a hearing of the Senate Energy and Natural Resources Committee, which Manchin chairs, the Energy Infrastructure Act covers many energy and climate initiatives that the bipartisan framework will not, with slimmed-down spending of $95 billion.

The West's record drought means the Colorado River basin could be making its first shortage declaration. Water restoration was a key theme at Thursday's hearing on Sen. Joe Manchin's Energy Infrastructure Act. | *Shutterstock*

Continued on page 3

Senate Ag Subcommittee Hears Talk of Transmission (p.5)

TOs, Consumer Groups Clash over RTO Adder

TOs Fear 'Hotel California'

By Rich Heidorn Jr.

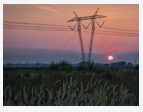
Transmission owners told FERC on Friday that limiting the incentive for RTO participation would reduce grid investments and undermine efforts to address climate change, while consumer groups and state officials said the commission's proposal was long overdue (RM20-10).

FERC proposed limiting the current 50-basis-point rate for participating in RTOs to the first three years in April (RM20-10). The commission's 3-2 vote approving a supplementary Notice of Proposed Rulemaking was a sharp turnabout from March 2020, when FERC, under then-Chair Neil Chatterjee, advanced a proposal to double the adder to 100 basis points.

The reversal prompted utilities to threaten litigation and petition members of Congress to intervene. (See *TOs Won't Give up RTO Adder*

Continued on page 6

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

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Daily
Michael Brooks
301-922-7687

Deputy Editor / Enterprise
Robert Mullin
503-715-6901

Art Director
Mitchell Parizer 718-613-9388

New York/New England Bureau Chief
Jennifer Delony 603-320-7043

MidAtlantic Bureau Chief
K Kaufmann 202-494-4386

Midwest Bureau Chief
John Funk 216-316-5413

Associate Editor
Shawn McFarland 570-856-6738

Copy Editor/Production Editor
Rebecca Santana 770-862-6004

CAISO/West Correspondent
Hudson Sangree 916-747-3595

ISO-NE Correspondent
Jason York 860-977-7830

MISO Correspondent
Amanda Durish Cook 810-288-1847

NYISO Correspondent
Michael Kuser 802-681-5581

PJM Correspondent
Michael Yoder 717-344-4989

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

NERC/ERO Correspondent
Holden Mann 205-370-7844

Sales & Marketing

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Account Manager
Kathy Henderson 301-928-1639

Account Manager
Phaedra Welker 773-456-4353

Marketing Director
Margo Thomas 480-694-9341

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

2021 Annual Subscription Rates:

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

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

In this week's issue

FERC/Federal News

Biden, Manchin Push Bipartisan Infrastructure Plans

White House Announcement Overshadows Manchin's Energy Infrastructure Bill

Continued from page 1

It would also be passed through the Senate's "regular order" rather than the budget reconciliation process some Democrats are saying must be part of any infrastructure deal.

Perhaps trying to head off such a potentially divisive move, Manchin opened the hearing on Thursday by saying his bill "would deliver on the president's American Jobs Plan in many big ways that can garner bipartisan support.

"Although I don't anticipate we will all agree on the size and scope of the investment ... I think all my colleagues will agree that the areas within our jurisdiction are an important piece of the broader conversation about our infrastructure needs," he said.

Sen. John Barrasso (R-Wyo.) | *Senate ENR Committee*

Sen. John Barrasso (R-Wyo.), the committee's ranking member, was quick to criticize Manchin on drafting the bill without input from Republicans on the committee. He also criticized the bill's funding — $45 million a year for 2022-2026 — to support upgrades for state building codes to promote energy efficiency, and $1 billion a year, for the same five years, for grants to help states undertake projects to improve grid resilience and reliability.

The funds for building codes could allow "the Department of Energy to coerce states to adopt building codes which may restrict the use of natural gas," Barrasso said. He also labeled the grid improvement funds as a bailout for California. However, the bill makes no mention of building code restrictions on natural gas and stipulates that no more than 20% of the grid resilience funds could be used for projects in California.

Other provisions in the bill include:

- the creation of regional hubs to promote direct air carbon capture and green hydrogen technologies. Funding for the direct air hubs would be $3.5 million and for green hydrogen, $8 million, both over the next five years.
- improved permitting, both for the responsible mining of critical minerals, such as lithium, and for interregional transmission. On mining, the bill calls for collaboration by the Bureau of Land Management and the Forestry Service to establish "clear, quantifiable and temporal permitting performance goals and [track] progress against those goals."
- to speed up transmission planning and permitting, FERC would be directed to open a docket on "the effectiveness of existing planning processes for identifying interregional transmission projects" and synchronizing "planning processes in neighboring regions."

Heat Waves and Drought

The testimony of the five witnesses commenting on the bill fell similarly along party lines. Officials from the Energy, Interior and Agriculture departments all praised specific provisions of the bill but said higher levels of funding would be needed.

"We see this discussion draft as inspired by the American Jobs Plan," said Kathleen Hogan, acting undersecretary for science and energy at DOE. Improvements to the bill could include "more flexible and larger state, tribal and local grants to advance clean energy throughout the country, greater supply chain investment beyond the battery and critical minerals sphere and more resources to help retool existing factories and [to] transition workers," she said.

Douglas Holtz-Eakin, American Action Forum | *ENR EIA*

Douglas Holtz-Eakin, president of the nonprofit American Action Forum, a free-market research and policy group, said infrastructure funding should focus on "things that raise productivity. Focusing on those core infrastructure areas and avoiding spending money on things which will not raise productivity is probably a key design issue for this committee and Congress," Holtz-Eakin said.

He pointed to spending on energy efficiency and school building upgrades as examples of nonproductive spending in the discussion draft and said infrastructure investments should come primarily from the private sector. Government investment gets "the incentives wrong ... you also tend to run past the project selection criteria and invest poorly," he said.

Sen. Angus King (I-Maine) answered Holtz-Eakin with a quote from President Abraham Lincoln, underlining the importance of public investment. "'Time and experience have verified to a demonstration the public utility of internal improvements.' In other words, infrastructure," King said.

Sen. Angus King (I-Maine) | *Senate ENR Committee*

But senators on both sides of the aisle — and especially those from the Western states — were more preoccupied with the record-breaking heat waves and droughts now affecting their states, and how infrastructure investments might help mitigate the impacts. "The Colorado River basin is facing its worst hydrology on record, which could lead to its first ever shortage declaration this year," Sen. Catherine Cortez Masto (D-Nev.) said. The drought is exacerbating wildfire risks, as well as cutting hydro power in the West.

Sen. Catherine Cortez Masto (D-Nev.) | *Senate ENR Committee*

Collin O'Mara, National Wildlife Federation | *ENR EIA*

Collin O'Mara, president and CEO of the National Wildlife Federation, said his organization estimates "we need almost $60 billion investment in our forests over the next five years. We also need a lot more resources for the Bureau of Land Management," he said. "A lot of the fires that are starting right now are not starting in our forests. They are starting in our grasslands."

A Tandem Deal

However, the discussion at the hearing and the prospects for the Energy Infrastructure Act were largely overshadowed by President Biden's announcement of the bipartisan infrastructure deal.

While only about half of the $2 trillion package Biden had originally proposed, the president focused on the "good-paying jobs" the deal would create. The price tag on the agreement is $973 billion over the next five years, going

FERC/Federal News

up to $1.2 trillion over eight years, according to a *fact sheet* released by the White House.

"This still makes key investments to put people to work all across the country building transmission lines, upgrading the power grid to be more energy efficient and resilient in extreme weather — to be able to sustain extreme weather and the climate crisis," Biden said in a Thursday afternoon briefing. "It also builds our natural infrastructure — our coastlines and our levees — to be more resilient as well.

"American workers will be installing electric vehicle charging stations and undertaking critical environmental cleanups. This bipartisan agreement represents the largest investment in public transit in American history," he said.

Specific spending over the next five years includes:

- $7.5 billion each for EV charging infrastructure and the electrification of buses and public transit;
- $73 billion for power infrastructure, including the creation of a Grid Authority, to build "thousands of miles of new, resilient transmission lines to facilitate the expansion of renewable energy"; and
- $43 billion for resilience to "prepare more of our infrastructure for the impacts of climate change, cyberattacks and extreme weather events."

The response from energy industry organizations was mixed.

Paula Glover, president of the Alliance to Save Energy, praised the bipartisan efforts on infrastructure but noted the absence of energy efficiency in the deal. "[We] will continue to work with the administration and Congress to ensure energy efficiency policies are fully funded and seen as a top priority in future legislation," she said in a statement released Thursday afternoon. Manchin's bill got higher marks for its energy efficiency provisions.

While not directly commenting on the bipartisan framework, Jason Burwen, interim CEO of the Energy Storage Association, said, "An infrastructure bill that does not include clean energy and storage will fail to address the failings of our power infrastructure." Manchin's bill incorporates policy recommendations supported by ESA, Burwen said, such as funding to build out a battery supply chain.

"An infrastructure bill coupled with a storage investment tax credit will ensure that energy storage deployments accelerate to keep the lights on in the face of severe weather threats, cyberattacks and other catastrophic impacts to our country's electric infrastructure," he said.

An analysis from ClearView Energy Partners, an energy research firm, suggests that Manchin could be positioning his bill to be either incorporated into the bipartisan agreement as it is translated into legislation or as part of a party-line budget reconciliation bill.

Biden stated clearly that he sees the infrastructure agreement as the first part of a tandem deal. "If [the deal] is the only thing that comes to me, I'm not signing it," he said. "It's in tandem. … I proposed a significant piece of legislation in three parts, and all three parts are equally important." ■

FERC/Federal News

Senate Ag Subcommittee Hears Talk of Transmission

By John Funk

A 90-minute hearing June 22 on renewable energy by the Senate Agriculture, Nutrition and Forestry Subcommittee on Rural Development and Energy focused mainly on ethanol blending, but senators also heard about the need for more electric transmission infrastructure in the Midwest.

Subcommittee leaders argued that future federal budgets ought to include dollars for new liquid fuels technologies and a possible mandate that future gasoline blends are 15% ethanol rather than the current 10%. But they also mentioned new incentives to pay for a massive buildout of wind and solar resources deep in America's Farm Belt.

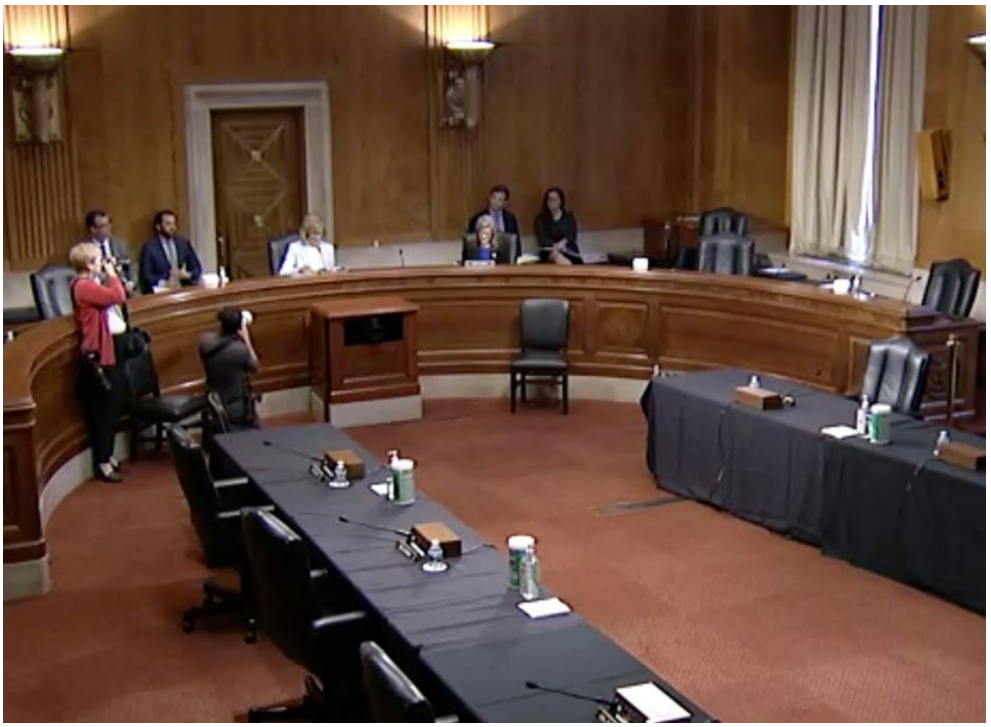
Minnesota PUC Chair Katie Sieben | *U.S. Committee on Agriculture, Nutrition and Forestry*

In a response to a question from Sen. Amy Klobuchar (D-Minn.) about the value of expanding renewable generation to rural communities as well as small farms, Katie Sieben, chair of the Minnesota Public Utilities Commission, said wind farms in their state have created rural wealth that farming alone had not.

"Renewable energy, especially wind projects, have created tremendous economic development opportunities for small communities. We are seeing the impacts of increased hiring of local workers, which leads to more careers in the renewable energy sector. We're also seeing increased manufacturing domestically of wind turbines and solar panel components. Combined with the tax benefits that come from renewable energy projects, it really is a holistic, helpful way to improve rural economies across Minnesota," she said.

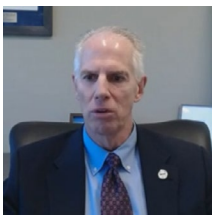
"Though what we really need in Minnesota, especially, is more transmission," she added. "As of January, there are 533 projects, renewable energy projects primarily, waiting to connect in the MISO queue [that] total over 15 GW.

"New transmission can maximize the value of low-cost renewable energy and create living-wage jobs that are essential to ensuring Americans have reliable power. Please include transmission investments in the American Jobs Plan or other relevant legislation."



Federal lawmakers made it clear last week that ethanol and biodiesel are here to stay for decades despite the Biden administration's efforts to electrify transportation and that Midwest wind power needs as much attention as offshore projects. | *U.S. Committee on Agriculture, Nutrition and Forestry*

Bill Cherrier, executive vice president and CEO of Central Iowa Power Cooperative, a nonprofit generation and transmission cooperative based in Des Moines, explained that federal tax credits are currently not available for electric cooperatives.



Bill Cherrier, Central Iowa Power Cooperative | *U.S. Committee on Agriculture, Nutrition and Forestry*

"It's important for policymakers to note that the current federal tax credit structure prevents electric cooperatives from taking advantage of tax benefits to directly build and own wind and solar assets. The current program requires cooperatives to work with third-party providers on long-term contracts to bring this energy into the market. The current incentive structure impedes our ability to adopt renewables and new technologies in a more cost-effective way," he told the lawmakers.

Still, biofuel remains a popular point of bipartisan agreement among rural lawmakers.

Included on the panel was Emily Skor, CEO of D.C.-based biofuels advocate Growth Energy, who used her testimony to unveil an economic analysis issued earlier this month demonstrating that boosting the E10 blending mandate to 15 would be a shot in the arm for the U.S. economy. Gasoline blenders have long resisted the switch to E15.

Emily Skor, Growth Energy | *U.S. Committee on Agriculture, Nutrition and Forestry*

The study by Pennsylvania-based ABF Economics, Skor said, determined that a move to a national E15 standard would add $17.8 billion to U.S. GDP, support an additional 182,700 jobs, generate $10.5 billion in new household income and save consumers $12.2 billion annually in fuel costs.

"In fact, studies show there is no path to net-zero emissions by 2050 without biofuels," she said. The Energy Information Administration "projects that gasoline- or flex fuel-powered vehicles will make up about 80% of new vehicle sales in 2050, meaning the vast majority of the cars on the road will continue to be powered by liquid fuels for decades to come." ■

FERC/Federal News

TOs, Consumer Groups Clash over RTO Adder

TOs Fear 'Hotel California'

Continued from page 1

Without a Fight.)

Friday was the deadline for filing initial comments on the NOPR, and dozens of utilities, RTOs, regulators and ratepayer groups weighed in, clashing over the legality and impact of the proposed change.

What Does the Law Require?

Supporters of the NOPR generally agreed the three-year limit is, as the American Public Power Association (APPA) put it, a "reasonable balance" for promoting RTO participation and protecting consumers against excessive rates.

But TOs said the NOPR would be contrary to Congress' intent in 2005, when it amended the Federal Power Act to direct FERC to "provide for incentives to each transmitting utility or electric utility that joins a transmission organization."

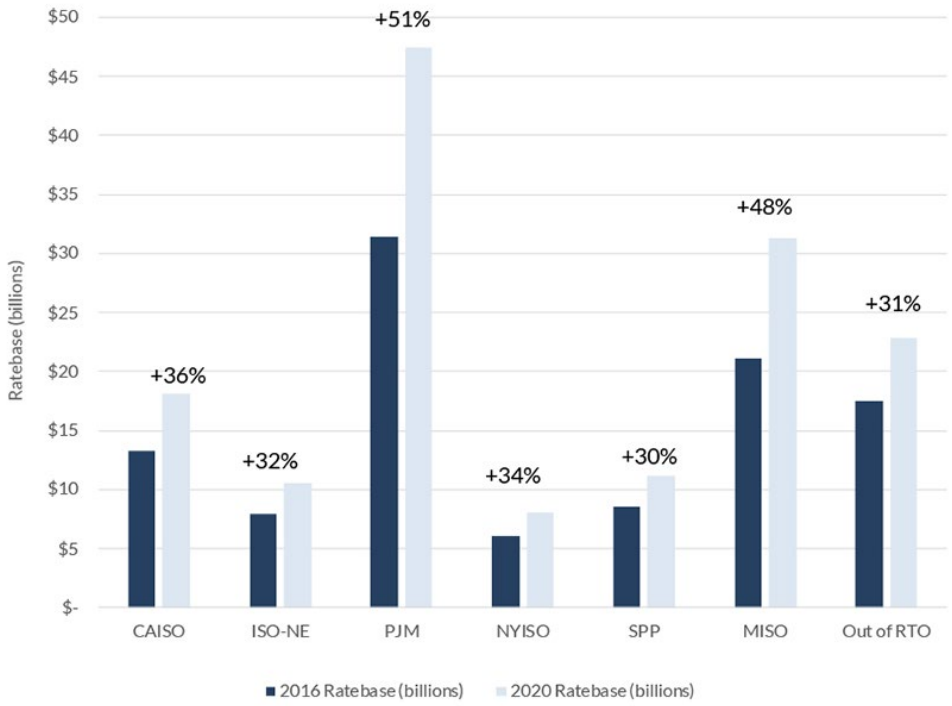
"That is the ***only*** specific conduct in all of Section 219 for which Congress *mandated* an incentive," ITC Holdings said. "The supplemental NOPR thus improperly attempts to rewrite the statute by replacing 'that joins' with 'to join.'"

The Edison Electric Institute's comments opposing the NOPR included an affidavit from former U.S. Rep. Joe Barton, who chaired the House-Senate conference committee that approved the 2005 legislation.

"Contrary to the interpretation proffered in the Federal Energy Regulatory Commission's April 21, 2021, Notice of Proposed Rulemaking, Section 219c does not contain a 'sunset' clause, and at no point does it implicitly, or expressly, state that the incentive to a utility that joins a transmission organization should be limited in duration," the Texas Republican said. "If the committee had intended that the incentive to a utility that joins a transmission organization was meant to be a one-time payment or one-time deal, I would have instructed conference committee staff to make that clear in the language of the statute."

SPP and MISO filed joint comments criticizing the NOPR as an "abrupt and unsupported change of course" by FERC, adding that "the benefits of RTO membership largely flow to the end-use customers and not to a regulated utility that owns the assets."

"The resilience of the RTO model is not infinite," they continued. "As voluntary constructs created by the commission, the RTOs are highly sensitive to the ever-changing calculus of costs and incentives. … Growing and disparate regulatory costs and burdens imposed by the commission solely on RTOs present a serious challenge to the voluntary membership model. In such an environment, it is not surprising that not only have no new RTOs formed after the initial period of RTO development, but large parts of the country continue to have no access to the significant and quantifiable benefits provided by RTO markets," the RTOs said.



Between 2016 and 2020, transmission ratebase increased by about 50% in PJM and MISO and by 30% or more in other regions. | *S&P Global Market Intelligence*

PJM also filed comments opposing the change. As of Monday evening, no comments had been filed in the docket by ISO-NE, NYISO or CAISO.

Potomac Economics, which performs market monitoring for MISO, NYISO and ISO-NE, said the commission's proposal "seems to be predicated entirely on a false distinction between the decision to 'join' an RTO and the decision to 'remain' in an RTO; unsupported assertions that all utilities benefit from being members of an RTO; and a disregard of the additional obligations and costs borne by members of an RTO."

Case-by-case Review Required?

SPP transmission owners American Electric Power (NASDAQ:AEP), Evergy (NYSE:EVRG), Oklahoma Gas and Electric (NYSE:OGE) and Algonquin Power's Empire District Electric (NYSE:AQN) said FERC would have to make individual findings on whether existing transmission rates including the adder are just and reasonable.

"How, for instance, would FERC support finding that one utility's total ROE [return on equity] of 10% is unjust and unreasonable and needs to be reduced by 50 basis points, if another utility with comparable credit ratings has a just and reasonable base ROE of 10.25% even without the 50-basis-point adder?" they asked.

The New England States Committee on Electricity (NESCOE) said it supported most of the proposed NOPR but also called for individual determinations on any future RTO adders.

"The proposal to codify a 50-basis-point adder incentive would make it impossible for the commission to fulfill its statutory obligation to ensure that rates are just and reasonable," NESCOE said. It asked FERC "to reaffirm the

FERC/Federal News

burden it placed on utilities in Order No. 679 to demonstrate, on a case-by case-basis, that the level of the transmission organization ROE adder incentive is appropriate."

NESCOE quoted from the order, in which FERC declined to "make a generic finding on the duration of incentives that will be permitted for public utilities that join transmission organizations."

The Electricity Consumers Resource Council (ELCON), which represents industrial consumers, said it supports limiting the incentive but said the commission should provide an empirical analysis to justify the size and duration of the adder. "The commission has not provided an analytical framework for judging whether (or why) that specific duration — and the associated ratepayer burden — is 'just and reasonable and not unduly discriminatory or preferential,' as required by Section 219d. The same critique applies to the level (or size) of the incentive."

It also said FERC should calculate the cost of the adder, which the Transmission Access Policy Study Group (TAPS), an association of transmission-dependent utilities, has estimated at $400 million per year. "We happen to agree with TAPS' estimate, but we are troubled that the commission does not provide its own estimate of the cost of its policy in rates under its jurisdiction," ELCON said.

The Virginia Office of Consumer Counsel noted that its investor-owned electric utilities are required by a 2003 state law to participate in an RTO. "An incentive … is something 'serving to encourage, rouse or move to action.' The dangling carrot must actually bring the donkey to a trot."

