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

ISSN 2377-8016 : Volume 2017/Issue 51 December 26, 2017

FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes

By Michael Kuser, Tom Kleckner, Rory D. Sweeney and Rich Heidorn Jr.

FERC dropped its plan for a one-size-fits-all rule on fast-start pricing Thursday, instead issuing individual orders requiring PJM, SPP and NYISO to change their tariffs.

In December 2016, the commission issued a Notice of Proposed Rulemaking that would have set generic rules to ensure RTOs and ISOs incorporate fast-start resources into energy and ancillary services pricing. (See *FERC: Let Fast-Start Resources Set Prices*.)

But the commission said Thursday it was withdrawing the NOPR, persuaded by commenters who suggested the changes would be burdensome and that it would be better to allow RTOs to implement pricing practices tailored to their regions and generator types.

"Having considered these comments, we are persuaded to not require a uniform set of fast-start pricing requirements that would apply to all RTOs/ISOs. Instead, we will pursue the goals of the NOPR through Section 206 actions involving NYISO, PJM and SPP focusing on specific concerns with each RTO's/ISO's implementation of fast-start pricing consistent with the concerns outlined in the NOPR," the commission said (RM17-3).

Cane Run Unit 7, a fast-start 640-MW combined cycle plant, went into service for Louisville Gas and Electric and Kentucky Utilities in 2015. | © *RTO Insider*

Continued on page 3

FERC to Review Gas Pipeline Approval Process

By Michael Brooks

WASHINGTON — FERC Chairman Kevin McIntyre closed out his first open meeting Thursday by announcing that the commission would reexamine its 1999 policy statement on certifying new interstate natural gas pipeline facilities.

McIntyre addresses reporters after Thursday's open meeting. | © *RTO Insider*

McIntyre said the effort is in its very early stages and that the scope and format of the review are still being considered.

"Obviously, [since] 1999 … much has changed in the industry," McIntyre said. "So, without prejudging anything, and without intending to forecast a policy direction … we believe it's a matter of good governance to take a fresh look at this area, and to give all stakeholders and the public an opportunity to weigh in."

Continued on page 25

Tightened Cyber Reporting Rules Ordered

By Rich Heidorn Jr.

FERC on Thursday ordered NERC to lower the threshold for mandatory reporting of cyber incidents, saying that the lack of any reports in 2015 and 2016 suggests gaps in the grid's protections (RM18-2, AD17-9).

NERC's Critical Infrastructure Protection (CIP) reliability standard only requires reporting of incidents if they have "compromised or disrupted one or more reliability tasks" (CIP-008-5, Cyber Security – Incident Reporting and Response Planning).

"Therefore, in order for a cyber-related event to be considered reportable under the existing CIP reliability standards, it must compromise or disrupt a core activity (e.g., a reliability task) of a responsible entity that is intended to maintain bulk electric system [BES] reliability," the commission said. "Under these definitions, unsuccessful attempts to compromise or disrupt a responsible entity's core activities are not subject to

Continued on page 26

Also in this issue:

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Production Editor
Michael Brooks 301-922-7687

Contributing Editor
Peter Key

CAISO/West Correspondent
Jason Fordney 571-224-8960

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Rory D. Sweeney 717-679-1638

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions and Advertising

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

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

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

Subscription Rates:

Payment Frequency	PDF-Only	PDF & Web
Annually:	$1,350.00	$1,650.00
Quarterly:	380.00	475.00
Monthly:	150.00	175.00

See details and Subscriber Agreement at rtoinsider.com.

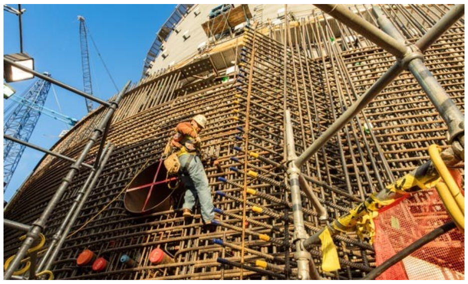
IN THIS WEEK'S ISSUE

Georgia PSC Votes to Complete Vogtle Units

By Peter Key

Georgia regulators Thursday voted to allow Georgia Power and its partners to complete the two nuclear reactors under construction at the Vogtle Electric Generating Plant near Waynesboro.

The state's Public Service Commission unanimously approved a motion by Commissioner Tim Echols finding that the reactors, which would be the plant's third and fourth generating units, should be completed.



The shield building wall of Plant Vogtle's Unit 3 in November 2017 | *Georgia Power*

The new units, like the rest of the plant, are jointly owned by Georgia Power, Oglethorpe Power, the Municipal Electric Authority of Georgia and Dalton Utilities. In July, they became the only nuclear generating units still being built in the U.S. when SCANA and Santee Cooper canceled the expansion of the V.C. Summer plant in South Carolina after cost overruns related to both plants forced Westinghouse Electric, the prime contractor, to declare bankruptcy in March.

In a statement, Georgia Power CEO Paul Bowers praised the commission's decision, calling it "important for Georgia's energy future and the United States."

Echols' motion was based on the assumption that Congress will extend nuclear production tax credits that would benefit the project. If it does not, the motion says, "the commission may reconsider the decision to go forward."

The motion also reduces the approved revised capital cost forecast for construction of the units to $7.3 billion from $8.9 billion to reflect the parent guarantee payments that Toshiba, which owns Westinghouse, has made to Vogtle's co-owners. Georgia Power, a subsidiary of Southern Co., said the payments, which totaled $3.68 billion, will reduce the cost of constructing the new units by $1.7 billion.

The motion does not impose a cost cap on the construction, but it also doesn't guarantee recovery of all costs. It also reduces the return on equity used to calculate the costs Georgia Power and its partners are allowed to recover if Unit 3 is not operational by June 1, 2021, and on Unit 4 if it isn't running by June 1, 2022. Georgia Power expects Unit 3 to be operational by November 2021 and Unit 4 by November 2022.

FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes

Continued from page 1

FERC said it had preliminarily concluded that the three regions did not adequately allow fast-start resources to set LMPs, resulting in prices that were not just and reasonable and that muted investment signals.

The commission spelled out about a half dozen tariff changes each that it seeks from PJM (EL18-34) and SPP (EL18-35), and two from NYISO (EL18-33).

Commissioner Robert Powelson called the orders an "appropriate balance."

Commissioner Cheryl LaFleur said that NYISO "has been an early leader in fast-start pricing … but we still see the possibility through targeted reform to improve certain aspects of their Tariff."

She added that the commission was not ignoring CAISO, MISO and ISO-NE "just because we were feeling charitable around the holidays."

"MISO and ISO-NE have largely already implemented the best practices that are outlined in the" Section 206 orders, she said. "With respect to the California ISO, I at least, was persuaded … that this line of reform would provide limited benefit for them relative to their other priorities that are going on right now."

The commission called on all three regions to relax fast-start resources' economic minimum operating limits by up to 100% so that they are considered dispatchable from zero to their economic maximum operating limit for setting LMPs.

