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House Democrats Put Climate Change Front and Center

By Michael Brooks

House Natural Resources Committee Chair Raul Grijalva (D-Ariz.) (right) and ranking member Rob Bishop (R-Utah) talk before the hearing begins. | *© RTO Insider*

WASHINGTON — Having regained control of the House of Representatives after eight years in the minority, Democrats have put a lot on their plate, including investigating President Trump's finances and Russian interference in the 2016 presidential election.

But last week, House Democrats added climate change to their agenda, with two committees holding hearings on the topic simultaneously Wednesday, and Rep. Alexandria Ocasio-

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Also in this issue:

SCE's $1 Billion Shortfall Perturbs State Regulators

Constraints in Natural Gas Supply Cited as Cause

By Hudson Sangree

A Southern California Edison natural gas peaker plant near Los Angeles | *SCE*

SACRAMENTO, Calif. — The Public Utilities Commission is considering whether to fine Southern California Edison for its failure to promptly report a nearly $1 billion shortfall in revenues last year that should have triggered action under state law.

The commission on Thursday ***unanimously approved*** a sizable rate increase in 2019 to cover the shortfall, adding to millions of Californians' already-high electricity costs. The increase amounts to about 1.4 cents/kWh, adding $11.50 to an average residential customer's electricity bill in the summer and $7.67 in winter, according to the ***most recent*** data available.

The commissioners weren't happy about the decision.

They criticized SCE's failure to act sooner to compensate for a $983.8 million Energy Resource Recovery Account (ERRA) under-collection as of Dec. 31, 2018.

Assembly Bill 57 required the PUC to establish the ERRA account in 2002 to reconcile the fuel and purchased power costs that investor-towned utilities can recover in rates but for which they do not earn a return. The resulting

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PJM Won't Act on FTR Order Before Stay Ruling

RTO Attempts to Lobby Commissioners

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — PJM won't act on FERC's order to rerun its July 2018 financial transmission rights auction unless the commission denies the RTO's planned motion for a stay, officials told members Wednesday.

FERC's Jan. 30 order rejected PJM's request to waive rules requiring it to quickly liquidate GreenHat Energy's FTR positions following the company's default. PJM liquidated only GreenHat's FTRs settling in August, saying that selling all the positions immediately would increase members' losses (*ER18-2068*).

Suzanne Daugherty, PJM | *© RTO Insider*

CFO Suzanne Daugherty *told* the Market Implementation Committee on Wednesday that unwinding settlements of the company's FTR portfolio could add $250 million to $300 million to the $186 million the RTO had earlier projected the default would cost members. Daugherty stressed that the calculations are preliminary and might vary significantly after PJM is able to rerun the results of the July auction. (See *PJM: FERC Order Could Boost GreenHat Default by $300M*.)

Chris O'Hara, PJM | *© RTO Insider*

Deputy General Counsel Chris O'Hara said PJM will ask FERC to stay its order until it rules on the RTO's

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NERC Member Representatives Committee Briefs

Stakeholders Get First Peek at Report on Supply Chain Risks

MANHATTAN BEACH, Calif. — NERC stakeholders last week got a first look at a draft *report* on supply chain risks as part of a FERC directive to develop a standard addressing risk management of the industry's vendors.

Roy Thilly, chairman of NERC's Board of Trustees, called the initiative a "very important undertaking," but he also cautioned that it is not a "silver bullet."

Supply chain risk management "requires a practical, effective, measured response," he said during the NERC Member Representative Committee's Feb. 6 meeting.

NERC staff have been working with the Electric Power Research Institute to assess the bulk electric system's (BES) product and manufacturer types, analyze BES cyber assets, and gather best practices and standards used by other industries to mitigate supply chain risks.

At the board's request, the North American Transmission and Generator Forums and other industry groups have developed white papers, which can be found on the initiative's *website*.

The report suggests applying industry practices to third-party accreditation processes; ensuring that hardware and software are protected during physical transport; using processes to mitigate risks from unsupported or open-sourced technology components; and using supply chain controls to address common-mode vulnerabilities.

Staff are recommending the standards include electronic access and physical access controls for medium- and high-impact BES cyber systems, and to collect more data on low-impact BES cyber systems. They also plan to monitor emerging technologies for new risks.

Howard Gugel, NERC's senior director of engineering and standards, said the industry's reliance on technology and the use of single platforms to host multiple applications has increased the risk of access through "the back door."

Despite that, he said he would be reluctant to certify a particular methodology for certifying third parties.

"I'm not sure we as the reliability regulator would want to get into any sort of third-party endorser of people selling in the market," Gugel said. "However, if there are third-party options for providing that, we'd certainly like to be involved with it."

FERC ordered NERC in 2016 to draft a "new or modified" standard addressing supply chain risk management for industrial control system hardware, software, and computing and network services associated with the BES. (See *FERC Orders NERC to Develop 'Flexible' Supply Chain Standard*.)

NERC responded with three supply chain standards — *CIP-005-6*, *CIP-010-3* and *CIP-013-1* — which FERC approved in October 2018. (See *FERC Finalizes Supply Chain Standards*.)

Staff are still accepting comment on the report. A final draft will be presented to the board in May.

Members Elect 4 Trustees to Board

The MRC elected the board's class of 2022, filling a vacancy created to add a Canadian trustee and re-electing three incumbents to three-year terms.

Colleen Sidford will step into the Canadian vacancy. She spent 10 years with Ontario Power Generation in various financial positions, following a career in international banking.

NERC is required to have two Canadian trustees. It has three with Sidford's election, but it is expected to reduce the number to two when Fred Gorbet's term expires next year. That will also leave NERC with 11 trustees.

Re-elected to three-year terms were:

- Robert Clarke, who has served on the board since 2013. He chairs the Corporate Governance and Human Resources committees and serves on the Enterprise-wide Risk and Nominating committees.
- Ken DeFontes, a trustee since 2016. He is the liaison to the Standards Committee and serves on the Compliance and Technology and Security committees.
- David Goulding, who was first elected to the board in 2010. He chairs the Enterprise-wide Risk Committee and serves on the Finance and Audit Committee.

NERC's trustee succession policy provides that no independent trustee may be re-nominated or re-elected if he or she has served 12 consecutive years.

Ford, Sterling Step into New Leadership Positions

MRC Vice Chair Jennifer Sterling and Chair Greg Ford | © *RTO Insider*

The meeting marked Greg Ford's first as MRC chair. Ford, CEO of Georgia System Operations Corp., replaces Wabash Valley Power Association's Jason Marshall, who cycled off the committee.

Jennifer Sterling, vice president of NERC compliance and security for Exelon, is serving as vice chair.

NERC Develops Participant Conduct Policy

NERC General Counsel Charles Berardesco shared with the MRC the organization's Participant Conduct *Policy*, which is applicable to participants in all organization activities. The policy was based on similar rules for the NERC Operating Committee and standards development process.

However, the policy doesn't apply to the MRC itself, Ford said. "The MRC is a creature of the bylaws," he explained.

Berardesco said the policy will create a professional environment for all participants supporting NERC's mission, including standing committee members and observers, drafting team members and observers, and other stakeholder volunteers that participate in the organization's activities or groups.

The policy calls for those it covers to conduct themselves in a professional manner, not to use NERC activities for commercial or private purposes, and not to distribute confidential information or certain work products. ■

— Tom Kleckner

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NERC Board of Trustees Briefs

Florida RE's Delegated Agreement to be Terminated

MANHATTAN BEACH, Calif. — The number of NERC Regional Entities will soon dwindle to six following last week's unanimous approval by the organization's Board of Trustees to enter into a termination agreement with the Florida Reliability Coordinating Council (FRCC).

During the board's Feb. 7 meeting and without discussion, trustees authorized NERC management to terminate the amended and restated delegation agreement between the organization and FRCC and to approve transfer of its registered entities to SERC Reliability.

FRCC serves as the RE, reliability coordinator (RC) and planning authority for much of the state of Florida, the latter two functions under its member services division. Its only geographic and electrical borders are with SERC.

FRCC announced last year it would dissolve its RE division following a review of its governance structure, set in motion by NERC's 2017 determination that REs should be separate corporate bodies from NERC-registered entities. A FERC audit in 2010 spurred FRCC to improve the separation between its RE and member services divisions.

NERC will file a petition with FERC seeking its approval of the delegated agreement's termination and the transfer of FRCC RE's delegated authority to SERC. It has proposed a transfer deadline of July 1.

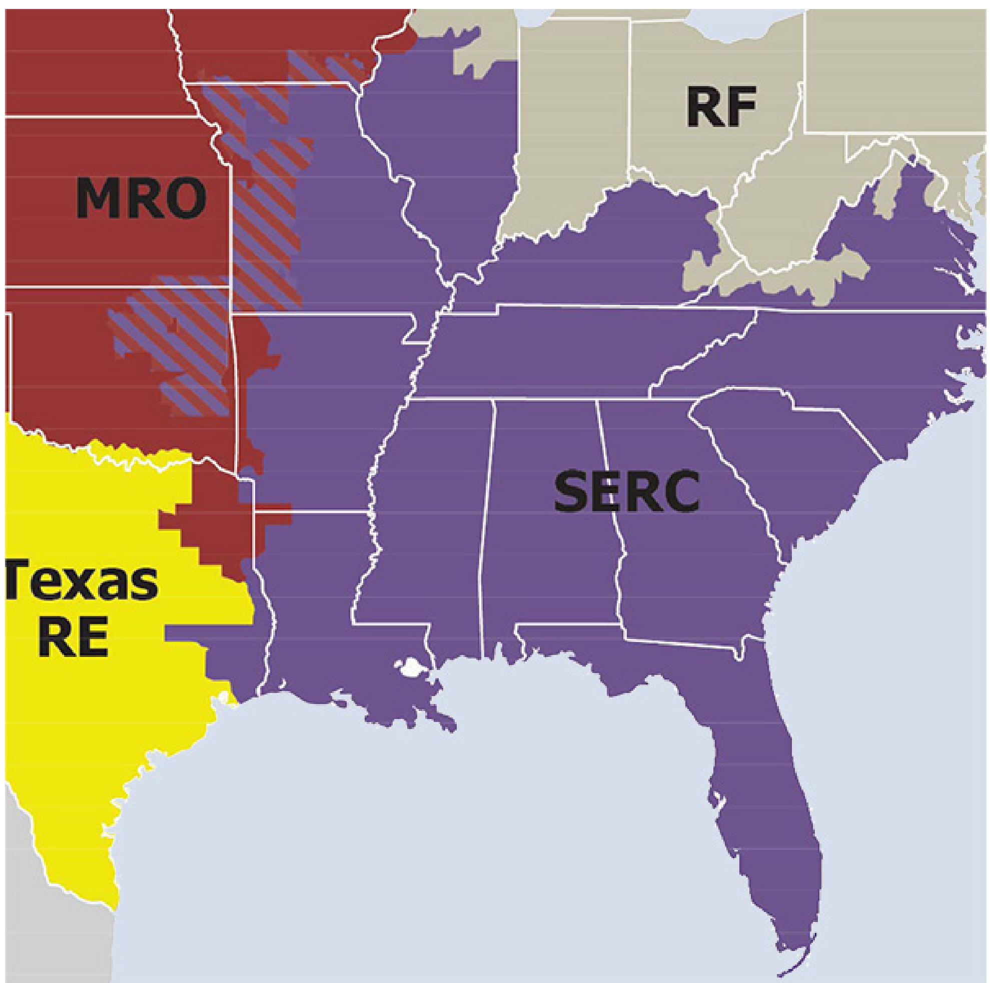
The organization will follow much of the same process as last year in approving the dissolution of the SPP RE, which ceased its activities in June. (See *SPP RE Ending Compliance Monitoring, Enforcement Activities*.)

Board Chair Roy Thilly thanked FRCC CEO Stacy Dochoda for moving the process along.

"This is a complex set of arrangements, but it's working very smoothly," he said.

As of March 2018, FRCC had 32 registered entities in its RE division and 22 in its member services division, including duplications.

The NERC Board of Trustees holds its quarterly meeting. | © *RTO Insider*



NERC REs | *NERC*

5th RC Provider Enters the Western Grid

WECC's Branden Sudduth | © *RTO Insider*

The number of RCs in the Western Interconnection could soon number five, said Bran-

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den Sudduth, the Western Electricity Coordinating Council's vice president of reliability planning and performance analysis.

Sudduth told trustees and stakeholders that Gridforce, a Houston-based control center, has notified WECC it intends to offer RC services to its Gridforce Energy Management (GEM) balancing authority in northern Oregon. GEM, the lone undeclared BA in Peak Reliability's footprint, is a member of the Northwest Power Pool.

Sudduth said WECC and NERC are reviewing the application. Gridforce has an expected go-live date of Dec. 3, when Peak will terminate all its services. Peak last summer decided to close its doors when it became apparent its budget couldn't withstand the loss of CAISO and other members. (See *Peak Reliability to Wind Down Operations*.)

CAISO has signed up the bulk of Peak's membership, but SPP has also made inroads by offering RC services to about 12% of the legacy load, primarily along the Rocky Mountains. BC Hydro will take over for its British Columbia service territory.

WECC will begin its certification visits in March at CAISO, which will go live with RC services for its own territory July 1 and for its non-members Nov. 1. BC Hydro goes live Sept. 2, and SPP will follow Dec. 3.

Peak staff will spend about two months conducting shadow operations with each of the incoming RCs to ensure continuity and shared expertise. Peak is following a detailed project management path until it hands over its RC duties.

"We have a very unique requirement of providing services for a year while closing the organization," Peak CEO Marie Jordan said. "I haven't closed too many companies. I've closed some power plants, but we always had the mother ship above us. This is truly a territory not too many of us on the leadership have been down, so [we] want to do it right."

NERC CEO Jim Robb said he found Jordan's presentation "confidence-inspiring."

"You've made it clear the focus is on reliability, not the closure of Peak," he said.

Robb said he was concerned about the California-Arizona seam, which was a part of the 2011 Southwest outage that led to Peak's creation. Jordan said Peak is in the final stages of executing a seams agreement with CAISO but noted that remedial action schemes (RAS) may prove more important.

"I do think RAS schemes need to be as much of a focus as the seams agreements," she said.

SCE's Payne: California Prepping for 'New Abnormal'

Southern California Edison CEO Kevin Payne welcomed NERC to sunny but chilly California, saying, "You've picked a pretty interesting time to come" to the state.

Payne said the state is at the forefront of a clean energy future, pointing to its renewables-heavy grid and focus on greenhouse gas reductions.

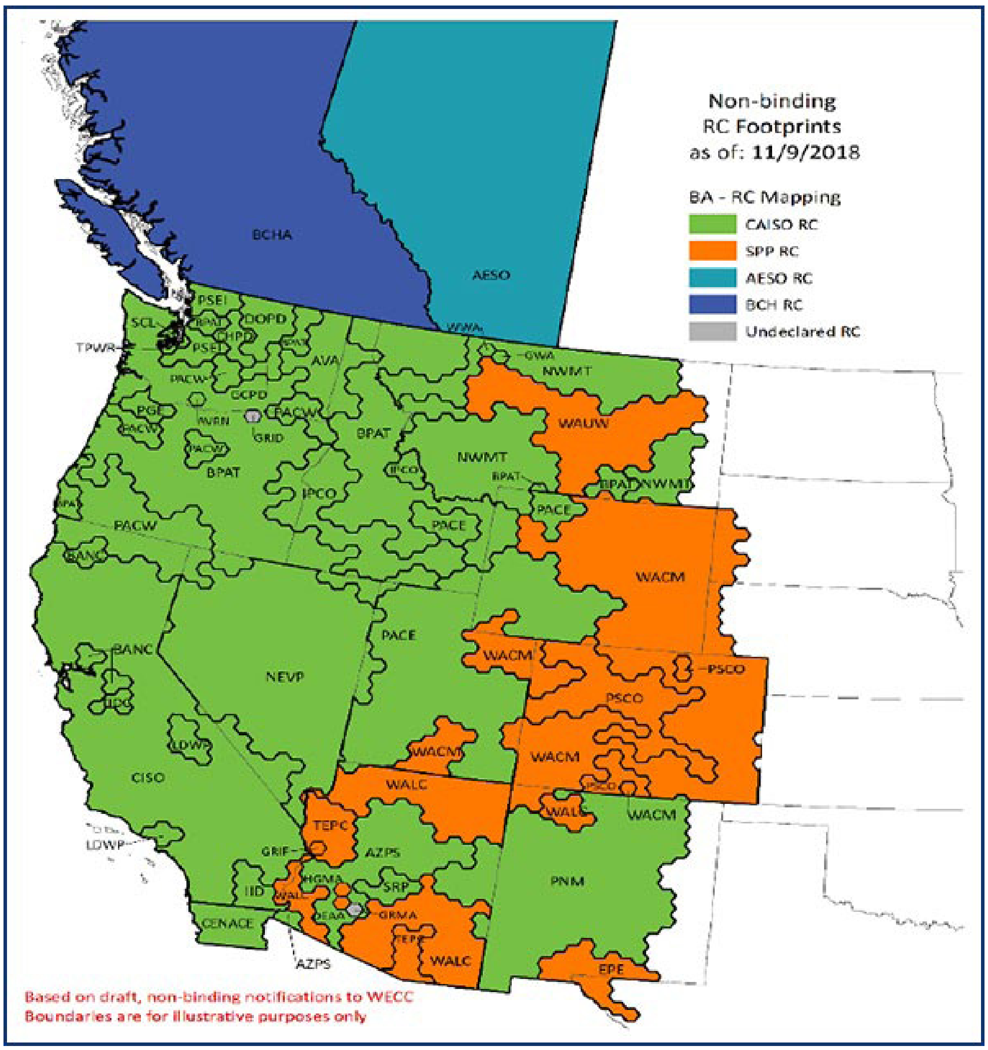
"Ironically," he said, "the very thing we've worked so hard to mitigate, climate change, is impacting us in real ways. If you're a skeptic of climate change, I guarantee you would be a believer if you lived through it like we are."

Payne said 2018 was the "most destructive, damaging and tragic fire year" in the state's history. Capped by the deadly Camp Fire, the last two years have seen Pacific Gas and Electric rack up $30 billion in potential wildfire liabilities, leading the utility to file for Chapter 11 bankruptcy reorganization. (See *PG&E Wants to Undo Contracts, Revamp Biz in Bankruptcy*.)

Former Gov. "Jerry Brown referred to the 'new abnormal,'" Payne said. "We're quickly preparing ourselves for the new abnormal."

That includes hardening the grid's infrastructure, aggressive vegetation management, installing covered conductors on thousands of miles of distribution lines and improving situational awareness by adding weather stations in the utility's service territory. Like the state's other investor-owned utilities, SCE filed a wildfire mitigation plan last week. (See *Federal Judge to Review PG&E's Wildfire Plan*.)

"We're working through all of this," Payne said.



WECC RC/BA footprint | *WECC*

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"We're getting the right policies in place, so we can move forward and focus on reliability."

NERC CEO Jim Robb confers with General Counsel Charles Berardesco. | © *RTO Insider*

Robb Honors McIntyre, LaFleur

Robb opened his regular report by asking for a moment of silence in honor of the late FERC Commissioner Kevin McIntyre, who died last month following an 18-month battle with brain cancer. (See *FERC's McIntyre Loses Cancer Battle*.)

"I'll miss his leadership at FERC. He was a rare talent," Robb said.

He also recognized Commissioner Cheryl LaFleur's recent announcement that she would not be nominated for another term on the commission. (See *LaFleur Announces Departure from FERC*.)

"That was a bit of a blow to all of us," Robb said. "She certainly took reliability as one of the pillars of her work at FERC. She's been good to us."

Robb reviewed his four priority areas with the trustees: the evolution of Western RCs; the pace of change in the resource mix; cyber and physical security; and addressing inverter-based technology. NERC defines inverter-based resources as renewable energy asynchronously connected to the grid through power electronics.

"We have to ensure these resources, which are growing at an extraordinary rate, play nicely with the rest of the grid," Robb said.

Thilly complimented Robb for his performance since stepping into NERC's leadership role last year. He noted Robb's focus on a collaborative culture, "which spreads throughout the leadership at NERC and the whole company."

"It's been a great set of changes at the right time," Thilly said. He then jokingly said, "I should mention, though, the honeymoon is almost over."

Trustees Elect Case as Vice Chair

The board elected Janice Case as its vice chair, returning her to a position she also held in 2013. Case, a trustee since 2008, serves on the Finance and Audit and Technology and Security committees. She spent 25 years with Florida Progress and its Florida Power subsidiary.