The Organization of PJM States Inc. (OPSI) said keeping "the incentive in perpetuity goes beyond the requirements of Section 219 and thereby imposes unnecessary and unjustified costs upon ratepayers." OPSI also said the adder should not apply to supplementary transmission projects which do not result from the RTO transmission planning process.

MISO generation and transmission cooperatives Great River Energy, Hoosier Energy Rural Electric Cooperative, Southern Illinois Power Cooperative and Wabash Valley Power Alliance said there is no evidence that the adder has been an incentive for joining RTOs. "While the transmission organization incentive was created through Order 679 in 2006, many of the largest (in terms of rate base) transmission owners in MISO did not receive the transmission organization incentive until Jan. 5, 2015. Many, if not all, of these transmission owners were MISO members prior to receiving the transmission organization incentive, so clearly it was not needed to incentivize them to join MISO or remain members."

Burdens, Benefits of RTO Participation

The two sides also clashed over the burdens and benefits of RTO participation.

PJM transmission owners, including Dominion (NYSE:D), Duke Energy (NYSE:DUK), East Kentucky Power Cooperative, Exelon (NASDAQ:EXC), FirstEnergy (NYSE:FE) and Public Service Enterprise Group (NYSE:PEG) complained that FERC's existing ROE methodology does not capture the risks TOs face in joining RTOs.

"RTOs are governed by increasingly divergent and combative stakeholders and are deferring more to stakeholders who can be hostile to transmission owner interests and who can make changes to the RTO's tariff and other governing documents difficult, if not impossible, for transmission owners," the TOs said. "Thus, the RTO incentive is necessary to maintain a proper balance by compensating the transmission owner for the risks of RTO membership. Removing the RTO incentive … would destroy that balance."

ITC said customer benefits from RTOs "far exceeds the costs of the incentive," citing estimates of $3.1 billion to $3.9 billion in annual net benefits in MISO alone. The incentive "appropriately (although not equally) enables ITC to share in the benefits it creates for others through its ongoing participation in MISO, Southwest Power Pool and PJM Interconnection," it said.

Will Eliminating Adder Affect Behavior?

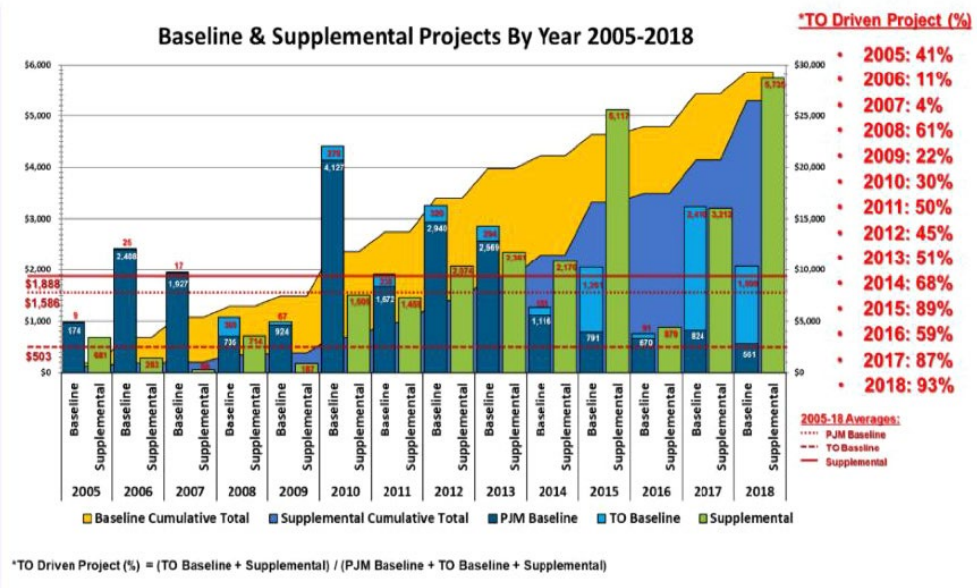
Opponents of the NOPR painted a dark picture of the transmission system without the adder.

"The legal threshold for transmission owner withdrawal is not high and, given the ever-increasing costs and regulatory burdens imposed on the RTOs, limiting the existing incentive could make both joining and staying in an RTO less attractive," MISO and SPP said. "The value of RTO membership is built, in part, on the value that each member, and each member's facilities, brings into the footprint. One member leaving could have a disproportional impact on the value of continued RTO membership for the other members. Any subsequent withdrawals further diminish the overall value for the remaining members to stay in the RTO."

ITC said eliminating the RTO adder "will only stunt transmission organization growth, potentially leaving these regions with only energy imbalance markets (EIMs). Worse yet, the policy could lead fully formed transmission organizations to devolve into EIMs."

"If even a few utilities exit transmission organizations, the disruption to organized markets would be significant and would substantially erode the benefits currently enjoyed by market participants and customers," ITC added.

The SPP TOs cited estimates that up to $600



The Organization of PJM States Inc. said the RTO adder should not apply to supplementary transmission projects, which do not result from the RTO transmission planning process. | *American Municipal Power*

FERC/Federal News

billion in transmission investments will be needed by 2050 to integrate renewables and reduce carbon emissions. FERC's proposal "is in direct conflict with the policy initiatives that are being pursued by the [Biden] administration and debated in the Congress," they said.

PJM said the commission "should neither assume that elimination of the incentive would have zero effect on the potential for transmission owners to exit an RTO, nor assume that the consumer benefits would remain at their same level should the size of the RTO be reduced."

If FERC does change the adder, PJM said, it "should avoid making a sweeping nationwide ruling that ignores region-specific issues such as the degree of vertical integration in a particular RTO; whether the RTO already has formal exit fees applicable to transmission owners; how particular transmission owners came to join the RTO; whether the region is dominated by restructured or traditional regulation states; and other aspects of transmission owners' profiles that differ across the nation."

"If it fails to do so, the commission may be making assumptions about affiliate relationships, the history of how particular transmission owners came to join RTOs as it relates to the 'voluntariness' issue, and other matters that do not necessarily fit for a large and mature multistate RTO such as PJM," it said.

Others said TOs are bluffing in threatening to leave RTOs over the loss of the adder.

"A utility that would contemplate leaving an RTO/ISO arrangement or refusing to participate in one absent an adder could be called upon to justify why that decision is reasonable for either the company or its customers," the Connecticut Public Utilities Regulatory Authority (PURA) said.

"As a practical matter, utilities that join transmission organizations are unlikely to leave because of the significant cost savings in the form of congestion cost relief or less expensive power due to access to economic dispatch of supply gained in joining a transmission organization, and they do not need an ROE adder incentive to remain," NESCOE said.

NESCOE noted RTO members are generally exempt from having to purchase energy and capacity from qualifying facilities under the Public Utility Regulatory Policies Act (PURPA) and can charge market-based rates because the region over which their market power is measured is much larger.

The MISO G&T co-ops said the RTO's exit fees will prevent TOs from leaving.

"The exit fees provide a significant barrier to exit for longstanding members, particularly those in MISO whose membership predates the 2011 approval of roughly $5.6 billion of Multi-Value Projects. For a utility that is considering exiting the transmission organization, the financial impact of the loss of the incentive is likely far outweighed by the financial impact of the exit fees," they said. "Thus, from a practical standpoint, the incentive does not prevent any utility that is a member of a transmission organization from exiting the transmission organization."

TAPS said limiting the incentive could increase RTO participation. "A state regulator that has authority to approve a utility's application to join an RTO might be more willing to do so if the ratepayer impact of joining is lower due to the limited duration of the transmission organization incentive," it said.

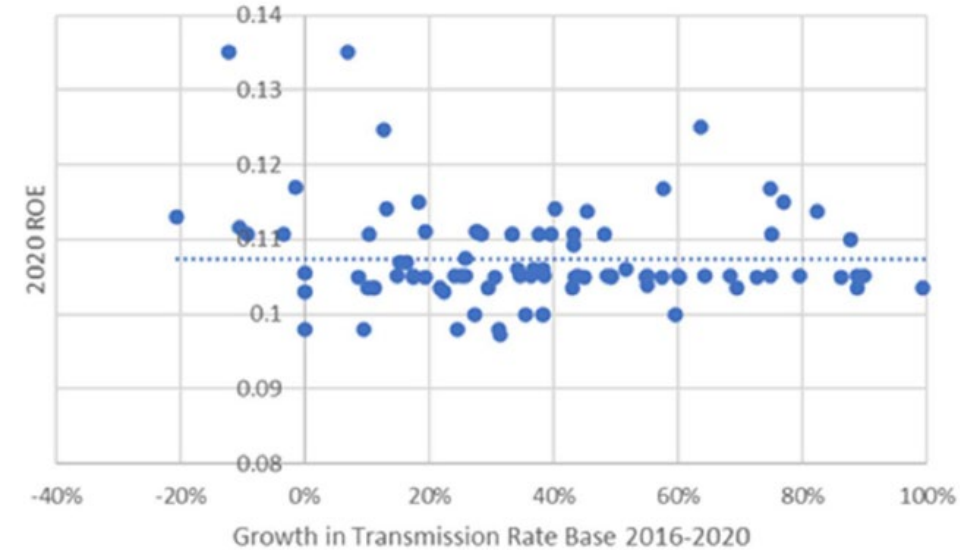
APPA said the decision to join or remain in an RTO "is not solely a decision of transmission owners; the decision is also influenced by other stakeholders — including state regulators."

It provided an affidavit from consultant Marc Montalvo, who said limiting the adder is unlikely to discourage transmission development in RTO regions. "The base ROE is explicitly designed to allow utilities to attract capital for their projects, without the necessity of any adder," Montalvo said. He included a scatterplot comparing RTO utilities' 2020 ROE rates with their rate base growth between 2016 and 2020. He said the analysis "reveals no discernible relationship between ROE and rate base, presumably because many other factors come into play in investment decisions."

Montalvo also presented data showing TOs' rate bases grew from $106 billion in 2016 to almost $150 billion in 2020, an increase of 41.5%.

"Applying an additional ROE adder to this incremental rate base produces an additional, steadily increasing revenue stream that is essentially a windfall to the utility," he said. "These additional revenues would plainly overcompensate utilities for any frictions management and shareholders may perceive to be associated with remaining in an RTO."

ITC included a fallback position in its comments. If the commission does eliminate the RTO adder, it said, it should also require RTOs to eliminate their exit fees. "The commission cannot adopt a 'Hotel California': 'You can check out any time you like, but you can never leave,'" ITC said. ■



Marc Montalvo, a consultant for the American Public Power Association, said an analysis of the growth in transmission rate base and average returns on equity among utilities shows no relationship between ROE and rate base. | *Daymark Energy Advisors*

"The commission cannot adopt a 'Hotel California': 'You can check out any time you like, but you can never leave.'"

—ITC

FERC/Federal News

DC Circuit Slaps FERC on Pipeline Need Analysis

Spire STL Pipeline May Lose Ability to Operate

By Rich Heidorn Jr.

The D.C. Circuit Court of Appeals ordered FERC on June 22 to vacate its decision permitting a 65-mile natural gas pipeline, saying the commission had failed to follow its own rules on evidence of a need for the facility (*20-1016*).

The court said FERC failed to balance the benefits and adverse impacts when it approved a certificate of public convenience and necessity for the Spire *STL Pipeline* line on a 3-2 vote in August 2018 (*CP17-40*). It said the commission "made a superficial effort to remedy the obvious deficits of the certificate order" when it rejected rehearing requests in November 2019 — the same month the line went into commercial operation.

ClearView Energy Partners told clients that "closure of the asset may be more a question of *when* than if."

Parent company Spire (NYSE:SR) did not respond to a request for comment. Shares in the company, which has gas utilities in Alabama, Mississippi and Missouri and storage operations on the Wyoming-Utah border, dropped by $3.49/share (-4.67%) after the ruling.

The ruling, by Senior Circuit Judge Harry Edwards and Circuit Judges David Tatel and Patricia Millett, was a victory for the Environmental Defense Fund (EDF), which filed the court challenge after failing to block the certificate in proceedings before FERC.

No Takers

Spire announced plans for the project in 2016 and held an "open season" in August of that year inviting gas shippers to sign preconstruction contracts. When it got no takers — the St. Louis area was already served by five existing pipelines — it signed an agreement with one of its affiliates, Laclede Gas (now called Spire Missouri) for 87.5% of the line's capacity. At the time, Spire Missouri obtained most of its natural gas from pipelines owned by Enable Mississippi River Transmission (MRT), a unit of Enable Midstream (NYSE: ENBL).

In its January 2017 application to FERC, Spire conceded that the line was not being built to serve new load but said it would provide other benefits, such as enhancing reliability and supply security by providing access to new sources of gas in the Rocky Mountains and Appalachian Basin and avoiding the New Madrid Seismic Zone. It also said it would eliminate the use of propane "peak-shaving" during periods of high demand. Spire later acknowledged that it had used propane peak-shaving on only three days between 2013 and 2018.

The certificate application was protested by several stakeholders, including the Missouri Public Service Commission and Enable MRT, which said the project had "been shielded from a truly competitive market."

Enable MRT also cited comments by Spire Missouri and Spire STL's corporate parent that construction of the pipeline would increase shareholder earnings. It said the economic risks of the pipeline would be shifted onto Spire Missouri's "captive ratepayers [for natural gas] and the ratepayers of pipelines that would experience de-contracting due to" the new pipeline.

EDF told FERC there was a growing trend for utility holding companies making transactions committing retail utilities to new long-term capacity with their pipeline developer affiliates.

"The essence of this financing structure is to take a cost pass-through for a retail gas or electric distribution utility — a contract for natural gas transportation services — and pay those transportation fees to an affiliated pipeline developer entitled to accrue return on its investment from that same revenue," EDF said. "Thus ratepayer costs which may not be justified by ratepayer demand are being converted into shareholder return."

EDF asked the commission to "apply heightened scrutiny" to the application because of the affiliate relationship, saying "there is a gap ... between state and federal regulatory oversight of affiliate precedent agreements, such as the one Spire STL has submitted in this proceeding to demonstrate market need."

Balancing Benefits and Adverse Impacts

Under the Natural Gas Act, FERC can only issue a certificate if it finds that the new pipeline "is or will be required by the present or future public convenience and necessity."

If FERC concludes there is a need, it then determines whether there will be adverse impacts on "existing customers of the pipeline proposing the project, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline," according to the commission's Certificate Policy Statement, issued in 1999 and clarified in 2000. If it finds adverse impacts, the commission must balance the public benefits — such as meeting unserved demand, providing competitive alternatives or advancing clean air objectives — against them.

The Spire STL Pipeline went into commercial operation in November 2019. | *Spire*

The policy statement says FERC will "consider all relevant factors" to determine the need for a project and that the evidence "will usually include a market study. ... Vague assertions of public benefits will not be sufficient."

FERC's decision acknowledged that the pipeline was not meant to serve new load and acknowledged the difference in the cost of gas delivered to Spire Missouri via the proposed pipeline versus current pipelines "was not materially significant."

Nevertheless, the commission majority — Republicans Kevin McIntyre, Neil Chatterjee and Robert Powelson — rejected calls for a market study.

Commissioners Cheryl LaFleur (D) and Richard Glick (D) dissented on the order. Glick, now FERC chairman, noted that "there are several potential business reasons why [Spire STL]'s corporate parent might prefer to own a pipeline rather than simply take service on it, such as the prospect of earning a 14% return on equity rather than paying rates to [Enable] MRT or another pipeline company."

Spire told FERC in 2019 that the pipeline, which runs between Scott County, Ill., and St. Louis County, Mo., cost about $287 million, an increase of $67 million (30%) from its original estimate.

FERC's 'Ostrich-like Approach'

The court concluded that FERC's decision "principally focused on the precedent agree-

FERC/Federal News

ment between Spire STL and Spire Missouri in finding that there was market need for the project. And the commission stated that it would not 'second guess' Spire Missouri's purported 'business decision' in entering into the precedent agreement with Spire STL, even though the shipper and the pipeline were affiliates. … We find that the commission ignored record evidence of self-dealing and failed to seriously and thoroughly conduct the interest-balancing required by its own Certificate Policy Statement."

The court said FERC took an "ostrich-like approach" by failing to consider "plausible evidence of self-dealing."

"The challenges raised by EDF and others were more than enough to require the commission to 'look behind' the precedent agreement in determining whether there was market need. If it was not necessary for the commission to do so under these circumstances, it is hard to imagine a set of facts for which it would ever be required.

"Instead of evaluating the legitimate claims that had been raised, the commission simply stated that it had "no reason to second guess the business decision of" Spire Missouri.

The court said EDF had standing to challenge the certificate because at least four of the group's members owned land transected by the pipeline and had property rights taken through eminent domain. Spire initiated eminent domain proceedings against more than 100 entities involving more than 200 acres of privately owned land, according to Glick.

However, the court said a woman who lived half a mile from the pipeline and was not subject to eminent domain had no standing to challenge FERC's environmental assessment, which found that construction and operation of the pipeline would have no significant environmental impact.

Remedy

The court said vacating the certificate order was an appropriate remedy because of the "identified deficiencies in the commission's orders."

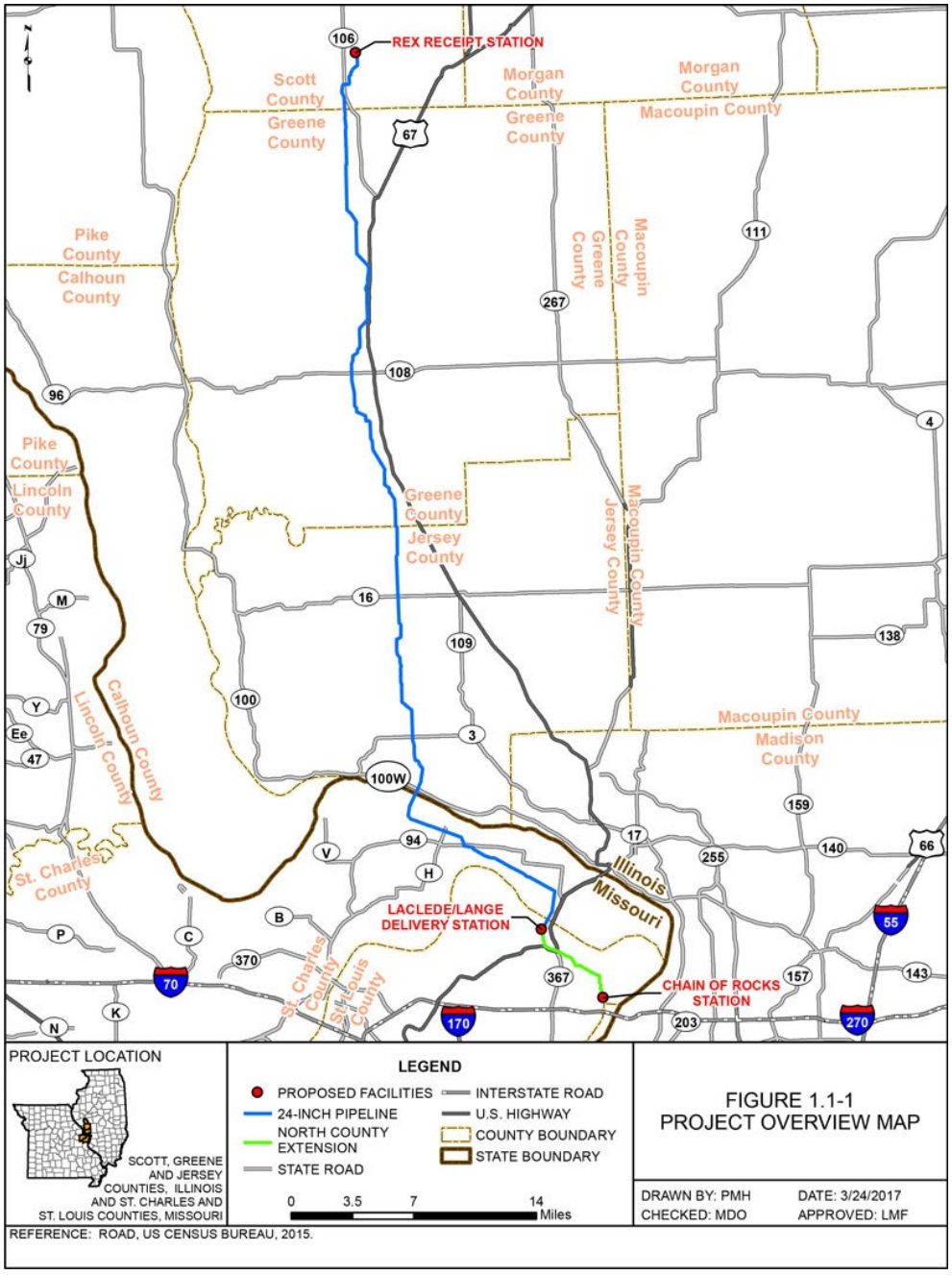
The commission's ability "to rehabilitate its rationale … is not at all clear to us at this juncture," the court said. "Furthermore, remanding without vacatur under these circumstances would give the commission incentive to allow 'build[ing] first and conduct[ing] comprehensive reviews later.'"

The court's mandate, which makes the ruling binding, will be issued seven days after the D.C. Circuit addresses any petition for rehearing or en banc review.

ClearView said it didn't expect FERC to appeal the ruling given its current composition. Chatterjee's term expires at the end of June, and he is expected to be replaced by a Democrat, giving the Democrats a 3-2 edge under Glick.

"Spire could seek rehearing from the panel on this decision or the full D.C. Circuit (en banc), but absent FERC support, we would give it scant odds of success. At this time, we think that an appeal to the U.S. Supreme Court would be unlikely to succeed should Spire STL pursue one," ClearView added. "The D.C. Circuit may not necessarily continue to withhold the mandate pending Supreme Court review. In our view, closure of the asset may be more a question of when than if."

Pamela Quinlan, Glick's chief of staff, tweeted that the decision "is a very big deal" and why Glick is pursuing the Notice of Inquiry that will look at how FERC assesses need, among other issues (PL18-1). (See *Glick Hits 'Refresh' at 1st FERC Open Meeting*.) ■



The Spire STL Pipeline spans 65 miles between Scott County, Ill., and St. Louis County, Mo. | *Spire*

FERC/Federal News

FERC Outlines New Office of Public Participation

By Michael Brooks

FERC on Thursday announced it has finished work on establishing its new Office of Public Participation (OPP) and that it will hire a director by Oct. 1, the end of this fiscal year.

"I am pleased to announce that FERC has established an Office of Public Participation, a step that is long overdue," Chairman Richard Glick said. "I am looking forward to finding a director to lead this office and continuing to engage with the public on these essential issues."

FERC has been required to establish the office since 1978 under the Public Utility Regulatory Policies Act, but Congress had not allocated it funding until late last year. Its purpose is to not only assist members of the public impacted by the commission's proceedings, but also gather more public input.