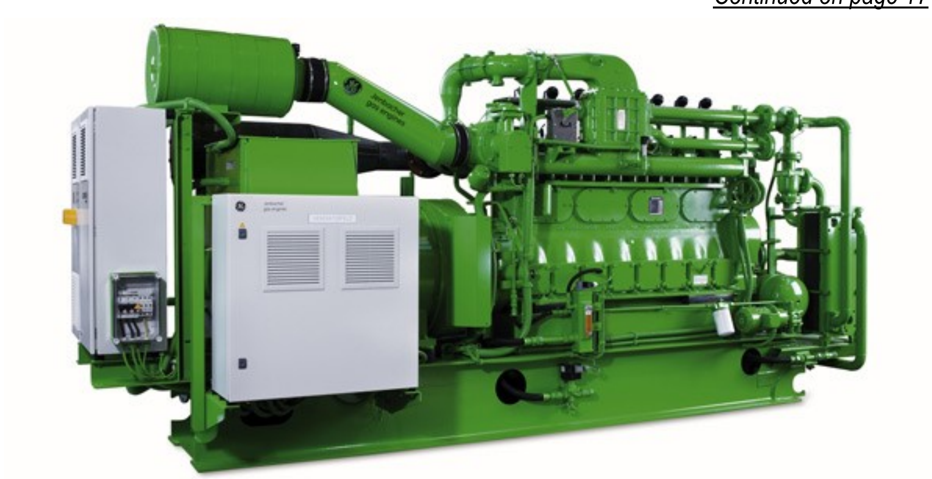
It also said the three RTOs must modify their pricing logic: PJM and SPP to allow the commitment costs of fast-start resources (start-up and no-load costs) to be reflected in prices, and NYISO to make changes capturing units' start-up costs.

It also said PJM and SPP needed to spell out their rules and practices regarding fast-start pricing in their tariffs, and include in their definitions of quick-start resources a requirement that those resources have a minimum run time of one hour or less.

The commission ordered the regions and other interested parties to file initial briefs within 45 days after the notice of the Section 206 proceedings are published in the *Federal Register*. Reply briefs are due within 30 days after initial briefs.

The commission took issue with the way the three regions relax fast-start resources' economic minimum operating limits to allow them to set prices, as detailed ahead.

Continued on page 17



Jenbacher2 reciprocating engine | *GE Power Generation*

Stakeholder Soapbox

Your Audit Report may be Worthless

By Terry Brinker

Brinker

If you are like me, some sounds drive you crazy. For example, nails raking across a blackboard have always made me cringe. Recently, another sound or comment has given me that same response. When I speak with companies about doing a compliance assessment, an internal controls evaluation or even a mock audit, often I hear, "We are good; we passed our most recent audit." Someone may as well have just raked his or her nails across a blackboard.

Just ask the entities involved in the 2011 Southwest Blackout how passing an audit helped their case in the subsequent investigation. I will tell you. It did not help. Federal regulators assessed $37 million in fines and penalties as a result of that event. Arizona Public Service was assessed a penalty of $3.25 million despite having passed an audit earlier in the year. The Western Electricity Coordinating Council and Peak Reliability, WECC's successor as the reliability coordinator for most of the Western Interconnection, was penalized $16 million. Peak had recently passed a NERC certification, which is essentially an audit of an entity's readiness and capabilities. No one received a get-out-of-jail-free card.

Entities have regarded a good audit report as proof that they have a good compliance program. In fact, your audit report may be worthless. Regional Entities perform audits and send a report to NERC. Often these regional auditors are folks with whom you either worked or see so often you become friends. Many potential violations are often reduced to recommendations or suggestions resulting in a clean audit report. After all, I know "Fred" or "Sue," and they will clean up these little nits.

What is overlooked or simply not understood is that if there is an event involving your company, an anonymous complaint filed against you or a spot check is performed that results in an investigation, your friends — oops, I meant regional auditors — will not be able to help you. NERC and FERC will step in and kick the regions out faster than a drunk uncle at the family Christmas gathering. NERC and FERC will go through your company with a fine-tooth comb, reviewing compliance documents, listening to voice recordings, conducting interviews and getting staff on the record. They will leave no stone unturned.

Not to mention, NERC and FERC have a higher standard than the regions. I know because I was a senior investigator at NERC and was responsible for conducting the above-mentioned duties, which resulted in millions of dollars in fines and penalties for entities. And remember, you do not have to be the utility that caused the event. Imperial Irrigation District (IID) was penalized $12 million even though they did not initiate the event. This is why I stress to my clients that I am not just preparing them for an audit, but also closing any compliance gaps in case there is a reason for NERC or FERC to come snooping around.

Leadership at utility companies must ask themselves if they are comfortable having a "check the box" compliance program, which meets the letter of the law, or a robust compliance program that meets the spirit of the law and would withstand the rigors of audits and investigations alike. Organizations owe it to their stakeholders to have a robust risk management program that will greatly limit its liability. If internal controls evaluations, mock audits and compliance assessments are not a part of the risk management strategy, I question leadership's commitment to be the best it can be. There will be another event that will lead to another investigation, and stiff fines and penalties will be handed out. In the words of Bruno Mars, "Don't believe me just watch."

"But we passed our audit!" will not help the utilities involved. So, let me ask, has your company conducted an internal controls evaluation, compliance assessment or mock audit lately? And remember, I hate the sound of nails raking across a blackboard.

Terry Brinker, who has 23 years of experience leading, facilitating and implementing improvements in power plant operations, control room operations, compliance and regulatory matters, is the president of Reliable Energy Advisors. Terry previously served in leadership roles during a five-year stint at NERC, where he served as senior manager of standards information and personnel certification, manager of registration services, and senior event investigator.

CAISO NEWS

CAISO 2030 Vision Gets Mixed Reviews

By Jason Fordney

Developers of renewable energy and emerging technologies are predictably supportive of CAISO's vision for the grid of the future, but operators of more traditional resources say the proposal drifts outside the ISO's purpose of assuring reliability and managing markets.

The nearly 200 pages of comments on CAISO's Vision 2030 paper illustrate concerns about the ISO's changing grid mix, laying out arguments that the transition is coming at the expense of reliability, fair markets and reasonable costs to ratepayers.

CAISO's Board of Governors and management published the discussion paper in October, saying it was "intended to help focus discussion on both technical and policy issues involved in decarbonizing and decentralizing electric service." The document identified California energy trends over the next 12 years, including more efficient energy use, a significant decline in gas-fired generation, more variable energy resources, decentralized service, regional collaboration and integration of electric vehicles. (See *CAISO Symposium Panelists Talk Grid of the Future, Western RTO*.)

The Independent Energy Producers Association, which includes both fossil fuel and renewable interests, suggested that CAISO had wandered from its core mission and is picking winners and losers by focusing on decarbonization and distributed resources.