The trustees also approved amendments to Texas Reliability Entity's bylaws, following a comprehensive review to examine their consistency with the Texas Business Organizations Code, and adopted four standards as part of their quarterly standards review:

- *TPL-007-3, Transmission System Planned Performance for Geomagnetic Disturbance Events*: Adopts Canadian-specific revisions to TPL-007-2, including a new variance for Canadian entities; a method to develop alternative geomagnetic disturbance planning events; and addressing Canadian regulatory approval processes for corrective action plans.
- *CIP-008-6, Incident Reporting and Response Planning*: Modifies CIP-008 Cyber Security Incident to require reporting of cybersecurity incidents that compromise or attempt to compromise the bulk electric system, in response to FERC Order 848. Includes the Department of Homeland Security in the reporting requirements.
- *IRO-006-WECC-3, Qualified Path Unscheduled Flow (USF) Relief*: Clarifies the purpose statement by replacing "qualified transfer path" with "qualified path" and retires six terms from NERC's glossary, following a five-year review.
- *PRC-004-WECC-2*: Revises the regional reliability standard's retirement date to Jan. 1, 2021, to coincide with PRC-012-2 Remedial Actions Schemes. ■

— Tom Kleckner

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House Democrats Put Climate Change Front and Center

Continued from page 1

Cortez (N.Y.) and Sen. Ed Markey (Mass.) introducing the "Green New Deal" on Thursday.

The hearings came the same day that NASA's Goddard Institute for Space Studies and the National Oceanic and Atmospheric Administration *reported* that 2018 was the fourth hottest year on record, with the average global surface temperature for the year coming in only behind those of the previous three.

Since the 1880s, the average temperature has risen about 1 degree Celsius (1.8 degrees Fahrenheit), according to climate scientists. A report released in October by the U.N.'s Intergovernmental Panel on Climate Change said that catastrophic effects from climate change could occur as soon as 2040, when warming is expected to reach 1.5 C if the current rate continues. International efforts, such as the 2015 Paris Agreement, have so far focused on preventing only a 2-degree C increase. (See *IPCC: Urgent Action Needed to Avoid Climate Trigger*.)

The IPCC report said the impacts of climate change are already being felt in increased storm intensity, precipitation, wildfires and heat waves; rising sea levels from melting polar ice; and the nearing extinction of several species, including coral.

It was these effects that the hearings by the House Natural Resources Committee and the Energy and Commerce Committee, and their witnesses, focused on during Wednesday's hearings.

"Our communities are paying the price for years of inaction on this issue," said Rep. Raul Grijalva (D-Ariz.), chair of the Natural Resources Committee. "The massive and unprecedented storms, heat waves, fires and droughts we are experiencing are not normal. They are being made worse by climate change, and if we don't take action now, we're only at the beginning."

Climate change "goes by many different names: Sandy, Harvey, Maria, Katrina, Camp Fire," said Rep. Paul Tonko (D-N.Y.), chair of the E&C Committee's newly renamed Subcommittee on Environment and Climate Change.

Many of the Democratic committee members used their allotted time to talk about the natural disasters unique to their states; Californians especially focused on the wildfires of the past few years.

North Carolina Gov. Roy Cooper (D) (left) and Massachusetts Gov. Charlie Baker (R) testify before the House Natural Resources Committee on Feb. 6. | *© RTO Insider*

Similarly, North Carolina Gov. Roy Cooper (D) and Massachusetts Gov. Charlie Baker (R) told the Natural Resources Committee about the challenges their states have faced.

"We've weathered two so-called 500-year floods in two years and three in fewer than 20 years," Cooper said. "In the Western North Carolina mountains, volatile weather has caused mudslides, damaged infrastructure, cost apple growers valuable crops and forced ski areas to close mid-season, hurting local businesses and putting jobs in jeopardy."

"Shortly after taking office in January of 2015, the snow started falling, hard, and it didn't end until well into April," Baker said. "What was different about those storms was the sheer volume of snowfall, with record-breaking amounts in Worcester and Boston."

Most of the Natural Resources Committee's witnesses after the governors were environmental and social activists, who spoke of how climate change would hit poor and minority communities the hardest.

"As a poor and working-class community, housing displacement and disruption of services due to storms and other severe weather affect our people much more acutely compared to resident of affluent communities with more resources," said Elizabeth Yeampierre, executive director of UPROSE, an organization representing the Latino community in Brooklyn's Sunset Park neighborhood.

Only two scientists appeared on the panel, one of whom, Judith Curry, was invited by Republicans and downplayed the severity of the threat. "Both the problem and its solution have been vastly oversimplified," said Curry, president of the Climate Forecast Applications Network and former chair of the School of Earth and Atmospheric Sciences at the Georgia Institute of Technology.

Republicans Resistant

Some Republicans at the hearings questioned the science of climate change, asking questions such as whether this was the hottest the planet has been, or whether extreme heat or extreme cold kills more people.

One GOP member of the Natural Resources Committee, Louis Gohmert (Texas), asked Curry, "Do you think we're causing the polar ice caps on Mars to melt? ... That's probably the sun."

The Republicans that did not question the science criticized the economic costs and job losses associated with closing down fossil fuel plants, said renewable resources are less reliable than baseload plants and rejected proposed solutions as infeasible.

"We want a healthy environment for our children, grandchildren and their children," said Rep. Greg Walden (R-Ore.), ranking member of the E&C Committee. "But we also want the people who live in our districts and in this country today, right now, to have jobs and to be able to provide for their families. These are not mutually exclusive principles. Working together, we can develop the public policies to achieve these goals."

Rep. Rob Bishop (R-Utah), ranking member of the Natural Resources Committee, criticized Grijalva for even holding a hearing on climate change, saying it wasn't in the committee's jurisdiction. Instead, he said he wanted the committee to focus on issues such as wildfire management and National Parks maintenance.

"Are these hearings simply for those of us around the horseshoe who are going to be making legislation, or are these hearings simply for those who sit around that table in the corner so they can write cute stories?" Bishop asked, pointing to the table of reporters seated next to the witness table.

He noted that Grijalva had dubbed February "climate change month."

"I appreciate the fact you picked the shortest month of the year to do that," Bishop said.

Ironically, between the two governors at the hearing, Baker received most of the Republicans' criticism. Rep. Tom McClintock (R-Calif.) cited the failure of two wind turbines in Falmouth, Mass. The town spent about $10 million to build the turbines in 2009 and 2011. Last month, the town's Board of Selectmen *voted* to shut down the turbines and potentially

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spend millions more dismantling them after residents continually complained of noise.

Baker responded by saying, "My father always used to say that there's two things: There's doing the right thing, and then there's doing the thing right. And doing the right thing but doing it wrong doesn't necessarily solve the problem. There were a whole series of issues with a well-intended effort in Falmouth that in many respects failed because they didn't make a lot of the decisions with respect to where they sited them and how they sited them that would have made sense. ...

"I think sometimes when something doesn't go the way it should go, everybody blames the concept. Well sometimes we actually just screw up the way we implement it, and it makes the concept looks bad."

Rep. Garret Graves (R-La.) noted that his state was one of the top oil and gas producers in the country, while Massachusetts was one of the top oil and gas consumers. "How do you reconcile what you're able to do based on your economy versus the challenges in Louisiana based on what our economy is founded on?" he asked Baker.

The governor began to explain how despite productivity and population growth, the state has reduced its emissions. Graves interrupted him, saying, "I do appreciate that you all have taken steps, I do. But I also think it's important to recognize that states in some cases are fundamentally different." He pointed out that Massachusetts' electricity prices are among the highest in the U.S.

Green New Deal

Republicans at the hearings also criticized the so-called "Green New Deal," a set of goals floated by the progressive wing of the Democratic Party after last year's midterm elections.

On Thursday, Rep. Ocasio-Cortez, with 60 co-sponsors, formally introduced the idea in the House as a nonbinding *resolution*, with Sen. Markey introducing an identical resolution in the Senate.

The 14-page document calls for "a 10-year national mobilization… to achieve net-zero greenhouse gas emissions."

The resolution also contains a hodge-podge of goals, including achieving "maximum energy efficiency" from all existing buildings and "spurring massive growth in clean manufacturing in the United States and removing pollution and greenhouse gas emissions from manufacturing and industry."

"A new national, social, industrial and economic mobilization on a scale not seen since World War II and the New Deal era is a historic opportunity to create millions of good, high-wage jobs in the United States; to provide unprecedented levels of prosperity and economic security for all people of the United States; and to counteract systemic injustices," the resolution says.

Specific policy proposals to achieve these goals, however, are absent from the document. And with Republicans still in control of the Senate and the White House, any legislation attempting to codify them is almost guaranteed to fail for the next two years.

Rather, many analysts last week saw the document — and the focus on climate change among Democrats this month in general — as more of a political rallying cry for the party ahead of the 2020 elections.

"It actually will be impossible to enact a Green New Deal while Trump is in the White House, but the resolution still has two useful purposes," Michael Grunwald *wrote* in *Politico Magazine* last week. "It's primarily a political manifesto, a messaging device designed to commit the Democratic Party to treating the climate crisis like a real crisis, pressuring its presidential candidates to support radical transformation of the fossil-fueled economy. At the same time, the Green New Deal is a policy proposal — or at least a sketch of one, a way to launch a substantive debate over how Democrats will attack the crisis if they do regain the White House."

"In an increasingly social-media-driven political culture, the bill's sponsors may be looking to generate 'likes' ... rather than votes," ClearView Energy Partners said.

Several Democratic contenders for president endorsed the Green New Deal on Twitter last week, including Sens. *Cory Booker* (N.J.), *Elizabeth Warren* (Mass.), *Kamala Harris* (Calif.) and *Kirsten Gillibrand* (N.Y.).

Republicans predictably lambasted the document.

"It's a socialist manifesto that lays out a laundry list of government giveaways, including guaranteed food, housing, college, and economic security even for those who refuse to work," Sen. John Barrasso (R-Wyo.), chairman of the Environment and Public Works Committee, said in a statement. "As Democrats take a hard left turn, this radical proposal would take our growing economy off the cliff and our nation into bankruptcy. It's the first step down a dark path to socialism." ■

Several major contenders to be the Democratic nominee in the 2020 presidential election endorsed the Green New Deal last week.

FERC & Federal News

Senate EPW Committee Advances Wheeler Nomination

By Michael Brooks

The Senate Environment and Public Works Committee on Feb. 5 voted 11-10 along party lines to advance the nomination of Andrew Wheeler to be EPA administrator to the full Senate.

Wheeler, who has been serving as acting administrator since the July resignation of Scott Pruitt, was nominated to be the official head of the agency by President Trump early last month.

Republicans on the committee praised Wheeler for his work at the agency, while Democrats expressed concern about his efforts to roll back Obama administration policies on vehicle and power plant emissions — statements that largely echoed those made at his confirmation hearing Jan. 16. (See *Dems Press EPA's Wheeler on Climate at Confirmation Hearing*.)

"It brings me no joy to say that he has not done what I had hoped he would do in a number of important respects," Sen. Tom Carper (D-Del.), ranking member of the committee, said of Wheeler's tenure as acting administrator. "In fact, in many instances, Mr. Wheeler has gone further than his predecessor in his rejection of important measures that are supported by a broad list of environmentalists and industry."

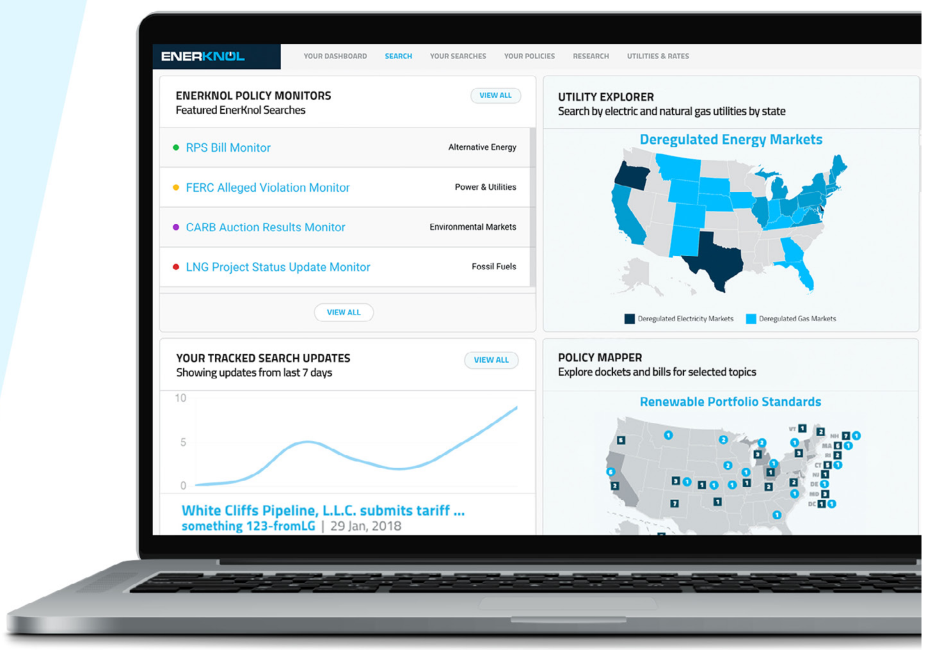
Acting EPA Administrator Andrew Wheeler at his confirmation hearing in January | © *RTO Insider*

Carper cited EPA's *proposal* to rescind its finding under the Obama administration that it is "appropriate and necessary" to regulate hazardous air pollutant emissions from power plants under Section 112 of the Clean Air Act — a finding that led to the creation of the Mercury and Air Toxics Standards.

"In this MATS rollback proposal, EPA is willfully ignoring the actual benefits of reducing air toxics that permanently damage children's brains and cause cancer, and ignoring the fact that the compliance costs were a third of what were originally estimated," Carper said.

Ahead of the vote, Sen. Shelley Moore Capito (R-W.Va.) had raised concerns about a Politico *report* that Wheeler had signed off on a plan not to regulate two toxic chemicals, PFOA and PFOS, in drinking water. She joined 19 other senators from both parties in signing a *letter* Feb. 1 urging Wheeler to reverse that decision.

"Mr. Wheeler and his staff came to my office and addressed those concerns by pledging to look at all available statutory authorities EPA has been granted by Congress to address this potential crisis," Capito said. "I intend to closely track the steps that EPA and other agencies are taking to address this public health and environmental health crisis, which has had a particular impact on West Virginians living in affected communities, to ensure that the federal government is sufficiently responsive to their concerns." ■



CAISO/WECC News

Ratepayer Advocates Request Part in PG&E Bankruptcy

By Hudson Sangree

Wildfire victims, creditors and ratepayers have been lining up to participate in the Pacific Gas and Electric bankruptcy process.

On Wednesday, consumer watchdog The Utility Reform Network sent a *letter* to federal trustees formally requesting the U.S. Bankruptcy Court in San Francisco appoint a committee of ratepayers to represent the interests of PG&E's 16 million customers in Northern and Central California. The utility filed for Chapter 11 last month, citing the more than $30 billion in claims it faced for Northern California's disastrous wildfires in 2017 and 2018. (See *Bankruptcy Only Viable Option for PG&E, Lawyer says*.)

"Ratepayers have at least as much at stake as any constituency in these Chapter 11 cases," TURN Executive Director Mark Toney said in a news release. "PG&E's electricity and gas customers generate nearly all of its revenues, and hence are its main source of income.

"With bondholders, banks and others who are represented by creditors' committees likely to assert tens of billions of dollars in claims, the court will be making critical decisions about which claims to allow and whether shareholders or consumers will pay them," Toney said. "Customers deserve a seat at the table."

The November 2018 Camp Fire was the deadliest and most destructive wildfire in California history. | *Cal Fire*

TURN's request was addressed to officials in the Justice Department's Trustee Program, which supervises the administration of bankruptcy cases. It was endorsed, TURN said, by the Public Advocates Office of the California Public Utilities Commission and by a number of public interest groups including the Sierra Club.

"Ratepayers form a unique creditor class with an interest in recovering funds owed to them," the letter says. "For example, ratepayers are entitled to the California Climate Credit (approximately $450 million for 2019), which represents proceeds from PG&E's sale of greenhouse gas allowances. Similarly, PG&E owes ratepayers $31.75 million from the calendar year 2019 Gas, Transmission and Storage proceeding as part of a settlement agreement, and $10 million from a settlement agreement regarding *ex parte* communication violations.

"PG&E also is authorized to collect in rates certain forecasted procurement costs recorded in its Energy Resource Recovery Account that could be subject to ratepayer refund. Thus, in some instances, ratepayers will be competing creditors."

A long list of would-be creditors, including fire victims, is collectively claiming in Bankruptcy Court that PG&E owes them tens of billions of dollars.

They include Karen Roberds and Anita Freeman, who claim in a lawsuit that PG&E owes $16 billion to those who lost real and personal property in the November 2018 Camp Fire in Butte County. The cause of the Camp Fire has yet to be determined, but PG&E equipment is suspected. (See *PG&E Troubles Mount After Camp Fire*.) Among the 62 other claims already filed with the Bankruptcy Court is a $10 billion claim from the owners of a restaurant in Glen Ellen. They filed a lawsuit for their losses and the losses of other businesses in Napa and Sonoma counties during the siege of wildfires in Northern California's wine country in October 2017. State investigators have blamed PG&E for starting 18 of the 21 major fires there during that time.

Dozens of smaller claims, such as a $10 million claim from a veterans' home in Napa County, have also been filed. ■

CAISO/WECC News

SCE's $1 Billion Shortfall Perturbs State Regulators

Constraints in Natural Gas Supply Cited as Cause

Continued from page 1

regulation mandates that utilities alert the PUC if their costs are likely to exceed or fall short of year-ahead projections by more than 4%.

Martha Guzman Acves | *© RTO Insider*

The company was aware it had a problem as early as May but assumed market forces would correct it, commissioners said.

"The trigger was not called, and so we're looking now at the end of the year where they incorporated this shortfall into their next year's revenue forecast," Commissioner Martha Guzman Aceves said. "This is not the type of process that we would like to see in any future year, particularly in this year. We want to be able to adjust [for] any shortfalls as they come."

It was "disappointing" SCE hadn't raised the matter in June or July, she said.

Even more alarming to the commission was the reason for the shortfall. The company *cited dramatic increases in natural gas prices* in August and November caused by supply constraints and suppliers taking advantage of safety fixes and upgrades as reasons for hiking prices.

The capacity of the Aliso Canyon natural gas storage facility, for instance, has been limited since a massive methane leak in 2015. The damage to Aliso Canyon, once the state's largest natural gas reservoir, poses challenges to generators and regulators alike. (See *FERC OK's Extension of Most Aliso Canyon Measures*.)

The PUC and California Energy Commission held a *joint workshop* Jan. 11 to discuss constrained supply and high gas prices in Southern California.

"The gas market is no longer competitive," Guzman Aceves said during Thursday's PUC voting meeting in Sacramento. Aging infrastructure and the state's increasing reliance on renewable sources of electricity are among the factors tightening gas supply, she said.

The PUC is weighing proposals to help alleviate the situation including reducing operational flow order (OFO) penalties and ensuring utilities "balance to the core," meaning they better forecast supply and demand, she said.

An SCE proposal to establish a cost-based natural gas supply procurement tariff for any CAISO-connected electric generation was "timely and innovative," Guzman Aceves said. The ISO has *endorsed* the plan.

"We have to move beyond the notion that the market itself is going to control the gas price," she said.

Commissioner Liane M. Randolph expressed support for the second phase of Thursday's proceeding to determine whether to fine SCE. That will happen at a future meeting, still to be determined.

"I think it's important to deal with the fact that the utility did not call out these increased costs in a timely manner so that we could have potentially dealt with them," Randolph said.