The announcement followed several months of public input, including several listening sessions led by Commissioner Allison Clements, a commissioner-led workshop in April and 115 written comments. (See *Panelists Urge Inclusive Approach to FERC's OPP*.) Among the many complaints levied by commenters was that they were often completely unaware of an infrastructure project (usually a natural gas pipeline) being built until developers asserted eminent domain.

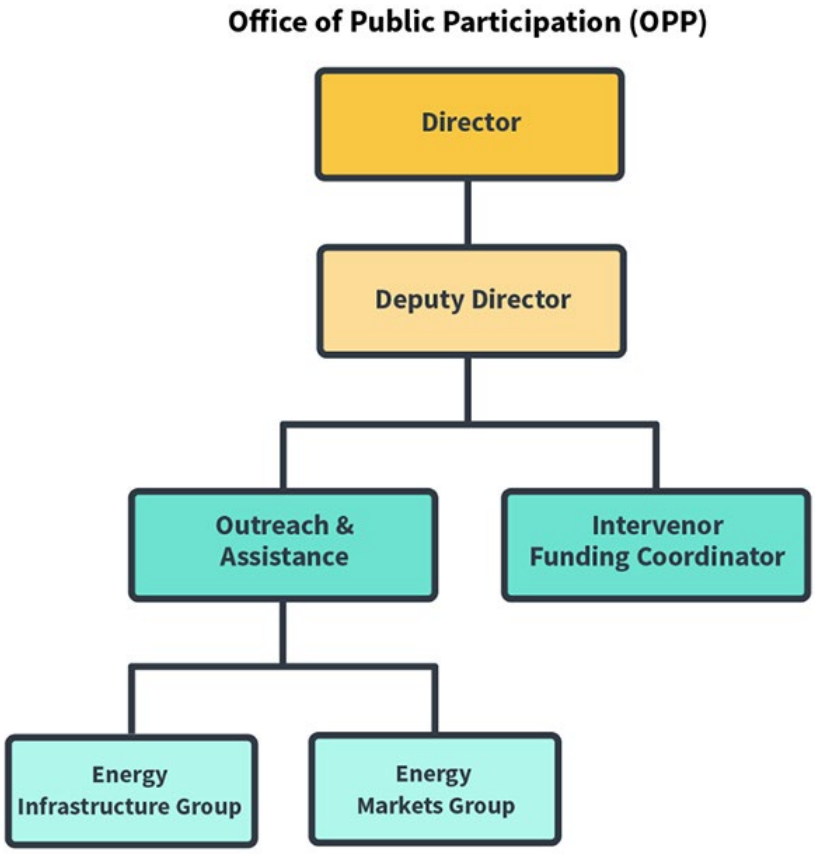
"Our process for establishing FERC's new Office of Public Participation was driven by the desire to hear directly from the audience that the new office will serve: the public," Clements said. "The form and function of OPP is based on a strong foundation of input, particularly from people and communities who traditionally have not had a voice in commission processes yet stand to benefit from participation. I look forward to seeing how OPP evolves to carry out Congress' directives."

In compliance with a congressional directive, FERC outlined the structure and functions of the new office in a 34-page *report*, released alongside the announcement. In it the commission said it would implement the office in four phases, beginning by detailing current staff for "the first few months" before beginning to hire new, dedicated staff over the course of the next fiscal year under its director.

The office will house an Outreach and Assistance unit, which will be divided into groups for energy infrastructure and energy markets. FERC expects the office to be fully staffed in FY24. Applications for the director position are due by July 15.

"We commend FERC for its action today of getting the Office of Public Participation off the ground," said Aaron Stemplewicz, senior attorney at Earthjustice. "The office will help correct the existing power imbalances in FERC proceedings. It will provide historically underrepresented communities and individuals with the critical tools and assistance necessary to meaningfully engage in those proceedings."

"Consumers finally have a seat at the table!" Illinois Rep. Jan Schakowsky *tweeted*. "The Office of Public Participation at FERC will give consumers a voice in how FERC regulates electricity rates or approves energy infrastructure." ■



Structure of the new FERC Office of Public Participation | *FERC*

FERC/Federal News

New Bill Would Tackle Tx Cost Allocation

Castor also Wants RTOs and ISOs to Consider Grid-enhancing Technologies

By K Kaufmann

A bill introduced in Congress last week would ensure that no single power generation or energy storage project seeking to interconnect to the grid would be hit with the full or a disproportionate amount of the cost of any system upgrades required.

Rep. Kathy Castor (D-Fla.) | *House Select Committee on the Climate Crisis*

Introduced by Rep. Kathy Castor (D-Fla.), who chairs the House Select Committee on the Climate Crisis, the *Efficient Grid Interconnection Act* would require FERC to issue new or revised regulations that would forbid utilities from allocating "the costs of a network upgrade to the requesting interconnection customer." Instead, the bill states, costs would have to be "reasonably" allocated to parties that use or take electricity from the transmission system or would "otherwise benefit from a network upgrade of the transmission facility or the transmission system."

FERC would also have to issue new or revised regulations for RTOs and ISOs to consult with interconnection customers to see if specific "grid-enhancing technologies," such as storage or advanced power flow controls, could be used to defer more expensive and time consuming system upgrades.

The need for reform of interconnection policies and procedures has been an ongoing focus for a range of industry stakeholders, made more urgent by power outages caused by the growing number of extreme weather events that will continue to strain transmission lines across the country.

According to a *recent analysis* from the Lawrence Berkeley National Laboratory, at the end of 2020, 755 GW of generation and 200 GW of energy storage were sitting in interconnection queues across the U.S. Renewable energy accounted for most of the queued generation — 680 GW — and the report says only 19% of the wind projects and 16% of the solar projects reach commercial operation.

Announcing the bill on June 22, Castor issued a statement framing the proposed legislation as a way to "save families money on their utility bills, create jobs in communities across America, reduce pollution and improve public health across the board. ... By making our grid more efficient, we'll also put money back in the pockets of working families, as we eliminate the barriers that stand between them and cheap, renewable energy."

The bill is being co-sponsored by five other Democratic representatives: Rep. Julia Brownley (D-Calif.), Rep. Sean Casten (D-Ill.), Rep. Jared Huffman (D-Calif.), Rep. Scott Peters (D-Calif.) and Rep. Jan Schakowsky (D-Ill.).

A Crowded Highway

Under current policies, once a transmission or distribution line has reached capacity, the last project to interconnect, or the next one in the queue, may be saddled with the cost of system upgrades, in some cases costing millions of dollars and making the project economically unfeasible.

"Today's grid interconnection policies are largely analogous to requiring the next car entering a crowded highway to pay the entire bill for a needed lane expansion," said Gregory Wetstone, CEO of the American Council on Renewable Energy, one of several clean energy organizations supporting the bill. "It doesn't make sense, and it has kept hundreds of thousands of megawatts of wind, solar and energy storage resources stuck in interconnection queues," he said in a statement.

Kyle Davis, head of public policy and institutional affairs for renewable energy developer Enel North America, said the bill would provide an appropriate balance for cost allocation. "It does not say that generators should pay nothing," he said in another statement of support for the bill. "Instead, it directs FERC to figure out the right way to fairly split the costs between generators and transmission owners or load ... based on level of impact the new generator imparts on the transmission system."

By deferring costly upgrades, grid-enhancing technologies could double the volume of renewables coming online by 2025, according to a recent study by the WATT Coalition. (See *Report: US Needs Grid-enhancing Technologies Now*.) The study focused on backed-up interconnection queues in Kansas and Oklahoma, reflecting the bipartisan scope of the problem.

Synchronized Planning Processes

Whether that appeal will translate to bipartisan support in Congress remains to be seen.

| © RTO Insider LLC

Castor's 13-page bill is modest and focused — trimming off a sliver of President Biden's embattled $2 trillion infrastructure plan. On *Thursday*, the Senate Energy and Natural Resources Committee will be discussing a larger chunk — a 423-page draft of a bill called the *Energy Infrastructure Act*. The draft encompasses not only transmission infrastructure, but supply chains for clean technology, infrastructure for hydrogen and nuclear energy, and energy efficiency and building infrastructure.

Specific provisions on transmission would:

- authorize the Department of Energy to fund a range of research and projects aimed at improving grid reliability and preventing "resilience events" such as power outages caused by wildfires;
- require FERC to open a docket on "the effectiveness of existing planning processes for identifying interregional transmission projects that provide economic, reliability, operational, public policy and environmental benefits (including reductions in carbon emissions), taking into consideration the public interest, the integrity of markets and the protection of consumers;" and
- promote streamlined permitting for projects with "interregional benefits" through the "synchronization of planning processes in neighboring regions, such as using a joint model on a consistent timeline with a single set of needs, input assumptions and benefit metrics." ■

CAISO/West News

CPUC Orders Additional 11.5 GW but No Gas

By Hudson Sangree

The California Public Utilities Commission reversed course Thursday on a proposal to include up to 1,500 MW of gas generation in its plan to add 11.5 GW of new resources by 2026 to ensure reliability — the largest single procurement order in state history.

Commissioners unanimously approved a *revised proposal* that requires all 11.5 GW of new resources to be free of greenhouse gas emissions.

Commissioner Clifford Rechtschaffen | *CPUC*

"This is a landmark decision," Commissioner Clifford Rechtschaffen said. "I don't think it's hyperbole to describe it as such. We are directing the various load-serving entities to procure what is an unprecedented amount of new clean energy resources … [that] will come online in the middle of the decade.

"Just to give you a sense of the scale, this is enough to power about 2.5 million households in the state, and all of it will be coming from renewable or zero-emitting resources," Rechtschaffen said. "We need these resources … to respond to the changing climate and to more extreme weather events, such as the ones we saw last summer and which we're going to continue to see. We need it to respond to the changing grid."

Multiple gas plants, including a group of aging once-through-cooling plants, are scheduled to retire within the next few years. So is Diablo Canyon, the state's last operating nuclear generator.

In a *proposed decision* in May, CPUC Administrative Law Judge Julie Fitch said the CPUC should include from 1,000 MW to 1,500 MW of additional gas generation in the procurement order to make sure the state can meet its evening peaks, after solar goes offline. Last summer's rolling blackouts happened in the early evening.

Continued outages could jeopardize the state's plan to supply retail customers with 100% clean energy by 2045, Fitch said. (See *CPUC Proposes Adding 11.5 GW of New Resources*.)

"The middle of this decade represents an inflection point and a transition; we need to make it through successfully in order to realize our goals," she wrote. "The potential for a destabilized electric grid and unreliable service if we fail to plan appropriately for the transition is a very serious threat to our ability to realize our long-term goals."

Rechtschaffen offered an alternative plan that limited the amount of added gas to 500 MW with a five-year time limit. Both plans said the gas should come from increased production at existing plants, not from new generation.

The proposal caused an uproar among stakeholders and residents, who saw it as a step backward and a move away from nearly all state policy in recent years.

"There's been a tremendous amount of party interest in this case," Rechtschaffen said. "We had over 50 parties filing comments [and] we had over 40 parties participating in the all-party meeting we [held on the matter]." Numerous public commenters critiqued the plan on June 17, saying the CPUC had failed to show that more gas generation was needed.

On June 22, however, Fitch had issued her revised decision, and Rechtschaffen withdrew his alternative plan.

The revised order retains the requirement that LSEs, including community choice aggregators and the state's three big investor-owned utilities, must procure resources in proportion to their share of load in *CAISO* in phases from 2023 to 2026. Batteries, long-duration storage, solar, wind and other renewables would make up the resource mix.

"The revised [proposed decision] that we're voting on today removes the requirement to procure any fossil resources, and instead our staff will work with the Energy Commission staff to conduct additional analysis over the next few months about the need for fossil resources for reliability purposes," Rechtschaffen said. "The results of this analysis from our staff and the Energy Commission will help inform our next procurement decision, which we will debate about later this year." ■

The Alamitos Generating Station is among the once-through-cooling plants set to retire, requiring replacement capacity. | *California Energy Commission*

CAISO/West News

Glick Says West Should 'Finish the Job' on RTO

FERC Technical Conference Examines Western Resource Adequacy

Continued from page 1

"I'm well aware of the history associated with the Western energy crisis 20 years ago and how that soured a lot of people in the region on developing an RTO beyond California's borders," he said. "While there has been a lot of progress, the [CAISO Western Energy Imbalance Market] for instance, much more work remains. In my opinion, the time is right for the states, the region's utilities and other key stakeholders to go ahead and finish the job."

FERC Commissioner Allison Clements | *FERC*

Commissioner Allison Clements agreed. Since the energy crisis of 2000/01, FERC has tried to leave Western entities alone to ensure their own resource adequacy and to design markets that promote reliability and cost savings, she said.

"This commission has been wise to respect [the West's] processes and not work to scare off progress from the East … [but] the urgency has changed," Clements said. "The urgency of efforts toward broader regional integration has changed in the last year, even in the last six months. The shared goals of ensuring reliability against these extreme weather threats, the goals of meeting state policy mandates [regarding greenhouse gas emissions], and the goals of protecting consumers in the process require continuing progress toward full regional integration.

"And it's no secret that I, like the chairman, believe that well designed regional markets — designed by westerners for westerners — are the best path forward to protect customers and ensure reliability while addressing resource adequacy concerns and the other serious challenges facing the West."

Doing so successfully will require transparent and effective market design and inclusive, fair governance, she said.

The commissioners' comments were the latest push toward a Western RTO.

The Public Utilities Commission of Nevada said last week that the West needs an organized market. Lawmakers in Nevada and Colorado passed bills that require transmission owners to join an RTO by 2030. And a state-led study funded by the U.S. Department of Energy found the West could save $2 billion annually by forming a single RTO. (See *Nevada PUC Calls for Organized Market in West* and *Study Shows RTO Could Save West $2B Yearly by 2030*.)

RTOs, Capacity Markets

In a subsequent panel Wednesday, FERC Commissioner Mark Christie asked panelists, who had been discussing challenges and trends in resource adequacy across the West, an open-ended question about whether Eastern-style RTOs or capacity markets would work in their region.

He got a series of nuanced answers that touched the relevant points on both sides of the argument.

Bryce Freeman, administrator for the Wyoming Office of the Consumer Advocate, said he did not understand how the development of a sound, resource adequacy construct that provides the lowest-cost assurance to customers gets done without a capacity market.

"I've thought about this a lot over the years," Freeman said. "Energy-only markets, I don't think work. That was part of the problem in Texas in February. The system needs reliability, costs money, and reliability in the form of capacity that can be dispersed when needed. Whether that's battery storage or gas or coal, or something else [like] hydrogen, the markets, or the customers, need that reliability. I don't see how you value that prudently without making a market for it."

Mark Holman, managing director of Powerex, conversely added that whenever the topic of resource adequacy comes from the West, raising the concept of a centralized capacity market along with it, "there is generally strong resistance to that structure." Holman favors a capacity market "in the form of bilateral transactions" that allow entities autonomy to decide what mix of resources — contracted or owned — work best for them.

Carrie Bentley, CEO of Gridwell Consulting, said there is a "robust" bilateral market in the West, and "capacity markets work best when you have a uniform product."

"When you have resources where you can easily compare the reliability, they have a similar obligation to the market," Bentley said. "I think the diversification of resources out here from year to year, and from hour to hour even, on what their contribution to reliability is, makes it really challenging to run a market, similar to the Eastern RTOs."

Bentley said as much as she could see "benefits of capacity markets in general, I just don't think they're well-suited to the West's resource mix or diverse set of buyers."

Paul Lau, CEO of the Sacramento Municipal Utility District, said there must be a way to control "how we want to address reliability … and not be something that's mandated through a capacity market."

"I think it's absolutely important right now that we don't have a mandatory capacity market because I think there's a lot of movement and a lot of good work that we're doing in the Pacific Northwest, certainly in the Northwest Power Pool," Lau said. (See *NWPP RA Program Taking Shape for Q3 Launch*.)

Governance Key

In the conference's second day Thursday, Scott Bolton, PacifiCorp's senior vice president of transmission development, said his company had been spending an "inordinate amount of time" working with CAISO to ensure that its integrated planning, procurement and market framework provides enough capacity to help California meet its clean energy goals.

"The stakes couldn't be higher. We're already in the midst of a very hot summer," Bolton said. "It's increasingly important, if not more important, to work across the interconnection. [FERC's] effort to facilitate greater dialogue between the fellow regulators and the state is critical. I can't overstate that, having worked both outside and inside California. I'm acutely aware that we need to keep progressing together and keeping our momentum."

Agreeing with Bolton, Oregon Public Utility Commissioner Letha Tawney said, "We see that there is a substantial resource adequacy issue heading towards us. It's abundantly clear that cooperating is to our benefit.

"I very much look forward to that opportunity to have a apples-to-apples conversation, recognizing that there will continue to be a challenge in bridging the California RA system and we'll all need some sort of clever cheat sheet or translation table," Tawney said. "I think that's possible, and I look forward to it."

So is an RTO the next logical step? Several

CAISO/West News

panelists pushed the idea.

SPP has proposed starting an RTO West, contending it is the logical choice to lead an organized market that includes diverse Western interests.

Bruce Rew, the grid operator's senior vice president of operations, noted SPP is a reliability coordinator in parts of the West and that it is helping the Northwest Power Pool develop a multistate resource adequacy program. SPP also manages a Western Energy Imbalance Service to compete with CAISO's EIM. (See *SPP CEO Pitches WECC on Western Benefits*.)

SPP's inclusive governance model would serve the West well, Rew said.

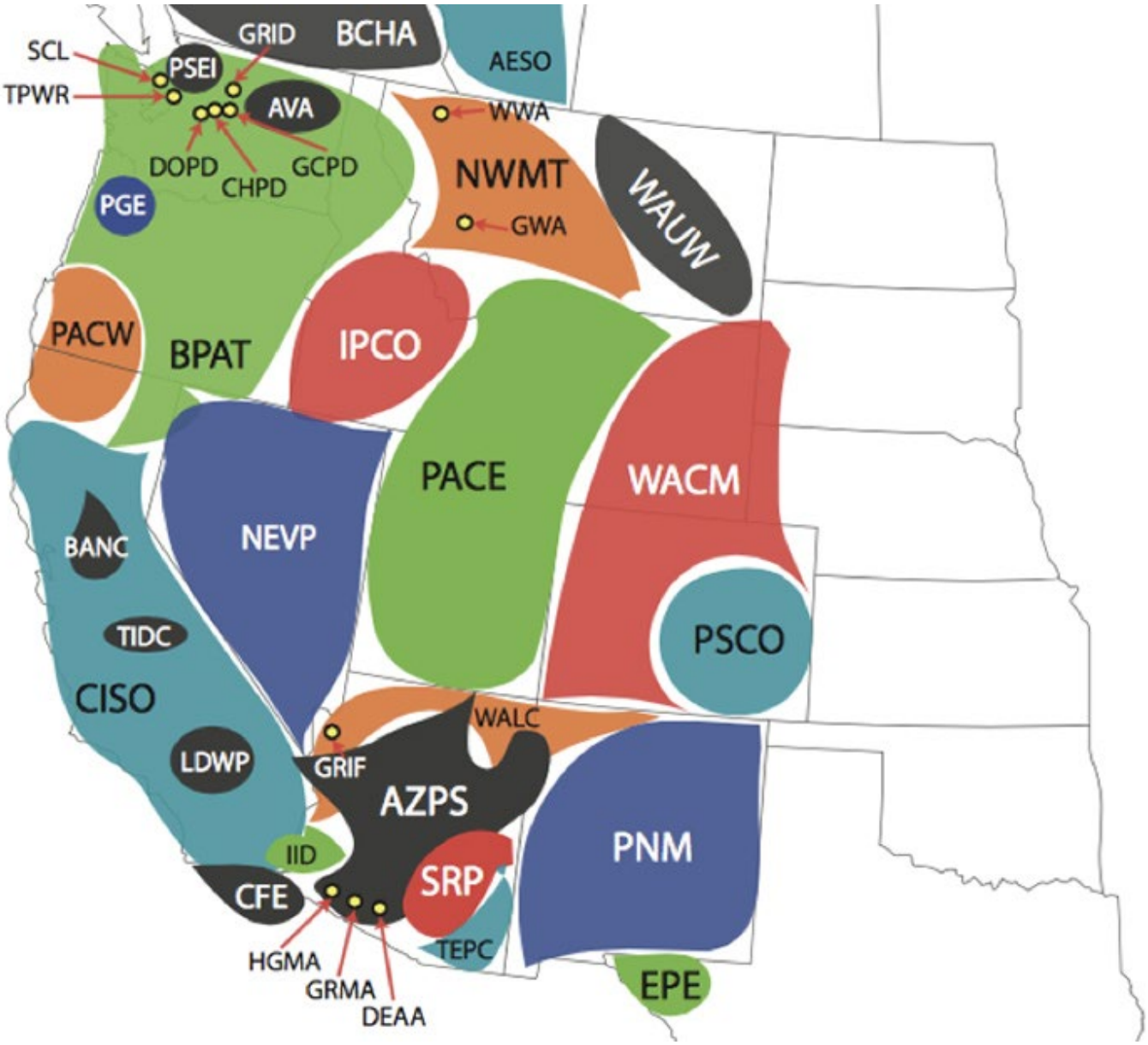
"From our perspective, governance is key for these regional organizations to be effective," he said. "Governance needs to be broad. It needs to be very inclusive for the stakeholders and all parties. Regional markets are going to be very diverse, from the small entities and large entities top the public organizations and state organizations. All those participants are the foundation for an RTO to be successful."

Western Grid Group Director Amanda Ormond pointed to the potential financial benefits.

"We know that the RTO will save $2 billion [annually] for customers," Ormand said, referencing the DOE-funded study. "Every year there's a delay, the customers are paying more than they need to.

"I totally understand that governance is an important issue," she said. "We need independence of an organization. We need state regulators to have a key place at the table. To build the best, we can look at the governance models all over the countries and the world."

In the meantime, "we're getting less reliable because weather patterns are changing," Ormand said. "Our systems are changing. At some point we need to make a decision to move forward." ■



Uniting parts of the divided West could help resolve RA issues | *WECC*

CAISO/West News

Polis Signs Bipartisan Bill to Support Interstate Tx

To help Colorado meet its ambitious decarbonization goals, Gov. Jared Polis on Thursday signed *Senate Bill 72*, an infrastructure and transmission bill that requires utilities with transmission facilities to join an RTO.

MIT Energy Initiative's Patrick Brown told the state's Public Utilities Commission in April that the fastest and most cost-effective method to reaching deep decarbonization would be to interconnect the state's grid to other regions. (See *Colo. Regulators Consider the Advantages of Interstate Tx*.) This allows for the transfer of more renewable energy and promotes grid resilience. By requiring local utilities to join an RTO, the state will be able to interconnect its transmission facilities and take advantage of other regions' renewable resources.