"Overall, we find the Vision Paper not particularly helpful in illuminating what, if anything, the CAISO management will be 'tasked' to accomplish over the near term, e.g. one to five years, related to the CAISO's primary function to maintain 60 Hz on the electric transmission grid and administer just and reasonable wholesale markets," said IEPA CEO Jan Smutny-Jones, a former CAISO board chair.

The group urged the ISO to focus on accessing low-cost, transmission-connected renewables. It also complained that while the California Public Utilities Commission's integrated resource plan assumes that about 30,000 MW of gas-fired generation will not be subject to retirement because of environmental rules by 2030, CAISO's paper makes no accommodation for sustaining those resources.

"The evidence clearly recognizes a need for this type of generation (flexible capacity), yet the market provides little if any means to ensure that competitive resources that can provide these necessary services are available to the CAISO when and where needed. Importantly, the Vision Paper is silent on what, if anything, CAISO intends to do to address this matter," the group said.

The California Municipal Utilities Association (CMUA) filed brief comments saying that issues identified in the paper, such as energy efficiency, vehicle electrification and economic impacts, "may all have an indirect impact on how the CAISO operates the grid. But the policies and choices inherent in each of these issues are not the CAISO's core function, which is critical and complex [in its] own right without these additional challenges."

CMUA Executive Director Barry Moline mentioned reliability-must-run agreements, the congestion revenue rights auction and the fact that most load-serving entities in the Western U.S. are vertically owned utilities that regulators want to remain in business.

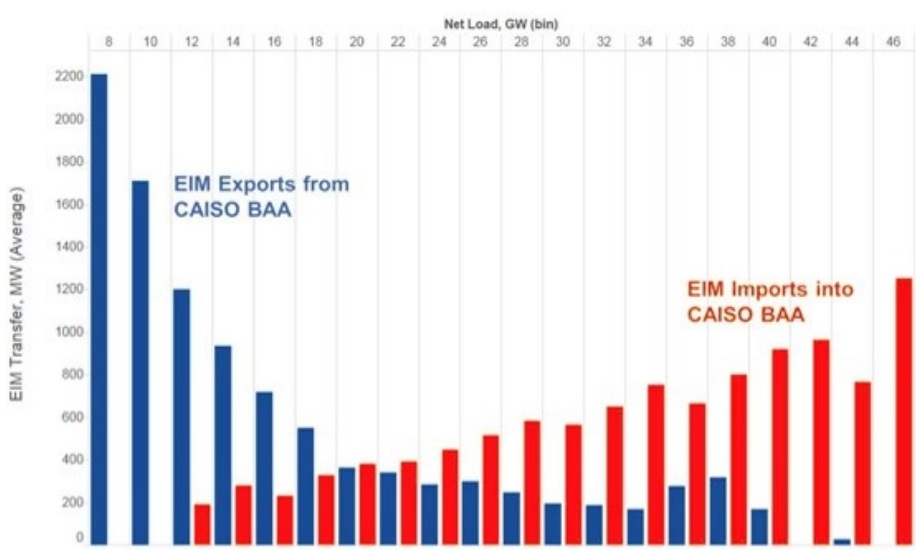
"The CAISO should be cautious when opining on these issues of industry structure, rather than focusing on its core functions, as it seeks to expand collaboration beyond California," Moline said.

NRG Energy, which operates some fossil fuel plants, said that relying on natural gas plants in constrained areas "is environmentally preferable to spending large amounts of money to eliminate those resources." CAISO recently determined that NRG's proposed Puente power plant would be the cheapest alternative out of a mix of alternative resources, but the company suspended its application after the California Energy Commission indicated it would not approve the plant. (See *CEC Members Recommend No-Go for Puente Plant*.)

NRG also noted that many topics in the paper are outside of CAISO's traditional role, such as developing a new zero-energy building plan and shaping the state's resource adequacy plan, which is under CPUC jurisdiction.

In Powerex's comments to the ISO, CEO Teresa Conway promoted "forward arrangements" for flexible capacity and renewable integration. The Canada-based power marketer is due to join the CAISO-run Energy Imbalance Market (EIM) in April 2018. (See *FERC Approves Powerex EIM Agreement*.)

"We believe the pursuit of forward arrangements, along with expanding short-term energy markets like the EIM, can be an effective strategy for unlocking the capabilities of existing clean resources outside of California, and in particular the unique



EIM imports/exports vs. CAISO net load, Oct. 1, 2016, to Sept. 30, 2017 | *CAISO*

Continued on page 6

CAISO NEWS

CAISO 2030 Vision Gets Mixed Reviews

Continued from page 5

capabilities of northwest hydro systems," Conway said. She said the state is at a "critical point" in the transformation of its energy grid and "the initial approaches responsible for the state's success cannot be scaled indefinitely, and signs of renewable integration challenges are already present."

Increased regional electricity trade and coordination will provide economic and environmental benefits by meeting customer needs with the cheapest resources, Powerex said, but increased coordination must accommodate differing and sometimes conflicting policy goals.

Powerex proposed establishing a "clean" resource adequacy requirement, aggressively pursuing storage, expanding forward commitment and procurement, and accurately measuring California's greenhouse gas emissions associated with out-of-state resources.

Southern California Edison said it is not sure it agrees with CAISO's assessment that, by 2030, demand-side resources will be as important as supply in balancing the system. About 4,500 MW of San Diego peak load will need to be met with supply sources, and "similar conclusions apply to loads in the SCE and [Pacific Gas and Electric] distribution service areas."

SCE said it supports a "well-designed" carbon cap-and-trade program and properly implemented regionalization, including a Western states committee advisory body.

The Public Generating Pool, which represents 10 publicly owned utilities in Oregon and Washington, gave a regional perspective as other states look to possibly join markets operated by CAISO. California's neighboring states have more hydro and coal resources and traditional cost-based utility regulation.

"The broad nature of this document and the numerous recommendations for policy, however, do not seem to fit the expected role of the CAISO as an independent system operator," the group said. "If there are future versions of this document, it would be helpful for the CAISO to be more specific about its role relative to California legislature and state agencies."

But the ISO's vision did get solid support from some corners. The California Electric Transportation Coalition said, "We agree with and support Cal ISO's emphasis on transitioning from fossil fuels to electricity in the transportation sector." The group said that EVs will be increasingly important to manage load and store excess renewable generation. The ISO's plan stated that California cannot reach its greenhouse gas reduction goals without electrifying the fossil energy now used in buildings and vehicles.

Arizona-based First Solar, which develops utility-scale photovoltaic modules, offered praise for the CAISO board's effort to provide a "guiding vision" for strategic planning. And while the company agreed with the "trends and solutions" offered in the paper, it also urged the ISO to consider transmission needs for renewable integration goals.

"Again this year, the CAISO is not addressing additional policy-driven transmission projects in its Transmission Planning Process, creating potential problems for the increased interconnection of renewables required to meet California's policy goals," First Solar said.

The CAISO board issued a statement of appreciation for the comments last Tuesday, saying they "will be valuable input into the ISO's ongoing strategic planning process."