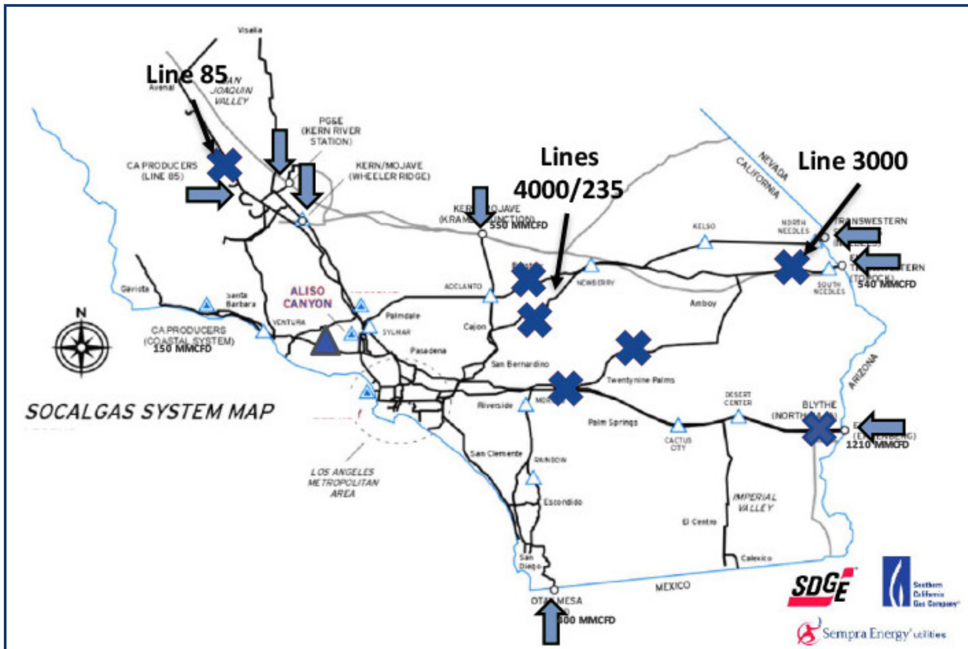
Electric ratepayers will see a roughly 5% increase in 2019 to compensate for SCE's under-collection, Commissioner Clifford Rechtschaffen said. The situation is "quite concerning," he said, especially when many "people are grappling with the collective cost of utility services" and will have trouble coping with costs that aren't predictable and stable.

Genevieve Shiroma, who was recently appointed to the PUC by Gov. Gavin Newsom, said she wanted to take action to "buffer customers" from spikes in natural gas prices.

"It's a warning signal in terms of what happened last summer," she said.

She too said she wanted to understand the reasons for Southern California Edison's "noncompliance."

"It's not some sort of discretionary thing, it seems to me," she said. "Regulations are regulations." ■



Capacity (Bcf)	Jan-15	Oct-17	Jan-19
Receipt	4.0	2.5	2.9
Withdrawal	3.6	1.0	1.0
Total	7.6	3.5	3.9

Natural gas constraints in Southern California | *California Energy Commission*

CAISO/WECC News

Federal Judge to Review PG&E's Wildfire Plan

Other IOUs also File Mitigation Plans with CPUC

By Hudson Sangree

California's investor-owned utilities submitted enhanced wildfire mitigation plans to the Public Utilities Commission on Wednesday, as required by last year's sweeping fire safety law, *SB 901*.

A federal judge said Jan. 31 he'll review *Pacific Gas and Electric's plan* before deciding whether to impose more stringent probation requirements on the utility, which was convicted of six felonies stemming from a gas line explosion in 2010. (See *Judge Postpones Strict Probation Conditions for PG&E*.)

The utility filed for Chapter 11 bankruptcy reorganization last month, citing the more than $30 billion in claims it faces for Northern California's disastrous wildfires in 2017 and 2018. (See *Bankruptcy Only Viable Option for PG&E, Lawyer says*.)

The PUC will review the IOUs' plans and hold an all-day workshop on Feb. 13 — the start of a *six-week process* of weighing and instituting measures to prevent the type of devastating fires the state has experienced in the past two years.

Those measures include de-energizing power lines in fire-prone areas during high-risk weather conditions, according to the plans submitted by PG&E and Southern California Edison. Both utilities have been blamed for massive, deadly fires in 2017 and 2018. The utilities, in turn, have cited climate change as a major factor in the disasters.

"Our state is faced with an extended and more dangerous wildfire season that demands urgent action and coordination," Sumeet Singh, head of PG&E's Community Wildfire Safety Program, said in a news release Wednesday. "While California's energy companies have a critical responsibility and role to play in reducing wildfire risk, we must all work together to keep our communities safe."

The IOUs have had to develop annual wildfire mitigation plans since 2017, but SB 901 required them to provide more detailed safety plans and seek PUC approval for their proposals. (See *California Wildfire Bill Goes to Governor*.) Under the new law, the PUC has authority to pursue enforcement actions if utilities fail to comply with the plans.

PG&E's wildfire mitigation plan includes enhanced vegetation management around power lines. | *PG&E*

Along with PG&E and SCE, San Diego Gas & Electric, CalPeco Electric, Bear Valley Electric Service and Pacific Power must participate in the PUC process.

Under Scrutiny

In PG&E's case, Judge William Alsup, of the U.S. District Court for the Northern District of California in San Francisco, said he was considering requiring the utility to inspect its entire grid for safety issues and make repairs prior to the start of the 2019 fire season this summer, a plan he was at least temporarily dissuaded from by opposition from PG&E and federal prosecutors.

Alsup is overseeing PG&E's probation in the 2010 San Bruno gas line explosion, which killed eight residents of a suburban San Francisco neighborhood. Jurors convicted the utility in 2016 of six felonies for failing to comply with safety regulations and for obstructing a federal investigation.

PG&E was placed on probation for five years. Alsup concluded in late January that it had violated the terms of its probation by failing to report a legal settlement for a 2017 wildfire in Northern California. He criticized the utility for its repeated safety failures and starting fires.

Whether PG&E's fire mitigation plan will satisfy the judge or result in further probation conditions remains to be seen. Alsup said he'd take up the matter at a future date, still to be determined. The judge gave interested parties until noon on Feb. 20 to file comments with the court regarding PG&E's fire safety plan.

That plan lays out a strategy of vegetation management, grid hardening and line inspections that goes beyond the measures PG&E began implementing in 2017 and 2018.

The company said it is expanding its power-shutoff program to include 5,500 miles of transmission lines and more than 25,000 miles of distribution lines in extreme-risk fire areas designated on the PUC's *High Fire Threat District Map*.

"Proactively turning off power is a highly complex issue with significant public safety risks on

CAISO/WECC News

both sides — all of which need to be carefully considered and addressed," Michael Lewis, senior vice president for electric operations at PG&E, said in a news release Wednesday. "We understand and appreciate that turning off the power affects first responders and the operation of critical facilities, communications systems and much more. We will only turn off power for public safety and only as a last resort to keep our customers and communities safe."

The PUC in December opened a dedicated proceeding to examine the controversial practice of de-energizing transmission lines during high-risk periods, a practice that one commission staffer said raises a "range of concerns" for the public. (See *Calif. Regulators to Scrutinize De-energization*.)

Other measures proposed by PG&E include installing 600 cameras in high-risk fire areas and adding 1,300 weather stations by 2022.

SDG&E's extensive use of cameras and weather stations — along with grid hardening and targeted power shutoffs — have helped that utility achieve one of the state's best fire-safety records in recent years and have been cited by state officials as a model for PG&E to follow.

"SDG&E's efforts to mitigate the risk of wildfire and enhance grid resilience began over a decade ago after San Diego experienced some of the most destructive wildfires in the county's history," the utility said in its *wildfire mitigation plan* filed Wednesday.

In its plan, PG&E did not say it would inspect its entire grid, as Alsup proposed, but that it would inspect 725,000 electric towers and poles across more than 30,000 miles of transmission and distribution lines in fire-threatened areas.

Disabling automatic reclosers, installing stronger poles and covering power lines — or putting some underground — are among the other measures PG&E submitted to the PUC.

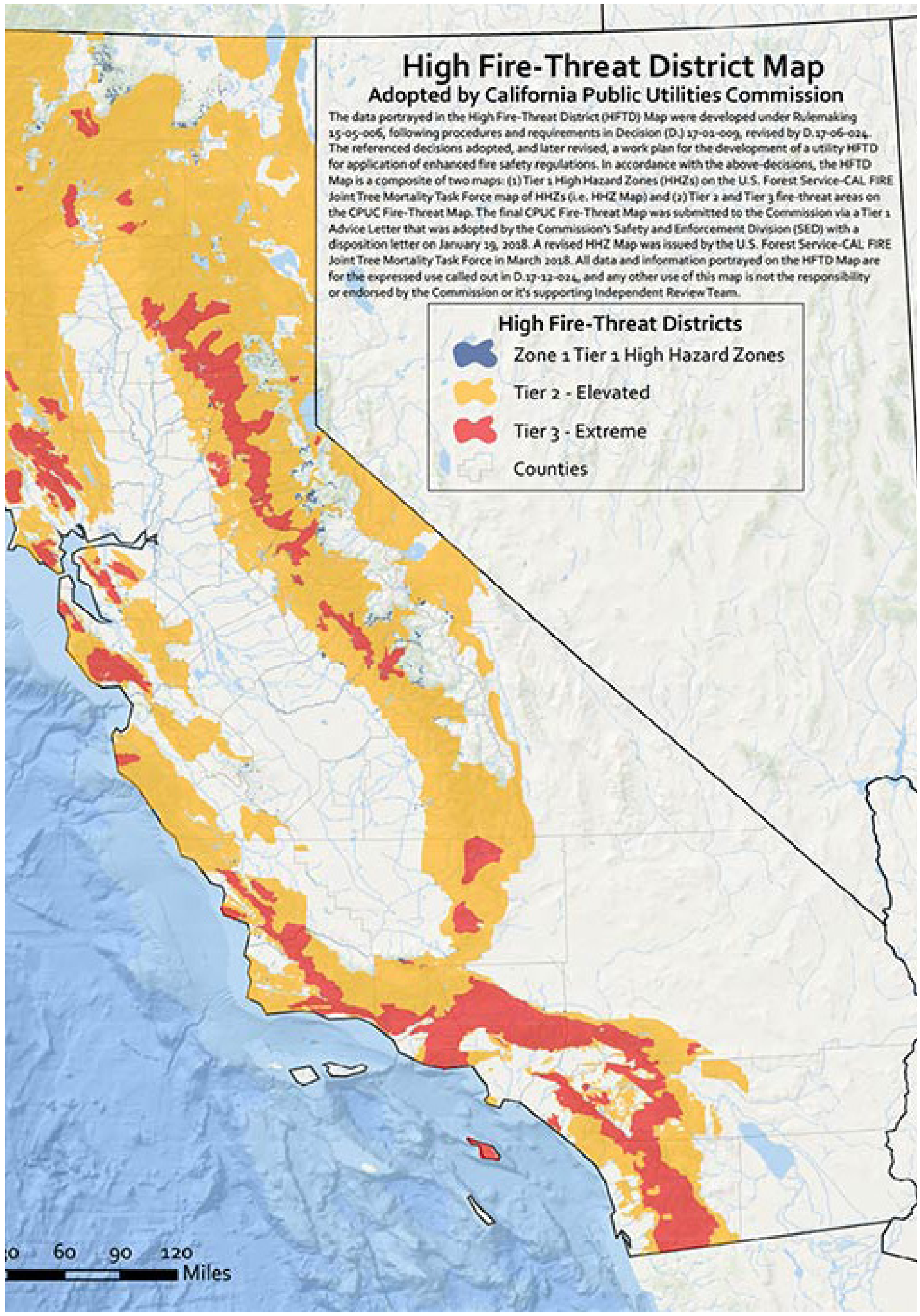
'Going Far Beyond'

SCE outlined a similar set of measures in its *fire mitigation plan*. The company proposed removing 7,500 hazardous trees, replacing conductor across 96 circuit miles and installing 7,800 fuses on unfused lines. It too plans to install additional cameras and weather stations as well as deploy "covered conductor in high fire risk areas" and explore "targeted undergrounding" of lines.

"Many of the ignitions associated with utilities are caused by objects that contact distribution power lines or conductor-to-conductor contact," the utility said in a news release. "Covered conductor has proven to be an effective mitigation measure against these ignition sources."

"We are going far beyond traditional good utility practices and incorporating advanced mitigation measures deployed in high fire risk regions around the world," Phil Herrington, SCE's senior vice president of transmission and distribution, said in a news release.

"This is an aggressive plan to protect public safety," he said. "We are implementing a variety of additional tools and technologies to advance fire safety even further throughout our system to respond to the 'new normal' of year-round wildfire risk." ■



The California Public Utilities Commission adopted its High Fire Threat District Map in January 2018. | *CPUC*

CAISO/WECC News

CAISO Raises Stakes for Intertie Non-delivery

By Hudson Sangree

The Board of Governors met Thursday at CAISO headquarters in Folsom, Calif. | *© RTO Insider*

FOLSOM, Calif. — CAISO's Board of Governors unanimously approved a proposal Thursday meant to ensure that bidders from outside the ISO deliver electricity as promised or face more stringent financial penalties.

Brad Cooper, CAISO's manager of market design policy, briefs governors on a plan to raise the stakes for bidders that don't deliver on intertie bids. | *© RTO Insider*

"The existing charge [for non-delivery] is relatively ineffective," Brad Cooper, CAISO's manager of market design policy, told the board in his *presentation*. That's because participants rarely exceed a 10% monthly threshold when the charge kicks in. The new policy does away with that threshold.

Currently, "if intertie declines are less than 10% of total transactions, no charge applies," the ISO wrote in an Aug. 15 *issue paper*. Anything more than a 10% failure-to-deliver rate can result in a charge of up to $10/MWh.

The lack of a financial incentive to follow through on bids can cause headaches, CAISO said in the paper.

"When an intertie resource receives a market award to import energy into the balancing authority area but does not deliver the awarded energy, the grid operator must maintain system balance by increasing internal supply or finding another intertie resource to import from," it said.

Grid reliability and stable pricing depend on expectations being met, Cooper said at Thursday's board meeting.

"When exports don't deliver, they can cause intertie congestion," he said. And "undelivered imports in a critical hour can have a big effect."

The revised policy is also meant to curb speculative bidding — when a market participant submits a bid and doesn't deliver because it can't find the energy it promised or can't find it at the right price.

When the 10% threshold was enacted in 2007, ISO computers couldn't distinguish between an intertie "decline" and a reliability curtailment, officials said. That meant that reliability curtailments, which weren't the fault of the market participant, could still count toward the decline charge.

The bar was set high at 10% to avoid penalizing participants who were unable to deliver because of unforeseeable problems.

Now the ISO's system can distinguish between curtailments and non-deliveries, meaning the 10% threshold can be eliminated. Instead, non-delivery charges will be assessed in 15-minute intervals and "non-delivery will be subject to a charge equal to 50% of the maximum of the 15-min market or the five-minute real-time dispatch LMP, with a $10/MWh minimum, plus any imbalance energy," according to the ISO.

Cooper said most stakeholders supported the plan as a way to reduce speculative bidding and to enhance reliability.

Severin Borenstein, *a University of California Berkeley professor* attending his first meeting as a newly appointed CAISO governor, asked planners to clarify why the charge applies to interties but not inside the ISO's system.

Keith Casey, CAISO's vice president for market and infrastructure development, explained that if an intertie bid — always scheduled an hour ahead of delivery — doesn't materialize, the ISO can't clear additional intertie energy until the next hour, but internally it can resort to the five-minute market to cover the shortfall. ■

FERC Lets New Mexico PURPA Ruling Stand

State Regulators Said QF Must be Built Before Purchase Obligation Applies

By Hudson Sangree

FERC declined to hear a complaint brought by a wind developer against the New Mexico Public Regulation Commission that sought to clarify when the Public Utility Regulatory Policies Act kicks in as a generation project moves forward in the development process (*EL19-25*).

Great Divide Wind Farm filed a petition for an enforcement action against the PRC pursuant to PURPA. The generator argued that Part 570 of the New Mexico Administrative Code, as interpreted by the commission, violated PURPA by requiring that a qualifying facility be built and ready to connect before a utility has a legally enforceable obligation to buy its power.

Great Divide said it could be difficult to obtain financing to build a project without assurances of future power purchases.

"Great Divide asserts that the effect of the New Mexico commission's requirement is to deny Great Divide the right to the legally enforceable obligation needed to provide the certainty required to obtain the financing to construct the QFs," FERC said.

FERC declined to initiate an enforcement action — legally freeing Great Divide to bring a case in federal court under PURPA.

Great Divide, a subsidiary of Scout Clean Energy in Boulder, Colo., is developing two 80-MW wind projects in southern New Mexico that will eventually connect with the El Paso Electric's grid in 2020, it said.

Great Divide Wind Farm, a subsidiary of Scout Clean Energy in Boulder, Colo., is developing a wind energy project in southwestern New Mexico. | *Scout Clean Energy*

After self-certifying the projects as QFs in August 2018, Great Divide filed a complaint before the PRC requesting it find El Paso Electric had a legally enforceable obligation to purchase the output of Great Divide's QFs starting in 2020.

The state commission issued a final order on Nov. 7, 2018, dismissing Great Divide's complaint without prejudice. It found that "a legally enforceable obligation is not created in New Mexico until the QF is ready to interconnect to the utility."

The PRC had decided a similar case, *Western Water and Power Production, Limited, LLC v. Public Service Company of New Mexico*, in which it had dismissed Western Water's complaint. In that case, the PRC also said its administrative code requires a QF to show it is ready to interconnect and deliver energy before a legally enforceable obligation is created.

FERC had declined to hear that case (*EL17-17*), letting the PRC's decision stand.

"The New Mexico commission … noted that its ruling was not declared by this commission to be contrary to PURPA and this commission's regulations," FERC said. ■

CAISO/WECC NEWS

FERC OKs Salt River Project Agreement to Join EIM

By Hudson Sangree

FERC last week approved a nonconforming agreement between CAISO and the Salt River Project (SRP) that establishes the rules governing the Arizona utility's participation in the Western Energy Imbalance Market.

Publicly owned SRP has ownership interests in more than a dozen major natural gas, coal and nuclear *generating stations*. It plans to begin participating in the EIM in April 2020.

"According to CAISO, the agreement [with SRP] differs from the pro forma EIM Entity Agreement in that it reflects the legal and regulatory issues unique to Salt River as a publicly owned utility under Section 201f of the Federal Power Act," FERC noted in its order (*ER19-539*).

CAISO's agreement with the Balancing Authority Area of Northern California (BANC) contained similar nonconforming provisions. (See *SMUD Balancing Area Inks Agreement for EIM Membership*.) FERC accepted that agreement in October 2018.

The ISO's agreements with the public entities are different in several respects from its agreements with private companies.

For instance, CAISO's agreement with SRP clarifies the utility is an exempt entity under FPA Section 201f and that it may terminate the agreement regardless of any action or inaction by FERC with respect to CAISO.

The EIM agreements with SRP and BANC contain identical indemnity and liability provisions.

And the CAISO-SRP agreement includes "language to address state law considerations unique to publicly owned utilities" that are modeled after the SPP Open Access Transmission Tariff, according to FERC.

"Salt River asserts that these negotiated terms were important to its decision to move forward with participating in the EIM because they recognize Salt River's exempt status under the FPA and provide Salt River with protection important to its ratepayers," FERC said.

"Salt River also states that the modifications made to section 10.5 of the agreement provide a process for addressing conflicts between Arizona law and the CAISO Tariff, and further notes that the process is modeled after similar processes found in the Southwest Power Pool Inc. and Midcontinent Independent System Operator Inc. tariffs."

Several entities filed motions to intervene, including the Southwest Public Power Agency (SPPA), which manages resources for *19 utility districts* in Arizona. SPPA did not oppose SRP joining the EIM, FERC said, but requested that the commission "further analyze the implications of Salt River's entry into the EIM to ensure that customers are not negatively affected."

"SPPA notes that, because Salt River is a public entity, its entry into the EIM will not be analyzed for market power implications, and that this may be the only opportunity the commission has to address issues associated with Salt River's EIM participation," FERC wrote.

But the commission rejected SPPA's comments as beyond the scope of the proceeding because the agency did not oppose SRP's entry into the EIM or raise concerns regarding its agreement with CAISO.

FERC noted that SRP would still be subject to the EIM Market Power Mitigation Procedures set forth in CAISO's Tariff and that it is the job of the ISO's Department of Market Monitoring to catch any market power issues.

"We also note Salt River's commitment to work with its wholesale energy and transmission service customers to examine current contractual relationships and assess whether they will be affected by Salt River's anticipated participation in the EIM," FERC said. "We encourage Salt River to follow through on this commitment and to work with its customers to address any issues that may arise."

The EIM has been expanding across much of the West.

Its current members include Arizona Public Service, Idaho Power, NV Energy, PacifiCorp, Portland General Electric, Puget Sound Energy and Powerex. The Sacramento Municipal Utility District plans to begin participating in the market in April 2019. The Los Angeles Department of Water and Power and Seattle City Light also are scheduled to go live in April 2020. Public Service Company of New Mexico recently received state regulators' permission to join the EIM by 2021.