The bill will exempt a utility from joining an RTO if the PUC determines that there is not a viable market or that it would not be in the public's best interest. The commission will also be responsible for approving new transmission projects and ensuring that those projects "support future expansion as needed to enable the utility to participate in a regional transmission organization."

Advanced Energy Economy Principal Emilie Olsen said in a press release that the bill "will put Colorado on a path toward achieving the state's ambitious decarbonization goals, sustain economic growth, and prepare our electricity grid for the challenges ahead." ■

| *Shutterstock*

— Rebecca Santana

CAISO/West News

Western 'Megadrought' Curtails Hydropower

By Hudson Sangree

A drought in the West is cutting into hydropower supplies that are important for summer reliability and threatening to have longer-term effects on the region's grid, panelists said Friday in a session hosted by the United States Energy Association.

In its short-term energy outlook in June, the U.S. Energy Information Administration predicted the Western Interconnection's hydroelectric production will decrease 9% from last year, the lowest level since 2015, EIA senior economist Tyler Hodge said.

"When you throw in things like extreme weather events … it could really add a lot of uncertainty," Hodge said.

Lower hydro generation could increase reliance on natural gas generation and raise prices for natural gas, he said. If California or other states require additional imports to offset the reduction in hydropower, it could cause transmission congestion, he said.

The Pacific Northwest and California account for most of the hydroelectric generation in the nation, and both areas are experiencing dryer-than-average conditions.

Snow water content in California peaked at 60% of normal in 2021 after a similarly dry winter last year, CAISO said its annual summer resource assessment. The average water level in large reservoirs was 70% of normal earlier this year. (See *CAISO Could See More Outages this Summer*.)

CAISO used *Northwest River Forecast Center* projections to assess hydropower imports this summer from the Pacific Northwest. The hydrologic center predicted reservoir storage at The Dalles Dam on the Columbia River, a key indicator, will be 89% of average from April to September.

Hydropower accounts for about 15% of California's summer peak capacity, making it the second largest generation source after natural gas, which fills 57% of the state's resource needs.

FERC focused on the California hydropower crisis in its *Summer Energy Market and Reliability Assessment*. Snowpack, the state's main source of dry-season water, was critically low at 6% of normal levels May 11. Earlier-than-normal runoff will worsen the situation, FERC said. (See *FERC Summer Assessment Spotlights Western Drought Risks*.)

CAISO has said low in-state hydro could cause problems meeting peak demand this summer. In Friday's meeting, CEO Elliot Mainzer said the situation adds volatility to resource planning and needs to be accounted for. Whether drought conditions will abate or continue is a big unknown, he said.

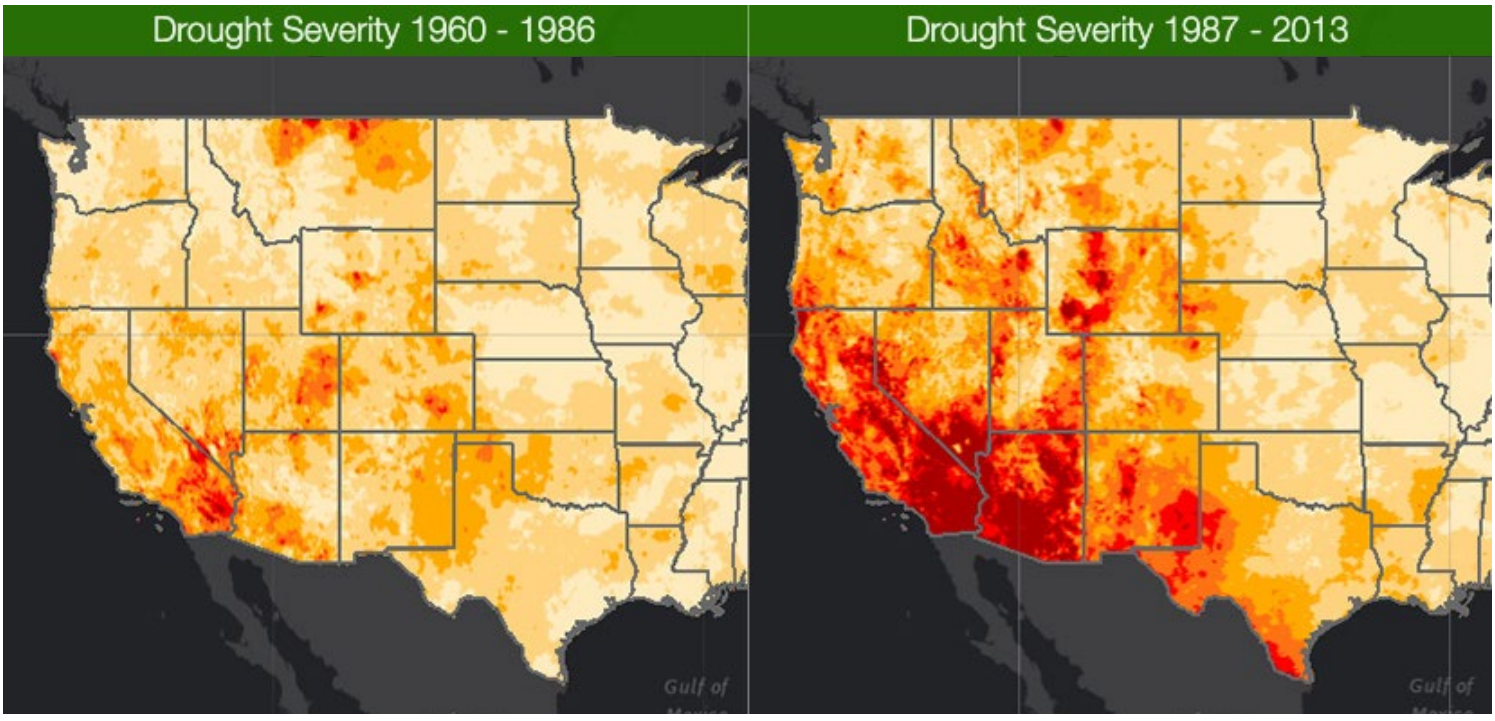
"The uncertainty … is absolutely something that we now need to bake into our planning," Mainzer said.

Hotter, dryer conditions exacerbate the water shortage, he said. Severe heat waves in the West led to energy emergencies in California and Nevada last summer, and heat waves have already impacted Western states this year.

Triple-digit temperatures and strained resources caused CAISO to issue a warning in June. Portland, Ore., hit a record high of 112 degrees Fahrenheit on Sunday and 115 F on Monday.

"The associated heat is the other variable that is really putting a lot of stress on the grid at the moment," Mainzer said.

"Under normal conditions, even on a day when it's really hot in California, but it's not super hot in Portland or Salt Lake City or Phoenix, our grid is typically OK," he said. "But when it gets simultaneously hot and dry in all these different regions, the amount of power available to California through imports … puts a lot of stress on the system." ■



Droughts became more frequent and severe in the West, as shown in this comparison of two 27-year time periods. | *USDA Forest Service | Office of Climate and Sustainability*

ERCOT News

ERCOT Technical Advisory Committee Briefs

Stakeholders Approve 1st Storm-related Protocol Changes

ERCOT stakeholders last week endorsed the first of several Nodal Protocol revision requests (NPRRs) addressing system changes stemming from February's severe winter weather that almost shut down the Texas grid.

One revision (*NPRR1080*) limits the ancillary service market's clearing prices to the systemwide offer cap of $9,000/MWh. A second (*NPRR1081*) requires that ERCOT's real-time online reliability deployment price adder (RTORDPA) be adjusted to take firm load shed into account.

Both measures, sponsored by ERCOT and its Independent Market Monitor, unanimously cleared the Technical Advisory Committee during its meeting Wednesday in separate votes. A handful of members abstained from each vote.

The Board of Directors approved both NPRRs and an accompanying other binding document request (*OBDRR030*) during a brief teleconference Monday morning.

Texas Public Utility Commission Chairman Peter Lake, presiding over the board meeting, recognized the "accelerated" approval process as being outside the normal stakeholder process.

"This will ensure that as we go through the summer, we have the best functioning market we can have," Lake said. "This is by no means the end. This is a part of the beginning in making our system better."

In approving NPRR1081, the TAC first rejected a proposed amendment by Lower Colorado River Authority (LCRA) to remove the RTORDPA from ancillary service (AS) imbalance settlement calculations.

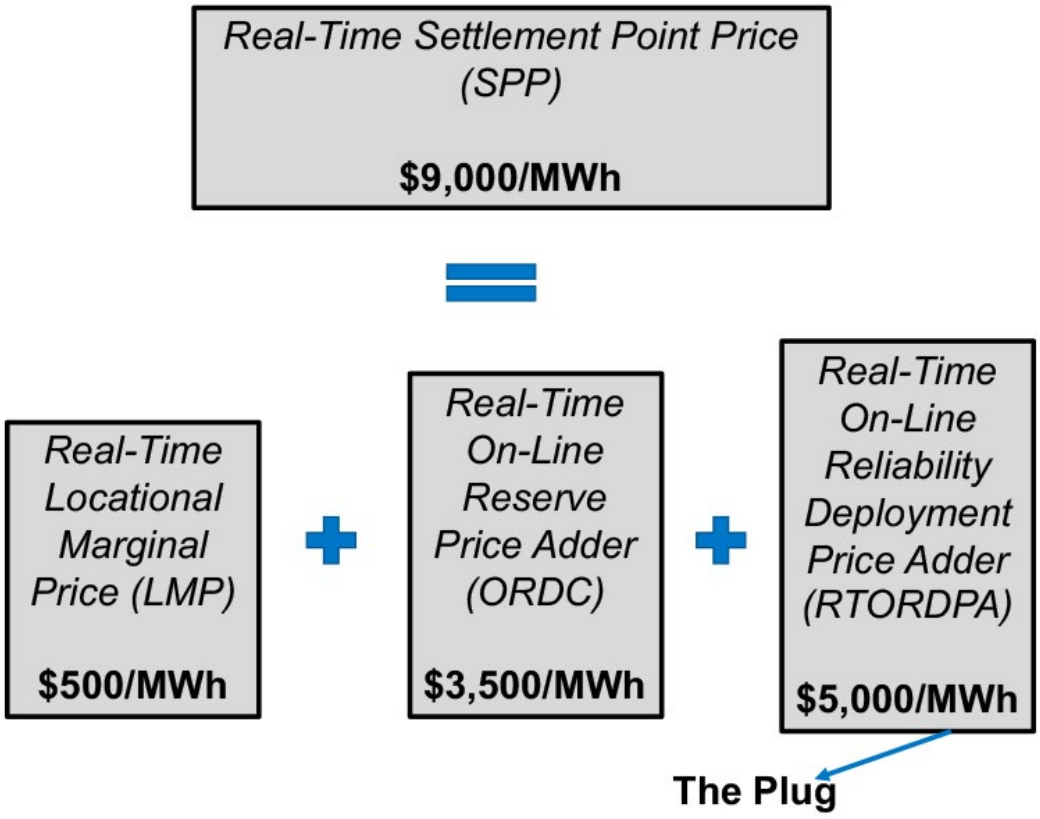
Referring to the adder as a "plug," Randa Stephenson, LCRA's senior vice president of wholesale markets and supply, said the public utility lost "tens of millions of dollars" when its services were deployed during the February winter storm, only to have the adder clawed back. She said the RTORDPA will increase real-time energy prices during periods of firm load shed before being clawed back from providers as part of the AS imbalance settlement.

"Our load paid $15 million for this uplift charge after they had done all the right things. This costs load money after they've hedged themselves," Stephenson said. "There really needs to be an understanding of what this does to generators when they're making decisions."

LCRA found general support for its proposal. Attorney Katie Coleman, who represents ERCOT industrial consumers. said the measure will create risk for responsive service providers and deter their participation in the day-ahead market and bilateral transactions.

"This will ultimately raise costs to customers, beyond the little benefit they get when a resource makes this imbalance payment," Coleman said. "Instead of adjusting for the actual megawatts of firm load shed, the [RTORDPA] adjustment is being used to backfill up to the cap. It's making that imbalance exposure exponentially larger than it otherwise should be. We have concerns about this approach of not adjusting for the actual megawatts of load shed, but backfilling up to the cap."

Kenan Ögelman, ERCOT vice president for commercial operations, said Stephenson and Coleman were not "necessarily incorrect" and



LCRA says NPRR1081's reliability adder, or "plug," will increase real-time energy prices during a firm load-shed event. | *LCRA*

ERCOT News

ERCOT's Kenan Ögelman listens to a pre-COVID TAC discussion. | © RTO Insider LLC

agreed there is a need to look at the going-forward incentives NPRR1081 creates. However, he pointed out, staff worked with the Monitor in filing the revision request to address "urgent recommendations" in its recent market report. (See *ERCOT Moves Quickly to Address Monitor's Recommendations*.)

"We don't want to preclude the discussion or efforts to solve [LCRA's issue]," he said. "We understand it might not be inherently clear around the new incentives being created here."

LCRA's amendment failed to pass, falling two votes shy of the 67% approval threshold, 14-9. Seven members abstained. The TAC then approved NPRR1081 26-0, with four abstentions.

NPRR1080 cleared the committee by a similar margin, 27-0, with three abstentions, despite some concerns that the change doesn't appropriately value AS.

The measure is a direct response to the winter storm, when AS prices exceeded $25,000/MWh. They will now be capped at the system-wide offer cap of $9,000/MWh. That cap has been reduced by rule to $2,000/MWh for the rest of the calendar year because the peaker net margin topped a threshold of three times the cost of entry for new generation plants on Feb. 16.

Ögelman said the NPRR's proposed changes "are consistent with economic market design principles." Because AS is procured to reduce the probability of losing load, those principles dictate that reserves' value should not exceed the value of lost load, which is equal to the offer cap.

The TAC also separately approved *NPRR1078*, which ensures only amounts owed to ERCOT by counterparties through the default uplift process can be collateralized. CPS Energy, with is involved in litigation with ERCOT and numerous natural gas suppliers, abstained from the vote.

More Reserves to be Procured

The committee will hold a special *virtual meeting* this Wednesday to consider ERCOT's proposal to modify procedures for deploying non-spinning reserves sooner, an acknowledgement of the likely tight conditions for the rest of the summer months.

"Going forward, ERCOT is going to be bringing more reserves online and deploying earlier than we have previously," said Jeff Billo, director of forecasting and ancillary services.

Billo said staff will be relying on their meteorologist's weather forecasts to determine the load, wind and solar forecasts before making decisions on procuring additional reserves. The forecasts will likely be classified as low-, medium- or high-potential certainty.

"There are likely to be those days when the weather forecast is not as certain, and that affects the load and the wind and the solar," he said. "On those days when we're just not as confident in the weather forecast's information, we may be procuring additional reserves."

Members asked for data on how accurate ERCOT's forecasts have been, noting deploying more reserves will affect prices.

"We're going to be very much open to stakeholders' comments and concerns," Billo said.

Securitization Issues

Staff promised the TAC as many as two opportunities to discuss the grid operator's plans for handling securitization legislation designed to address the market's and market participants' losses during the winter storm.

Members expressed a desire for a "full soup-to-nuts" workshop, but Ögelman cautioned that staff will be limited in what it can detail.

"We're happy to share what our thinking is and an outline of what we're working on," he said. "What we would share would be our interpretations, which is not necessarily the final version of the application of those laws … potentially laying out options and talking about what we can do within our systems.

"I think everyone is going to have to weigh in on their preferences at the" PUC, Ögelman said.

"It sounds like the filing may be more high level, and we'll be doing the designing of the process at the commission," Reliant Energy Retail Services' Bill Barnes said.

ERCOT is working on a tight timeline, as it must file its proposals with the PUC within 30 days.

Lawmakers passed several securitization measures that use customer-financed bonds to help market participants pay back the massive bills many incurred during the February storm. ERCOT's market was short $2.991 billion as of June 4, while several participants have filed for bankruptcy. (See *Texas Legislators Finish Work on Electricity Market — for Now*.)

Combo Ballot Includes 7 Changes

The TAC unanimously approved a combination ballot that included three additional NPRRs, two revisions to the resource registration glossary (RRGRR), and single changes to the nodal operating (NOGRR) and planning guides (PGRR):

- *NPRR995:* sets the term "settlement-only energy storage system" (SOESS) and further defines it as transmission-connected or distribution-connected; relocates the settlement-only generator (SOG) term from under resource to stand alone as its own unrelated term; and incorporates the relevant SOESS terms into the market information system (MIS) reporting created for SOGs.
- *NPRR1005:* redefines point of interconnection (POI) to refer to any physical location where a generation entity's facilities connect to a transmission service provider's facilities, and removes references to load interconnections; introduces the term "point of interconnection bus" (POIB) for the bus in the substation closest to the resource's POI or any electrically equivalent bus in the substation; and changes POI to POIB throughout the protocols, among other revisions.
- *NPRR1063*: requires ERCOT to post dynamic rating approval information to the MIS secure area.
- *NOGRR210*: clarifies language in the revised POI term and NPRR1005's POIB.
- *PGRR089*: revises the list of data sets posted to the MIS by removing the planning horizon transmission capability methodology and adding long-term system assessment postings, geomagnetic disturbance vulnerability assessments and the monthly generator interconnection status.
- *RRGRR025*: clarifies language for NPRR1005's defined POIB term by modifying the existing POI term to conform to the generation agreement's conception of the POI as the point of ownership change. The revision also removes the generation agreement's reference in that definition.
- *RRGRR028*: adds transformer manufacturer test reports to the data collection requirements and clarifies the required transformer information. ■

— Tom Kleckner

ERCOT News

Texas PUC Briefs

Commission Shortens Release of Generator Outage Data to 3 Days

Texas regulators last week directed ERCOT to waive its protocols and disclose generator outage information in three business days after an outage, rather than the standard 60 days.

The action comes after an unusual large number of forced outages led ERCOT to ask for weeklong customer conservation on June 14 to avoid another disaster similar to February's. (See *Generation Outages Force ERCOT Conservation Alert*.)

In a *memo* filed before Thursday's open meeting, Public Utility Commission Chair Peter Lake said the commission needs more transparency and information on forced outages and that the data should quickly be made available to the general public (*51617*).

"Recent events have made it clear that, when it comes to forced outages, the public deserves to know what generation units are unavailable, the amount of unavailable capacity, the cause of the outage and when the units are expected to return to service," Lake wrote.

The commission, with newly sworn-in Lori Cobos joining Lake and Will McAdams, was unanimous in its decision as it tries to determine why the outages occurred. Was it the weather? Was it damage from February's winter storm? Was it something else?

"Transparency is a means to send market signals to stakeholders, both private companies and the [municipalities] who have significant generating capabilities and are more than likely involved in the outages," McAdams said. "It's important to invest in your maintenance, to adequately perform maintenance, to rehab your facility to meet basic reliability parameters which are commonplace in the industry."

The commission made the waiver effective June 1 to Sept. 30 to ensure that the forced outages earlier in the month are made available, along with additional outages through the summer. It gave ERCOT seven days from the PUC's order to make the information available on its website.

Lake said he is asking for the generation units that are unavailable, the amount of unavailable capacity, the outage's cause and when the units are expected to return to service. He said the PUC could work with staff on potentially adding company names.

Michele Richmond executive director of Texas Competitive Power Advocates, a trade association that represents 70% of the state's competitive generation — urged caution in what information ERCOT eventually releases.

"We need to accept that machines require maintenance. That is just a fact. We want generators to do that to gain maximum performance and extend the useful life of the plant," she said. "Providing the info … in a shorter time frame doesn't bring additional capacity online; it doesn't enhance reliability. … We're trying to understand the goal of doing so."

Richmond said her trade group would work with the PUC and ERCOT in working to place the outage data in proper context.

"Without that, there's the potential that information could be misleading to the public and lead to misinformed political discourse," she said.

ERCOT said it was "fully onboard" with the PUC's efforts to increase transparency and accountability.

"Our team is working on the best way to present the outage information as directed in a timely fashion and with the requested degree of detail," spokesperson Leslie Sopko said in an email.

Lori Cobos, the PUC's newest commissioner, discusses a case with Will McAdams (left) and Chair Peter Lake. | *Texas PUC*

ERCOT News

Sopko said that as of 2 p.m. Friday, ERCOT still had 10.98 GW of generation offline, much of it for mechanical failure or other issues. The grid operator had 12.2 GW of forced outages when it called for conservation measures on June 14.

ERCOT had more than 9 GW of operating reserves on hand Friday, she said, a result of a "more aggressive" approach to maintaining a larger minimum amount of reserves and ensuring it can meet demand during unexpected tight conditions.

Woody Rickerson, ERCOT vice president of grid planning and operations, said the grid operator classifies three different levels of outages: planned, 45 days in advance; forced, when something breaks or leaks; and maintenance-level, for pending outages to prevent a forced outage.

He told the commission that ERCOT has noticed a "bubble" of forced outages that stubbornly fails to dissipate.

"We're seeing that at the end of the day, forced outages that were supposed to end are being extended another day. [The bubble] keeps moving one day to the next and the next," Rickerson said.

Commission Nixes Gas Index Link

The PUC approved a *rulemaking* that revises ERCOT's pricing mechanism by eliminating a provision that ties the low systemwide offer cap's (LCAP) value to the natural gas price index and replaces it with a make-whole provision (*51871*).

Previously, the LCAP had been set daily to the higher of $2,000/MWh or 50 times the natural gas price index, as calculated by ERCOT. The revision eliminates the gas price index component and sets the LCAP at $2,000/MWh without an alternate calculation.

ERCOT will now be required to use existing settlement processes to reimburse generators for marginal costs above real-time revenues "during an event when the system-wide offer cap is set to the LCAP."

Commission staff disagreed with stakeholders who said that a fuel index price multiplier supports reliability and market stability because it incentivizes a generation provider to lock in and control its fuel costs. Staff countered by pointing to three-figure gas prices during the February storm that contributed to the $9,000/MWh prices.

"Natural gas prices can vary significantly such that applying any multiplier could result in large swings in energy prices, as the events of February 2021 demonstrated," staff said.

McAdams said tying the LCAP to the fuel index price "distorted" the scarcity pricing mechanism. "Addressing it now provides certainty. It keeps resources affordable, so we don't have this perverse phenomenon in the future," he said.

Commission Defers Action on Entergy DG

The commission declined to rule on an Entergy request to install distributed natural gas generation to provide backup power at customer facilities, saying they preferred to address these issues in a broader policymaking rulemaking rather than piecemeal analysis (*51575*).

McAdams filed a *memo* before the meeting saying existing PUC rules do not provide enough guidance to properly evaluate Entergy's proposal.

"Ultimately, the questions surrounding distributed generation will have an industrywide impact," he wrote. "A rulemaking would be a better forum to allow manufacturers and installers of backup power generators, batteries and other participants in the distributed generation space to be involved."