CAISO News

'Load Bias,' Prices Rise in CAISO Q3

By Jason Fordney

CAISO's Department of Market Monitoring on Wednesday discussed the ISO's third-quarter market results with participants, but it referred a stakeholder query about a key development in the market to the ISO itself.

"It was an eventful quarter," Lead Market Monitoring Analyst Amelia Blanke said during her presentation in the conference call.

The department noted that day-ahead system marginal prices hit $770/MWh on Sept. 1, when CAISO's load came within 150 MW of its all-time system peak of 50,270 MW, set in July 2006. The Monitor said high temperatures and demand, along with the evening ramp-down of solar production caused the price surge. (See *Tight Supplies, Solar Ramps Drive CAISO Summer Spikes*.)

Powerex analyst Mike Benn pointed out that "load biasing" in CAISO has increased dramatically over the past year. Load biasing seemed to be too large, especially in the morning and evening hours when the system is ramping, Benn said, questioning whether the procedure was being used to correct inherent market flaws rather than adjust short-term deviations.

Load bias, also called "imbalance conformance," describes the last-minute adjustments an operator makes to the load forecast ahead of a market run to account for potential inaccuracies and inconsistencies in the forecast. There are multiple reasons for adjusting loads, including managing load and generation deviations, automatically correcting time errors, variations in schedule interchange, reliability events and software issues.

"That is a valid question," Director of Market Monitoring Eric Hildebrandt told Benn. "I think that should be passed on to the ISO. That is exactly why we provide this kind of information for stakeholders like yourself." He added that CAISO "addressed the issue in various forums."

CAISO indicated that third-quarter load adjustments in the hour-ahead and 15-minute markets climbed from about 600 MW last year to more than 1,100 MW this year.

In an attempt to address the issue, the ISO on Nov. 29 issued a straw proposal for "imbalance conformance enhancements" to clarify its authority to use the tool and implement process changes. The ISO expects to post a final draft proposal Jan. 24 and seek approval from the ISO Board of Governors in March. The DMM has voiced its support for the proposal.

The department said that most of the high prices during the quarter occurred as a result of high bids clearing the market, with extremely high bids in many instances clearing after use of the "load bias limiter." Introduced in 2012, the limiter adjusts load in the market model to better reflect actual conditions during the market's pricing run so that power balance is no longer being violated, reducing the potential for a "penalty parameter" to drive up the clearing price.

The DMM also said total payments for the ISO's flexible ramping product were about $5.1 million in the third quarter, down from $7.5 million in the previous quarter. About 55% of payments during the quarter were made to generators in the ISO rather than external units.

ERCOT NEWS

ERCOT: Tightening Reserve Margins no Cause for Concern

By Tom Kleckner

ERCOT's reserve margins may be tightening, but executives last Monday assured reporters that all is well with the Texas grid.

The ISO's year-end Capacity, Demand and Reserves (CDR) report projects a 9.3% planning reserve margin for 2018, half of what it was in the May report and 4 points below the 13.75% target ERCOT established for itself in 2010. But during a conference call with media, staff described the CDR report's reserve margin projections as a "snapshot in time" and detailed a list of tools available to handle any emergencies.

"The reserve margin that comes out of the CDR is a snapshot," said Warren Lasher, senior director of system planning. "Reserve margins are expected to fluctuate in the current market design."

The May CDR reported an 18.9% reserve margin for next summer. Since then, Vistra Energy has said it would retire about 4 GW of coal resources and ERCOT has reported a year's delay in completing construction of almost 4 GW of planned capacity. (See *Vistra Energy to Close 2 More Coal Plants*.)

Lasher pointed out that since 2010, the Public Utility Commission of Texas has directed ERCOT to develop a new standard for determining the planning reserve margin, similar to a 2014 Brattle Group study on estimating "economically optimal" margins that minimize total system and operating costs. The ISO is currently conducting its own study, which it intends to complete in the third quarter of 2018 before reporting back to the PUC, Lasher said.

"I wouldn't call [the CDR] cause for concern," he said.

ERCOT expects 14 GW of resources to be in service by 2020 and will still have 77.2 GW of capacity on hand to meet a 2018 summer peak demand forecast of almost 73 GW. That would break the August 2016 record peak of 71.1 GW.

Demand is expected to grow at a 1.7% average annually over the next 10 years. The reserve margin is expected to increase to 11.7% by summer 2019, peaking at 11.8% in 2020 before dropping to 9% in 2022. Total capacity is expected to reach almost 83 GW in 2022.

"We see these types of shifts as the ERCOT market experiences cycles of new investments, retirement of aging resources and growing demand for power," CEO Bill Magness said in a statement.

If the worst comes to worst, Lasher said ERCOT can always request emergency assistance across DC ties with Mexico or the Eastern Interconnection, or fall back on interruptible customers and switchable units obligated to other regions.

The December CDR report includes information about existing and planned generation resources and expected energy needs over the next 10 years. The report does not include the potential additional migration of nearly 600 MW of load should Lubbock Power & Light and Rayburn Country Electric Cooperative eventually migrate customers from SPP into the Texas grid. (See "ERCOT, SPP to Coordinate Second Load-Migration Study," *PUCT Briefs: Aug. 17, 2017*.)

ISO-NE NEWS

Mass. Receives Three OSW Proposals, Including Storage, Tx

By Michael Kuser and Rich Heidorn Jr.

BOSTON — Three developers submitted proposals Wednesday in response to Massachusetts' solicitation for up to 800 MW of offshore wind energy, offering projects that include a transmission "backbone" and storage to enable them to perform like a baseload resource.

The state's 2016 Act to Promote Energy Diversity mandates that the Department of Energy Resources and the state's distribution utilities — Eversource Energy, National Grid and Unitil — sign long-term contracts for 1,600 MW of offshore wind by June 30, 2027. (See *Massachusetts Bill Boosts Offshore Wind, Canadian Hydro*.)

The state's first request for proposals (solicitation 83C) called for a minimum of 400 MW but said the state would consider bids of up to 800 MW if it determines that a larger proposal "is both superior to other proposals submitted in response to this RFP and is likely to produce significantly more economic net benefits to ratepayers."

The three developers — all with ties to the state's utilities — have purchased renewable energy leases off the coast from the federal Bureau of Ocean Energy Management.

Bay State Wind

Bay State Wind, a joint venture between Ørsted and Eversource, proposed a 400-MW or 800-MW wind farm 25 miles off of New Bedford. It would be paired with a 55-MW battery storage facility, "the largest battery storage system ever deployed in conjunction with a wind farm," it said.

Ørsted, formerly DONG Energy, is the No. 1 offshore wind generator in the world. The company would use New Bedford as the staging area for construction and the base of its operations and maintenance through the wind farm's lifetime. The storage facility and an onshore substation would be located in Somerset.

Deepwater Wind

Deepwater Wind's proposal would firm its project's wind output through an agreement with the largest hydroelectric pumped

Northfield Mountain storage facility | *Northfield Mountain*

storage facility in New England, the -1,200-MW Northfield Mountain station operated by FirstLight Power Resources.