The Bonneville Power Administration remains in discussions with stakeholders about joining the EIM, with a possible activation date in 2022. (See *BPA Stays on Track to Join the Western EIM*.) ■

Gila River Power Station | *SRP*

ERCOT News

Texas Public Utility Commission Briefs

Regulators Grant Preliminary Approval to Sharyland-LP&L Projects

The Texas Public Utility Commission last week issued preliminary orders approving certificates of convenience and necessity (CCNs) related to integrating a portion of Lubbock Power & Light's SPP load into the ERCOT system.

The commission *consented* to a request by the city of Lubbock and Sharyland Utilities to build a single-circuit 345-kV transmission line and associated facilities, which include an expanded LP&L switchyard. Sharyland will take care of the construction, while LP&L will own and operate the line upon its completion (Docket *48668*).

The project has a total estimated cost of $65.3 million to $90.4 million. The 18 proposed routes range between 30 and 50 miles.

During its Feb. 7 open meeting, the commission also *conditionally approved* LP&L and Sharyland's joint application to build a 345-kV transmission line and a 115-kV line that will eventually interconnect (Docket *48909*).

Sharyland will own the 115-kV line but will share ownership of part of the 345-kV line with LP&L. The former is expected to cost $49.7 million to $61.4 million and has 14 potential routes ranging between 14 and 26 miles. The latter project has an estimated cost of $88.4 million to $103.9 million and 22 possible routes ranging in length from 42 to 53 miles.

In a *memo*, PUC Chair DeAnn Walker said it was inappropriate for two separate transmission lines to be filed in a single CCN application because "it raises concerns of efficient administrative processing of the cases."

But Walker said she was willing to make an exception in LP&L's case because severance might be too difficult at this point and the project is time-sensitive. She recommended the State Office of Administrative Hearings issue separate proposals for decisions for each line and said that future CCN applications should be split apart if more than one transmission line is included.

Sharyland had proposed a $247.5 million, 345-kV project in the Texas Panhandle that overlapped with the facilities needed to integrate LP&L into ERCOT, but predated LP&L's move. ERCOT was unable to find the project as meeting economic needs.

The PUC must issue a final decision in both dockets by Sept. 20.

LP&L announced in 2015 that it intended to move about 70% of its load, currently provided through two long-term contracts with Southwestern Public Service (one of the contracts expires in 2021). The PUC approved the migration in March 2018. (See "LP&L Welcomed into ERCOT," *Texas PUC OKs Sempra-Oncor Deal, LP&L Transfer*.)

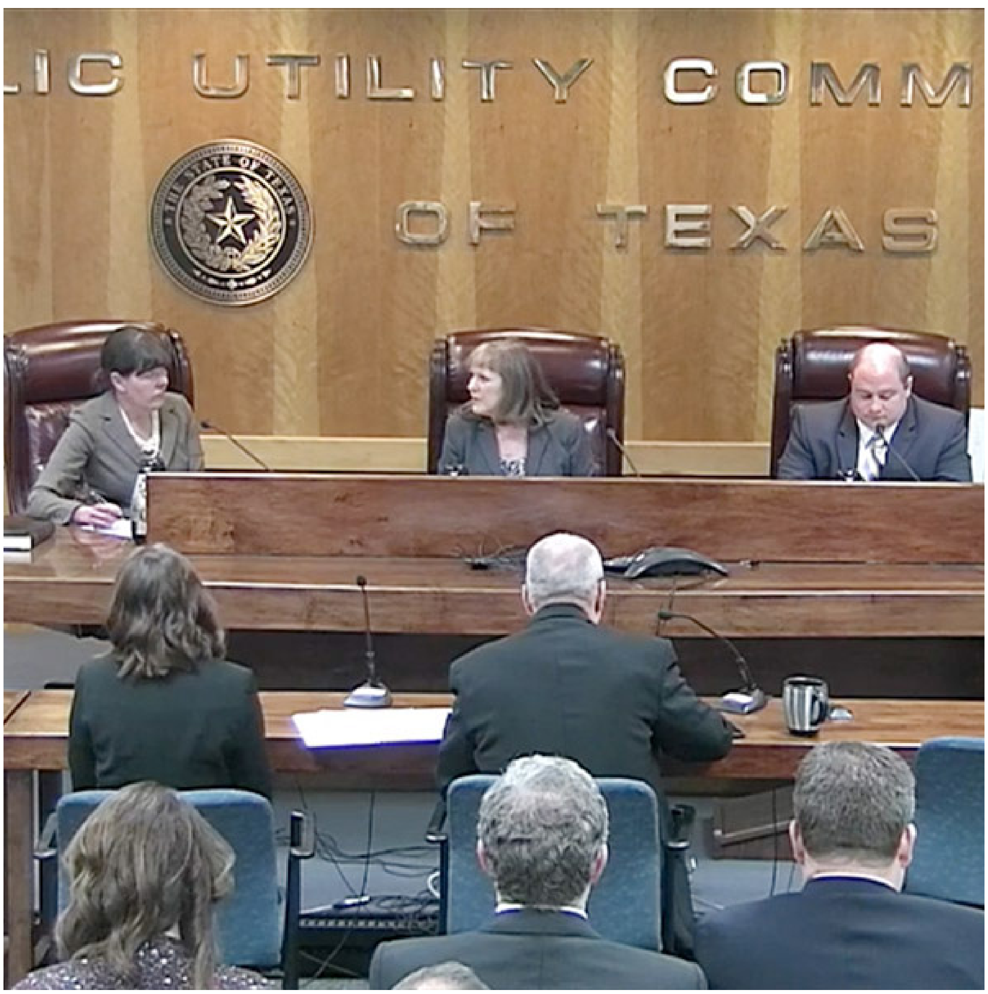
PUC Puts off Final Decision on Rayburn Country

The commission debated but put off two decisions related to Rayburn Country Electric Cooperative's proposal to move 96 MW, or about 12% of its load, from SPP into ERCOT.

At issue is Rayburn's request that the load being transferred to the Texas grid be included in the co-op's existing non-opt-in entity load zone (an area without retail choice), and that it be granted a good-cause exception from a four-year notice requirement for ERCOT Board of Directors approval. The commission also expressed concern that congestion revenue rights holders in the area might not have been properly notified (Docket *48400*).

Following the open meeting, the PUC filed a *briefing order* requesting briefs from the settlement's signatories by Feb. 26. The commission expects to file a completed order at its March 13 meeting.

Rayburn signaled its intentions to transfer the load in 2016, and late last year it reached an unopposed settlement with commission staff, Oncor and the Texas Industrial Energy Consumers that approved the transfer of the



The Texas Public Utility Commission meets in open session.

ERCOT News

load and associated facilities into ERCOT. The agreement denied the sale of transmission facilities and associated CCN rights to Lone Star Transmission.

ERCOT and SPP did not join in the agreement, but they did not oppose it either.

Separately, the commission held off on an *order* approving Rayburn's sale of a 30-mile, 138-kV line in its territory to NextEra Energy Transmission Southwest (NETS). Southwestern Electric Power Co. owns the substations at both ends of the line, and NETS plans to transfer functional control of the line to SPP when the transaction is completed (Docket *48071*).

NETS has applied to become a transmission-owning member of SPP.

"I see a lot of inefficiencies," Walker said.

Commissioner Arthur D'Andrea supports Walker's decision, but Commissioner Shelly Botkin said she had not yet formed an opinion on the "broader issues."

The PUC's final order is clouded by its 2017 ruling under different commissioners that SPS does not possess an exclusive right to construct and operate transmission facilities, including new regionally funded transmission facilities, within its service area. Former Commissioners Ken Anderson and Brandy Marty Marquez had also determined the commission had the authority to grant a certificate to an entity that will provide only transmission service outside of ERCOT (Docket *46901*).

"I don't believe we have the authority to grant this," Walker said. "I read everything in 46901. I would not have come down that way."

ERCOT General Counsel Chad Seely (center) explains the grid operator's position while discussing Rayburn Country Electric Cooperative.

"We might need time to think creatively about the best way to do this and change course," D'Andrea said.

SPS appealed the decision in November 2017 to the 459th District Court (D-1-GN-18-000208).

Staff to Study ERS Load Resources

In other actions, the PUC:

- Directed staff to open a project on emergency response service (ERS) and the potential for daily offers into the market. Walker noted some load resources are currently excluded from offering ERS because of unavailability for particular contract periods.
- Delegated authority to Executive Director John Paul Urban to sign joint comments with the Texas Commission on Environmental Quality and the Railroad Commission of Texas in response to EPA's *proposal* to eliminate the requirement that new coal-fired generation incorporate carbon-capture technology (EPA-HQ-OAR-2013-0495). The three agencies have joined together before to provide comments on similar legislation. (See *EPA Eases Rules for New Coal Generation*.)
- *Approved* CCNs for Electric Transmission Texas' 345-kV project in South Texas. The commission found the $44.8 million cost for 5 miles of 345-kV double-circuit line and a substation expansion to be reasonable. The area has incurred overloading since the 524-MW Frontera combined cycle generation facility began exporting its capacity to Mexico in 2016 (*Docket 47973*). ■

— Tom Kleckner

ISO-NE News

ISO-NE Completes FCA 13 Despite Controversy

By Michael Kuser

Killingly Energy Center natural gas combined cycle plant schematic | *Killingly Energy Center*

ISO-NE concluded Forward Capacity Auction 13 last week at the lowest clearing price in six years, moving ahead with the event despite Vineyard Wind's pre-dawn, emergency motion asking FERC to stay the process.

It was the first auction run under the Competitive Auctions with Sponsored Policy Resources (CASPR) rules, which established a secondary substitution auction in which Vineyard assumed an obligation of 54 MW from an existing resource that will retire in the relevant 2022/23 commitment period, the RTO said.

The Feb. 4 auction's preliminary clearing price of $3.80/kW-month was well under last year's clearing price of $4.63/kW-month.

"This year's auctions procured the resources needed for a reliable power system at a competitive price, while implementing new procedures to accommodate state-sponsored renewable resources," Robert Ethier, ISO-NE vice president of market operations, said in a statement. "It's our responsibility to run these auctions and our wholesale markets under the rules approved by FERC, and we fulfilled that responsibility again this year."

Resources totaling 43,641 MW, including 34,925 MW of existing capacity and 238 new resources totaling 8,716 MW, qualified to participate in this year's auction, while the regional capacity target for 2022/23 is 33,750 MW, the RTO said.

Border Issues

Vineyard's emergency motion came after the commission failed to act on the wind developer's Dec. 14 ***request*** for waiver of ISO-NE Tariff provisions requiring that the auction's renewable technology resource (RTR) exemption be granted only to resources within the borders of a New England state (*ER19-570, ER19-444*). (See *Vineyard Wind Files Emergency Motion to Stay ISO-NE Auction*.)

FERC Commissioners Cheryl LaFleur and Richard Glick issued a joint ***statement*** Feb. 4 saying that "by failing to act, the commission has introduced significant uncertainty into this auction. All parties, including New England's states, consumers and auction participants, deserve better."

A joint venture by Iberdrola and Copenhagen Infrastructure Partners, Vineyard last May won a contract to supply Massachusetts with 800 MW of offshore wind energy, and in December won another lease area off Martha's Vineyard in an auction conducted by the Bureau of Ocean Energy Management. (See *Mass. Offshore Lease Auction Nets Record $405 Million*.)

FCA #9 in 2015 for CCP 2018/2019	34,695	367	1,060	System-wide: $9.55 SEMA/RI: $17.73/new & $11.08/existing
FCA #10 in 2016 for CCP 2019/2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020/2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021/2022	34,828	514	174	$4.63

Closing at a preliminary clearing price of $3.80/kW-month, FCA 13 continues the trend of declining prices shown in the previous three auctions. | *ISO-NE*

The RTO on Wednesday reported the primary auction concluded with commitments from 34,839 MW to be available in 2022/23, leaving a surplus of 1,089 MW over the capacity requirement.

"More than 2,600 MW of new resources secured obligations during the primary and substitution auctions, including the Killingly Energy Center, a 650-MW natural gas plant under development in Connecticut, new energy efficiency and demand response resources, and imports," the RTO said.

In addition, approximately 145 MW of resources received obligations under the RTR designation, which allows a limited number of renewable resources to participate in the auction without being subject to the minimum offer price rule.

Under ISO-NE's Tariff, only renewable resources built within a New England state were eligible for the RTR exemption in FCA 13. Offshore wind projects proposed for federal waters will be eligible for the exemption in FCA 14, scheduled for February 2020. More than 300 MW remain in the RTR exemption cap and will be carried over to next year's auction, the RTO said.

The grid operator also reported that it had retained two units, Mystic 8 and 9, needed for fuel security in the 2022/23 capacity year, as approved by FERC. (See *ISO-NE Fuel Security Measures Approved*.)

The RTO said by the end of this month it will file with the commission finalized auction results, including resource-specific information. ■

ISO-NE News

Conn. Lawmakers Get, Give 2019 Energy Issues Rundown

New DEEP Commissioner Wants Wholesale Market Changes

By Michael Kuser

HARTFORD, Conn. — With fewer than four months to go in this year's session of the Connecticut General Assembly, state regulators made their cases short and sharp last week when briefing legislators on the Energy and Technology Committee.

"One of the big challenges that we face is that our wholesale electricity market is governed by FERC, and at the federal level, there has been no recognition of the need to address climate change and reduce carbon emissions through the design of the wholesale electricity market," said Katie Dykes, commissioner-designate of the Department of Energy and Environmental Protection and chair of the Public Utilities Regulatory Authority.

Dykes, nominated to be DEEP commissioner by new Gov. Ned Lamont last month, made her remarks in a *presentation* to committee members and the public at an informational forum held in the Legislative Office Building on Feb. 5.

She said that the state has had to work by itself over the past several years to ensure that an increasing volume of power is being sourced from zero-carbon and renewable resources, mainly through utility-backed contracts and state procurements.

"The challenge, though, is that in our wholesale market, we are not always getting credit for what we are procuring in these contracts and in these different mechanisms that the state has had to establish in order to correct for the failure of the wholesale markets to ensure investment in those types of resources," Dykes said.

Katie Dykes | © *RTO Insider*

The urgency of climate change requires a speedy transition to a zero-carbon electric grid, while at the same time retaining units such as Dominion Energy's Millstone nuclear plant in Waterford, which supplies a "significant share" of the region's carbon-free generation, she said.

In December, the 2,111-MW plant was one of the winning bidders in a state solicitation for nearly 12 million MWh of zero-carbon energy, securing purchase of about half its output for 10 years. (See *Conn. Zero-Carbon Awards Include Nukes, OSW, Solar*.) The PURA deemed Millstone at risk for retirement without ratepayer support, which allowed its bids to be considered in terms of environmental and grid reliability benefits, as well as price.

Dykes pointed to another challenge for New England: fuel security. The region sits at the end of the U.S. natural gas pipeline system, and while the wholesale market has driven investment into natural gas-fired power plants, it has not provided the infrastructure needed to supply those plants, she said.

"So this challenge of fuel security, a very gas-dependent wholesale electricity market that is not achieving carbon reductions, has also reached a tipping point where the ISO New England is not confident ... that they can maintain the reliability of that electric grid in the near term if certain units that do not run on natural gas were to retire," Dykes said.

"Just to be explicit," she said, ISO-NE concluded it can't run the grid without the Millstone units, the largest power plant in the region.

The RTO's fuel security *analysis* released last year actually showed the New England grid would become extremely stressed if the Millstone units were lost under a scenario of maximum retirements of coal- and oil-fired generators.

Dykes also cited a state report from a year ago that projected regional CO_2 emissions would increase by 25% if Millstone retired.

Unfortunately, Dykes said, the wholesale market is not designed to value carbon reduction and fuel security benefits, which leaves the responsibility to the state.

While Connecticut has been able to procure power at good prices, "the challenges now are in respect to ISO New England, whether its leadership is acknowledging where this future is heading us ... and whether they have the ability to adapt their market design to accept and help to achieve the carbon emission goals of the states and to address in a proactive manner the fuel security needs of our grid, or whether they're going to continue to adopt a reactive posture to the states' leadership role," Dykes said.

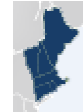
Dan Dolan, president of the New England Power Generators Association, addresses the legislator panel at the CPES dinner in Hartford on Feb. 5. | © *RTO Insider*

CPES Hears from Legislative Leaders

Later that day, the Connecticut Power and Energy Society (CPES) partnered with the state's bar association to host a panel discussion with the leaders of

Sebastian Lombardi | © *RTO Insider*

ISO-NE News



Sen. Norm Needleman | © *RTO Insider*

Rep. Charles Ferraro | © *RTO Insider*

the Energy and Technology Committee at the University of Connecticut.

Day Pitney attorney Sebastian Lombardi, who represents the New England Power Pool, moderated the panel of Rep. Charles Ferraro and Sen. Paul Formica, the ranking Republican members, and Rep. David Arconti and Sen. Norm Needleman, the Democratic co-chairs.

"We need to make sure that our public utilities are accountable," Needleman said. "We are trying to move to renewables and at the same time trying to manage rates, which seem to be pretty high in Connecticut. I have some pretty well-known issues with management decisions that Eversource [Energy] has made, but I'm going to put those on the shelf, to some extent."

Needleman last month criticized the utility for asking the state to allow it to charge ratepayers an extra $150 million to recover storm-repair costs incurred over the past two years.

A local news source, CT News Junkie, *quoted* him saying: "If Eversource had invested in effective weather responses in the past, instead of reducing staff and equipment to save money, they wouldn't need to ask for $150 million in repairs."

Rep. David Arconti | © *RTO Insider*

"My priority is to not allow one bill or issue suck up all the oxygen in the room," Arconti said, adding that technology could be a big part of the committee's agenda given the IT background of Gov. Lamont, who has yet to announce his legislative program.

Ferraro said it was important "to keep ratepayer rates as low as possible, but still keep opportunities open for procurement of renewable energy sources and letting them come to bear by also limiting the effect of subsidies that we add on the ratepayer, because if you subsidize renewable energy, eventually somebody's going to pay for it."

Lombardi said it seemed legislators were striving to find a balance between protecting ratepayers and increasing investments in procurements like offshore wind, fuel cells and grid-scale solar.

Day Pitney attorney Sebastian Lombardi moderates the panel of leaders of the Connecticut General Assembly's Energy and Technology Committee (left to right): Rep. Charles Ferraro and Sen. Paul Formica, the ranking Republican members; and Rep. David Arconti and Sen. Norm Needleman, the Democratic co-chairs. | © *RTO Insider*

Dan Dolan, president of the New England Power Generators Association, said one of the challenges is balancing how the market is structured.

"Over the years, my organization has raised a lot of concerns about carving out more and more of the market to individual resource types," Dolan said. "How do you folks think about trying to integrate some of these different attributes within the market and be able to move away from a long-term contracting structure?" He added that NEPGA is specifically "looking at putting a more meaningful price on carbon emissions" beyond the Regional Greenhouse Gas Initiative.

"I think working with our colleagues at PURA and with DEEP ... is going to be a big focus point for me," Arconti said. "They just have way more institutional knowledge at this point when it comes to striking those balances."

Needleman said he thought the idea of a carbon tax was more of a national issue and that he wouldn't know how to implement it in Connecticut without making the state less competitive, "but I would certainly support it in a broad way."

Needleman also expanded on Arconti's point of consulting with state agencies.

"Meeting Commissioner Dykes today and listening to her blew my socks off," he said. "She's very knowledgeable, and I think [Arconti] is right that we have to follow the institutional knowledge. In some of the presentations we're hearing about offshore wind, they're comparing it to other forms of generation and emphasizing that we are a coastline state and that we have the perfect area to launch a lot of work and reap the benefits."

Offshore Wind Base

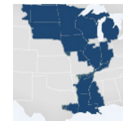
Asked what single issue he would focus on more than any other, Formica replied that he would try to make the Port of New London part of the supply chain for the growing offshore wind industry in the Northeast.

"With no overhead obstructions, it puts itself in good position to be a base of operations for offshore wind," Formica said. He recounted how years ago he had served "on a regional rail committee that created a freight line from that pier moving north" through the state and all the way to Montreal.

"There's going to be $30 million to $50 million invested in the New London pier specifically to accommodate wind," and if the state can establish some assembly or manufacturing plants for turbine components up north it could take advantage of the economic opportunities in renewables, he said.

Ferraro said people talk about New London, but "we also have offshore wind capability in Bridgeport. ... Once those industries are up and running, it's going to make sense to have the large components — the wind turbines — made right here in Connecticut in the ports, instead of shipping them from a place like Denmark, which would bring jobs and economic development to our state." ■

MISO NEWS



MISO Details 'Uncertainty' Behind Winter Max Gen Event

By Amanda Durish Cook

CARMEL, Ind. — MISO proactively managed its eighth maximum generation event in six years last month despite the difficulty of pulling together the forecast leading up to the episode, RTO staff reported last week.