Lake directed staff to add the issue to the PUC's rulemaking calendar. Entergy *withdrew* its application on Friday.

The commission in 2018 rejected AEP Texas' request to connect two West Texas battery storage facilities to the ERCOT grid. It opened a rulemaking on energy storage ownership (*48023*) before requesting state lawmakers clarify who will own the devices in the market. (See "Commission Welcomes Legislative Input on Energy Storage," *Texas PUC Briefs: Jan. 17, 2019*.)

In other action, the commission approved Sam Houston Electric Cooperative's application for a certificate of convenience and necessity for a 138-kV transmission line in East Texas. The 16.6-mile line will connect a new substation with an existing Entergy Texas transmission line (*50485*).

PUC to Open its Meetings

The PUC is ending COVID-19 restrictions and will open its open meetings to all stakeholders, effective July 15. The meetings were originally limited to staff only as the pandemic raged last year; witnesses were allowed into the hearing room only recently. Attendance will be limited to two representatives per company or institution.

"We've been out for 18 months or so. I believe it's time to open these meetings back up," Executive Director Thomas Gleeson said. ■

— Tom Kleckner

ISO-NE News

In Maine's GridMod Movement, Innovating on Flexibility Gains Traction

By Jennifer Delony

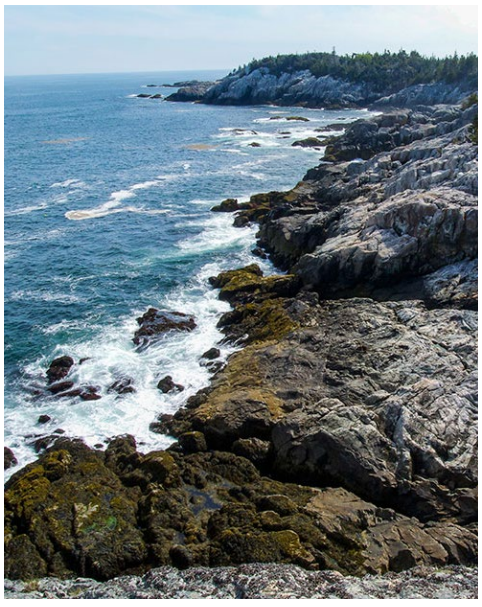
Maine's efforts to decarbonize are highlighting the role flexibility will play on the grid of the future.

"We need to start figuring out how to create demand flexibility today," Ian Burnes, director of strategic initiatives at Efficiency Maine Trust, said June 22 at E2Tech's Planning the Grid of the Future *webinar*.

The call for flexibility seeks innovation beyond just demand-side management to accommodate and balance growing distributed generation and loads from electric vehicles and heat pumps. At Efficiency Maine, Burnes says, it will be necessary in the coming years to "demonstrate and put real numbers behind what full-scale demand flexibility is going to provide."

To do that, he said, utilities must invest in transparent, real-time load data at the distribution level. From there, "we're going to need the capability to take the data on what's happening all the way down to the distribution level and model that [transmission and distribution] system to identify the load constraints and generate solutions," he said.

A foundation of systems and policies that allows utility-level data to be shared with others will enable the private sector to develop "an ecosystem of devices that live on the system and provide benefits to ratepayers," he added.



A microgrid pilot project on Isle au Haut off the coast of Maine, seen here, will put transactive energy principles to work for load flexibility. | *Shutterstock*

Real-time price signals at a granular level will likely become a part of a flexible grid solution for maximum integration of renewables and customer benefit, while reducing infrastructure investment.

"The hard part is to be able to say when we need [real-time pricing] and what we need to do to get there because that's a long way off," Burnes said. "We could have a great deal of customer benefit if we had even well-designed static pricing for a while."

Efficiency Maine wants to move toward a flexible grid with its proposal for a demand management program that features a traditional demand response program and a load shifting initiative. The proposal is part of the trust's *Triennial Plan* for 2023-2025, which is open for public *comment* through July 28.

The demand response program would compensate participants for reducing electricity usage when they are given a signal to do so. Under the load-shifting program, however, residential, low-income and commercial customer devices would offer programmable and potentially networked operations that respond to internal or remote signals.

During a previous pilot program, Efficiency Maine identified EV chargers and battery storage systems as having the highest potential for load shifting, while heat pumps were less viable because of their inherent high efficiency.

For EV smart chargers, the program will incentivize charging to take place during ISO-NE off-peak hours, according to the plan. And for energy storage measures, the program will require verification of connectivity, curtailment performance and algorithm effectiveness.

Transactive Energy

An upcoming microgrid pilot in Maine is set to demonstrate how the use of transactive energy principles can enable load flexibility.

The pilot, which Kay Aikin, founder and chief product officer at Dynamic Grid, says is set to begin this summer, will address aging electric system challenges on Isle au Haut in Maine's Penobscot Bay. The community has turned to a microgrid option that includes solar, battery, heat pump and diesel technologies for its power.

Dynamic Grid's technology will allow the heat pumps on the microgrid to transact with the system based on energy prices they receive. The heat pumps essentially look at a price signal and decide if it is cost-effective to run or defer to another generation resource.

The company is also leading another pilot on Mount Desert Island off the coast of Maine that it has submitted to the U.S. Department of Energy's Connected Communities funding opportunity for grid-interactive efficient building communities.

As proposed, the pilot would move the island toward "a networked group of microgrids, all driven by price, or dynamic pricing scheme, to coordinate the loads as well as the supply from storage and solar on the grid," Aikin said.

The pilot will manage 2 MW of loads, which is about 10% of the peak loads on the system, as well as 3 MWh of energy storage, according to Aikin.

"This is an example of how we can make loads and distributed generation benefit and optimize for the greater grid," she said. "Eventually, this is the direction where we will have to go."

Maine Grid Policy

This year, the Maine legislature moved six bills related to grid modernization to Gov. Janet Mills for her signature.

Mills has signed three of the bills.

LD 1682 incorporates climate change into the Public Utility Commission's powers and duties, Rob Wood, director of government relations and climate policy at The Nature Conservancy Maine, said during the webinar. The law also directs the Governor's Office of Policy Innovation and the Future to examine equity and environmental justice and how those concepts should be defined and incorporated into state agencies' decision making, he said.

LD 1100 and *LD 1053* are related to interconnection rulemaking and establishing a microgrid framework for the state, respectively.

The remaining bills are waiting for the governor's signature.

LD 936 addresses net energy billing and would form a stakeholder group to make recommendations on a holistic long-term grid planning process, Wood said. *LD 528* would implement recommendations from the state's Energy Storage Commission and direct regulators to examine time-differentiated rates, he said. And *LD 1710* would require the PUC to expedite transmission development in northern Maine to support renewables development. ■

ISO-NE News

NEPOOL Participants Committee Summer Meeting Briefs

External Market Monitor Delivers 2020 Assessment

ISO-NE energy prices and uplift costs exceed those in other RTO markets, External Market Monitor Potomac Economics told the NEPOOL Participants committee last week.

The Monitor was presenting its 2020 ISO-NE *assessment* at the committee's annual summer meeting.

Other than ERCOT's energy-only market, ISO-NE had the highest average prices among RTO markets over the last three years because of higher natural gas prices.

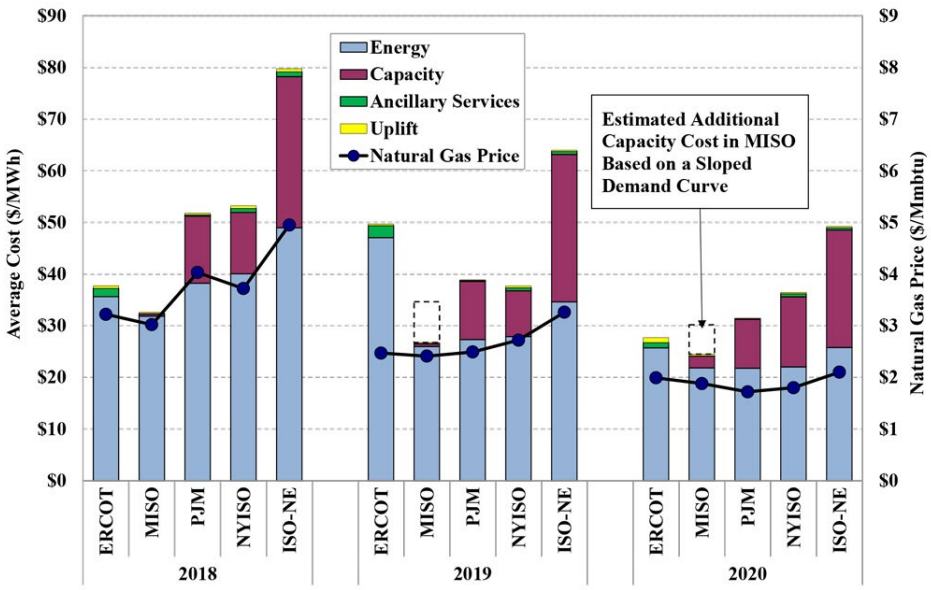
The Monitor also found that New England energy prices are more sensitive to costs for complying with state greenhouse gas emissions policies. Compliance with the Regional Greenhouse Gas Initiative (RGGI) last year added about $6.60/MWh to the marginal production costs of a gas-fired combined cycle generator in Massachusetts and $2.90/MWh in the other five New England states. While NYISO is also subject to RGGI, no such programs impact generators in ERCOT or MISO. RGGI compliance costs are included in a small number of PJM states.

ISO-NE also incurs more uplift costs than MISO and NYISO, in part the result of New England's higher fuel costs and the fact that ISO-NE does not have day-ahead ancillary services markets to coordinate and price its system-level and local operating reserve requirements.

ISO-NE additionally makes real-time net commitment period compensation (NCPC) payments to resources under a broader range of circumstances than MISO and NYISO. In 2020, ISO-NE's market-wide NCPC uplift ($0.42/MWh) was more than double that of NYISO ($0.19) or MISO ($0.18). Day-ahead ancillary services markets also help reduce uplift charges.

And while all three markets have rules for compensating a generator whose scheduled output level differs from its most profitable output level, ISO-NE's tariff provides compensation in some circumstances when MISO's and NYISO's do not. The Monitor recommended that the grid operator examine differences and identify best practices across markets.

ISO-NE does experience far less congestion than other RTOs. Congestion costs have averaged under $0.35/MWh in the last five years, 10 to 20% the levels seen in other RTO markets. That reflects significant transmission investments made over the past decade, resulting in a transmission service cost of more than $19/MWh in 2020, which is far higher than the rates in other RTO markets.



All-in prices in RTO markets from 2018-2020 | *Potomac Economics*

Transmission investments made in ISO-NE primarily satisfy relatively aggressive local reliability planning criteria. The primary reasons for transmission expansion in ERCOT, MISO and NYISO have been to increase the deliverability of renewable generation to consumers, the EMM said.

The Monitor withdrew its recommendations to improve the minimum offer price rule (MOPR) after ISO-NE said it plans to eliminate the rule to ensure market access for state policy resources but will reassess in the future.

The EMM also plans to provide comments to NEPOOL this summer identifying market rule changes needed to ensure that the markets will attract necessary investment and maintain needed existing units after the MOPR is eliminated. Such changes will improve the RTO's accreditation of capacity resources and reflect increased financial risk in the capacity demand curves that investors will face in New England without the MOPR.

RTO Presents Preliminary Budgets for 2022-23

ISO-NE Chief Financial and Compliance Officer Robert Ludlow *provided* a look at the preliminary 2022 and 2023 operating and capital budgets, with the respective year-over-year increases before depreciation for the operating budgets projected to be $10.61 million (5.9%) and $9.16 million (4.8%).

The RTO plans to add several full-time equivalent positions to address changes impacting the capacity market, including the proposed elimination of the MOPR. Additional new FTEs will:

- help deal with increased interconnection studies for renewable resources;
- work on continuing studies on carbon pricing and a forward clean energy market; and
- consult on the Pathways to the Future Grid work.

The RTO expects its capital budget over the next five years to increase from $28 million to $35 million, including $32 million for 2022. The primary drivers of the spending spike are: GEMplatform replacement, cybersecurity, the clean energy transition, and reliability improvement projects, as well as IT asset and infrastructure replacement.

The proposed budget timeline includes meeting with state officials in August and the RTO's Board of Directors in September, a vote before the Planning Committee during its Oct. 7 meeting and filing with FERC by Oct. 15. ■

— Jason York

MISO News

MISO Monitor Warns of Ramping Needs, Tx Congestion

By Amanda Durish Cook

MISO's Independent Market Monitor this year has singled out transmission congestion, heightened ramping needs and undervalued capacity prices as areas of concerns in 2020 and into the future.

MISO Monitor David Patton | © *RTO Insider LLC*

The topics are part of Monitor David Patton's annual State of the Market *report*, delivered to the MISO Board of Directors' Markets Committee during a special teleconference Wednesday.

The Monitor's report drove home several previous warnings about MISO's future and suggested four market changes, including:

- creating a new uncertainty capacity product that can be deployed in the place of operators making out-of-market commitments;
- better matching up the emergency procedures and pricing of transmission emergencies versus capacity emergencies;
- disqualifying wind generation from providing ramping services; and
- developing individual effective load-carrying capabilities (ELCCs) to be used in more specific capacity accreditations for distributed resources, load-modifying resources, solar generation and battery storage.

Ramping Needs

Patton said MISO's current wind resources coupled with a coming surge in solar generation will intensify the RTO's ramping needs. And, he said, when wind generation is used for ramping services, it usually exacerbates transmission constraints.

Wind generation served an average 18% of hourly load in 2020, up from under 12% in 2018, according to the Monitor.

"Wind fluctuations have grown as output has increased. On 27 days during September to December, wind varied by more than 10 GW," Patton told the committee. "The volatility is becoming increasingly challenging to manage. … It puts a heavy burden on conventional resources to make up the slack. … We need a market that's going to sustain our controllable resources. We cannot keep the lights on with storage and intermittent resources alone. You do need to supplement those with conventional resources," he said, predicting that within 20 years, many natural gas plants will burn biofuels.

Patton also said renewables growth paired with transportation electrification stands to change load and congestion patterns. To manage the change, MISO needs better shortage pricing, more expensive capacity prices and a four-hour look-ahead dispatch tool, he said.

He pointed to a new recommendation that MISO develop a real-time capacity product to handle more real-time and day-ahead market uncertainties.

MISO currently makes several out-of-market commitments and "tacitly" relies on offline generators, which yields uplift payments, Patton said. "It's an indicator that the markets don't have enough generation … to fulfill commitments."

Transmission Congestion

Transmission congestion rose 26% in 2020, costing about $1.2 billion, Patton reported. If MISO transmission owners had more dynamic line ratings, congestion could have been about 13% lower, he said.

"It's becoming the dominant issue for MISO to manage," Patton said. "We've never seen as much congestion coming out of the north, where the wind is located."

To combat congestion, he said, MISO should develop a means to coordinate transmission and generation outages, lower the generation shift factor cutoff for transmission constraints and more readily define market-to-market constraints.

He also repeated his previous recommendation that MISO adopt ambient-adjusted transmission line ratings.

"Right now, there's really half of one employee that does this today," Patton said, suggesting that MISO create a dedicated three- to four-person team to work on the optimized use of transmission lines.

"The economic benefits would pay for themselves 10 times over," he said.

MISO CEO John Bear said the Transmission Owners Agreement specifies that TOs establish their own line ratings, and that the RTO is limited in what it can dictate. He added that TOs take on risk determining the capabilities of their lines.

"There's a lot of coordination and work to make this possible," Bear said. "It's not just as simple as us adding a few analysts and moving forward," Bear said.

Capacity Pricing

Unsurprisingly, Patton again criticized MISO's Planning Resource Auction for its mostly "inefficiently low prices," something he routinely has called out in his reports. (See *MISO Capacity Auction Values South Capacity at a Penny*; *Michigan Prices Soar in 8th MISO Capacity Auction*.) He said the "flawed" vertical demand curve used in the auction continues to be the source of the problem.

"MISO's markets are not providing net revenues sufficient for investment in new resources in any location," Patton said.

In addition to his recommendation that MISO develop new ELCCs for different resources, Patton said the grid operator should switch to a capacity resource accreditation that is based on a unit's availability during the tightest margin hours of the year.

MISO recently mellowed its proposal for a stricter capacity accreditation to include availability during non-risky hours in addition to risky hours as the basis for accreditation. Patton said MISO's leniency in its accreditation proposal will render it ineffective against improving resource availability. (See *MISO Softens Capacity Accreditation Proposal*.)

Patton acknowledged that while such an accreditation might not be "popular" with market participants, it's a better way to solve MISO's emerging generator availability problems.

Otherwise, Patton said real-time prices averaged $24.50/MWh in 2020, an 8% year-over-year drop driven by 4% lower average load and 22% dip in natural gas prices.

"Our costs were lower in 2020 than they've ever been," he said.

MISO also has a particularly active and healthy day-ahead market, Patton noted. "We have more virtual trading than virtually any other RTO."

MISO Executive Director of Market Operations Shawn McFarlane said MISO has kicked of an internal review of the report and recommendations. He said it will release a final response to the recommendations in October. ■

MISO News

MISO Prepares Hybrid Participation Model for Unknown Numbers

By Amanda Durish Cook

MISO is grappling with how many hybrid generation formats could be coming its way as it prepares a dedicated participation model.

The grid operator's staff believe there could be a crush of hybrid resources — which MISO defines as storage paired with generation, often renewable — on the way. The RTO held a June 21 teleconference to discuss near-term market prospects for hybrid resources.

"It will be hugely helpful to MISO to know about the projects you have in your pipelines," Wind and Solar Program Manager Laura Hannah told stakeholders.

MISO's approximately 83-GW interconnection queue contains about 5 GW of hybrid projects set to come online in 2023, mostly in the form of solar and storage. But the grid operator is bracing for more than that.

"That could be only a fraction of the projects that become hybrid," Hannah said, explaining that interconnection customers sometimes request two separate applications for the storage and generation components, with others requesting surplus interconnection capability for storage that's added later.

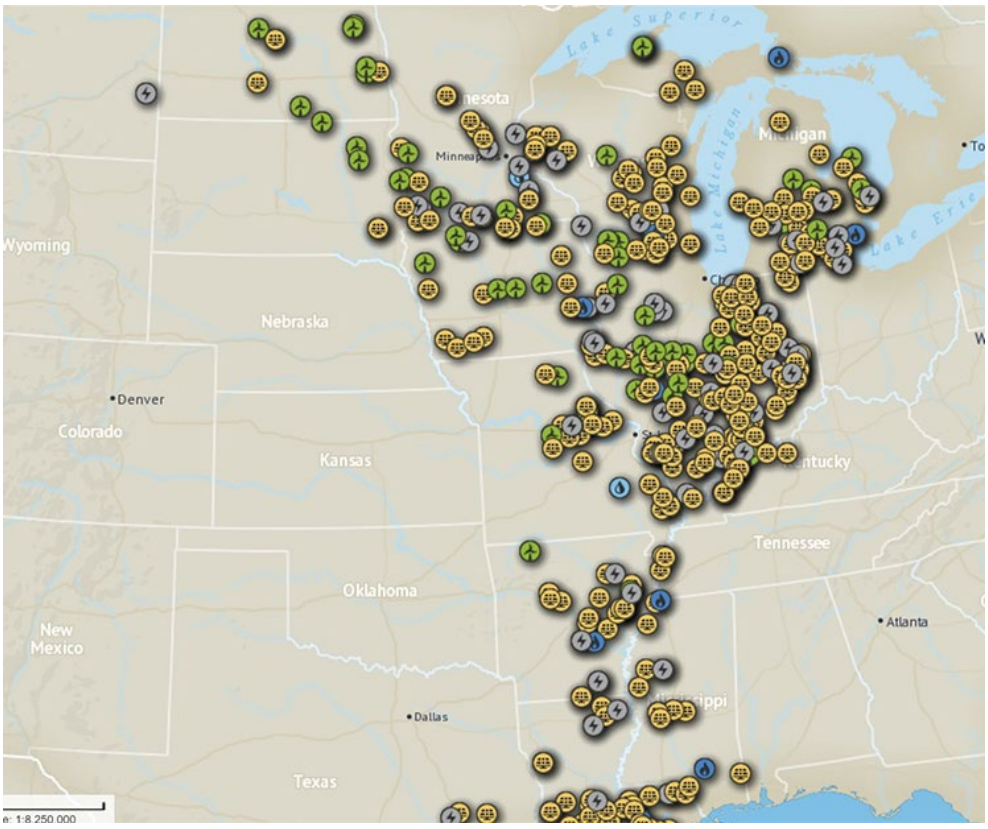
"Just glancing at the queue, it's difficult to tell how many projects that are hybrid are coming our way," she said.

"Hybrids are definitely a requested method of interconnection," MISO Director of Market Design Kevin Vannoy added. He said that MISO should facilitate the entry of new generation resources to allow for "more participation and increased competition in MISO markets."

Vannoy said MISO currently has no generation operating as a hybrid resource. It does, however, have co-located resources: multiple generators operating independently at a single point of interconnection. Unlike the co-located category, hybrid resources operate as a single asset.

Last year, stakeholders prioritized a MISO hybrid resource participation model in MISO's Market Roadmap list of improvements.

Market Design Adviser Bill Peters said hybrid resources might be able to pursue interconnections through one of three existing options until a definition is added to the MISO tariff: the traditional generation registration, which doesn't use fuel forecasts; as a dispatchable intermittent resource; or as a stored energy resource type II.



MISO's active interconnection queue projects as of late June, most solar | *MISO*

"We'll have to approach this on a case-by-case basis until those lines are drawn," Peters said.

MISO counsel Mike Blackwell said the RTO in late July will file a proposal with FERC for a hybrid resource capacity accreditation. At first, the new resource accreditation will rely on default ratings, then morph into a performance-based accreditation once enough data rolls in on the asset's output.

Some stakeholders said MISO should consider expanding its dispatchable intermittent resource type to be more versatile, allowing hybrid assets to follow MISO wind forecasts.

Clean Grid Alliance's Natalie McIntire said if MISO also developed forecasts for hybrid resources, it would provide more certainty for those wanting to develop them.

"Nothing today offers the full capability for hybrids to participate," Great Plains Institute's Matt Prorok commented. He said MISO might consider making a more general participation model that allows the full participation of more flexible resources.

Clean Grid Alliance's Rhonda Peters said so far there doesn't seem to be any interest among developers in interconnecting under MISO's *stored energy resource type II* definition.

Prorok agreed that it has failed to attract a string of projects.

NextEra Energy Vice President of Renewable Energy Policy Mark Ahlstrom has said that there is no need for MISO to create special market definitions for hybrid storage resources because they can emulate existing, conventional generation.