Deepwater proposed two versions of Revolution Wind, a wind farm of approximately 25 turbines to generate 200 MW, or double that size to generate 400 MW. The company had proposed an initial 144-MW phase of the project in response to the state's 83D solicitation for 9.45 million MWh of clean energy. The state is due to announce winners of that RFP on Jan. 25.

Deepwater is the developer of the Block Island Wind Farm off Rhode Island, the nation's first commercial offshore wind farm. It also partnered with National Grid Ventures to propose an offshore transmission "backbone" scalable to 1,600 MW that would be open to other wind developers. (See *Offshore Wind Developers Ponder Tx Options*.)

The company's project would connect to land at the Brayton Point substation in Somerset.

Vineyard Wind

Vineyard Wind, a joint venture of Avangrid Renewables and Copenhagen Infrastructure Partners, is betting that its promise to deliver an operating project by 2019 will win the state's favor. It submitted proposals for 400-MW and 800-MW wind farms, with approximately 50 and 100 turbines, respectively. Avangrid owns Unitil.

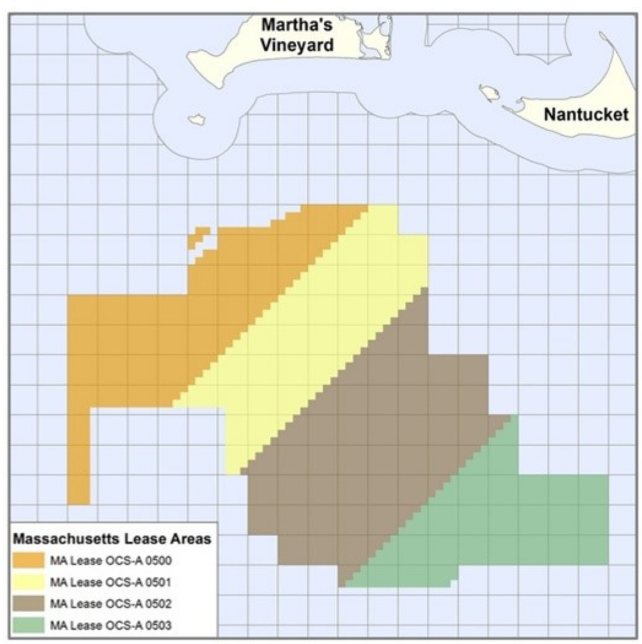
Vineyard Wind said it has already submitted applications with BOEM and the state Department of Public Utilities' Energy Facilities Siting Board for the wind farm, about 15 miles south of Martha's Vineyard. "By filing for construction permits, Vineyard Wind is on track to complete the permitting process in time to begin construction in 2019," it said.

Deepwater said if it is selected it would begin construction in 2022, with the project in operation in 2023. Bay State did not mention a timeline in its press release.

The state will announce the winners of the offshore wind solicitation on April 23, 2018, and contracts are to be submitted at the end of July.

This month saw an early offshore wind project, Cape Wind, exit the stage. It announced Dec. 1 that it had notified BOEM it was stopping development of its proposed wind farm project in the Nantucket Sound and filing to terminate its offshore lease issued in 2010.

Nevertheless, the state's solicitation has been a cause for optimism among green energy advocates, who note the attractiveness of the Atlantic's strong winds and shallow waters. (See *'Momentum' Seen for U.S. Offshore Wind*.)



Massachusetts Wind Energy Area leases | *BOEM*

ISO-NE NEWS

PAC Briefs

SOARES Study Slated for Q1 Release

ISO-NE planning engineer Steven Judd on Wednesday described to the Planning Advisory Committee the key differences between the first and second phases of RTO's System Operational Analysis and Renewable Energy Integration Study (SOARES).

While last year's Phase I consisted of the RTO's traditional economic analysis of scenarios provided by the New England Power Pool, this year's Phase II focused on operations, requiring input data for wind, solar and electric vehicle charging to analyze intra-hour ramping, regulation and reserve requirements. Phase II will help inform stakeholders about the physical range of resource quantities that could be needed and available given the studied scenarios but will not indicate a requirement going forward, Judd said.

The 2017 study will be released in the first quarter of 2018, he said.

RTO's Neighbors Seeing Similar Conditions

Michael Henderson, ISO-NE's director of regional planning and coordination, told the PAC the RTO is seeing the same issues across the Eastern Interconnection, including a surge in distributed energy resources and the retirement of conventional fossil-fuel generators.

"Our other needs we see in New England we do not feel could be better met with additional ties with neighboring regions, and PJM and New York feel the same," Henderson said.

He noted NERC's recently published 2017 Long Term Reliability Assessment report, which showed slower demand growth across North America, with conventional generation continuing to retire and new additions of natural gas, wind and solar coming quickly online. (See *NERC Report Urges Preserving Coal, Nuke Attributes*.)

The changing composition of the resource mix calls for more robust planning approaches to ensure adequate essential reliability services and the fuel supplies. NERC said that 6,200 miles of transmission additions are planned to maintain reliability and meet policy objectives.

New Guidance on Asset Condition Presentations

ISO-NE lead engineer Michael Drzewianowski said the RTO is providing additional guidance to transmission owners regarding when they should present their asset condition needs to the PAC for inclusion on the RTO's asset condition list.

Drzewianowski noted that a presentation is required if an asset condition need occurs on a pool transmission facility (PTF), and the associated cost of modifications on a single circuit or facility is $5 million or more over a period of five years or less.

For all other asset conditions related to PTF modifications, a presentation is optional. Non-PTF presentation thresholds are determined by each TO.

"It's tough when each TO has its own idea on when an asset needs to be replaced," but the planning process does work, Drzewianowski said.

National Grid Updates on NPCC Implementation Plan

Varsha Chatlani, a planning engineer with National Grid, told the PAC that his company estimates it will cost $12.4 million (with a tolerance of +50/-25%) to complete Phase 2 of a project to install dual high-speed protection systems on its PTF circuits. The company in June reported that Phase 1 would cost $1.8 million with a +200/-50% tolerance.

Continued on page 11

ISO-NE NEWS

PAC Briefs

Continued from page 10

The project was developed in response to a 2015 Northeast Power Coordinating Council plan to install the protection systems on all bulk power system circuits over 10 years.

National Grid first laid out its implementation plan for 45 identified transmission circuits to the PAC in June. The company has started to develop conceptual cost estimates for the other three phases, and it will provide additional updates when more refined estimates are available, Chatlani said.

Pole top rot | *Eversource*

Eversource Replacing Obsolete Oil Circuit Breakers

Eversource Energy has approximately 1,400 transmission circuit breakers in service and expects to spend nearly $20 million to replace 31 aged and obsolete oil circuit breakers (OCBs), company engineer George Wegh said.

Over the past 10 years, Eversource has been replacing OCBs with sulfur hexafluoride units to upgrade equipment and reduce maintenance costs. These upgrades protect the environment from oil spills and also improve system reliability by reducing equipment failures.