Ron Arness | © *RTO Insider*

Ron Arness, MISO director of Central Region operations, said "a significant amount of uncertainty" characterized the Jan. 30-31 *event*, spurred by a polar vortex bringing record cold conditions.

High load, fuel supply issues and the possibility of equipment failure coupled with substantial voluntary load management, such as school and business closings, made load profiles uncertain over the period, Arness said. MISO called the maximum generation event beginning 2:38 a.m. ET on Jan. 30 and terminated it at 11 a.m. the following day.

"We had some extreme temperatures … and because of the actions of you as members and MISO took, we reliably maintained service. It was essential because public safety was critical at that time," Arness told stakeholders at a Feb. 7 Market Subcommittee meeting.

MISO originally forecasted a 104-GW peak load on Jan. 30, though the actual peak clocked in at 101 GW as temperatures sunk to -30 degrees Fahrenheit in some parts of the balancing area.

"We thought we were going to be short, and then we weren't," Arness said. "Even though temperatures were colder than we predicted, this voluntary load curtailment" scaled down load.

To produce its regional weather forecasts, MISO uses two separate third-party weather forecasters, both of which rely on multiple weather models.

MISO said that for much of the event, it experienced increased imports in response to its emergency conditions pricing. On Jan. 30, spot natural gas prices nearly doubled to $7.42/MMBtu and the average real-time LMP quadrupled to about $108/MWh. By Jan. 31, the real-time LMP dropped to about $49/MWh, still about double the energy price two days prior.

The RTO entered a cold weather alert on Jan. 25, an important and proactive step, Arness said. (See *MISO Maintains Reliability Through Arctic Midwest Temps*.)

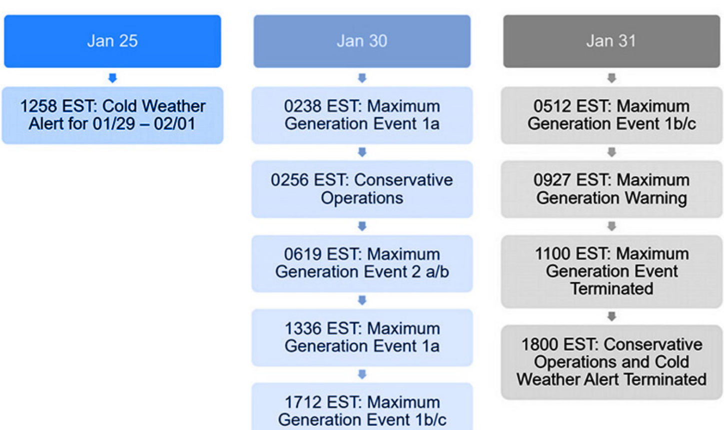
"Really the intent of that cold weather alert is so members can update their offers and unit availability," Arness said, stressing that MISO is better able to manage the market with the most accurate offer and commitment information.

"Thank you to all your companies that worked so hard to keep the lights on," Chris Miller, of FERC's Office of Energy Market Regulation, told members.

Winter Winds, but Few to Harness

MISO operators were further stymied by lower wind generation than expected during the arctic blast.

Wind output during the morning peak Jan. 30 was about 4 GW below forecast as the worst of the cold struck the Midwest. Wind output averaged 4.3 GW and 4.7 GW on Jan. 30 and 31, respectively, compared with about 13 GW for the two days prior to the event.



MISO max gen timeline | *MISO*

"It was cold and the wind was blowing, but we suspect that there were significant cold weather cutoffs. We did expect some cutoffs due to the cold — about 1 GW — but we didn't expect this magnitude," Arness said.

"This is something we have not seen since MISO has been in existence," he added.

Arness said MISO staff will continue to investigate the drop in wind output, as well as other factors during the event. The RTO will review wind generator availability during cold temperatures, including maintaining a list of wind generators that have cold weather shutoffs installed, he said.

"What we're looking for is lessons learned and to enhance our preparedness for future events," Arness said.

LMR Data Forthcoming

All told, MISO requested about 2,500 MW worth of load-modifying resources during the event. LMR performance reports are expected later.

Stakeholders asked if MISO would consider decoupling its LMR dispatch from its emergency operating procedures so LMRs can be used outside of a declared emergency. Under MISO's emergency procedures, LMRs are classified as emergency-only resources, requiring the RTO to declare an emergency before dispatching them.

Executive Director of Market Operations Shawn McFarlane said a December Tariff filing would allow MISO to issue scheduling instructions for LMRs as early as 12 hours ahead of a called emergency, allowing the resources to activate and be ready to deploy during an emergency.

Stakeholders questioned whether MISO remains confident about in that approach.

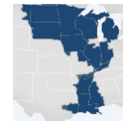
"We can't deploy emergency resources when it's not an emergency," Executive Director of Market Development Jeff Bladen said.

Arness said MISO will continue to dissect the event with stakeholders in public meetings later in February and March.

Customized Energy Solutions' David Sapper asked for a pricing analysis around the event, given that average energy prices two days before the event hovered around the usual $26/MWh and $27/MWh, even as temperatures ranged from -20 to 2 F.

MISO staff promised to return with more pricing information. ■

MISO News



FERC Declines to Re-examine White Pine SSR Refunds

By Amanda Durish Cook

White Pine power plant | Traxys

FERC last week denied the Michigan Public Service Commission's request to reconsider a decision over refunds associated with a two-year system support resource (SSR) agreement for an Upper Peninsula generating plant.

The PSC sought rehearing of a June 2018 order accepting MISO's compliance filing containing a report setting out refunds for overcharges stemming from the RTO's SSR agreement with P.M. Power Group's White Pine natural gas plant. FERC rebuffed the request Feb. 4, saying it fell outside the scope of the compliance proceeding, among other issues (*ER15-767-004*).

The proceeding originated in a 2014 decision in which FERC ordered MISO to scrap its practice of allocating SSR costs on a pro rata basis to all load-serving entities in the American Transmission Co. service territory and instead assign costs to LSEs that required the White Pine, Escanaba and Presque Isle power plants for reliability. Two years later, FERC approved MISO's plan to refund Wisconsin LSEs overcharged under the original rules of the White Pine SSR agreement. (See *FERC Upholds MISO's White Pine, Escanaba Refunds*.)

MISO was authorized to end the White Pine SSR in late 2016 after ATC submitted a transmission reconfiguration plan to split a load pocket, boosting reliability in the area. (See *MISO Allowed to End White Pine SSR*.)

The PSC argued that MISO's refund report was problematic on three counts, saying the refunds run "contrary to [FERC] precedent where the commission has traditionally denied refunds in cost allocation cases" and that they amount to "retroactive ratemaking," which is prohibited under the Federal Power Act. It also contended that MISO's corrected cost allocation methodology should only be implemented prospectively.

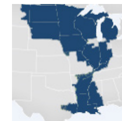
"MISO did not make clear it would seek authorization to impose retroactive surcharges in this proceeding until the filing of the refund report," the PSC added.

The state regulator further argued that FERC should not have considered the refund report final while a pending appeal of three other Upper Peninsula SSR reallocation cost methodologies was before the D.C. Circuit Court of Appeals. The court has since rejected the appeal.

In denying the PSC's rehearing request, FERC said the White Pine proceedings weren't the place to "challenge the commission's authority to order retroactive surcharges."

The "Michigan commission's challenge to the requirement for refunds and surcharges, including its arguments that the refunds and surcharges are contrary to commission precedent, the FPA, the filed rate doctrine and the rule against retroactive ratemaking, are outside the scope of this compliance proceeding and, in any event, have been rejected by the D.C. Circuit," FERC said. ■

MISO News



MISO Preliminary PRA Data up Slightly from Early Prediction

By Amanda Durish Cook

Tim Bachus | © *RTO Insider*

CARMEL, Ind. — MISO's recent resource adequacy filings with FERC will affect the timeline of an otherwise unremarkable capacity auction in terms of load forecasts, stakeholders learned last week.

MISO staff confirmed the 2019/20 Planning Resource Auction numbers haven't moved much from the previous planning year, in line with estimates made last month. (See *Early MISO PRA Data Show Little Change*.)

The RTO predicted systemwide coincident peak load will be about 122 GW for the period, up from the 121.6-GW prediction made in January for the planning year. The RTO's total zonal coincident peak now stands at 125.6 GW, up from an earlier 125.3-GW prediction.

MISO now *estimates* an almost 135-GW planning reserve margin requirement, also up from the earlier 134.4-GW estimate. Similarly, combined local resource requirements are up slightly from 152.6 GW to nearly 153 GW.

"A lot of the data is pretty close to the data we presented in January," Tim Bachus, MISO capacity market administration analyst, said during a Feb. 6 Resource Adequacy Subcommittee meeting.

Final preliminary data will be presented during the March RASC meeting. MISO will conduct its seventh annual PRA during the second week of April.

In some cases, PRA data deadlines have already passed for resources hoping to participate in the auction — particularly load-modifying resources. Generation owners were also expected to provide the Independent Market Monitor with data to calculate reference levels by Feb. 12, while load-serving entities have until Feb. 15 to request revisions to their coincident peak demand figures.

LMR Registration Confusion

Existing and new LMR registrations, usually due Feb. 1 and Feb. 15 respectively, will be due March 1 only if FERC approves a Tariff filing meant to ensure LMRs are available as promised. MISO *said* it expects FERC to rule on the matter by Feb. 20, and a more detailed LMR registration survey under the RTO's proposal is available now.

If the filing is approved, MISO will ask some LMRs with a lead time greater than two hours and that are available fewer than nine months out of the year to submit their monthly megawatt availability and a documented required notification time necessary to begin generating. (See *MISO Moves to Examine Long-term Supply Measures*.) MISO will allow LMR owners that have already registered their asset according to the current Tariff to amend their registration surveys.

If FERC rejects the filing, MISO will revert to its current LMR registration process, with LMRs not already registered disqualified from auction participation.

Some stakeholders said the competing timelines are creating confusion. Others pointed out that several LMRs have already submitted registration in accordance with MISO's current Tariff. MISO staff said it would reopen registrations to make sure the new data requirements are met if approved.

MISO Manager of Capacity Market Administration Eric Thoms reassured stakeholders that, should FERC reject the filing, the RTO would not use LMRs' additional data, and the current process would stand without change.

Stakeholders asked if MISO was satisfied with this year's load forecast data supplied by LSEs.

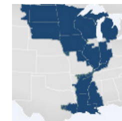
"There are always a few numbers that might be outside the curve," Bachus said, adding that MISO determined there were good reasons for the discrepancies after reaching out to LSEs.

"In the end, there were no concerns about any numbers that may have seemed out of line," Bachus said.

As in years past, stakeholders continued to question why MISO combines the forecast data for Iowa and Missouri in Local Resource Zones 3 and 5 and all of MISO South. The RTO has long combined PRA data in zones where pivotal suppliers are sparse and their private information could be revealed. Stakeholders again asked MISO to separate the data by zone to provide a clearer picture of resource adequacy.

Meanwhile, MISO will on March 25 send out its annual resource adequacy survey in cooperation with the Organization of MISO States. Completed surveys are *due* from LSEs and independent power producers by April 15. The RTO will present results in June and July. ■

MISO News



Stakeholders Seek Slowdown on MISO RAN Project

By Amanda Durish Cook

CARMEL, Ind. — Stakeholders are urging MISO to slow down on bigger ideas to address its disjointed resource availability and need (RAN) effort until it can measure the effects of three smaller related filings pending before FERC.

For the remainder of this year and through 2020, MISO's Market Subcommittee and Resource Adequacy Subcommittee will discuss long-term methods of shoring up resource availability as reserve margins decline.

Speaking at a Feb. 5 RASC meeting, MISO Director of Resource Adequacy Coordination Laura Rauch said most of the discussions will take place independently, though the RTO may schedule joint MSC and RASC meetings on the topic.

MISO recently filed new near-term rules for load-modifying resources (LMRs) and planned outages to buy time for more comprehensive solutions. Up to the filings, stakeholders had also urged a slower approach to developing those rules. (See ***MISO Moves to Examine Long-term Supply Measures*** and ***MISO Files New Planned Outage Rules***.)

Nearly a month later, MISO is ready to take on the broader proposals, which may include changes to the annual capacity auction, loss-of-load expectation study and capacity accreditations. It said the second and third phases of the project will address "gaps in the efficient conversion of committed capacity to energy."

So far, a number of stakeholders maintain that MISO's timeline on the multifaceted project is too aggressive, with some saying that it should evaluate the effects of its LMR and outage filings before it moves on to long-term remedies.

"A lot of comments focused on that we're moving too fast; the two phases are being rushed. ... We do plan on working through the stakeholder process over the next few months to make sure that any solution is vetted," MISO planning adviser Davey Lopez told stakeholders at a Feb. 6 RASC meeting.

Davey Lopez | *© RTO Insider*

MISO Executive Director of Market Development Jeff Bladen said the RTO is starting conversations now with an eye on implementing long-term solutions within a year and a half.

Jeff Bladen answers stakeholder questions from the audience | © *RTO Insider*

"This is a marathon, not a sprint," Bladen said.

"At what point does MISO declare victory? Is there some point where there's enough of a buffer that MISO stops making changes?" asked Bill Booth, consultant to the Mississippi Public Service Commission, adding, "We're moving at warp speed."

Rauch said the RTO will continue determining whether improvements are enough to maintain reliability by gauging whether increasingly frequent maximum generation events are more accurately predicted and managed.

"The goal is not to eliminate all emergency conditions. That's part of our normal operations," Rauch added.

Lopez said MISO plans to analyze the impacts of the LMR and outage filings and compare upcoming capacity auction results with prior year auctions before it proposes any changes to capacity accreditation. MISO has said it will investigate adjusting capacity accreditation "based on the ability to resolve resource risk."

Seasonal LOLE?

Lopez asked for stakeholders' written feedback on the usefulness of a seasonal capacity construct, an idea long pondered in MISO. The RTO last proposed a two-season capacity auction in mid-2016 before talks stalled, and stakeholder appetite for a revised proposal resurfaced last year.

Some stakeholders said MISO's loss-of-load expectation (LOLE) study could use improvement if the RTO moves to a capacity auction structure based on either two or four seasons.

Multiple stakeholders said MISO should first examine possible technical changes to the LOLE study — which is based on an annual summer peak — in light of moving to a one-day-in-10-year reliability standard based on seasons.

"Without basic technical LOLE work, I don't know if we can start the discussion. ... I think that needs to be upfront before we can even start on the policy of this," Minnesota Public Utilities Commission staff member Hwikwom Ham said. "Software can spit out any number you want to. That doesn't mean you're getting the right result on your statistical theory."

Rauch said MISO would have to conduct research to determine which LOLE inputs and calculations would be appropriate.

A seasonal construct also raises the question of whether interconnection service should be divided by seasonal availability, Lopez said. He also said stakeholders should consider whether they prefer a single annual action with seasonal offers or multiple separate seasonal auctions.

Independent Market Monitor staff Michael Chiasson said a seasonal auction would satisfy some IMM recommendations, particularly its longstanding recommendation that resources be accredited according to their ability to deliver across varying conditions.

A day later at a Feb. 7 Market Subcommittee meeting, Bladen insisted that MISO doesn't currently have a load forecasting problem, but an uncertain resource availability problem.

"It's not the uncertainty itself that's increasing. It's the nominal impact of that uncertainty that's increasing," Bladen said.

Beyond LMRs

Stakeholders also asked if MISO will begin focusing on other resources besides LMRs, inquiring about possible changes to the modeling or accreditation of baseload or intermittent resources.

MISO staff said a wide array of changes are on the table and that the RTO might also consider incentives for LMRs with shorter lead times.

"We're going to let the advice from this committee guide us," Bladen told the RASC. He later added that while stakeholders and MISO may not have the time to examine upwards of 30 solutions, there's still a "veritable menu" of options.

MISO said stakeholders may want the RTO to further incentivize economic demand response and improve its scarcity price formation. It also said it could reduce capacity accreditation for long-lead resources.

MISO plans to continue the RAN discussion at the March RASC and MSC meetings. ■

NYISO News

NYPSC Approves $32 Million for EV Fast Chargers

By Michael Kuser

EV Charger | *© RTO Insider*

The New York Public Service Commission on Thursday authorized utilities to spend $31.6 million to build up to 1,075 fast-charging electric vehicle stations and recover costs from ratepayers over seven years (*18-E-0138*).

The program is intended to help spur sales of EVs by reducing people's "range anxiety" — the fear of running out of juice on the road — and to achieve Gov. Andrew Cuomo's Charge NY goal of 10,000 EV charging stations by the end of 2021 and 800,000 zero-emission vehicles by 2025.

The commission's Feb. 8 *order* outlines a flow of actions, including annual reviews, that "are smart and timely steps to enable new and needed infrastructure at sensible budgets and at sensible payment structures," PSC Chairman John B. Rhodes said. "It puts a wide range of partners in a position to invest their money in our agenda for the benefit of all New Yorkers."

The PSC last April approved a seven-year tariff for Consolidated Edison's quick-charging station program (*17-E-0814*). (See *NYPSC OKs Con Ed EV Charging Program, REV Initiatives*.)

In a related case (*18-E-0206*), the PSC in November rejected tariff filings for residential EV charging from all the major utilities in the state and ordered them to file revisions that implement time-of-use rates equal to the traditional residential customer charge. (See *NYPSC OKs CCA, Rejects Residential EV Charging Tariffs*.)

The new proceeding grew out of a joint *petition* last April by the New York Power Authority, along with the state's Department of Environmental Conservation, Department of Transportation and Thruway Authority, seeking rate relief for DC fast-charging (DCFC) facilities for EVs.

The state's Department of Public Service held a technical conference on the issue last summer, and in November the utilities joined the state agencies in filing a consensus *proposal* for the program.

Mary Ann Sorrentino, N.Y. DPS

Rate Design

Mary Ann Sorrentino, chief of electric rates and tariffs for the DPS, testified that rate design was the PSC's main concern.

"To capture cost savings from potential technology cost declines, the draft order requires that initial incentive amounts be tied to the year in which the station qualifies for the program," she said.

Sorrentino said plugs must have a 50-kW minimum charging capability to qualify for the program and that higher incentives will be provided to plugs with a minimum simultaneous charging capability of 75 kW.

Within 90 days of Thursday's order, the New York State Energy Research and Development Authority must disburse the $31.6 million in unencumbered legacy system benefits charge (SBC) funds to the state's six regulated utilities in the following amounts: Con Ed ($6.4 million); Orange and Rockland Utilities ($1.66 million); Central Hudson Gas & Electric ($4.4 million); Niagara Mohawk Power ($9 million); New York State Electric and Gas ($5.1 million); and Rochester Gas & Electric ($5 million).

The *SBC* provides funding for NYSERDA programs targeting energy efficiency, research and development and the low-income sector.

Commissioner Diane Burman

Commissioner Diane Burman brought up the $128 million New York received as its share of Volkswagen's national settlement for flagrant emissions standards violations, which the state has earmarked for clean transportation measures such as promoting EV use.

"I understand there's a separate track for that;

Continued on page 27

NYISO News

NYISO Public Policy Tx Revisions Approved

By Michael Kuser

FERC on Friday approved NYISO's proposed Tariff revisions "to clarify, streamline and enhance" its public policy transmission planning process.

The commission's Feb. 8 order accepted changes that include a provision to hold a technical conference prior to issuing a solicitation on a public policy transmission need (PPTN). Another provision removes a requirement that the ISO wait to evaluate and select a project until the New York Public Service Commission issues an order confirming a PPTN (*ER19-528*).

FERC noted that the ISO's related planning report, issued following project evaluation, "will identify the information and sources relied upon" in addition to describing "assumptions, inputs, methodologies and results, which will allow developers to see how NYISO applied all of the metrics in selecting the more efficient or cost-effective solution" to any PPTN.

The commission found the Tariff changes additionally ensure transparency by requiring that a related project description in an interconnection application or request contain "the same electrical characteristics, related modeling information and contingency information to perform all analyses, including thermal, voltage, stability, short circuit and transfer limit analysis" as the project information submitted in the planning process.

The changes also call for NYISO to post a brief description of project proposals on its website within five business days after the close of the solicitation window. It must also make available, at least 30 calendar days prior to the viability and sufficiency assessment, project proposals with confidential information redacted.