"It simplifies the approach for the RTO," Ahlstrom said last year at a MISO Market Subcommittee meeting, adding that hybrid resource can perform with the "same quality, reliability and forced outage rate" as conventional generation. Currently, MISO models hybrid resources separately for each fuel source.

"It's the most flexible resource you can likely imagine," he said.

Ahlstrom said capacity values could be calculated by adding the effective load carrying capability of the renewable generation plus the nameplate capacity of the battery. ■

MISO News

Consumers Energy to End Coal Use by 2025

Environmentalists Question Plans to Add Gas

By Rich Heidorn Jr. and John Lindstrom

Consumers Energy, Michigan's largest utility, announced Wednesday that it will shutter its five remaining coal plants by 2025 — 15 years earlier than previously planned — while tripling its renewable capacity and increasing use of natural gas.

Consumers, a unit of CMS Energy (NYSE:CMS), said it will cut carbon emissions 60% by 2025 from a 2005 baseline.

Environmentalists praised the early coal retirements and renewable pledges but said they would challenge the proposed gas additions in proceedings before the Michigan Public Service Commission.

"Moving off coal by 2025 is an important move by Consumers Energy … but this is only a half-step if they are going to replace coal with other fossil fuels like natural gas," said Derrell Slaughter, Michigan Clean Energy Advocate for the Natural Resources Defense Council.

The company said it will seek PSC approval to:

- retire coal-fired Campbell units 1, 2 and 3 (1,440 MW) in 2025 — six to 15 years sooner than their scheduled design lives;
- retire Karn units 3 and 4 (1,100 MW), which run on natural gas and fuel oil, in 2023, eight years sooner than their design lives. (Karn's coal-fired units 1 and 2 (500 MW) are already scheduled for retirement in 2023.);
- purchase four existing natural gas-fired plants in the state totaling more than 2 GW: the 1,176-MW Covert combined cycle plant in Van Buren County; Dearborn Industrial Generation, a 770-MW natural gas and waste cogeneration plant in Wayne County; and two peaker plants: Kalamazoo River Generating Station in Kalamazoo County and Livingston Generating Station in Otsego County.

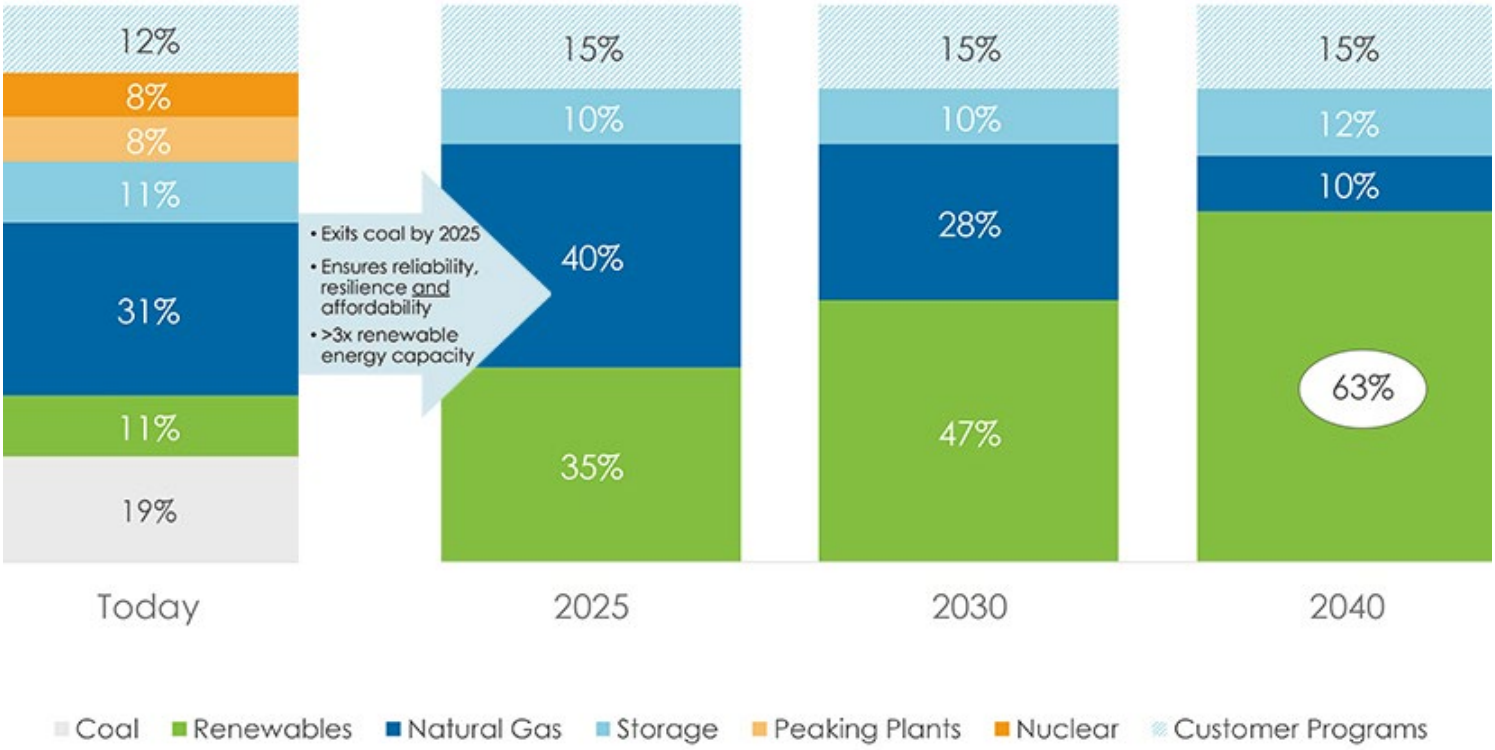
In a *filing* with the Securities and Exchange Commission, the utility said it had signed a contract June 21 to purchase the Covert facility for $810 million, with closing expected by April 2025.

Consumers currently owns two natural gas-fired plants in Zeeland (527 MW) and Jackson (542 MW).

The utility pledged to construct 8 GW of solar power (up from 6 GW in its current plan) and generate 60% of its power from renewables by 2040.

"Combining that growth with advances in energy storage and customer efficiency will allow us to meet customers' needs with 90% clean energy resources," the company said in a statement.

Consumers spokesperson Katie Carey said the company will file its revised integrated resource plan (IRP) with the PSC next week, kicking off a nearly year-long proceeding in which it will seek approval. A *presentation* on the IRP lists 1.1 GW of energy efficiency, 750 MW of demand response, more than 100 MW of conservation voltage reduction and 475 MW



Consumers Energy plans to shutter its five remaining coal plants by 2025 while tripling its renewable capacity and increasing use of natural gas. | *CMS Energy*

MISO News

of battery storage.

Consumers currently runs solar plants at Western Michigan University, Grand Valley State University and in Cadillac, and purchases solar power from other locations in the state.

The utility said the proposals would save ratepayers about $650 million through 2040 compared to its current plan, in part by depreciating the retired plants over their design life rather than using securitization. Reduced fuel costs also will contribute to the savings, Carey said.

Consumers retired seven coal-fired plants totaling 900 MW in 2016. Its remaining 1.8 GW burns 9 million tons of coal annually.

At a press conference, Consumers CEO Garrick Rochow said the plan would reduce carbon emissions by 63 million tons.

Company executives said purchasing the existing four gas plants was critical to the plan's success, contending it needs the additional natural gas capacity for reliability. "A predominantly renewables scenario offers insufficient capacity to meet reliability standards in the winter when solar energy is less abundant — and in the summer," the company said.

Purchasing existing plants with less remaining life at a lower cost "reduces long-term risks," it added.

Reaction

"This historic and critical announcement from Consumers Energy to shutter coal plants ahead of schedule will improve the health of Michigan residents and protect our Great Lakes from pollution," said Charlotte Jameson, program director of energy for the Michigan Environmental Council. "However, we are skeptical of the transition to using additional natural gas to fulfill our state's energy needs. We will be intervening in the case to put forward ways for Consumers Energy to more rapidly transition to fully carbon-free, clean energy, like wind and solar, energy efficiency, and battery storage."

John Delurey, Midwest senior regional director for Vote Solar, also criticized the company's gas plans. "To meet Gov. Gretchen Whitmer's goal of carbon neutrality, we need stronger investments in clean energy, including a hard look at the benefits of increased distributed generation," he said.

"We appreciate Consumers' commitment to move beyond coal and not to create new fracked gas infrastructure, unlike DTE, who have used every opportunity to double down on coal and fossil fuels," said Mike Berkowitz, Michigan Beyond Coal Campaign representative for the Sierra Club.

Nick Occhipinti, government affairs director for the Michigan League of Conservation Voters, said that, in addition to investing in renewables, Consumers "should prioritize energy waste reduction and expanding rooftop and local community solar before investing in additional natural gas plants."

'Just Transition' Promised

In addition to touting the environmental impact of the new plan, company officials also said it would be good for their shareholders, noting the gas plant purchases would add $1 billion to its rate base over five years. With the addition of the gas plants and CMS Energy's recently announced sale of EnerBank, more than 95% of CMS's earnings will be from its regulated utility and 5% from unregulated businesses, it said.

Brandon Hofmeister, CMS Energy | *CMS Energy*

At the press conference, Brandon Hofmeister, CMS Energy senior vice president of governmental, regulatory and public affairs, said the company will ensure a "just transition" for the 510 employees at the five coal plants as well as the communities hosting them.

"We have a great track record of success of taking care of both the coworkers at these facilities — ensuring that they have the opportunity to continue to find work at Consumers Energy — as well as working proactively with the communities to reimagine the economic development opportunities for those communities and for these sites," he said. ■

MISO News

MISO Analyses Show Reliability Woes Without Transmission Builds

By Amanda Durish Cook

MISO last week said that without major, long-range transmission projects, reliability issues will explode in the Midwestern portion of its footprint.

The grid operator used the most conservative scenario of its three planning futures — Future I — to look 10 years into the future. It said days containing high renewable generation and shoulder seasons could yield thousands of thermal and voltage stability issues. MISO has yet to perform future reliability analyses using Futures II and III, which predict more renewable penetration and electrification growth.

The reliability analysis is the latest in MISO's attempt to bolster its case for long-range transmission projects. (See *MISO Leadership Says Tx Expansion, Market Redefinition 'not Optional'*.)

Future low-voltage and thermal issues are most ubiquitous in the West planning region, which includes Minnesota, Iowa, parts of the Dakotas and western Wisconsin. On winter days, MISO said reliability violations could number more than 4,400 in the West.

MISO also said high renewable generation paired with light-load days is the biggest cause of concern into the 2030s for its Midwest region. The grid operator said more frequent thermal problems are caused by localized transmission issues and shifting regional flow patterns. The voltage violations are a product of high renewable output and load-serving needs.

Speaking during a special workshop Friday, MISO Senior Economic Planning Engineer Ranjit Amgai said Local Resource Zone 3 in Iowa sees the most reliability violations during shoulder months, nights with light load and winter days. He said the region sees strong southern flows from Minnesota, Wisconsin and the Dakotas (Zone 1), and west-to-east flows across eastern Iowa will probably overload the zone's 161- and 345-kV lines.

Stakeholders asked MISO to also study how its indicative map of projects could assist with the identified reliability issues. (See *MISO Reveals Contentious Long-range Tx Project Map*.) MISO planners said they have not yet looked at how the draft line routes could solve the looming reliability troubles, but they noted the RTO's first round of reliability results are only the beginning.

"Identifying violations are the main focus right now before we can propose any projects," Amgai said. "We're on step 1-A of about 10 steps."

"Analysis is going to get more intense as we go along and have more models. This is going to be a multiyear effort," MISO Senior Manager of Transmission Planning Coordination Jarred Miland told stakeholders. He said MISO will complete some 20-year reliability models next month, and he added that a transfer analysis is forthcoming.

Other stakeholders asked why MISO South was so far absent from the reliability analysis.

"Our focus right now is really on the East, West and Central," Executive Director of System Planning Aubrey Johnson said. He said a MISO South focus in reliability analyses — including the exploration of projects that could open the RTO's Midwest-to-South transfer capability — won't arrive until late 2021 or early 2022.

MISO also has yet to investigate future thermal and low-voltage issues on its seams with PJM and SPP. WEC Energy Group's Chris Plante said it's imperative MISO provide reliability results into tie lines on neighboring systems.

"We have to respect those constraints on our neighbors' system," Plante said.

Miland said MISO still may put forward a "limited number" of initial long-term projects for board approval by year-end with the 2021 Transmission Expansion Plan (MTEP 21). Without long-term projects, MTEP 21 is shaping up to bring the lowest investment to the footprint in three years. (See *MISO Annual Tx Investment Falls in 2021*.)

'Generation Pays' Deliberations

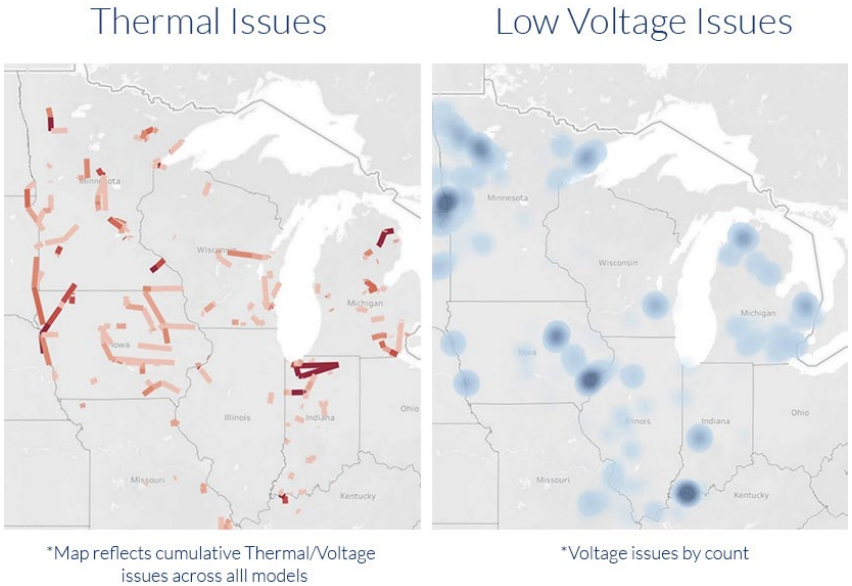
Meanwhile, MISO's stakeholder-led Regional Expansion Criteria and Benefits Working Group (RECBWG) on Thursday debated whether generators should bear some cost-sharing for long-range projects.

Some stakeholders at the teleconference said that if an interconnecting generation project is found to be dependent on a long-range project, it should be assigned a portion of the costs, similar to MISO's current shared network upgrade process in its interconnection queue procedures.

"Generators aren't the only 'free-riders' in cost allocation. New load can be free riders. Cost allocation is based on a snapshot, and that changes the next day. There are going to be free riders all over this," Sustainable FERC Project counsel Lauren Azar said.

MidAmerican Energy's Neil Hammer said the discussion was too focused on the benefits that generators stand to obtain when the larger picture is the long-range plan is necessary for MISO's future system overall. He said the transmission projects will enable multidirectional flows, reliable resource retirements and members' renewable goals.

"Really, this is benefiting the pool and load," Hammer said. ■



MISO Midwest thermal and voltage isssues 10 years into the future | *MISO*

NYISO News

Panel: Storage Needs Experience in NY Power Markets

By Michael Kuser

New York's wholesale electricity markets are awash with opportunities for energy storage but lack experience in integrating the technology.

That was a key takeaway from a panel June 22 that included officials from FERC, NYISO and an energy storage developer.

Key Capture Energy CEO Jeff Bishop | *NY-BEST*

From a public policy perspective, New York is doing everything all at once, Key Capture Energy CEO Jeff Bishop said at the 11th Annual Meeting of the New York Battery and Energy Storage Technology Consortium (NY-BEST).

New York's Climate Leadership and Community Protection Act (CLCPA) requires the state to consume 70% renewable electricity by 2030 and switch to 100% zero-emission power by 2040. It also calls for the procurement of 6 GW of solar by 2025, 3 GW of storage by 2030, and 9 GW of offshore wind by 2035. The state is targeting shutdown of some of its most polluting fossil plants from an environmental justice perspective.

FERC three years ago issued Order 841, which directs grid operators to integrate energy storage into their wholesale markets, and NYISO outpaced most of its counterparts in anticipating last September's Order 2222, which directs RTOs/ISOs to allow distributed energy resource aggregations to participate in their markets. (See *NYISO Discusses FERC Order 2222 Compliance*.)

Right Rules

NYISO Executive Vice President Emilie Nelson | *NY-BEST*

"In order to fully realize what New York would like to achieve in the transportation and building sectors, we need to make sure that we have a reliable grid," NYISO Executive Vice President Emilie Nelson said during the panel. "Many of the studies that have been done by NYISO and, quite frankly, by many others frame some of the challenges that we really need to meet successfully with respect to thinking about storage."

"Really it's just a fundamental question of are the rules in place right now in order to really spur development to be able to get the capacity needed for the next generation of ultimate electricity and power demands for the overall state," Bishop said.

Key Capture Energy has operations both in New York and in Texas. "One of the key things that I look at in all of these markets as a reflection of Order 841 is that there is still an imbalance of information, where when we came in and put our first 20 MW project online in 2019, we had no idea what the frequency regulation market actually was in New York state," Bishop said. "We were able to model it, and we sat down with very patient New York ISO staff just trying to figure out what is actually the frequency regulation market in New York because it was very opaque."

Testing, Testing

Pete Fuller, Autumn Lane Consulting | *NY-BEST*

Panel moderator Pete Fuller, of Autumn Lane Consulting, said he liked Bishop's example of the frequency regulation market but said the lack of operational history and data on storage was a barrier to development.

"We can make our best guess of simulations ... but the granularity, the real-time operations, the reactivity, the responsiveness of batteries — it's a new ballgame and we don't necessarily have all the tools," Fuller said. "Are we at a point where we really just need some, for lack of a better term, guinea pigs — those early adopters and early movers to get on the system and build that history and that data?"

Nelson said the question is how to shift projects from being on paper to reality, which dovetailed with an audience question about how to help utilities and others charged with maintaining reliability of transmission and distribution grids to think about new techniques and opportunities made available by emerging technologies.

"I believe that really getting some experience with them will certainly help ... and until we have some experience with these technologies it is a very educated guess on exactly what is going to need to come together," Nelson said.

Bishop said that the ability for energy storage projects to get capacity payments would really provide "the data that we need to be able to build the following year a 200-MW size project closer to New York City... [and] 'guinea pig' is probably not quite the right word, especially for my investors, but you know clearly there has to be some data and right now there is clearly a lack."

The state's Public Service Commission has tried to push storage forward both from a wholesale market perspective and by getting utilities "comfortable" through a series of non-wires alternatives and utility procurement, he said.

FERC Commissioner Allison Clements | *NY-BEST*

FERC Commissioner Allison Clements said the commission has plenty of work to do on the issue of storage and hoped to get robust participation in a two-part technical conference in September on energy and ancillary services.

In its rulemaking, FERC must consider the interaction of the parties and the need to disrupt the status quo, she said. "So, when I look at 2222 implementation coming down the pike, I think some of the hardest part of it is that there is no regulation; it falls between FERC's regulation and the state's regulation."

New York has the benefit of having only two balancing authorities instead of multiple states around it, but Clements said she is focusing on standards and "other coordination and interoperability issues between states at distribution system operators and transmission system operators and finding opportunities to facilitate those interactions in a way that both bring down kind of the unknowns, the fear level, but also save costs relative to potential costs of implementation."

Nelson said that NYISO has prioritized the idea of dual participation for storage in wholesale and retail markets. "We have always really highly valued operator situational awareness and visibility... [for] reliability needs on the grid, so we fairly quickly established rules to allow for dual participation. But part of that is having that awareness and that communication from a telemetry perspective that allows a good line of sight between the utilities and the NYISO." ■

NYISO News

FERC Accepts NYISO Reserve Demand Curve Revisions

But Commission Rejects Supplemental Reserves Procurement Process Component

By Michael Kuser

FERC on Wednesday accepted NYISO revisions to its operating reserve demand curves (ORDCs) but rejected the supplemental reserves procurement process component of the ISO's proposal (*ER21-1018-001*).

NYISO proposed two sets of changes, with the first concerning the current ORDCs and designed to improve pricing efficiency; provide for better alignment with the cost of actions that may be taken to preserve sufficient availability of reserves and maintain system reliability; and reduce historical occurrences of reserve shortages.

The commission found that the proposed ORDC changes would improve pricing efficiency by introducing additional steps to the New York Control Area's 30-minute reserve demand curve based on recent NYISO data demonstrating the value of various operator actions taken to maintain reserve availability and system reliability.

"These additional steps will make the ORDC more graduated and assign more accurate prices to these actions and avoid unnecessary price volatility by further graduation of the NYCA 30-minute reserve demand curve," the commission said, adding that the proposed updated ORDC values better reflect the locational price signals necessary to incent resources to develop and/or maintain the capability to provide reserves when and where needed.

"Further, based on the evidence NYISO provided, we find that the proposed ORDCs would significantly address the reserve shortages that NYISO has experienced. Together, the ORDC changes will improve NYISO's ability to manage operational uncertainty via market signals," the commission said.

The compliance filing must provide at least two weeks' notice of the actual effective date; NYISO requested a flexible effective date between June 1 and 30.

Supplemental Reserves

The second set of tariff revisions concerned the establishment of a process to facilitate procurement of operating reserves in excess of the quantities required by minimum reliability standards and rules to the extent such supplemental reserves are needed to assist with maintaining system reliability as intermittent renewable generation increases over time.

The commission, however, rejected this proposal and directed the ISO to submit a compliance filing removing all instances of supplemental reserves from its proposed language within 30 days.

The New York Department of State's Utility Intervention Unit (UIU) had protested the supplemental reserves component, arguing that the filing lacked the information the commission needs to assess the proposed changes. The Independent Power Producers of New York supported the proposal, arguing it was made in collaboration with stakeholders to address reliability concerns as intermittent renewable resources increase in the near future.

"As a preliminary matter, we disagree with NYISO's assertion that the procedures for implementing and adjusting supplemental reserve requirements are substantially similar to the existing procedures for adjusting regulation services requirements," the commission said. "We agree with UIU's assertion that the two requirements are not substantially similar because the criteria by which the regulation services requirements are established and adjusted rely on reliability rules established by external reliability organizations rather than at NYISO's discretion."

The commission said NYISO's proposed tariff revisions "lack sufficient specificity" because they only describe how the ISO would review any supplemental reserve procurement with its market participants; obtain Operating Committee approval at least 30 days prior to any procurement; and then post the targeted procurement level.