The 31 OCBs remaining on the Eversource 115-kV system are concentrated at three stations: Frost Bridge and Plumtree in Connecticut, and the Agawam station in Western Massachusetts. Three Frost Bridge OCBs are leaking oil.

115-kV OCB catastrophic failure | *Eversource*

Eversource recently replaced nine OCBs, not included among the 31 slated for replacement, on an emergency basis.

Further delay in replacing the obsolete OCBs would leave the transmission system vulnerable to age and condition-related reliability risks, and pose safety and maintenance concerns for the remaining circuit breaker fleet, Wegh said.

Eversource 345-kV Structure Replacement Projects

Eversource plans to spend an estimated $231.9 million to replace 1,019 wooden 345-kV structures with steel pole structures, John Case, the company's director of transmission line engineering, told the PAC.

New England has seen a large increase in the population of pileated woodpeckers, "in the hundreds of percent according to some researchers," and the birds are damaging old wooden transmission poles, Case said.

Eversource manages approximately 1,100 miles of 345-kV overhead lines in the region, or nearly 50% of such lines in New England, and maintains more than 10,000 345-kV structures. Inspections have revealed significant degradation and decreased load-carrying capacity of wooden 345-kV structures, many of which date from the early 1970s.

Replacing the structures resolves multiple structural and hardware issues, and supports safe and reliable operation, Case said. Hardware, insulators and guy wires are to be replaced along with the structures.

SEMA/RI 2027 Needs Assessment Scope of Work

Jon Breard, ISO-NE associate transmission planning engineer described the scope of work for the upcoming Southeastern Massachusetts and Rhode Island (SEMA/RI) 2027 Needs Assessment.

The study aims to evaluate the grid's reliability performance and identify reliability-based needs in the area for 2027 while also considering reliability over a range of generation patterns and transfer levels, he said.

A 2026 SEMA/RI Solutions Study report completed in March 2017 developed solutions to time-sensitive needs, which will be examined if any exist for the study area. Time-sensitive transmission needs are those that occur within three years of completion of a needs assessment. The RTO plans to issue the report in the second quarter of 2018. (See "Time-Sensitive Tx Needs Determination," *ISO-NE Planning Advisory Committee Briefs: Nov. 16, 2017*.)

The short-circuit base case used for the SEMA/RI assessment is based on the expected topology in the 2022 compliance steady state base case. That year was chosen because "no significant project is expected in the 2022-2027 time frame, and the 2022 case was considered acceptable," Breard said.

— Michael Kuser

MISO NEWS

MISO Studying Tx Upgrade for Massive Foxconn Factory in Wisc.

Factory Would be State's Largest Power User

By Amanda Durish Cook

PrjId	Project Name	Project Description	Expected ISD	Estimated Cost
14073	Mount Pleasant Tech Interconnection Project	Construct New 345 - 138 kV Mount Pleasant Substation For Load Interconnection Request	12/31/2019	$140M

| *MISO*

MISO is reviewing an expedited project request from American Transmission Co. to connect a massive Foxconn manufacturing plant that would be Wisconsin's largest power user.

ATC's proposed $140 million Mount Pleasant Tech Interconnection Project is one of the first two expedited review requests for MISO's 2018 Transmission Expansion Plan. Along with a small substation upgrade in Minnesota that the RTO has approved, the project was presented to stakeholders at last Tuesday's Planning Advisory Committee conference call, days after MISO's Board of Directors approved MTEP 17.

ATC has proposed a new 345/138-kV substation, 14 miles of new 345-kV line and four short 138-kV underground lines to connect a southwestern Wisconsin manufacturing plant proposed by Foxconn to We Energies supply.

Foxconn, headquartered in Taiwan, is the world's largest electronics manufacturer, responsible for building Apple mobile devices, Amazon Kindles and video game consoles.

Its factory will be similarly outsized. Wisconsin Gov. Scott Walker has framed the $10 billion plant, which is expected to create as many as 13,000 jobs, as a "once-in-a-century opportunity" and called for it to be operating by 2020. ATC has said the plant will require up to six times as much power as the next-largest manufacturing facility in Wisconsin.

ATC hopes to get the $10 billion plant connected to the grid by the end of 2019 and plans on ordering some long-lead time equipment beginning in February. It said MTEP 18 approval would arrive too late for its planned construction timeline.

The company said it received the load interconnection request from WE on Oct. 12. MISO posted ATC's expedited request on its website Dec. 6, although it is not clear when the RTO received it.

MISO is still studying the implications of the request and will convene a Technical Study Task Force meeting in January to go over study results with stakeholders, according to Lynn Hecker, manager of expansion planning.

ATC plans to seek project approval with the Wisconsin Public Service Commission in February, with hope for approval in August.

In addition to the new substation, ATC plans to string a new 12-mile, 345-kV circuit from Pleasant Prairie to Mount Pleasant, Wisc., and create two 1.2-mile, 345-kV loops into the new substation on existing transmission structures. The project also includes the construction of four new 138-kV underground lines at less than a mile apiece connecting the Mount Pleasant substation to the manufacturing plant.

Foxconn manufacturing plant in the Czech Republic | *Syner*

Minn. Capacitor Bank

Meanwhile, MISO has already studied and approved a much smaller substation upgrade in Minnesota, making it the first expedited project approval in the 2018 package.

The project — a $500,000, 14.4-MVAR capacitor bank addition to a substation in southern Minnesota — is expected to be in service by the end of January, according to developer Great River Energy. Capacitor banks counteract a power factor lag or phase shift in a power supply.

MISO recommended the project be granted expedited status in MTEP 18 as a baseline reliability project because the substation is currently susceptible to low voltages when a generator outage is followed by a line outage, a NERC-defined contingency. The project will also improve local area voltage performance in general, Hecker said.

MISO NEWS

Ark. Regulators Contest Entergy Bandwidth Payments

By Tom Kleckner

The Arkansas Public Service Commission asked the D.C. Circuit Court of Appeals to overturn a FERC decision that rejected the state regulator's request to exclude Entergy Arkansas from making backdated "bandwidth" payments to its affiliate companies.

The PSC made oral arguments before a three-judge panel on Dec. 15 in a bid to protect the utility's Arkansas customers from bearing the costs of the payments (16-1193). A decision from the court is likely months away.

Under the Entergy System Agreement, which expired in 2016, low-cost Entergy operating companies made annual payments to the highest-cost company in the system using a "bandwidth" remedy that ensured no operating company had production costs more than 11% above or below the Entergy system average.

The PSC is appealing FERC's 2015 rejection of a request to shield Entergy Arkansas Inc. (EAI) from making $11 million in retroactive 2005 bandwidth payments and related interest assessed after EAI's withdrawal from the system agreement in 2013. The state regulator contends the system agreement made no provision for assessing payments after withdrawal, which meant the utility had no continuing obligation to its sister companies (EL01-88-013).