Under the new rules, developers must provide a major milestone schedule and an expected in-service date for proposals, and also provide a transmission and substation routing study and demonstrate that they have or will have the property rights necessary to implement the project.

The new rules became effective Feb. 10.

NYISO's Board of Directors in December issued a mixed decision on the ISO Management Committee's selections for a major PPTN — the AC Public Policy Transmission Project — accepting the committee's recommendation for one segment, but switching the other to a competing proposal by National Grid and New York Transco. (See *NYISO Board Partially Reverses AC Tx Project Selection*.) ■

NYPSC Approves $32 Million for EV Fast Chargers

Continued from page 26

I'm not looking to get involved in stuff that's outside our jurisdiction," Burman said. "To the extent that it complements us ... it is extremely important that we are complementing each other in a way that makes sense. Here we're talking about taking unencumbered legacy funds that seem to never, ever be ending over at NYSERDA, and utilizing them now for part of this."

The state estimates EV sales were up 50% last year from 2017, with more than 43,000 EVs on the road by October, one-third of them battery electric and the rest plug-in hybrids.

Commissioner Gregg C. Sayre

"EVs, as is well known, have a chicken-and-egg problem," Commissioner Gregg C. Sayre said. "Chargers aren't being built because there aren't enough EVs, and EVs aren't being bought because there aren't enough chargers. This item helps us get out of that cycle."

Notable Differences

The PSC decided to minimize some of the "notable differences" contained in the consensus proposal.

"For example, pursuant to the consensus proposal, the Con Ed and Orange and Rockland per-plug incentives were to provide a combined benefit in conjunction with delivery rate discounts offered under the Business Incentive Rate [BIR] and Economic Development Rate, respectively, whereas the other utilities' per-plug incentives were designed assuming that DCFC stations will not receive other delivery rate discounts," Sorrentino said.

The Con Ed and O&R proposals were also unique in that they contained a separate load-factor incentive whereby station owners would earn a $500 incentive annually for achieving a 5% load factor, and $1,500 annually for achieving a 10% load factor, she said.

The commission found "the load-factor incentive to be unnecessary at this time, as station owners have a natural incentive to maximize station utilization," Sorrentino said.

Under Con Ed's tariff, the BIR was available to owners of EV quick-charging stations with a minimum aggregate charging capacity of 100 kW and a maximum aggregate demand of 2,000 kW in New York City and Westchester County.


Bridget Woebbe, N.Y. DPS

"This BIR has been open to electric vehicle quick-charging station developers since April, and that market has not materialized," testified Bridget Woebbe, assistant counsel for the DPS. "Removing the restrictions really allows site hosts that are providing a direct capital investment by building the critical infrastructure to receive the appropriate incentive to deliver the public good of the DCFC." ■

NYISO NEWS

NYISO Ponders Response to Carbon Charge Shortfalls

By Michael Kuser

RENSSELAER, N.Y. — NYISO stakeholders last week debated the need to consider the improbable: that a proposed carbon pricing scheme could occasionally leave New York electricity consumers paying into the carbon revenue account rather than drawing from it.

ISO staff prompted the discussion with a proposal for responding to such an event in the wholesale market.

"In the unlikely circumstance the carbon residual is negative, the Tariff will include rules for allocating these carbon residual shortfalls to" load-serving entities, Ethan D. Avallone, NYISO senior energy market design specialist, *told* the Market Issues Working Group on Feb. 4.

The total carbon residual represents carbon charges collected from internal generators plus those collected from imports, minus carbon payments to exports, he said. Wheel-through transactions are netted out of the total. (See *NYISO Looks at Carbon Charge Tariff Impacts, Residuals*.)

A negative residual would occur when carbon payments exceed carbon charge collections, which could arise when an emitting resource is on the margin while much of the energy being delivered is being provided by zero-carbon resources, Avallone said. Dispatching that marginal emitting resource for export would trigger a payment to the resource, but the ISO wouldn't be collecting charges to cover that payment in the interval.

To ensure that benefits are spread equitably across the state, NYISO has recommended allocating carbon charge residuals proportionally to consumers across all zones, Avallone said. But in instances when it must cover a potential negative balance in the residual account, the ISO is proposing to allocate costs back to load based on load-ratio share.

Avallone said the load-ratio share methodology makes more sense than a proportional one in dealing with negative residuals. It would prevent piling additional costs on load zones with higher locational-based marginal prices and also avoid further cost shifts.

Load in zones with higher prices will already bear a higher impact from the carbon charges in their energy payment. If the proportional carbon allocation were used, those zones would also carry a higher proportional burden for a negative residual, Avallone said.

Statewide Issue

"It's important to note that any shortfall would be a statewide issue, because the calculation includes both imports and exports," Avallone said.

NYISO's principal economist, Nicole Bouchez, explained that renewables tend to be on the margin upstate, but that the negative residual phenomenon would become a statewide issue when no emitting generators are producing, an emitting resource is marginal and exports are occurring, which is unlikely with the current generation fleet.

"Over time, as you get more and more renewables, it might happen more often," Bouchez said.

Asked if the ISO had done any analysis on the shortfall issue, Avallone replied, "No formal analysis; just the observation that it is possible to be a net exporter today around midnight when you have many renewables on."

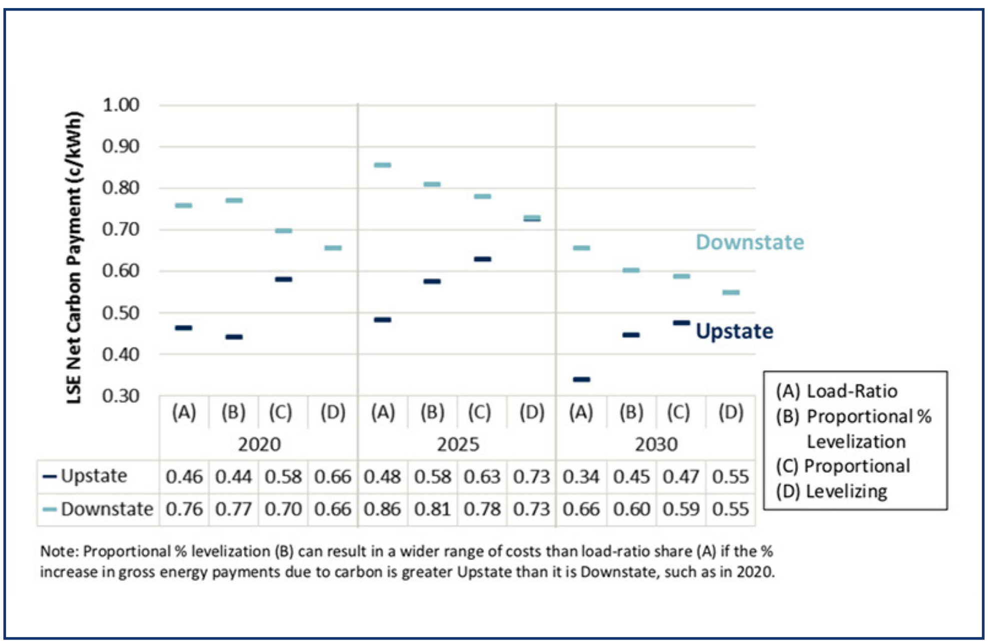
Mark Reeder, representing the Alliance for Clean Energy New York, said the analysis could be done with data from previous multiarea production simulation runs.

"You'd have to have downstate having almost no carbon emissions to have the shortfall situation arise," Reeder said.

Upon implementation, the ISO would expect the "majority of hours" to see a credit to load, calculated on an hourly basis, Avallone said, but some stakeholders did not like the fuzziness of the term.

Mark Younger of Hudson Energy Economics pointed out that there would be carbon revenues both from emitting resources on the margin and those running at minimum load. He said NYISO had "undersold" the statistical improbability of getting a residual shortfall, which would require payments to exports to exceed the carbon revenues from all resources in the market, an unusual occurrence. The ISO would need to show a hypothetical example of potential negative residuals occurring when exports are coupled with generators running at minimum carbon generation, he said.

NYISO's schedule for carbon pricing calls for discussing calculating its impact on LBMP and identifying marginal units on Feb. 15, Tariff revisions on Feb. 28 and March 18, and carbon bid adjustment for opportunity cost resources on March 4. Opportunity cost resources represent carbon-free resources able to store energy and structure their bids to achieve delivery schedules during the most economic periods of the day. (See *NYISO Plan Revises Treatment of Carbon-Free Resources*.) ■



	2020 (A)	2020 (B)	2020 (C)	2020 (D)	2025 (A)	2025 (B)	2025 (C)	2025 (D)	2030 (A)	2030 (B)	2030 (C)	2030 (D)
Upstate	0.46	0.44	0.58	0.66	0.48	0.58	0.63	0.73	0.34	0.45	0.47	0.55
Downstate	0.76	0.77	0.70	0.66	0.86	0.81	0.78	0.73	0.66	0.60	0.59	0.55

The graph shows how the proportional method (C) of allocating carbon charge residuals results in an equitable impact across load zones without levelizing costs. | *Brattle Group*

PJM News

Last Gasp Bid on PJM Price Formation Falls Short

Board to File Plan Without Stakeholder Consensus

By Christen Smith

PJM's Stu Bresler (left) and Adam Keech | *© RTO Insider*

VALLEY FORGE, Pa. — PJM stakeholders failed again to reach agreement on energy price formation rules Wednesday, as a last-ditch effort at compromise fell short in a 62% sector-weighted vote.

As a result, Stu Bresler, PJM's senior vice president of operations and markets, said staff will move forward with recommendations to the Board of Managers this week for a unilateral Federal Power Act Section 206 filing with FERC.

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

Calpine's David "Scarp" Scarpignato led an informal group of stakeholders in attempting to piece together a compromise after five proposals fell short of the two-thirds threshold at the Jan. 24 Markets and Reliability Committee meeting. (See *PJM Stakeholders Deadlock on Energy Price Formation*.)

"The proposal is not any individual company position and all parties moved off their underlying ideologies," Scarp said in describing the proposal at a special Members Committee meeting.

The *alternative plan* included many of the revisions in Vistra Energy's proposed modifications to PJM staff's plan, which received 41% support at the MRC.

Like the Vistra proposal, the latest compromise included a concession by load interests to eliminate an energy and ancillary services (E&AS) revenue offset in the capacity market.

The Vistra proposal also included a concession by suppliers to phase in an increase in the penalty factor, beginning at $850/MWh for all products in all hours for the first two years. After that, the factor would increase to $1,000 to $2,000/MWh during hot or cold weather alerts.

The plan capped nested reserve pricing at $4,000/MWh — one-third the level in PJM's proposal — and reduced the 30-minute time horizon on the operating reserve demand curve (ORDC) error distribution to 20 minutes.

Generators also agreed to remove about 30 outlier generators from the forced outage risk assumption, a concession to criticism by the Independent Market Monitor.

The proposal also would have boosted demand response's maximum share of the synchronized reserve requirement to 50% from the current 33%.

Bresler said PJM's preliminary calculations suggested the compromise would have reduced the increase in energy and reserve prices by an "order of magnitude … of about 25%" compared with the RTO's proposal.

While the compromises *won* support by 43% of the End-use Customers sector, it was not enough to overcome unanimous opposition by the Electric Distributors, which voted 30-0 in opposition. Transmission Owners (100%), Generation Owners (96%) and Other Suppliers (76%) overwhelmingly supported the plan.

Before the vote, stakeholders thanked Scarp for his efforts to build a compromise.

"I think it was some of the more open and honest stakeholder discussions that I've seen," said Adrien Ford of Old Dominion Electric Cooperative. "I think Scarp did a great job of pulling people together across different sectors."

"Everyone who supports that has given blood," Direct Energy's Marji Philips said. "No one is extremely happy."

"I think everyone is uncomfortable with some of the aspects presented here," agreed Susan Bruce, representing the PJM Industrial Customers Coalition. "It was truly an exercise in mutual gains and consensus building. The best of Manual 34 in a microcosm." Bruce said the ICC voted in favor as a measure of "risk management" because of the higher costs in the PJM plan.

Next Steps

Bresler said after the vote he expects staff will recommend the board file PJM's proposal — which includes an immediate increase to a $2,000 penalty factor per reserve product — though he said stakeholder discussions helped evolve some of the RTO's thinking since December.

"I don't think our recommendation will have any sort of reduction in the penalty factors on the ORDCs," he said. "We think $2,000 is the best answer."

But he said staff "heard some compelling arguments [against] adjustments to ancillary and energy services … so that will all bake into our thinking as far as our recommendation to the board is concerned."

In a letter to members, the board had included the E&AS adjustment as a transitional mechanism it thought should be included in the plan. Suppliers, however, said the change would be speculative.

"We haven't done it in the past," Bresler said of the adjustment. "We'll see what direction we get from the board."

The board is expected to decide on its path forward at its Feb. 12 meeting, following a Feb. 11 Liaison Committee meeting. Bresler said a FERC filing is likely in early to mid-March with June 1, 2020, as a "reasonable target" date for implementation. ■

PJM News

PJM Operating Committee Briefs

Utilities Question Primary Frequency Response Calculation

VALLEY FORGE, Pa. — PJM's Operating Committee last week endorsed revisions to Manual 12: Balancing Operations over the opposition of FirstEnergy, which challenged the manual's formula for judging primary frequency response performance.

Under the *formula* included in a newly added Section 3.6 of the manual, PJM will evaluate generators' performance during events in which the system frequency goes outside a +/-40-MHz deadband for 60 continuous seconds and the minimum or maximum frequency reaches +/-53 MHz.

PJM's Danielle Croop, senior engineer of operation analysis and compliance, said the formula was vetted by the Primary Frequency Response Task Force based on NERC criteria.

"We opened up our criteria to be more lenient … and we are catching as much performance as we can," she said. "We are open to changing the formula."


Jim Benchek, FirstEnergy | © *RTO Insider*

Jim Benchek, FERC and RTO market technical support at FirstEnergy, said the formula is too sensitive and could result in false failures. "We prefer not to have the formula memorialized in the manual at this time."

He added that his company remains committed to providing PFR.

The manual *changes* were endorsed despite 24 objections by FirstEnergy and Duke Energy and 20 abstentions.

At the January OC meeting, American Electric Power noted that FERC's order did not require scoring of PFR and said PJM had little stakeholder support for it. (See "*The Right Metric on Frequency Respons*e?" *PJM Operating Committee Briefs: Jan. 8, 2019*.)

PJM Continues Review of Non-retail BTM Generation Business Rules

PJM provided stakeholders additional background on a proposed *problem statement* and *issue charge* that could result in revised rules for non-retail behind-the-meter generation (NRBTMG).


Terri Esterly, PJM | © *RTO Insider*

Terri Esterly, PJM's senior lead engineer for capacity market operations, said business rules in the RTO's governing documents need modifications to address the growth of distributed generation. NRBTMG refers to resources used by municipal electric systems, electric cooperatives or electric distribution companies to serve load; they do not participate in PJM markets but can be netted against load to reduce certain charges.

Esterly said it's been nearly 15 years since a settlement agreement established rules for NRBTMG — long before the RTO implemented the Reliability Pricing Model and Capacity Performance and took on several utility companies as members, including American Transmission Systems Inc., East Kentucky Power Cooperative and Duke Energy's Ohio and Kentucky divisions.

Under existing rules, NRBTMG must operate at full output during the first 10 instances of maximum emergency generation conditions between Nov. 1 and Oct. 31. However, it's not clear in Manual 13: Emergency Operations what procedures trigger this requirement.

Likewise, the RTO doesn't know how close the grid is to exceeding the 3,000-MW NRBTMG cap set in 2005. PJM estimates put this value closer to 4,600 MW, but incomplete public records make it difficult to determine an exact figure.

PJM first proposed reviewing NRBTMG rules during a Jan. 8 Operating Committee meeting and faced suspicion from several municipal utilities and cooperatives. (See *Munis Wary of PJM Rules on Non-Retail BTM Generation*.) Stakeholders at last week's meeting requested more firm data surrounding megawatt estimates before moving forward in the process.

Committee Endorses Updates to TO/TOP Matrix

Stakeholders unanimously endorsed *changes* to the Transmission Owners/Transmission Operator Matrix to document their responsibilities under new NERC reliability standards.

The matrix is an index between the PJM manuals and NERC reliability standards that spells out which responsibilities are PJM's as the TOP and which are assigned to member TOs.

Version 13 of the matrix adds references for reliability standards:

- TOP-001-4 R20 and R21, which took effect in July 2018;
- VAR-001-5, which took effect Jan. 1;
- EOP-004-4, EOP-005-3 and EOP-008-2, which take effect April 1; and
- PER-003-2, which takes effect July 1.

The endorsed changes head to the Transmission Owners Agreement Administrative Committee for approval.

Incremental RFP Window for New Black Start Resources Closes May 1

PJM opened a window for new black start resources in the Baltimore Gas and Electric and Potomac Electric Power Co. (PEPCO) zones on Feb. 1.

PJM initiated the new *request for proposals* — separate from the five-year process completed in November 2018 — after receiving notice late last year of generator *deactivations* in BG&E's territory not included in the original scope of projects. The RFP seeks service beginning by April 1, 2021.

"We have included the PEPCO zone and also some surrounding adjacent TO zones in this RFP in the event there are cross-zonal black start options that may be considered," said David Schweizer, PJM's manager of power system coordination. "We did not specify megawatts in the RFP because we want to be able to consider any size black start unit that's proposed."

Expressions of interest are due by Feb. 25, with detailed proposals due May 1.

Lisle RAS Scheduled for Retirement

A reinforcement *project* will trigger the retirement of two remedial action schemes designed to prevent thermal overloads at the Commonwealth Edison's Lisle substation.

The project will add breakers to the four existing 345-kV lines and reconfigure the 345-kV bus into a ring-bus. ComEd said the schemes will be removed as they become unnecessary. The work is scheduled to begin in March and be complete by June 1, 2020. ■

— Christen Smith

PJM News

Nuclear 'Bailout' Memo Circulating Through Pa. Assembly

Lawmakers Consider Adding Nuclear Energy to Alternative Portfolio Standards

By Christen Smith

Co-sponsorship memos supporting a plan to save Pennsylvania's nuclear reactors began circulating through the state legislature last week as the window of opportunity to prevent facility closures dwindles.

The bipartisan proposal — born out of discussions within the state's *Nuclear Energy Caucus* (NEC) last year — would add nuclear energy to the Alternative Energy Portfolio Standards (AEPS) Act. The 2004 law mandates electricity distributors boost usage of renewable or alternative energy sources to 18% by 2021. Nuclear generation supplied about 42% of the state's net generation in 2017, compared with 4.5% for renewables, according to the U.S. Energy Information Administration.

State Sens. Ryan Aument (R) and John Yudichak (D) spearheaded the Senate version of the *memo*. Both lawmakers served as caucus co-chairs and oversaw a November 2018 *report* that concluded "allowing any nuclear plant in the commonwealth to close would have significant consequences for fuel diversity, resiliency, the environment, customers and the state's economy."

"Given our state's prominence in energy production, it is important that lawmakers focus on an inclusive energy policy that promotes and respects the contribution that each resource offers. The NEC looks forward to continuing the dialogue with our colleagues in the General Assembly in the coming weeks and months," Yudichak said last year. "But time is not on our side. Pennsylvanians — especially those whose livelihood depends on nuclear energy — are looking to us for action."

Sponsoring legislators urged support from other members to thwart a projected $4.6 billion annual cost to taxpayers should the state's five nuclear facilities deactivate — including $788 million in increased electricity rates, a $2 billion GDP loss, $1.6 billion carbon emissions-related increases and $260 million lost to managing harmful criteria air pollutants.

"Unless we address this inequity, Three Mile Island will shut down in October 2019, Beaver Valley will shut down in 2021 and the commonwealth's three other nuclear power plants are likely not far behind," the memo said. "To be clear, this shutdown process is irreversible, thereby guaranteeing the permanent loss of Pennsylvania's nuclear assets."

A Controversial Rescue

Proponents of the measure — including *Nuclear Powers PA* — say nuclear energy deserves inclusion in AEPS because it provides 93% of the state's zero-carbon electricity. Rescuing the state's aging generators from decommissioning could likewise preserve up to 16,000 full-time jobs and $69 million in state tax revenues, they contend.

"These lawmakers are demonstrating tremendous vision and leadership by identifying an achievable legislative plan to reform AEPS and help address a fundamental flaw within the markets," said Martin Williams, NPP co-chair and business manager of Boilermakers Local 13 in Philadelphia. "Pennsylvania is the second-largest nuclear power-producing state. We have been leaders in this industry for years, and so it's encouraging to see our lawmakers matching that with their own leadership. Much work remains, but we are encouraged by this important step forward."