"Additional specificity in the Services Tariff will provide a degree of predictability as to costs associated with any procurement of supplemental reserves," the commission said. ■

NYISO News

NYDPS Investigating Alleged Bribery Scheme at National Grid

NYPSC Issues Key Orders Ahead of Expanded Commission

By Michael Kuser

New York regulators on Wednesday opened an investigation into an alleged bribery scheme involving National Grid's natural gas distribution company facilities in New York City and Long Island that federal prosecutors say has been running for seven years and affected tens of millions of dollars in maintenance deals.

Acting in his capacity as CEO of the Department of Public Service, interim Public Service Commission Chair John Howard issued the order launching the investigation, citing the June 17 indictment of five former National Grid employees by the U.S. Attorney for the Eastern District of New York (*21-M-0351*).

"The allegations presented in the complaint raise significant concerns related to the internal controls established and implemented by National Grid ... to ensure the integrity of the companies' contracting process," the order said.

National Grid said it is fully cooperating with the FBI investigation and that it was not aware of the scheme, which prosecutors say involved maintenance contracts for Brooklyn Union Gas and KeySpan Gas East. The company stated that the contracts did not involve critical gas infrastructure, so public safety is not at risk.

"In this proceeding, we will examine potential imprudence, the adequacy of National Grid's internal controls and National Grid's compliance with its own internal procedures as well as provisions of the public service law, the commission's regulations and commission orders," Howard said in a statement.

The legal troubles come at an awkward time, as National Grid last month made a joint *proposal* to the PSC in May 2021 for a three-year, $193 million increase in revenues for its gas infrastructure maintenance.

Newsday last week *reported* that the Long Island Power Authority, PSEG Long Island and the state DPS plan to review whether payments made to any contractors and subcontractors were billed to the utilities' ratepayers, as PSEG leases space at facilities owned and operated by National Grid.

National Grid's downstate gas distribution utilities serve 1.9 million customers, employ 4,600 workers and have 12,400 miles of gas distribution and transmission pipe.

Service territory map of National Grid subsidiaries KeySpan Energy Delivery New York (KEDNY) and KeySpan Energy Delivery Long Island (KEDLI) | *National Grid*

Lacking a Quorum

With three newly confirmed commissioners not yet seated and one absent, the PSC lacked a quorum for its regularly scheduled session June 17, so it scrapped its consent agenda and only reviewed the investor-owned utility performance for 2020 in electric reliability service, gas safety, electric safety and customer service.

The *reviews* led the commission to cut the revenue of Consolidated Edison Company of New York by $5 million and that of New York State Electric and Gas (NYSEG) by $7 million for failing to meet reliability targets. The PSC cut NYSEG revenue by an additional $1.4 million and that of Rochester Gas and Electric by $1.8 million for poor performance on measures of customer service established within their respective rate case proceedings. Because of the impacts of COVID-19, NYSEG and RG&E have filed a petition to waive meter reading requirements, which is pending before the commission.

By its next scheduled regular session July 15, the PSC should have its full complement of seven commissioners.

The New York State Senate voted June 10 to confirm three new commissioners to serve six-year terms: former state Sen. David Valesky; longtime Cuomo aide John Maggiore; and Rory Christian of Concentric Consultants. It also confirmed Commissioner James Alesi to a second term.

PSC spokesman James Denn told *RTO Insider* that, "since the three recently appointed commissioners are still being onboarded, including necessary steps such as signing the oath of office, and given the practical reality that there was insufficient time for them to be fully briefed for the June session, they were not in a position to vote."

Meanwhile, Howard issued several one-commissioner orders, in addition to the one launching the investigation into National Grid.

A June 23 order granted Con Ed rate recovery for expenses up to $5.9 million between now and 2023 on two "non-pipeline alternative" (NPA) natural gas load relief programs: the Behavioral Demand Response Program and the Heat as a Service Financing Program. "These programs will help the company reduce gas demand in a constrained portion of its service territory and simultaneously advance the state's energy policy goals" (*19-G-0066*). The commission denied $1.1 million in funding for a Solar Photo Voltaic Heat Recovery program.

The commission also authorized Con Ed to spend $5 million to continue implementing its Gas Demand Response Pilot Program through March 31, 2022 (*17-G-0606*).

The term of Con Ed's existing gas rate plan ends on Dec. 31, 2022, so if the company were to file for new rates in 2022 and include the terms of a gas DR proposal within such filing, tariffs reflective of the commission's decision regarding that filing would not be effective until Jan. 1, 2023, at the earliest, which is midway through the 2022/2023 Winter Capability Period, the order said.

Howard also signed an order granting a certificate of public convenience and necessity and providing for lightened regulation for Con Ed's 100-MW East River energy storage facility in Astoria, Queens (*21-E-0122*). (See "New York Supports Con Ed Project," *NYPSC Considers Two Utility Storage Petitions*.) ■

PJM News

SOO Green Seeks Participation in PJM RTEP Process

By Michael Yoder

Direct Connect Development Co. on June 21 filed a complaint with FERC that PJM's tariff and Operating Agreement are unjust and unreasonable because the RTO requires merchant transmission facilities to complete a "profoundly delayed generation interconnection process" for studies and integration into the grid (*EL21-85*).

The Minnesota-based company — which is seeking to construct the interregional SOO Green HVDC Link transmission line to connect wind generation in MISO with the PJM market, said the commission should require PJM to modify its tariff and OA to allow merchant transmission facilities to participate in the Regional Transmission Expansion Plan (RTEP) process with other transmission projects without having to first pass the generator interconnection process. It also requested that FERC use its authority to order PJM to adhere to project timelines for the rest of the interconnection process.

Under the current PJM tariff and OA, merchant transmission facilities are not permitted to participate in the RTEP process directly.

PJM stakeholders originally approved an *issue charge* in June 2020 to consider integrating HVDC converters as a new type of capacity resource in the RTO. (See *HVDC Initiative Endorsed by PJM Stakeholders*.) Work at the HVDC Senior Task Force failed to reach a consensus on the issue. (See "HVDC Senior Task Force Update," *PJM MRC/MC Briefs: March 29, 2021*.)

"Allowing merchant transmission facilities to participate in the RTEP process will relieve the unjust and unreasonable impacts caused to such facilities, including SOO Green, by their inclusion in the PJM generation interconnection queue," the company said in its filing. "Requiring PJM to allow merchant transmission projects to be assessed in the RTEP, including demonstrating whether such projects would provide reliability or public policy benefits, would enhance and facilitate efficient transmission development."

Project Stalled

SOO Green would be a 350-mile, 2,100-MW, 525-kV underground transmission line designed to deliver renewable energy from upper MISO to Illinois and the PJM grid.

Direct Connect is planning to install the line primarily along existing rail rights of way from Mason City, Iowa, to Plano, Ill. The company says it would be the first major transmission project crossing the MISO-PJM seam.

The filing said the expected total investment for the project exceeds $2.5 billion and is anticipated to provide about $2 billion in consumer savings over 20 years by injecting more than 2,000 MW of renewable energy into the PJM market.

The company is working on the required permitting in Iowa, the company said, and it has already received authorization from the commission last July in its application for negotiated rate authority. (See *FERC Oks Negotiated Rates for Merchant Tx Line*.)

The company said the development stage for the project was expected to conclude by the end of 2021, with the line operational by late 2024. However, it said PJM interconnection study delays have pushed the commercial operation date to 2026, halting construction absent an interconnection agreement with the RTO.

Direct Connect argues that PJM should have completed a system impact study by August 2020, but the RTO has notified it that the study is now expected to be completed by Nov. 30, a 15-month delay.

"At the current rate of delay, the project can be entirely constructed and operational in far less time than it will take for PJM to complete its studies," the company said.

It said that in 2020, PJM took an average of 821 days to process facilities studies, and only five projects received their results on time. The studies are supposed to be completed in six months.

Direct Connect said PJM's current implementation of existing transmission planning and generation interconnection study rules "constrain the ability of innovative transmission projects" to pursue market-driven opportunities.

"The current rules, which include merchant transmission in the generation or new services queue, have become unjust and unreasonable, raising barriers to entry by merchant transmission developers like SOO Green into PJM's market," the company said in its filing. "In essence, the current rules have exacerbated the very problem which they were intended to solve."

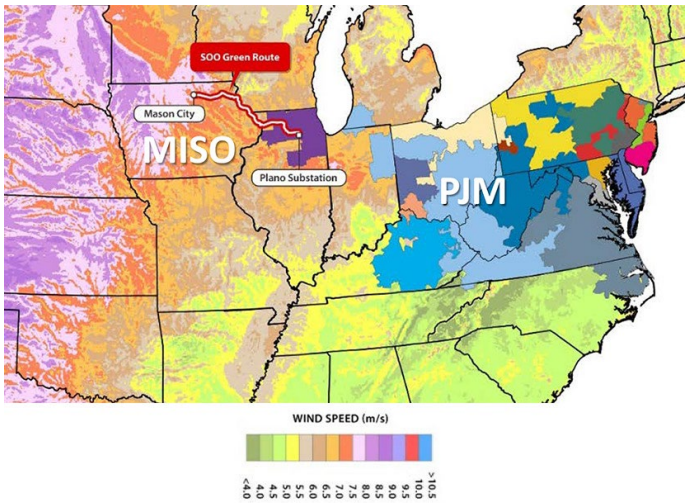
Project Procurement

Direct Connect said it has been forced to "make difficult choices daily" regarding the procurement of parts necessary to complete the project.

"SOO Green faces an impossible choice: enter into supply agreements early and risk substantial penalties, or wait until the interconnection process is complete and not have the equipment necessary to build the project," the company said in its filing.

On June 21, it announced it selected the Italian company Prysmian Group as its preferred supplier of HVDC cable systems for the project. The $900 million contract is still subject to finalization.

"As can be seen recently in Texas and California, the U.S. must invest in its transmission infrastructure, and SOO Green's underground rail co-location model is a game-changer that can be replicated nationwide to build a clean energy grid," Direct Connect CEO Trey Ward said in a press release. "Our partnership with Prysmian provides us with best-in-class cable to build a highly reliable and climate-resilient transmission line to supply U.S. households and businesses with affordable renewable energy for decades to come and bring manufacturing back to the U.S." ■



Direct Connect's SOO Green HVDC Link project | *SOO Green*

PJM News

Transource Challenges Pa. PUC Decision in Court

By Michael Yoder

Transource Energy has appealed the Pennsylvania Public Utility Commission's decision to reject the controversial Independence Energy Connection (IEC) transmission project between the commonwealth and Maryland.

The Columbus, Ohio-based company, made up of a partnership between American Electric Power and Evergy, filed two different challenges last week — one in the U.S. District Court for the Middle District of Pennsylvania and another in the Commonwealth Court of Pennsylvania — against the PUC and its four commissioners (1:2021cv01101).

The PUC voted 4-0 during its public meeting last month to *reject* a series of related applications and petitions filed by Transource for the siting and construction of high-voltage electric transmission lines in Franklin and York counties. The PUC denied the project based upon concerns about whether the need established in the PJM planning process met the requirement for needs specific to Pennsylvania. (See *Transource Tx Project Rejected by Pa. PUC*.)

PJM selected Transource's market efficiency proposal in August 2016 to reduce congestion along the RTO's AP South interface. The congested interface was included in PJM's inaugural window for proposing market efficiency projects as part of the RTO's implementation of FERC Order 1000.

"New transmission infrastructure is necessary to incorporate new energy sources into the market while maintaining system reliability, and the evidence clearly demonstrates that multistate regional planning is the most effective way to meet these needs," said Brian Weber, Transource senior vice president.

Court Filings

In its filings, Transource said PJM's determination of need for a project is the requirement that should be followed to operate a multistate regional transmission system efficiently and reliably. The company said the PUC determined the lines were not needed because eliminating the bottleneck would primarily help out-of-state customers and raise wholesale energy prices paid by Pennsylvania customers.

Transouce said the PUC's decision to reject the siting applications violated two separate constitutional constraints on state action. In the first case, the company said Pennsylvania's decision to deny the applications was pre-empted by federal law because the state's "broad authority over siting determinations" does not allow the overruling of a determination made under federal law that the interstate transmission system needs a new line.

"The authority claimed by the PUC — to deny that a line is needed when the federally authorized transmission planning process has reached a contrary conclusion — improperly second-guesses the result of a federally approved process and is an obstacle to achievement of national policy and FERC's regulatory authority over the interstate transmission system," Transource said in its filing. "If a state can determine that local, parochial interests allow it to reject a regional determination of need, regional transmission planning will be effectively impossible."

Transource also argued that the PUC's decision violates the dormant Commerce Clause, the legal doctrine that the Constitution prohibits states from regulating interstate commerce, a power prescribed to Congress. The company said the PUC's ruling blocked the construction of an "interstate channel of commerce" that would allow less expensive energy produced in Pennsylvania to flow out of the state and reach the broader market.

Transource said the commerce clause also bars states from "imposing burdens" on interstate commerce that outweigh local benefits.

Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project | *Transource Energy*

PJM News

"The court cannot allow a state to point to the local economic benefits that result from interstate transmission congestion as the justification for blocking a project needed to alleviate congestion and benefit the entire region by improving the efficiency of the electric grid," Transource said in its filing.

Project's Status

Transource's transmission line proposals, known as the IEC East and West projects, have gone through several rounds of litigation and investigation since they were first brought to the PUC and other state and federal agencies in 2017. The project got the go-ahead with a certificate of public convenience and necessity from the Maryland Public Service Commission last June. (See *Md. PSC OKs Independence Energy Connection Deal*.)

Transource's plan for the eastern section of the project originally called for extending 15.8 miles of transmission lines from a new Furnace Run substation in York County, Pa., to the Conastone substation in Harford County, Md. By October 2019, an updated configuration designed in consultation with PJM increased the size of the new substation in Pennsylvania and added 4 miles of lines connecting to an existing right of way that would feed into two upgraded Baltimore Gas and Electric substations. (See *Transource Files Reconfigured Tx Project*.)

The western segment of the IEC project includes a 230-kV double-circuit transmission line running 28.8 miles from Franklin County, Pa., into Washington County, Md.

Transource said the project is expected to create 130 full-time jobs and support $40 million in local economic activity.

But from early in the project, local landowners challenged Transource and PJM on the necessity of the transmission lines, creating community groups to protest and challenge the project in court. (See *Protesters Doubt PJM Analysis of Transource Alternative*.)

| © RTO Insider LLC

In December, PUC Administrative Law Judge Elizabeth Barnes issued her *recommended decision* on the project, citing 233 findings of fact and 16 conclusions of law. In her decision, which was ultimately adopted by the PUC, Barnes said she was "not persuaded" that Transource had carried the burden by a "preponderance of the evidence" to establish need after viewing the evidence of the case and finding the opposing arguments made by local landowners to be "more persuasive."

Barnes ultimately concluded that data used by PJM regarding congestion on the AP South interface were "not reliable enough to form the basis of need" for the project. (See *PJM Analysis of Transource Alternative Challenged*.) ■

PJM News

Paper Hearing Opened on PJM DFAX Method

FERC: 'We Need to Look Anew at the Question'

By Michael Yoder

FERC ordered a paper hearing Friday to reconsider whether the 1% *de minimis* threshold and netting provisions of PJM's solution-based distribution factor (DFAX) method result in fair transmission cost allocations (*EL21-39*).

Neptune Regional Transmission System and Long Island Power Authority (LIPA) filed a complaint last December alleging the assignment of costs of the regional cost allocation method included in the PJM tariff results in unjust and unreasonable rates.

In the complaint, Neptune and LIPA challenged PJM tariff provisions of the cost allocation method the commission previously accepted in Order 1000 for the portion of cost responsibility assigned to the solution-based DFAX method for transmission facilities selected in the RTO's Regional Transmission Expansion Plan (RTEP) process.

The DFAX method allocates costs of new transmission facilities by modeling how each load zone contributes to the electricity flows over a new transmission facility. PJM simulates the incremental flow on the new transmission facility resulting from an increase in load of 1 MW in each load zone, FERC said, while holding load in all other load zones at a constant.

The result of PJM's calculation is the DFAX value, the commission said, which represents incremental flows on the new transmission facility "per incremental increase in demand for a particular load zone." PJM then applies a 1% *de minimis* threshold to the calculated DFAX values and replaces any DFAX value less than 0.01 with a DFAX value of zero.

As part of the procedure, PJM models the transfer of the net of energy flow in the positive and negative directions from generation to all load within an individual transmission zone.

The commission had rejected a 2015 complaint by Linden VFT that raised similar allegations (*EL15-67*), reiterating its position in rulings last year. (See *FERC Rebuffs Challenges to PJM Tx Cost Allocation*.)

But the commission said the new complaint, and filings by Exelon supporting it in part, persuaded it "to look anew at the question of whether the 1% *de minimis* threshold and netting provisions of PJM's ex ante cost allocation method have become unjust and unreasonable."

| © RTO Insider LLC

Complaints

Neptune owns the Neptune Line, a merchant transmission facility running from northern New Jersey in the Jersey Central Power and Light zone of PJM to New York. Neptune holds 685 MW of firm transmission withdrawal rights.

LIPA contractually holds long-term transmission rights over the Neptune Line through Dec. 31, 2027, and pays the transmission enhancement charges assessed to Neptune under Schedule 12 of the PJM tariff.

Neptune and LIPA said netting and 1% *de minimis* threshold provisions in the PJM tariff "materially distort the assignment of cost responsibility resulting from application of the solution-based DFAX method." The companies said the netting of modeled energy flows in both directions across a transmission facility "produces an incorrect measure of total usage," and the *de minimis* threshold "arbitrarily excludes zones from cost allocation."

Neptune and LIPA also assert that the netting and 1% *de minimis* threshold provisions "result in cost responsibility assignments that are not roughly commensurate with derived benefits," making them unjust and unreasonable. The companies said the DFAX method should be "implemented without netting, by measuring gross zonal usage of a transmission facility in the positive and negative directions and assigning cost responsibility based on each zone's gross relative usage in both directions."

Neptune and LIPA submitted examples showing a zone with the highest relative use of a transmission facility receiving no cost allocation for the facility.

Questions

FERC listed 14 questions for PJM and stakeholders to answer in the paper hearing.

The commission said it wants an explanation on whether cost responsibility under the DFAX method with a *de minimis* threshold value less than 1% "should be considered anomalous rather than an indication that there is a circuitous low-impedance path for a zone to serve its own load."

FERC also said it wants to know why it's appropriate to "exclude zones from cost allocation based on their solution-based DFAX values rather than their relative megawatt usage of the transmission facility in question" under a "beneficiary-pays approach to cost allocation for transmission facilities."

Stakeholders interested in intervening were given 21 days to notify FERC of their intent. Responses to FERC's questions are due within 60 days of the order, and comments on the responses are due 30 days after that. ■

PJM News

PJM MRC/MC Briefs

Markets and Reliability Committee

ICSA Revisions Endorsed

Stakeholders unanimously endorsed PJM's proposed tariff revisions to address concerns associated with the *pro forma* interconnection construction service agreement's (ICSA) lack of superseding language and current automatic termination provision.

Mark Sims, PJM | © RTO Insider LLC

Mark Sims, PJM manager of infrastructure coordination, *reviewed* the proposed solution and associated tariff *revisions* at last week's Markets and Reliability Committee meeting. Sims first presented the issue at the March MRC meeting, with stakeholders providing recommendations to PJM's proposal.

The Planning Committee endorsed the changes in May, as PJM said the growing interconnection queue volume has created the need for improvements. (See "ICSA Endorsed," *PJM PC/TEAC Briefs: May 11, 2021*.)

PJM identified improvements in two areas of tariff Attachment P that deal with ICSAs. Section 1 of the attachment does not contain *pro forma* language that considers when an ICSA supersedes an already effective agreement, and the solution involved simple tariff language revisions, Sims said.

The tariff also provides for automatic termination of ICSAs upon the occurrence of certain conditions, which can occur without PJM's knowledge at the completion of construction of all interconnection facilities, a transfer of title, final payment of all costs or delivery of final as-built drawings to the transmission owner. PJM proposes to update the language to make any termination contingent upon PJM receiving notice of the conditions from the TO.

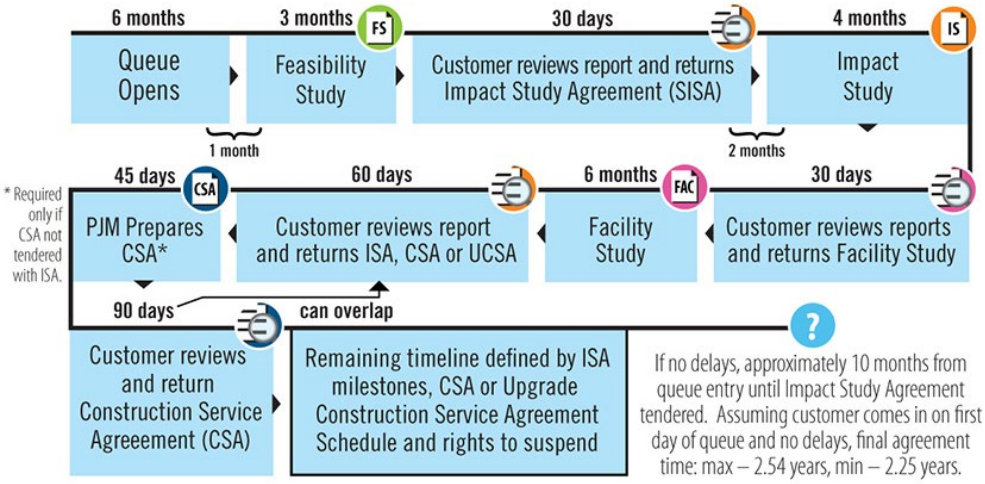
Sims said the changes directly relate to improving process efficiency related to the PJM interconnection queue volume. He said the vetting of the language at the PC and additional review and feedback at the Transmission Owners Agreement-Administrative Committee provided "great feedback" from stakeholders throughout the process.

"As a result, we have a very good proposal," Sims said.

The tariff revisions will now go to the Members Committee on July 28 for a final vote.

Alex Stern, PSEG | © RTO Insider LLC

Alex Stern, director of RTO strategy for PSEG Services, thanked PJM staff for "taking a little extra time" to work on the proposal. Stern said the additional work allowed language regarding the automatic termination provisions for conforming and nonconforming agreements to be clarified and enhanced.



PJM interconnection process timeline | *PJM*

Regulation Mileage Ratio First Read

Members questioned PJM's proposed solution to address issues with the regulation mileage ratio, asking the RTO to reconsider the mileage value it has suggested as an alternative to the existing value.

Michael Olaleye, senior engineer with PJM's real-time market operations, *reviewed* the proposed solution addressing the regulation mileage ratio and corresponding revisions to the *tariff*, the *Operating Agreement* and *Manual 28: Operating Agreement Accounting*. Olaleye first introduced the proposed solution at the May Market Implementation Committee meeting. (See "Regulation Mileage Ratio," *PJM MIC Briefs: May 13, 2021*.)