FERC rejected the Arkansas commission's argument that EAI's 2005 bandwidth payments — $167.3 million for a seven-month period in 2005, plus $56.5 million in compounded interest — amounted to "exit fees," saying the payments were "obligations specifically required by the system agreement and are for a period when Entergy Arkansas was subject to the system agreement." (See *FERC Sets Hearings for Entergy's Cost Allocations*.)

FERC also ruled that nothing in a previous order rejecting an Entergy compliance filing related to the agreement indicated that EAI would be excluded from further compliance filings.

Dennis Lane, lead counsel for the PSC, told the court the commission was not challenging an earlier figure of $156 million in 2005 payments, which he said EAI had already paid.

2005 bandwidth payments | *Entergy*

"We're not asking [FERC] or the court to say we didn't owe any of the bandwidth payment," Lane said. "We're not asking for [the $156 million] to come back. We're just asking for the $11 million, plus any interest related to that, because that amount was determined after the system agreement was terminated."

PSC Executive Director John Bethel told *RTO Insider* that if his agency were to prevail, "the preferential effect would bar payment of the payments and interest due after 2013."

Lane told the court EAI is heavily reliant on coal, while its sister companies have a lot more natural gas generation.

"During the time period when the bandwidth got out of whack, natural gas prices were very high," Lane said. "The bandwidth was a rough way to get those production costs back in."

FERC framed the issue in a brief as whether "assuming jurisdiction, the commission reasonably determined that Entergy Arkansas remains obligated to make bandwidth remedy payments for a seven-month period in 2005," notwithstanding its withdrawal from the system agreement.

The commission argued the time was not ripe for immediate judicial review. "The orders challenged here resolved only Entergy Arkansas's liability for the 2005 bandwidth payments; they do not address the amount of that liability," FERC said. It pointed out the liable amounts are the subject of "ongoing, vigorous litigation" before the commission.

"What's going on at the commission is disputes over the actual methodology and the dollar figures," said FERC counsel Carol Banta.

Entergy's bandwidth payments have long been a source of contention for the five regulatory agencies that have jurisdiction over the corporation's six operating companies. The system agreement and all of its service schedules ended in August 2016, with all of the operating companies having joined MISO.

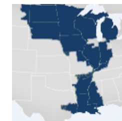
Judge Patricia Millett at one point expressed surprise that Entergy was not represented in the courtroom.

"I'm kind of shocked they don't seem to care at all," she said. "They're paying these millions and millions and millions of dollars."

Banta said she could not speak for Entergy but responded with her understanding of the bandwidth agreement.

"Because they're operating affiliates owned by a holding company, in most instances, as far as Entergy is concerned, it's a zero-sum game. It's one affiliate paying another affiliate," Banta said.

MISO NEWS



MISO Releases Transmission Cost Estimates Guide

By Amanda Durish Cook

MISO has released a draft guide detailing how it estimates costs for cost-allocated transmission projects after state officials and stakeholders called for more transparency around the process.

The guide is intended to cover any market efficiency or multi-value projects that might be approved under MISO's 2018 Transmission Expansion Plan. State regulators in the Organization of MISO States earlier this year asked the RTO to provide more visibility on project costs. (See *Commissioners Ask MISO to Share Tx Project Cost Data*.)

The RTO is asking stakeholders to review the guide and suggest revisions by the end of January. After being vetted by stakeholders, the guide will become effective in March, MISO design engineer Alex Monn said during a Dec. 18 Planning Subcommittee conference call.

MISO accepts stakeholder assessments as a starting point for estimating the costs for market efficiency and multi-value projects but develops final planning-level cost projections based on its own project assumptions.

The RTO said its total estimates include a construction cost estimate, a 20% construction cost contingency fund and a 7.5% allowance for funds used during construction. MISO initially uses a straight line plus 30% calculation to estimate transmission line length, then updates the measurement using the proxy route provided by transmission developers. For substation upgrades and new builds, it similarly uses general estimates based on the area, then updates cost needs once developers submit more details.

For the construction estimate, MISO factors in land and right-of-way costs in addition to the costs of potential substations, transmission structures, conductor, accessories like shield wire and professional services such as the engineering and testing needed to assemble the line. Right-of-way acquisition terrain and grading estimates are based on the length of the new transmission line and the topography along the route. MISO also said it has the right to assume other project-specific mitigation costs "when necessary."

Before MTEP 15, MISO relied on transmission owners to provide cost estimates for projects that fell within their service territory, but it began developing its own cost estimates after FERC issued Order 1000. The estimates are used to assess the worthiness of a project: MISO's Tariff requires a benefit-to-cost ratio of at least 1:1 for multi-value projects and 1.25:1 for market efficiency projects.

2018 Construction Assumptions

The guidelines stipulate that MISO will assume the need for seven tangent structures per mile on 69-kV single circuit line (nine per mile for a double circuit) to three tangent structures per mile on a 500-kV single circuit line (five per mile for a double circuit). For all line ratings, MISO assumes developers use a steel pole structure type, except for 500-kV lines, which will have steel lattice towers.

The RTO also assumes a right-of-way width of anywhere from 80 feet for 69-kV and 115-kV lines, and up to 200 feet for 500-kV lines. For substations, MISO will assume 1.5 acres are needed for a 69-kV rated substation, 1.75 acres for a 115-kV substation, 2 acres for a 138-kV substation, 2.5 acres for a 161-kV substation, 4 acres for a 230-kV substation, 8 acres for a 345-kV substation and 20 acres for a 500-kV substation. Land costs for the 2018 planning year will vary by state, with the cheapest land in Montana for $677/acre and the most expensive in Illinois at $3,583/acre.

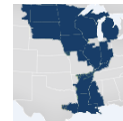
To mobilize and then break camp for all equipment and people needed for construction of a project, MISO will assume costs ranging from $51,250 for a 69-kV project to $153,750 for a 500-kV line project, up to $262,660 for certain substation work.

For terrain-clearing costs, MISO will assume $260/acre for level ground with light vegetation, $4,920/acre for forested land and $57,500/acre for wetland matting, as well as an additional $46,125/acre to secure environmental mitigation credits for wetlands. MISO will also factor in a $6,400/acre cost to grade any mountainous terrain a transmission line might traverse.

As part of the guide, MISO is also releasing state-by-state exploratory construction estimates, which represent high-level cost estimates for potential projects that still lack specifics.

The exploratory cost estimates range anywhere from $1.2 million/mile for a single-circuit 69-kV line in Iowa, the Dakotas and Montana, to $6 million/mile for a double-circuit 500-kV line in Arkansas, Louisiana and Mississippi.

MISO News



MISO Competitive Tx Task Team Concludes Work

By Amanda Durish Cook

A MISO task team is slated for retirement after successfully developing several changes to the RTO's competitive transmission process that were approved by FERC.

The Planning Advisory Committee last Tuesday passed a motion recommending that the Steering Committee approve the immediate retirement of the Competitive Transmission Task Team. Six sectors voted in favor with three abstaining.