Power generators, natural gas industry advocates and industrial electricity consumers argue nuclear generation companies, like Exelon, shouldn't expect ratepayers to bail them out for failing to adjust to the competitive electricity market — particularly when cleaner and cheaper alternatives exist to fill the void.

"More efficient and affordable power generating resources have lowered energy costs and are providing a new lifeline to Pennsylvania's manufacturers," said Rod Williamson, executive director of Industrial Energy Consumers of Pennsylvania. "Now that Pennsylvania's manufacturers are experiencing a competitive advantage based upon energy costs, we cannot afford subsidies to nuclear generation owners that will risk tens of thousands of good manufacturing jobs."

Glen Thomas, president of GT Power Group and former chairman of the state's Public Utility Commission, told *This Week in Pennsylvania* a state bailout undermines the current market infrastructure and should be avoided.

"The competitive markets have worked really well here, and when you start interfering with those markets by picking winners and losers in Harrisburg, ultimately that's not the system we should aspire to," he said. "We should aspire to have a system where consumers are empowered to pick where their electricity comes from."

Tony Iannelli, NPP co-chair and president and CEO of the Greater Lehigh Valley Chamber of Commerce, said correcting a faulty electricity market, preserving jobs and boosting air quality remain a "critically important effort." Including nuclear energy in AEPS will add resilience to the power grid and prevent 37 million tons of carbon dioxide emissions annually, according to the legislative memo.

Exelon's Three Mile Island nuclear power plant is in Pennsylvania, where the company is working to get subsidies for nuclear generation.

Continued on page 33

PJM News

PJM Won't Act on FTR Order Before Stay Ruling

Continued from page 1

request for rehearing or clarification, which will be filed before March 1.

"There's a couple things we unquestionably need clarification from FERC on, assuming the order stands," O'Hara said, noting members' approval in January of a new mark-to-auction component for FTR collateral requirements. "Is FERC saying we should go back to the credit rules that existed in July?"

PJM filed the credit rule change with FERC on Jan. 31 (*ER19-945*). (See "FTR Mark-to-auction Credit Requirements OK'd," *PJM MRC/MC Briefs: Jan. 24, 2019*.)

Ex Parte Communications

RTO officials are so alarmed by the impact of the ruling that Craig Glazer, PJM's D.C.-based vice president of federal government policy, may have violated FERC's ex parte rules. Commissioners *Cheryl LaFleur* and *Richard Glick* and their aides, along with *Rachel Marsh*, legal advisor to Chairman Neil Chatterjee, said Glazer attempted to speak to them about the issue in separate phone calls on Jan. 30, according to filings the three offices put in the docket.

Marsh and LaFleur aide Jessica Cockrell said Glazer called them for what he initially said was a "procedural update" on the case. "Mr. Glazer explained that PJM intends to file an emergency motion for stay, and also that the order may have significant financial implications for PJM members and require inclusion of relevant amounts on members earnings reports," Cockrell said.

Glick said Glazer "indicated that PJM was going to issue a press release pointing out that the commission's order was going to cost its members hundreds of millions of dollars. I told Craig that I was aware of the proceeding and that it remains an outstanding issue and that we should not discuss it. He followed up by noting that PJM was going to file an emergency order with the commission seeking a stay of the Jan. 30 order. I reiterated that we should not discuss this matter until the proceeding is concluded and he agreed. We then ended the conversation."

PJM spokeswoman Susan Buehler denied that Glazer was attempting to lobby the commissioners.

"As the filed record indicates, Craig contacted commissioners to give them a procedural update on the order which could have a significant impact on PJM members. He wanted to make sure they knew PJM intended to make several filings," Buehler said in an email. "Regarding the ex parte filing, PJM understands the need for sensitivity when addressing procedural matters with the commission."

'Disappointed' in Delay

O'Hara said the RTO was disappointed that it took FERC six months to rule on the waiver request. "They could have ruled within 30 days. Waiting six months obviously makes [unwinding FTR settlements] more complicated," he said.

Direct Energy's Marji Philips asked O'Hara why PJM did not ask the commission for expedited treatment for the waiver request. "Fair question," O'Hara responded. "I'll have to look into that."

FERC ordered PJM to rerun the auction conducted in July under Tariff rules requiring it to offer all of GreenHat's FTR positions at a price designed "to maximize the likelihood of liquidation." That means including liquidation offers for all GreenHat's FTR positions for August 2018 through May 2019, instead of just the prompt month.

The order also requires PJM to recalculate the default allocation assessments made based

dollars in millions	Default Reference Points As Auction Conducted in July 2018 was Cleared		Potential Increase Resulting from FERC Denial of PJM Waiver Request
June and July 2018	Settled	19	250 – 300
August 2018	100% Liquidated	24	
September through December 2018	Settled	35	
January through May 2019	Mark-to-Auction	62	
2019/2020 Planning Year		44	
2020/2021 Planning Year		2	
Totals	**186**		

Potential default allocation assessment implications of FERC's order denying PJM's waiver request | *PJM*

PJM News

on GreenHat FTRs that went to settlement between September and January 2019 if those FTRs get liquidated as a result of the rerun of the July auction.

Tim Horger, PJM | © RTO Insider

PJM's Tim Horger said the RTO, which has never rerun a cleared FTR auction, is still evaluating potential implications of the ruling. "You're going to have … auctions [after July] where members sold positions they never owned," he said.

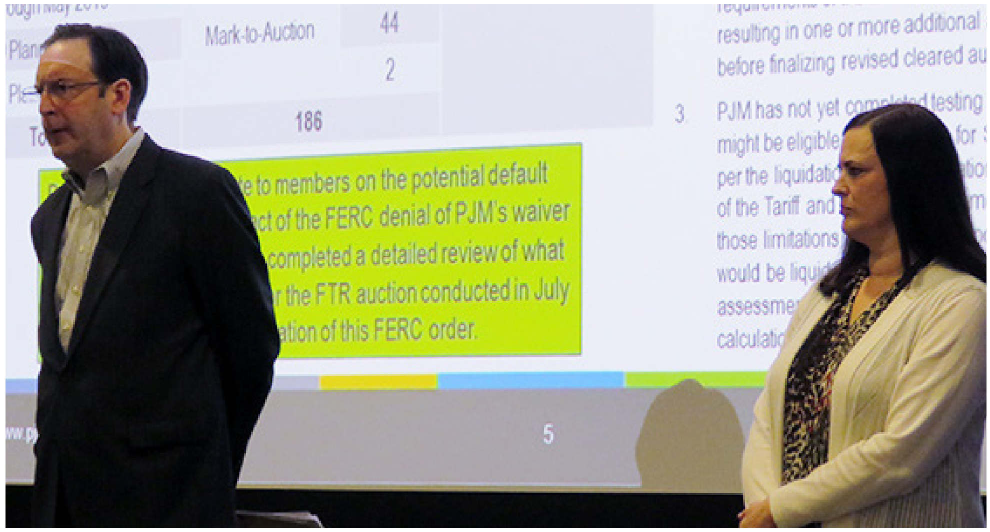
Because the FTR portfolios of participants who traded in the July auction will be revised, the reshuffling is expected to trigger credit collateral calls.

The revised results also will cause FTR auctions from August 2018 through January 2019 "to become infeasible solutions," violating the simultaneous feasibility test, PJM said.

The RTO will have to make billing adjustments reflecting revised default allocation assessment charges since Aug. 1 — revisions that may cause additional members to default.

There could be additional briefings in the docket regarding how PJM can remedy the violations, O'Hara said. "We're not entirely sure what to do."

Daugherty said PJM believes the order only requires it to rerun the July 2018 auction for August because the auctions from September forward were under revised rules approved by the commission.



Chris O'Hara, PJM & Suzanne Daugherty, PJM | © RTO Insider

In October, the commission approved PJM's requests to change its rules so it wouldn't have to immediately offer any GreenHat positions for liquidation after Aug. 24. (See *FERC OKs Key PJM Changes to Address GreenHat Default*.)

FERC last week approved PJM's request to withdraw an earlier petition to allow bilateral counterparties the option to assume indemnified positions (*ER19-24*). The RTO made the request after FERC issued a deficiency notice seeking more information on its indemnification procedures.

In asking to withdraw its filing, the RTO said "the proposal does not provide sufficient benefits to the PJM membership to justify PJM continuing to seek approval." The commission acted over the opposition of Shell Energy, which said the withdrawal would prevent the commission from ruling on its dispute with the RTO over existing indemnification rules. (See *Shell Energy Seeks to Avoid Liability in GreenHat Trades*.)

The commission also rejected Shell's request to institute a Section 206 proceeding but said "Shell remains free to file a complaint." ■

Nuclear 'Bailout' Memo Circulating Through Pa. Assembly

Continued from page 31

"Two of the state's five plants have announced plans to close prematurely beginning later this year due to an imbalanced electric marketplace," Iannelli said. "And the sad reality is that all five Pennsylvania nuclear plants are hindered in the current market environment and projected not to meet costs if this fundamental market flaw is not addressed."

Exelon Behind a Similar Proposal Elsewhere

Exelon manages the largest nuclear fleet in the country, with 13 facilities nationwide and three in Pennsylvania alone. The company said last year its three main goals include ensuring fair compensation for resilient resources, addressing PJM's identified price formation flaws and expanding zero-emission credit (ZEC) programs, like those seen in New York and Illinois. (See *Exelon Confident in Nuclear Support Programs*.) Illinois legislators passed the Future Energy Jobs bill in 2016, providing Exelon $235 million in ratepayer-funded ZECs and keeping its Clinton and Quad Cities facilities operational for another decade. (See *Illinois Lawmakers Clear Nuke Subsidy*.) New York's Public Service Commission created a ZEC program that same year as part of a plan to reduce greenhouse gas emissions by 40% by 2030. (See *New York Attempts to Thread Legal Needle with Clean Energy Standard, Nuke Incentives*.)

Paul Adams, Exelon's senior manager of corporate communications, said updating Pennsylvania's AEPS to include nuclear energy among the 16 other forms of renewable and alternative energy options detailed in the law makes sense on multiple fronts.

"The climate challenge is urgent and we must consider all energy options to accelerate our transition toward a low-carbon economy," he said. "This is an important next step toward valuing the carbon-free energy that nuclear energy provides Pennsylvania. The loss of these plants would cost the commonwealth $4.6 billion annually in the form of increased pollution, higher electricity prices to consumers, lost jobs and reduced economic activity." ■

PJM NEWS

Exelon: Need Pa. Action by May to Save TMI

By Rich Heidorn Jr.

Three Mile Island | *123rf*

Exelon CEO Chris Crane | *© RTO Insider*

Pennsylvania lawmakers must approve nuclear subsidies by May to prevent the retirement of Three Mile Island Unit 1, Exelon CEO Chris Crane told stock analysts Friday.

Crane's comments came days after a bipartisan group of legislators circulated a proposal to add nuclear energy to Pennsylvania's Alternative Energy Portfolio Standards Act. (See related story, ***Nuclear 'Bailout' Memo Circulating through Pa. Assembly***.)

Speaking during the company's fourth-quarter 2018 earnings call, Crane called the legislative effort "promising," saying, "We have some strong support."

But he said the company would need to order a new reactor core by May to refuel the 2,568-MW plant if it is to remain in operation. "We've let the stakeholders know that. So, if we can get this through in that period of time, we will be able to save the unit. Short of that, we would be beyond the [point of no] return at the end of May."

The company announced in May 2017 that it would shutter TMI by about Sept. 30, 2019.

Kathleen Barron | *© RTO Insider*

Kathleen Barron, senior vice president of federal regulatory affairs and wholesale market policy, said lawmakers have not decided on the value of the support the state might offer its nuclear plants.

"That is subject to discussions that are ongoing among the lawmakers now. So, we don't have an estimate for you on how the program will look," she said.

Crane also said the company continues to seek ways to boost the earnings of its Dresden, Braidwood and Byron nuclear plants in Illinois, all or parts of which did not clear PJM's 2018 capacity auction.

"We will continue to engage with stakeholders on state policies while advocating broader market reforms at the federal level," Crane said. "We will support PJM price formation changes like fast-start and reserve market reforms with our states to implement the expected FERC order on PJM capacity reforms and preserve the authority of our states to advance their clean energy policies and continue our efforts to seek fair compensation for zero-emitting nuclear plants."

In June, FERC ruled that PJM's Tariff was unjust and unreasonable because it allows resources receiving out-of-market revenues to depress capacity prices. The commission suggested modifications to PJM's fixed resource requirement (FRR) option could allow the removal of state-subsidized resources and corresponding amounts of load from the capacity market. The first round of filings in FERC's "paper hearing" on the issue were filed in October (EL18-178). (See ***Little Common Ground in PJM Capacity Revamp Filings***.)

Crane said the company could benefit from "market reforms" underway in PJM, including moving some or all of the Illinois plants into the FRR "so we can get better capacity treatment that matches state's environmental needs." He also pointed to the RTO's effort to improve price formation and revise reserve curves.

"So, that's why we are keeping more of an open position [and not doing more hedging on future prices]. We believe the market will strengthen," he said.

The company said its nuclear fleet set an all-time production record for 2018, generating 159 TWh.

In response to an analyst's question, Barron said it was unclear when FERC would act on changes to PJM's capacity market.

"Clearly, there has been some delay in the schedule, and I think that's a function of the transition at FERC," she said, noting the death of former Chairman Kevin McIntyre, and Commissioner Cheryl LaFleur's announcement that she won't be nominated for another term.

"So, while they have been able to get out a number of important orders, others have lagged and the capacity market order [is] among them. … We really have no signal yet from them as to when we will see their final decision in that docket."

Q4 Results, Investment Opportunities

Exelon's net income for the fourth quarter of 2018 ***dropped*** to 16 cents/share from $1.94 a year earlier, while operating earnings rose slightly to 58 cents/share from 56 cents.

The company said it expects operating earnings of $3 to $3.30/share for 2019, based on growth in utility revenue, the impact of zero-emission credits on its New Jersey nuclear plants and previously announced cost reductions.

Exelon officials also discussed capital investments, the Pacific Gas and Electric bankruptcy and ERCOT's declining reserve margin during the call.

The company's Utilities unit expects to make $23 billion in capital expenditures through 2022, boosting its rate base by 7.8% annually.

Anne Pramaggiore, CEO of Exelon Utilities, said the company's investment opportunities include electric vehicle infrastructure at Bal-

PJM News

timore Gas and Electric, distribution automation at Commonwealth Edison and security investments "across the utilities." It expects to spend about $900 million on cybersecurity, substation security and IT systems.

The company noted its Pepco Holdings Inc. unit could see increased electric load as a result of recently approved legislation in D.C. requiring all public buses and taxis to be zero-emission vehicles by 2045.

Everett LNG Terminal

CFO Joe Nigro said Exelon's fourth-quarter acquisition of the Distrigas LNG terminal in Everett, Mass., will be "earnings negative" through 2021 because of a need for increased operations and maintenance spending. The company paid $81 million for the import terminal to ensure fuel supplies for its nearby Mystic Units 8 and 9.

Nigro said the terminal is "bundled" with Mystic and will begin to add to earnings when the plant's cost-of-service contract with ISO-NE begins in 2022. The RTO sought the agreement after Exelon said it would retire Mystic when its capacity supply obligations expire on May 31, 2022. The company announced the retirement plans after Mystic Unit 9 failed to clear the RTO's capacity auction for the 2021/22 planning year. (See *FERC Approves Mystic Cost-of-Service Agreement*.)

"We are very clear that with any type of asset that is economically viable, we are going to work for solutions and ways to try to make that asset viable," Nigro said. "But I think you've seen with our financial discipline that when we've had to, we've taken the stance of making the necessary change."

ERCOT Reserve Margins

Jim McHugh, CEO of Constellation NewEnergy, Exelon's competitive retail and wholesale supplier, said the company is seeking to profit from the volatility in forward prices in ERCOT. The Texas grid operator expects reserve margins to drop below 8% this summer and was ordered by state regulators in January to tweak its operating reserve demand curve (ORDC) to increase the likelihood of price adders during scarcity. (See *Texas PUC Responds to Shrinking Reserve Margin*.)

"I think with the ORDC changes, you are just making the likelihood that scarcity is going to play a bigger role in where the summer prices go," McHugh said. He said on-peak forward prices for summer 2019 rose by $15/MWh since the end of the third quarter but prices have "been more up and down" in the last month.

"I think what we are going to see the market do is really trade on a pretty volatile range as the assessment of how many scarcity hours there may" be varies, McHugh said.

The company "is keeping a relatively significant open position and capability to extract value as we see volatility occur," Nigro added.

PG&E Bankruptcy

Nigro said the company is "actively following" the bankruptcy of PG&E, which is the sole off-taker of Exelon's 242-MW Antelope Valley Solar Ranch. "We will remain diligent in protecting the contractual value of AVSR and the role that assets like ours have in California's clean energy future," Nigro said. "AVSR provides 3 cents/share to Exelon in operating earnings and is not significant to our credit metrics."

Earnings call *transcript* courtesy of Seeking Alpha. ■

PJM News

PJM DR Subcommittee to Review Capacity Test Requirements

The Market Implementation Committee last week heard first read on an initiative to update testing rules for demand response. | © *RTO Insider*

VALLEY FORGE, Pa. — The PJM Demand Response Subcommittee would be tasked with updating the testing rules for rarely dispatched DR resources under a ***problem statement*** and ***issue charge*** presented to members Wednesday.

PJM's Jack O'Neill told the Market Implementation Committee that the RTO's current testing rules are based on limited demand response (LDR) requirements made obsolete by Capacity Performance.

LDR applied only to summers, non-holidays and weekends, while CP requires the resource on demand year-round. Likewise, CP events can now last up to 15 hours — versus just six under LDR — and lack LDR's cap of 10 reductions a year.

PJM says it is concerned because load management events are "low frequency, high impact" incidents. The last recorded event, in 2013, required reductions totaling 6,000 MW across 15 transmission zones. In years when there are no events, there is only a one-hour summer test of performance.

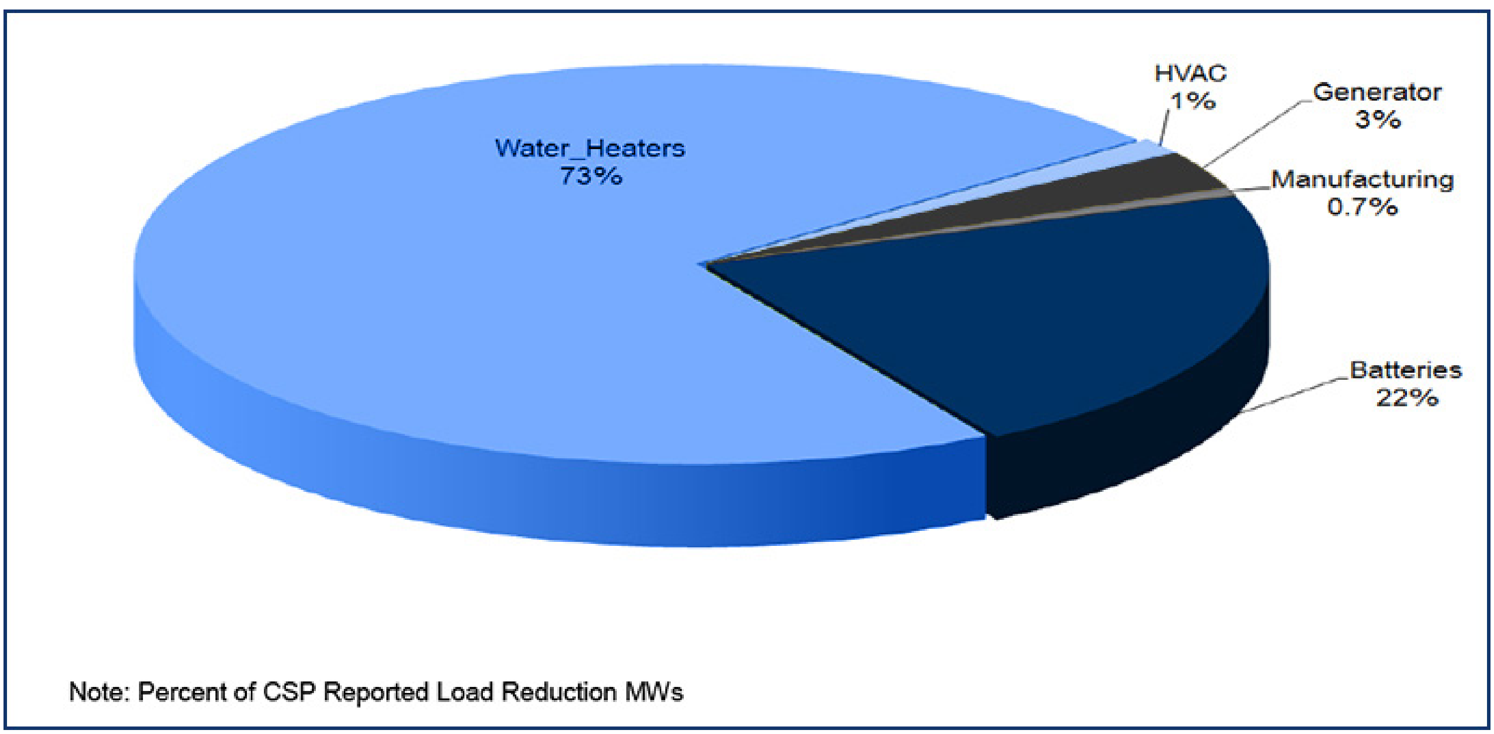
"Testing is our fallback position when there isn't anything to measure against," O'Neill said.