Regulation mileage is the measurement of the amount of movement requested by the regulation control signal that a resource is following, and it's 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.

Olaleye said PJM has seen increased frequency of RegA signal pegging and times the RegA signal is pegged for extended periods. He said the pegging highlights a potential problem in the regulation mileage ratio calculation, setting the RegA mileage at zero for a given hour and creating a divide-by-zero error in the calculation of the mileage ratio.

PJM is proposing to set the floor RegA mileage at 0.1 instead of zero, Olaleye said, which would allow for a "valid solution" for mileage ratio and still maintain market design objectives. He said there would be no impact to the regulation signal design, operations or regulation market clearing.

Joe Bowring, IMM | © RTO Insider LLC

Independent Market Monitor Joe Bowring raised a *counterproposal* at the MIC after questioning PJM's value of 0.1. Bowring proposed a cap of 5.5 on the realized mileage ratio in all hours, indicating

PJM News

the cap would eliminate the current undefined mileage ratio result that PJM is attempting to address, but it in a "preferable way."

The cap would reduce but not eliminate the market distortion that results from the use of mileage ratios when they incorrectly represent regulation output, Bowring said, and would affect less than 50% of impacted hours based on data collected by the Monitor over the last 15 months.

Bowring said he believes the PJM proposal ignores the fact that there's still going to be "excessively high" mileage ratios for a significant number of hours.

"It's important to recognize this is more than just a simple mathematical issue," Bowring said. "It reflects an underlying issue with mileage ratio."

David "Scarp" Scarpignato, Calpine | © *RTO Insider LLC*

Calpine's David "Scarp" Scarpignato said the numbers currently used in the regulation mileage ratio calculation are "majorly messed up" and need to be addressed. Scarp said Bowring's solution "makes a lot more sense" than PJM's because it uses a high mileage ratio but does not create "insane" results. Scarp said dividing by PJM's 0.1 value "can give you some pretty insane numbers."

"Joe's proposal is a temporary fix that actually addresses the real issue, which is more than a mathematical issue," Scarp said. "It's where do you reach a point of craziness."

Local Hour	RMCCP	RMPCP	Hourly Mileage A	Hourly Mileage D	Hourly Mileage Ratio (settled)	Hourly Mileage Ratio (Proposed)	Difference in Mileage Ratio
3/4/2013 18:00	$37.67	$0.03	0.074304	0.257536	3.47	2.58	0.89
11/9/2013 18:00	$12.40	$0.97	0.072887	15.649591	214.71	156.5	58.21
5/31/2015 15:00	$187.06	$0.78	0.070406	14.128501	200.67	141.29	59.38
12/11/2015 16:00	$12.49	$0.01	0.078511	13.35094	170.05	133.51	36.54
12/31/2015 18:00	$0.27	$0.00	0.056789	12.54787	220.96	125.48	95.48
1/1/2016 2:00	$8.45	$0.00	0.013579	10.582214	779.31	105.82	673.49
6/28/2016 16:00	$3.08	$0.00	0.018116	11.818568	652.38	118.19	534.19
2/27/2018 9:00	$0.00	$0.00	0.040318	20.448624	507.18	204.49	302.69
1/21/2019 11:00	$313.49	$0.00	0.006478	27.402607	4230.10	274.03	3956.07
1/30/2019 14:00	$17.49	$0.01	0.046133	5.225629	113.27	52.26	61.01
6/22/2020 15:00	$0.01	$0.00	0.048004	19.204105	400.05	192.04	208.01
6/26/2020 0:00	$11.37	$0.00	0.096609	23.562192	243.89	235.62	8.27
8/12/2020 14:00	$15.09	$0.01	0.03332	22.412721	672.65	224.13	448.52
2/17/2021 9:00	$0.00	$0.00	0	19.159495	#N/A	191.59	191.59
4/2/2021 4:00	$8.59	$0.00	0.099567	6.182331	62.09	61.82	0.27
4/15/2021 9:00	$6.91	$0.00	0.052218	33.582262	643.12	335.82	307.30
5/8/2021 13:00	$13.77	$0.00	0.011427	31.296327	2738.81	312.96	2425.85

Instances of RegA hourly mileage rates less than 0.1 in PJM since 2013. | *PJM*

ELCC Manuals

Andrew Levitt, of PJM's market design and economics department, *reviewed* conforming revisions to *Manual 18: PJM Capacity Market*, *Manual 20: PJM Resource Adequacy Analysis*, *Manual 21: Rules and Procedures for Determination of Generating Capability* and *Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis* to address the effective load-carrying capability (ELCC) for limited-duration and intermittent resources.

ELCC sets the capacity value for storage and renewables. The revisions would require a unit's ELCC accreditation to be updated annually based on system conditions and unit performance.

Stakeholders endorsed a revised joint stakeholder proposal to use the ELCC method to calculate the capacity value of limited-duration, intermittent and combination (limited-duration plus intermittent) resources at the September MRC and MC meetings. (See *ELCC Method Endorsed by PJM Stakeholders*.) Levitt said PJM expects a final ruling by FERC on the ELCC issue by July 30.

Levitt said Manual 18 includes conforming changes to coordinate the term "installed capacity (ICAP)" with new terminology used for ELCC resources, including the new term "accredited unforced capacity (UCAP)."

Manual 20 has a description of the technical details of the ELCC analysis and its methodology, Levitt said, while Manual 21 strikes the "10-hour rule" for limited-duration resources and provides for a sunset date of June 1, 2023, for testing provisions for ELCC resources in the manual.

Levitt said Manual 21A is a new manual describing the business processes for deriving an accredited UCAP value for each ELCC resource.

Stakeholders will be asked to endorse the proposed revisions at the July MRC meeting.

Levitt said PJM is proposing to have ELCC tariff rules currently in front of FERC take effect by Aug. 1 so they're able to be applied to the 2023/24 delivery year and Base Residual Auction, scheduled for Dec. 1.

Consultant Roy Shanker asked Levitt what PJM would do if FERC doesn't act on the ELCC proposal by July 30.

Levitt said FERC has a statutory obligation to make a decision by July 30. He said if the commission's decision involves a denial of the ELCC proposal or moving the decision date, PJM would have to "assess our options." He said he has a "difficult time seeing" how PJM could run the 2023/24 BRA under ELCC rules if FERC doesn't approve them on time.

Manual 14 Revisions Endorsed

Stakeholders *endorsed* revisions to *Manual 14B: PJM Region Transmission Planning Process* and *Manual 14F: Competitive Planning Process* conforming to tariff revisions accepted by FERC in December (*ER21-162*) in the MRC consent agenda.

PJM proposed including capacity constraints as inputs to the analysis for market efficiency projects in the Regional Transmission Expansion Plan and to clarify when capacity benefits of such projects are calculated. Both manual changes were unanimously endorsed at the May PC meeting. (See "Manual 14F and 14B Updates," *PJM PC/TEAC Briefs: May 11, 2021*.)

Members Committee

Consent Agenda

Two proposals were endorsed with two objections as part of the consent agenda at last week's MC meeting.

Stakeholders *endorsed* tariff *revisions* to address new service requests deficiency review requirements. Members unanimously endorsed the proposed solution and tariff revisions at the May MRC meeting. (See "New Service Requests Approved," *PJM MRC Briefs: May 26, 2021*.)

Members also *approved* OA *revisions* to address the avoidance of future CIP-014 facilities. The avoidance proposal was approved by an acclamation vote at the May MRC meeting. (See "CISO Avoidance Endorsed," *PJM MRC Briefs: May 26, 2021*.) ■

— Michael Yoder

PJM News

PJM Reserve Price Formation Issue Charge Approved

By Michael Yoder

PJM stakeholders narrowly approved an issue charge to examine the RTO's operating reserve demand curve (ORDC) and transmission constraint penalty factors and the possible creation of a "circuit breaker" to control energy prices in an emergency.

The problem statement and issue charge, sponsored by nine different stakeholders, was approved in a sector-weighted vote of 2.505, barely passing the 2.5 threshold for endorsement at last week's Markets and Reliability Committee meeting. Sixty-one members voted in favor, with 59 voting against.

John Rohrbach, representing Southern Maryland Electric Cooperative, presented the issue charge designed to consider whether an administrative mechanism, such as a circuit breaker, should be established in PJM's energy market to protect consumers and market participants from financial impacts resulting from scarcity price signals.

Rohrbach said the recent pricing events in ERCOT, SPP and MISO during the winter storm emergency in February illuminate the potential adverse impact from the lack of a circuit breaker in PJM's ORDC and transmission constraint penalty factor rules. Rohrbach said the issue charge was designed to highlight the lack of a circuit breaker in the future PJM ORDC rules and pertinent sections of the Operating Agreement for addressing an extended period in which ORDC penalty adders are binding.

Rohrbach said extreme pricing for an extended or indefinite period during an emergency can create costs that far exceed the value of any contribution to preserve grid reliability.

PJM uses an ORDC and transmission constraint penalty factors to establish locational marginal pricing. Under current PJM rules, the maximum price the energy component of an LMP can reach is $3,750/MWh.

But the "downward sloping" ORDC that was approved by FERC in May 2020 and takes effect in PJM on May 1, 2022, allows the RTO's LMPs to reach or exceed $12,050/MWh in cases of extreme reserve shortages. (See *FERC Approves PJM Reserve Market Overhaul*.)

Key Work Activities

Adrien Ford of Old Dominion Electric Cooperative outlined the key work activities of the issue charge.

The first includes education on the current and pending PJM market rules for use of ORDCs and transmission constraint penalty factors in LMPs, including the input assumptions for the ORDCs. Ford said the education will also include pricing rules during emergency actions, triggers for performance assessment intervals (PAI) and the automatic use of the maximum reserve penalty factors. Education is slated to begin in July.

The second key work activity features exploring potential circuit breakers or other stop loss approaches that could limit extreme pricing when the cost "likely far exceeds the value of any contribution to preserving grid reliability."

Ford said discussion would also include potential additional operational authorities needed by PJM to maintain grid reliability under conditions with excessive costs.

"Grid reliability is extremely important," Ford said.

Work on the second key work activity is expected to take six months. Ford said efforts will be made to expedite voting to receive FERC action on any potential rule changes before the downward sloping ORDC takes effect in May 2022.

The third key work activity features exploring potential enhancements to PJM's ORDC rules to address the impact of recent changes in PJM's dispatch protocols on forecast uncertainty. Ford said stakeholders will examine and address the additional market and credit risks of the ORDC changes considering the recent pricing events in ERCOT, SPP and MISO.

Work on the issue charge will take place in the Energy Price Formation Senior Task Force.

Stakeholder Opinions

Stakeholder opinions on the issue charge were divided, with some saying the planned work doesn't go far enough and others indicating the issue could become too complicated to implement before the ORDC changes next year.

Kent Chandler, executive director of the Kentucky Public Service Commission, said he sees the new ORDC as a "massive risk" to consumers in PJM. Chandler said the revised ORDC should have never been filed by the PJM Board of Managers or approved by FERC. (See *PJM Files Energy Price Formation Plan*.)

A review of the ORDC is necessary, Chandler said, but PJM and stakeholders need to "move immediately" to ensure a circuit breaker is in place before the implementation in May 2022. Chandler said any proposal that doesn't prioritize having a circuit breaker in place at the end of the work is "inadequate."

Dominion Energy's Jim Davis, a co-sponsor of the issue charge, said the concept behind the work is not to reexamine the ORDC issue but focus on the creation of a circuit breaker. Davis said in order to develop an effective stop-loss provision, stakeholders need to be able to consider different aspects of the ORDC set to be implemented.

"I think we're fortunate to be able to contemplate a circuit breaker prior to the implementation of the new ORDC construct, but we cannot do so in a vacuum," Davis said. "We need to be able to consider enhancements to the ORDC rules."

Susan Bruce, counsel to the PJM Industrial Customer Coalition (ICC), said many ICC members have facilities in ERCOT, SPP and MISO that were impacted by the winter emergency event and don't want to see a similar event happen in PJM. Bruce said it's the stakeholders' responsibility as "stewards" of the PJM market to make sure markets work for customers.

"We want to make sure the markets are working for all market participants," Bruce said.

Becky Robinson of Vistra said she believed it was more appropriate to proceed with a "focused effort" to address circuit breakers instead of a broader discussion in the issue charge. Robinson said the work to create a circuit breaker could be "weighed down" by a broader discussion of the issue.

Paul Sotkiewicz of E-Cubed Policy Associates said the third key work activity in the approved issue charge was "a bit more open-ended" than he would like. Sotkiewicz said having the circuit breaker in place is very important but thinks discussions may get "bogged down" in the third key work activity and won't get to the point of creating a circuit breaker.

Sharon Midgley of Exelon presented an alternative problem statement and issue charge on behalf of multiple sponsors regarding a scarcity pricing circuit breaker for a vote. Midgley said the alternative issue charge arose out of the "overly broad scope and ill-defined problems" of the first issue charge and to focus specifically on creating a circuit breaker. ■

Company Briefs

AEP Announces Leadership Changes

American Electric Power last week announced several changes to the company's leadership team, effective July 31.

Toby Thomas, currently the president and COO for Indiana Michigan Power, will move to a new position as senior vice president of energy delivery. Mark McCullough, the executive vice president of energy delivery, is retiring.

Also taking on new positions: Raja Sundararajan (senior vice president of regulatory and customer solutions); Janelle Coleman (vice president of community engagement, diversity and inclusion); Marc Reitter (president and COO for AEP Ohio); and Steve Baker (president and COO for Indiana Michigan Power).

More: *AEP*

Amazon Becomes Largest Corporate Renewables Buyer in US

Amazon last week announced 14 new renewable energy projects in the U.S., Canada, Finland and Spain to advance its goal to power 100% of its company activities with renewable energy by 2025, five years ahead of its original target.

The new projects bring the company's total renewable energy investments to 10 GW of capacity and make it the largest corporate buyer of renewable energy in the U.S. and the world.

Amazon will have a total of 232 renewable energy projects globally, including 85 utility-scale wind and solar projects and 147 solar rooftops on facilities and stores worldwide.

More: *Solar Power World*

Duke Energy Applies to Keep Oconee Nuclear Plant Going into 2050s

Duke Energy last week filed an application with the Nuclear Regulatory Commission seeking approval to run the Oconee Nuclear Station into the 2050s.

Oconee, which has two reactors, is seeking a 20-year license extension that would let them run until at least 2053 and 2054. Only three nuclear plants in the country provide more electricity.

More: *Greenville News*

Nikola Buys Stake in Indiana Hydrogen Plant

Nikola, which plans to mass-produce hydrogen-powered electric semi-trucks, last week said it is buying a $50 million (20%) stake in a Wabash Valley Resources project that is converting an idled Indiana coal plant into a large-scale hydrogen factory.

The project aims to chemically separate hydrogen from solid waste materials for use as fuel for Nikola's trucks and electric-power generation, while capturing and burying the carbon emissions from the process. Wabash Valley Resources said the plant will be one of the biggest carbon sequestration projects in the U.S. when it begins operating.

The facility will be able to produce up to 336 tons of hydrogen per day, enough to generate about 285 MW of electricity, the companies said. Nikola will have access to about 50 tons of hydrogen per day for fuel stations it wants to build across the Midwest.

More: *Forbes*

Oracle Pledges 100% Renewables by 2025

Oracle last week announced plans to cover 100% of its global electricity needs with renewable power by 2025.

Currently, Oracle's European Cloud regions are supplied with 100% renewable energy, while 51 of its offices have switched to all-renewable power.

More: *Renewables Now*

Federal Briefs

Biden Bans Solar Panel Material from Chinese Firm over Forced Labor

The Biden administration last week said it will block imports of silicon material from Hoshine Silicon Industry, as part of what it called a "whole-of-government" approach to combating forced labor in supply chains that run through China. The company is a major manufacturer of the raw materials used in the polysilicon inside most solar panels.

The Customs and Border Protection action, called a "withhold release order," allows the agency to hold shipments that include materials from Hoshine at the border, only releasing them if the importer can prove they are not made with forced labor.

Hoshine was largely the subject of a report on Uyghur forced labor in the northwestern Xinjiang region of China, which provides about half the world's supply of polysilicon to the solar industry.

More: *POLITICO*

House Passes Resolution to Repeal Trump-era EPA Rule on Methane

The House of Representatives last week voted 229-191 to repeal a Trump-era rule that rolled back regulations of methane emissions from oil and gas industries and to restore an Obama-era rule.

Last September, the Trump administration rolled back the 2016 regulation limiting methane leaks by requiring companies to monitor and repair new natural gas equipment. The Senate had passed a resolution at the end of April under the Congressional Review Act.

More: *CNN*

DC Metro to Transform its Fleet to Electric by 2045

Metro's Board of Directors last week approved a plan that will phase in an electric-powered bus fleet over the next 20 years.

The plan shifts the agency's annual purchase of buses away from natural gas and diesel and toward electric each year starting in

2023. It will then phase out the purchasing of nonelectric buses by 2030 with the hope of making its entire fleet fully electric by 2045.

Metro will begin buying electric buses in the summer of 2023. The plan's pace is meant to give the agency time to add charging stations and other infrastructure, but the pace will quicken as technology improves the performance of the buses.

More: *The Washington Post*

State Briefs

CALIFORNIA

PUC Extends Power Shutoff Moratorium Through September

The Public Utilities Commission last week unanimously passed an extension of the moratorium on utility power shutoffs through September.

The PUC also approved a plan that requires utilities to automatically enroll customers who are lagging on monthly payments into a two-year debt relief program. In the first quarter of this year, more than 3.3 million residential customers of the state's big four utilities have fallen behind on their bills.

More: *The San Diego Union-Tribune*

Shasta County Denies Wind Farm Permit

The Shasta County Planning Commission last week unanimously rejected the use permit for the Fountain Wind farm project.

Commissioners said the project's impact on the environment, the scenery and the potential long-term harm it would do to the area's economy outweighed its benefits.

Project Manager Henry Woltag said the company will appeal the commission's decision to the Shasta County Board of Supervisors.

More: *Redding Record Searchlight*

INDIANA

CenterPoint to ask URC to Replace A.B. Brown Coal Plant

CenterPoint Energy last week petitioned the Utility Regulatory Commission for approval to replace its coal-burning A.B. Brown power plant with natural gas turbines. If approved, CenterPoint would be able to ask for a rate increase to cover the cost.

If the project is approved, CenterPoint would start construction immediately with the new turbines beginning operation in 2024. The increase would be requested in 2023 during the next review of rates.

The new turbines would add about $23 to the bill of a homeowner who uses 1,000 kW per month. However, that estimate does not take into account the savings and costs recovered from no longer operating A.B. Brown's coal units.

More: *Evansville Courier & Press*

NEW MEXICO

PRC Orders Avangrid to Explain Why It Withheld Info in PNM Merger

Public Regulation Commission Hearing Examiner Ashley Schannauer last week ordered Avangrid to state why it withheld information in its proposed merger with the Public Service Company of New Mexico and why it shouldn't be penalized. The order is part of an ongoing dispute over the degree to which Avangrid avoided questions about customer service penalties its subsidiaries have faced in the Northeast.

Schannauer ruled that questions concerning the role of the Four Corners Power Plant in the merger proposal are relevant, while Avangrid and PNM argue PNM's abandonment of the plant is a separate matter from the proposal.

The order states Avangrid and PNM should respond by June 28 to criticisms that they haven't been forthcoming in the discovery process, which involves disclosure of information in the case.

More: *Santa Fe New Mexican*

NORTH CAROLINA

Gov. Cooper Picks New Environment Leader

Gov. **Roy Cooper** last week named Elizabeth Biser as his next secretary for the environment, after the Senate did not confirm his previous choice.

Biser, who has been operating her own consulting business and working for a national group that promotes recycling, also will be subject to Senate scrutiny.

Senate Republicans voted down Cooper's appointment of Dionne Delli-Gatti as secretary of the Department of Environmental Quality earlier this month, saying her reticence during her confirmation hearing about Cooper's natural gas policy disqualified her for the post.

More: *The Associated Press*

OHIO

Cleveland Heights Joins Power a Clean Future Ohio Coalition

The Cleveland Heights City Council last week voted to join the Power a Clean Future Ohio coalition.

The city joins the coalition at no cost and with a goal to reduce greenhouse emissions another 30% by 2030. The "Ohio 30-by-30 pledge" would build upon the 20% reduction that Cleveland Heights already saw between 2010 and 2017.

More: *Cleveland.com*

Siting Board Approves Renewable Projects, Denies Wind Project

The Power Siting Board last week approved two solar projects and one wind project, while rejecting one wind project.

The projects approved were the 80-MW Angelina Solar Project, the 69.9-MW Alamo Solar Project, and the 297-MW Emerson Creek wind farm. Both solar projects will consist of large panel arrays and associated facilities.

The board unanimously rejected plans for the $92 million Republic Wind Farm project, citing opposition from Seneca County residents and elected officials. Republic Wind initially proposed a 66-turbine (450 MW) farm before scaling it back to 47 (200 MW)

in hopes of pleasing its opposition.

More: *The Blade*, *The Columbus Dispatch*

OKLAHOMA

EV Startup Canoo to Build Plant in Pryor

Electric vehicle startup Canoo will build its first manufacturing plant in Pryor, state officials said last week.

The company, which plans to build the factory on a 400-acre site at the MidAmerica Industrial Park, said it is slated to open in 2023.

Canoo plans to market its first vehicle at the end of 2022, partnering initially with a Netherlands automotive manufacturing company while its Oklahoma factory is constructed.

More: *Stillwater News Press*

TEXAS

El Paso Suspends EPE's Proposed Rate Increase

The El Paso City Council last week voted unanimously to suspend El Paso Electric's proposed rate increase for its state retail customers for 90 days from the effective date.

The suspension, which will be in effect until October, allows the city time to review the proposed change and prepare for a public hearing to determine if the increase is fair. EPE has proposed an annual net increase to its base rate of $41.8 million (7.8%) to recover costs associated with more than $953 million in investments made into its generation, transmission and distribution system.

Had the council not suspended the rate increase, the proposed increase would have gone into effect on July 6.

More: *El Paso Herald-Post*

WISCONSIN

Potosi Residents Appeal Solar Farm Approval

Potosi residents opposed to the construction of a 1,400-acre solar farm have filed a petition with the Public Service Commission and are seeking a rehearing after the state signed off on the project in May.

Opponents of the farm said the PSC "abdicated its powers and duties" by approving the 200-MW project without sufficiently investigating potential impacts, requiring environmental review, and initiating fact-finding studies.

Groundbreaking on NextEra Energy Resources' $250 million Grant County Solar Energy Center is expected to begin this fall.

More: *Telegraph Herald*