PJM noted that DR has averaged about 123% performance in tests versus about 97% in actual events. "This indicates that testing may not reflect performance during actual events," the problem statement says.

The RTO hopes to bring the revisions to the MIC for a first read in August, a schedule it said would allow for a FERC filing by February 2020 and a commission ruling in time for next year's Base Residual Auction.

The daily load management test failure charge rate will not be affected by the review. ■

— Christen Smith



2018 PJM demand response confirmed regulation registrations load reduction methods | *PJM*

PJM News

PJM PC/TEAC Briefs

PC Moves Forward on Offshore Interconnection Rights

PJM's Planning Committee on Thursday unanimously approved a *problem statement* to consider granting merchant transmission developers capacity interconnection rights (CIRs) for offshore wind.


Sue Glatz, PJM | © *RTO Insider*

Current rules allow merchant transmission developers to obtain transmission injection and withdrawal rights for DC facilities or controllable AC facilities connected to a control area outside the RTO. Under the problem statement, stakeholders will consider allowing merchant transmission developers to request CIRs, or equivalents, for non-controllable AC transmission offshore, PJM's Sue Glatz said.

The vote came after PJM officials resisted calls to broaden the initiative to also consider rules for non-controllable AC transmission facilities onshore.

"My concern is that in essence what we are doing is that we are going to prioritize the transmission facilities built out into the ocean, but we are not giving a path for the same thing to occur for facilities with future plans to connect to renewable resources," said Ryan Dolan, director of transmission planning for American Municipal Power. "We are mitigating risk for offshore and not doing the same thing for AC onshore."

Offshore transmission developers want to acquire CIRs so PJM can identify the necessary network upgrades.

The key difference from the normal procedure is that the developers want to build transmission before the generation is sited. Without generation at the other end of the line, PJM cannot perform stability or short-circuit analyses. (See "PJM Ponders Rules for Offshore Wind Transmission," *PJM PC/TEAC Briefs: Jan. 10, 2019*.)

PJM said the narrow scope of the problem statement addresses an immediate need from pending interconnection requests.

The RTO hopes to develop a FERC filing on Phase 1, focusing on rules for a single offshore generator lead line, by July.


Steve Herling, PJM | © *RTO Insider*

Steve Herling, PJM vice president of planning, said the RTO could discuss extending similar rights to onshore developers in Phase 2 of the initiative, when it will consider networked offshore transmission for connecting multiple wind sites.

"We don't have a fundamental issue with doing the same thing onshore … but because of the immediacy of the need, we would prefer to develop this with respect to offshore and then it would probably be a fairly straightforward extension of it in Phase 2 if there's value of doing it onshore," Herling said. "We do feel a sense of urgency offshore."

PJM has targeted Phase 2 for a September 2020 FERC filing.

Quick Fix for Queue Filing Errors Endorsed

The PC approved a problem statement and solution to prevent transmission customers from falling out of the interconnection queue because of minor errors.

The one-sentence rule change allows customers 10 days to fix any deficiencies in their requests — whether they submit their application on the first or the last day of the new services request window.

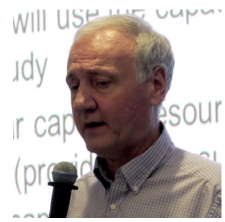
PJM's Susan McGill first presented the *problem statement* to the committee in January, suggesting the RTO reverse rules implemented in 2016 by the Earlier Queue Submission Task Force that didn't allow requesters adequate time to clear errors found in their submissions. (See "PJM Seeks Fix on Queue Filing Errors," *PJM PC/TEAC Briefs: Jan. 10, 2019*.) The change — intended to encourage generation customers to submit requests earlier in the six-month window — led to a 6% increase in terminated or withdrawn applications filed in the last month.

PJM is proposing to give all projects 10 days to address problems by removing the following sentence from the Tariff: "Any queue position for which an interconnection customer has not cleared the deficiencies before the close of the relevant new services queue shall be deemed to be terminated and withdrawn, even if the deficiency response period for such queue position does not expire until after the close of the relevant new services queue."

The problem statement is *scheduled* for endorsement at the March 21 Markets and Reliability Committee meeting. It would be effective with queue AF1, which opens April 1.

PJM Pushes Change in Wind, Solar Capacity Measurements

PJM has decided to use effective load carrying capability (ELCC) to calculate wind and solar capacity credits, calling it a "superior alternative" to current rules using average values. ELCC measures the additional load that a group of generators can supply without a reduction in reliability.


Tom Falin, PJM | © *RTO Insider*

The new *methodology* combines wind and solar capacities in one calculation that is later prorated. Tom Falin, PJM's director of resource adequacy planning, said this process sets wind and solar factors to 12.3% and 41%, respectively.

"I think all along we should have done this in a composite manner," he said. "Why? Because both wind and solar are going to be around to serve PJM load. It's a model of the entire system."

Falin said considering the total amount of intermittent generation is crucial to the process, noting the "point of ELCC is to really figure what's the incremental value of a new type of unit when you add it to the existing fleet."

Some stakeholders disagreed with PJM's decision to calculate solar and wind capacities together, citing their different characteristics.


John Brodbeck, EDP Renewables | © *RTO Insider*

"I agree they are both going to be here, barring some disaster," said John Brodbeck of EDP Renewables. "We've been working them as separate numbers. … I haven't noodled through what this does here. It just seems to mix apples and oranges."

The new rules will be included in Manual 21

PJM News

changes that will be presented to members in March. PJM wants to request MRC endorsement by the April meeting so that unforced capacity (UCAP) values for wind and solar can be posted by May 1 for use in the 2022/23 Base Residual Auction in August. They would not affect UCAP values from prior auctions.

Holistic Review of RTEP Removal Suggested

PJM said Thursday it's considering drafting a problem statement regarding how projects get removed from the Regional Transmission Expansion Plan, suggesting the process needs a "holistic" review.

Aaron Berner, PJM | © *RTO Insider*

PJM's Aaron Berner said because of differing regulatory requirements in its 13 states, the RTO has dealt with cancellations on a case-by-case basis. Cancellations can result from a reduction in load forecasts — eliminating the need for a project — or because developers are unable to get state siting approval.

"In the past there have been changes to the load profile or the actual load forecast that's resulted in a reduction for a need for reinforcement on the system, and we have pulled some baseline upgrades based on that," he said. "Primarily, it's our need that drives our decision around the various insertions and removals of the project."

Sharon Segner, LS Power | © *RTO Insider*

The issue arose after Sharon Segner, vice president of LS Power, proposed an *amendment* to Manual 14B: PJM Region Transmission Planning Process specifying that a transmission owner's supplemental project "will generally be removed from the RTEP" following a final order by a state siting agency rejecting the project.

"It's very important that the rules be very clear with how projects are added to the RTEP and how they are removed," Segner said. "We stand behind the viewpoint that PJM should be a strong regional planner and have complete authority over the regional and supplemental process."

Segner first presented the new manual language during the Jan. 24 MRC meeting as a friendly amendment to a proposal from American Municipal Power to increase transparency of supplemental project planning. AMP accepted the amendment as friendly. Despite winning a majority of stakeholder approval, PJM declined to implement the entirety of the AMP proposal, calling it an overreach of the RTEP. (See *PJM Rebuffs Stakeholders on Supplemental Projects*.)

PJM said it will discuss the issue further with stakeholders after identifying requirements in the Operating Agreement, Tariff and manuals that spell out when projects should be removed from or added to the RTEP.

Segner declined to say whether she will seek a vote on her language at the MRC. "I'm still getting feedback; the purpose of this discussion was to talk through substance. It's not a procedural discussion today," she said. "PJM said they're taking this [PC discussion] under advisement. That's what LS Power is doing as well."

Dominion, ATSI Present Supplemental Projects at TEAC

TOs presented two supplemental projects to the Transmission Expansion Advisory Committee.

American Transmission Systems Inc. plans *upgrades* to a 345-kV line between Erie, Pa., and the Perry nuclear plant in Ohio. The three-terminal line is prone to misoperations and subject to longer restoration efforts, and its relay transmission communication equipment is nearing its end of life, ATSI said. No cost was listed.

Dominion Energy Virginia *presented* seven supplemental project needs and one solution, a second distribution transformer at the Greenwich substation to address growing load. The $1.4 million project is expected to be complete by Oct. 15.

Dominion listed the following needs:

- A third distribution transformer at the Winterpock substation;
- A second distribution transformer at the Rockville substation in Goochland County;
- A second 84-MVA distribution transformer at the Cumulus substation in Loudoun County;
- A new Lockridge substation to support a new data center campus in Loudoun County with a total load exceeding 100 MW;
- A third 84-MVA distribution transformer at the Pacific substation in Loudoun County;
- A new Perimeter substation to support a new data center campus in Loudoun County; and
- A new Relocation Road substation to support a new data center campus in Loudoun County with a load exceeding 100 MW.

— Christen Smith

SPP

FERC Approves South Central Tx Formula Rate Changes

By Tom Kleckner

FERC last week conditionally approved South Central MCN's proposed revisions to its transmission formula rate and protocols and granted a rehearing request that set a Federal Power Act Section 206 proceeding (*ER15-2594*).

In seeking the rehearing, South Central (now called GridLiance High Plains), a subsidiary of competitive transmission company GridLiance and an SPP member, argued that FERC erred in a 2017 order (*EL18-16*) by requiring the company to include a fixed federal income tax rate component in its formula rate instead of allowing for annual transmission rate adjustments based on the tax liability of the company's various owners.

FERC's Feb. 4 order terminated a Section 206 paper hearing imposed on South Central in 2017, when the commission determined the company's revised rate protocols "attempt to define the scope of future filings" under FPA Section 205. (See *FERC Orders Section 206 Proceedings for 5 SPP TOs*.) FERC said the utility's proposed revisions to its formula rate protocols in that docket satisfied its concerns in the 2017 order and directed South Central to submit revised tariff records implementing its proposed revisions.

In granting the rehearing request, the commission noted that its general policy calls for estimated cost components of formula rates to be fixed in the formula rate. It said it has recently exercised "greater flexibility with other formula rate components that are traditionally fixed where formula rate protocols provide protection to customers in the form of information exchange and challenge procedures."

The commission found that South Central's formula rate protocols provided such protection in providing any information necessary to understand the inputs to its formula rate that includes income tax allowance and its subcomponents. FERC specifically pointed to federal and state income tax rates attributed to different categories of owners, and the percentage of federal income tax deductible for state purposes attributed to those different categories. ■

| 123rf

Company Briefs

Vistra to Expand Retail Business with Crius Acquisition

Vistra Energy has entered into an agreement to acquire Crius Energy Trust for about $328 million, the company announced Thursday.

With the acquisition, Vistra would serve 19 states and D.C. in the electricity and natural gas product market for residential and small business customers. Crius' assets are expected to complement Vistra's generation fleet — adding about 11.6 TWh of load — and existing municipal aggregation and large commercial and industrial portfolio in the Midwest and Northeast markets, according to Vistra.

The transaction has already been approved by Crius' board of directors. It is still subject to approval of at least two-thirds of Crius' unitholders, in addition to regulatory approvals.

More: *Dallas Business Journal*

Ørsted to Sell 50% of US Offshore Wind Assets to Eversource

Ørsted is selling a 50% stake in a portfolio of offshore wind assets to its partner Eversource Energy for about $225 million.

The company is divesting 50% of the 704-MW Revolution Wind and the 130-MW South Fork projects, as well as interests in two undeveloped New England lease areas that can potentially add more than 1 GW of offshore wind capacity. The undeveloped sites are known as Massachusetts North and Massachusetts South.

More: *Renewables Now*

CEO: GM's EVs Won't be Profitable for a Few More Years

General Motors does not expect its electric vehicles to turn a profit for at least a few more years, **CEO Mary Barra** told investors Wednesday.

The company repeated its commitment to make its entire vehicle lineup "all-electric," but it provided investors with few details about those plans on a conference call after it reported its fourth-quarter earnings for last year.

Barra also demurred when asked when customers can expect to see an electric pickup truck from GM, saying simply that the company is "committed to an all-electric future" and to "stay tuned" for more news.

More: *CNBC*

Federal Briefs

Trump Selects Bernhardt for Interior Secretary

President Trump last week tweeted that he intends to nominate **David Bernhardt** to be secretary of the interior.

Bernhardt, who was confirmed as deputy secretary in July 2017, has been acting secretary since the beginning of the year, after the resignation of Ryan Zinke. "It's a humbling privilege to be nominated to lead a department whose mission I love, to accomplish the balanced, common sense vision of our president," Bernhardt tweeted in response.

Just days before Trump's announcement, Bloomberg reported that White House officials were seriously considering former Rep. Cynthia Lummis (R-Wyo.) to serve as the next secretary.

More: *Politico*; *Bloomberg*

FERC, DOE to Hold Joint Tech Conference on Infrastructure Security

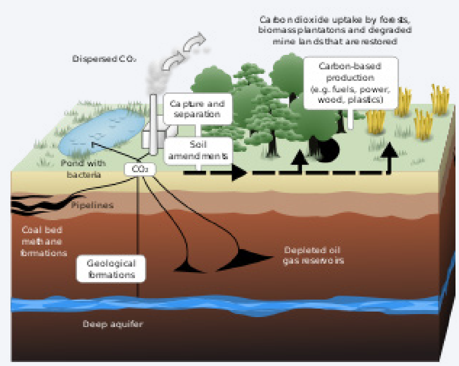
FERC and the Department of Energy announced last week they will hold a joint technical conference March 28 at commission headquarters to discuss security practices to protect energy infrastructure.

"The threats against our nation's energy infrastructure, particularly the electric and natural gas sectors, continue to grow and the responsibility for protecting our energy infrastructure is shared across industry as well as states and the federal government," FERC Chairman Neil Chatterjee said. "In light of this shared responsibility, we will join with DOE to explore current threats against energy infrastructure, best practices for mitigation, current incentives for investing in physical and cybersecurity protections, and current cost recovery practices at both the state and federal level."

"We look forward to building upon our partnership with FERC to jointly discuss and find solutions for the emerging threats facing our critical energy infrastructure," DOE Assistant Secretary of Electricity Bruce Walker said.

More: *FERC*

Sens. Reintroduce Bill to Support Carbon Capture R&D



Sens. John Barrasso (R-Wyo.) and Tom Carper (D-Del.) last week reintroduced a bill that would support carbon dioxide utilization and direct air capture research, as well as support the development of carbon capture and sequestration facilities and carbon dioxide pipelines.

It would establish a nine-member Direct Air Capture Technology Advisory Board, appointed by the EPA administrator, to advise the agency and the Energy Department on projects to fund.

The bill, dubbed the Utilizing Significant Emissions with Innovative Technologies (USE IT) Act, passed the Environment and Public Works Committee last year, but the Senate wasn't able to vote on it before the session of Congress ended.

More: *Politico*; *Axios*

DOE Proposes Rolling Back Light Bulb Efficiency Rule

The Department of Energy last week proposed repealing an Obama administration regulation that expanded the number of light bulbs subject to stringent efficiency standards under existing regulations, effective next year.

Department officials said their predecessors improperly interpreted the 1975 law that allows for such standards. "DOE has since determined that the legal basis underlying those revisions misconstrued existing law," the department said in its proposal.

The rule redefined the term "general service lamps" to include certain light bulbs that were previously considered to be so specialized that they should not be subject to standard rules, mainly various sizes of bulbs known as incandescent reflector lamps.

More: *The Hill*

State Briefs

CALIFORNIA

San Francisco Gas Explosion Burns Buildings

Private construction workers accidentally cut a natural gas line in San Francisco last week, igniting towering flames that burned five buildings, sending panicked residents and workers fleeing into the streets. No injuries were reported.

It took nearly two hours for firefighters to put the fire out while Pacific Gas and Electric crews tried to shut off the natural gas line. PG&E spokeswoman Melissa Subbotin said state excavation rules required crews to dig by hand around other pipelines before they were eventually able to "squeeze" a 4-inch plastic line.

"Had we turned the gas off to a transmission system, we would have shut off gas to nearly the entire city of San Francisco," she said. "The objective of this was to turn the gas off safely and as quickly as possible."

More: *The Associated Press*

MICHIGAN

House Votes to Reject Whitmer's Environmental Order

The state House of Representatives last week voted to overturn Gov. Gretchen Whitmer's executive order revamping the Department of Environmental Quality, arguing she usurped their power by abolishing oversight panels they created last year.

Whitmer countered by asking Attorney General Dana Nessel for a formal opinion on the legality of the panels. They "create unnecessary bureaucratic hurdles that get in the way of our state government responding to problems with drinking water quickly," she argued.

The concurrent resolution approved by the House in a 58-51 vote and now headed to the Senate would nullify Whitmer's executive order to create a new Department of Environment, Great Lakes and Energy. Both the House and Senate are controlled by Republicans; Whitmer and Nessel are Democrats.

More: *The Detroit News*

NEW MEXICO

Lawmakers Propose 100% Carbon-free Electricity by 2045

Sens. Mimi Stewart and Jacob Candelaria and Rep. Nathan Small last week introduced legislation that would mandate utilities procure 100% of their electricity from carbon-free resources by 2045.

Senate Bill 489, dubbed the Energy Transition Act, would also authorize the use of bonds for Public Service Company of New Mexico to pay for costs associated with closing the coal-fired San Juan Generating Station near Farmington by 2022, and for pulling out of the nearby Four Corners Power Plant by 2031.

Gov. Michelle Lujan Grisham supports the bill, saying, "This robust package puts us in the driver's seat. ... The renewable and zero-carbon standards outlined in this bill are among the strongest in the country."

More: *Albuquerque Journal*

RHODE ISLAND

National Grid Files Revolution Wind PPA with PUC

Under a power purchase agreement filed with the Public Utilities Commission last week, National Grid would pay Deepwater Wind a flat rate over 20 years of 9.8 cents/kWh for power from its proposed 400-MW Revolution Wind Farm.

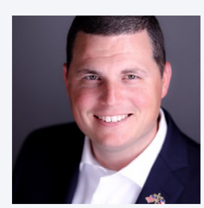
The agreement would save the state about $90 million in energy costs over its term, or about 50 cents/month for the typical electric customer, according to the company.

The price is drastically lower than what residents are paying for power from the Block Island Wind Farm: 26.1 cents/kWh.

More: *Providence Journal*

TEXAS

Lawmaker Proposes Axing Power to Choose Website



Rep. Jared Patterson (R) last week introduced a bill that would eliminate the state's Power to Choose website, which allows residents to shop for electric suppliers.

Patterson, a freshman lawmaker, argues

that the government shouldn't be competing with private businesses. "Government doesn't offer pricing comparison sites for groceries or car tires and shouldn't for electricity rates either," he said.

Patterson is director of energy services at Rapid Power Management, a retail electric brokerage firm based in Carrollton that buys electricity on behalf of manufacturers and commercial clients.

More: *Houston Chronicle*

WYOMING

Senate Passes Bill Requiring Utilities to Put Coal Plants on Sale

The state Senate last week passed a bill that would require utilities to search for buyers before retiring coal-fired plants, or risk losing money on whatever they replace the plants with.

"I wanted something that could address the importance of the jobs associated with those plants in Wyoming's communities," said Sen. Dan Dockstader (R), the bill's sponsor. "This bill brings a possible solution for our Wyoming workers and the communities they call home."

The bill "brings up some very complicated issues at the core of providing reliable and affordable electric service for our customers," a spokesman for Rocky Mountain Power said.

More: *Casper Star-Tribune*