Brian Pedersen, MISO senior manager of competitive transmission administration, said the task team has completed its work to improve the selection process behind competitive transmission projects. The team was created last December days after the conclusion of the RTO's first competitive process, for the Duff-Coleman 345-kV transmission project in southern Indiana and western Kentucky. (See *LS Power Unit Wins MISO's First Competitive Project*.)

"In 2017, we sought out incremental operational changes to scale our competitive transmission process. From our perspective, this has been a successful process," Pedersen said during a Dec. 19 PAC conference call.

Consequently, MISO submitted five FERC filings to amend the competitive process portions of its Tariff — all of which were accepted without changes by the commission. (See *FERC OKs Changes to MISO Competitive Tx Process*.)

The changes allow the RTO to:

- Review and weight competitive projects that contain both substation and transmission line facilities (ER18-44);
- Stagger its current proposal submission and evaluation timelines should the RTO encounter two simultaneous competitive projects (ER18-41);
- Replace the annual qualified competitive transmission developer recertification process with a biennial process (ER18-40); and
- Request a description of safety measures transmission developers will take during both construction and operations and maintenance (ER18-42).

A fifth filing was made to correct grammar, citation and formatting errors (ER18-39).

MISO updated its Business Practices Manuals and request for proposal forms to align with the changes, Pedersen said. He added that MISO will still take up any future stakeholder improvement suggestions "as conditions permit."

Pedersen said the changes will be in effect for MISO's second-ever competitive project, the $130 million Hartburg-Sabine 500-kV line market efficiency project in eastern Texas, which will be bid out in early 2018. MISO has hired two new employees to help with the evaluation and selection process for the project, which includes substation construction — a first for its competitive projects.

The project — originally intended to be approved with MISO's 2017 Transmission Expansion Plan — is currently subject to an approval delay while the RTO awaits a FERC decision on separating cost allocation zones in Texas and Louisiana. (See *MISO Board Approves $2.6B Transmission Spending Package*.) The Board of Directors has pledged to approve the project no later than Feb. 5, and the RTO plans to issue its RFP on Feb. 6. The window for proposals will be open until July 20, with MISO expecting to announce a developer no later than Jan. 2, 2019.

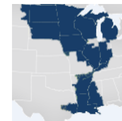
Pedersen said the Hartburg-Sabine project will be evaluated similarly to last year's evaluation of the Duff-Coleman project, with cost and design details weighted at 30%, project implementation at 35%, operations and maintenance at 30%, and transmission planning participation at 5%.

Forty-seven existing qualified developers will not be required to recertify next year after FERC accepted MISO's biennial qualification process, although Pedersen said developers must still disclose annual audited financial statements along with statements of any material changes to keep the RTO aware of developments such as bankruptcies or business name changes.

Queue Task Force Extension

PAC sectors also voted overwhelmingly to extend the RTO's Interconnection Process Task Force through December 2018. The group will oversee and suggest further improvements to MISO's major queue process changes made at the beginning of this year. (See *FERC Accepts MISO's 2nd Try on Queue Reform*.)

MISO NEWS



MISO Wins OK for Dynamic Narrowly Constrained Areas

By Amanda Durish Cook

MISO won FERC permission last week to expand its mitigation measures to address intense but temporary congestion.

Thursday's order allows MISO to begin enforcing dynamic narrowly constrained areas (NCAs) for short-lived congestion and market power Jan. 4 (ER17-2097-001). The RTO will extend Module D mitigation provisions in its Tariff to alleviate instances of momentary congestion that are not accounted for under its existing market power mitigation provisions.

"Establishing dynamic NCAs will improve MISO's current market power mitigation procedures by providing an additional means to limit the exercise of market power during periods of transient but severe congestion," FERC said.

MISO has five regular NCAs with conduct thresholds — prices that indicate potential exercises of market power — that range between $22.31 and $100/MWh. NCAs are defined by FERC as those constraints that can bind for more than 500 hours annually. They can be defined in advance and are subject to tighter market mitigation thresholds than broad constrained areas.

Dynamic NCAs will involve areas that do not meet the 500-hour trigger but need stricter thresholds because they are dominated by one or more pivotal suppliers, according to MISO.

A dynamic NCA would be declared when conduct has occurred that would warrant mitigation on a non-NCA constraint, and that constraint has bound in 15% or more hours over at least five consecutive days. The new category sets a conduct threshold at $25/MWh. MISO said it will terminate a dynamic NCA when either the outages or other conditions causing the binding transmission constraints have been resolved or the Independent Market Monitor hasn't had to mitigate economic or physical withholding or uneconomic performance for 30 days.

"MISO explains that although a given transmission constraint is not expected to bind for a total of 500 hours or more in a given year based on historical data, thus not warranting an NCA designation, that constraint can ultimately bind over shorter periods at a rate that exceeds 500 hours per year (e.g., at a rate greater than approximately 9.6 hours per week)," FERC summed up.

FERC had issued a deficiency letter Sept. 6 seeking more detail on MISO's proposal. In response, the RTO clarified that a dynamic NCA can be designated in the same area where a standard NCA already exists and provided FERC with a list of conduct categories and the conduct and impact thresholds for designating dynamic NCAs and mitigation. (See *MISO to Address FERC Query on Constrained Areas*.)

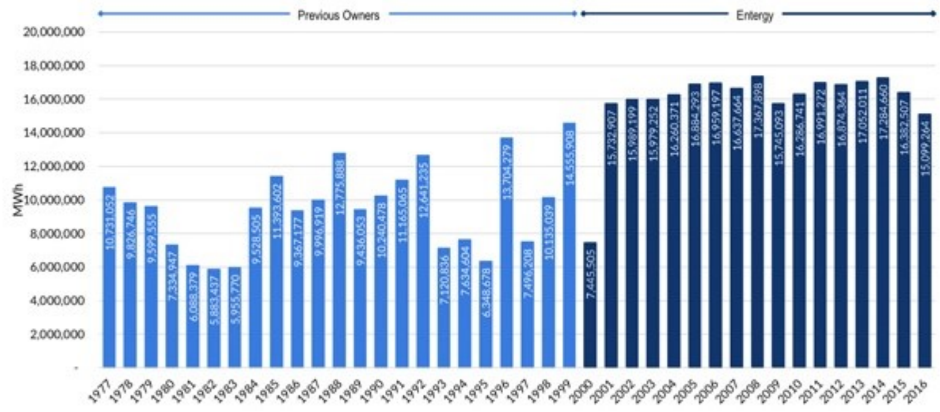
The Monitor first recommended creating dynamic NCAs in its 2012 State of the Market Report.

In accepting MISO's new definition, FERC rejected NRG Energy's argument that the RTO failed to take into consideration the differences between its Midwest and South regions by applying a uniform $25/MWh conduct threshold. NRG said that placing "unduly low thresholds" in MISO South could prevent generators from recovering their actual costs.

NYISO NEWS

Entergy Asks FERC to Clarify NYISO Deactivation Process

By Michael Kuser



Indian Point net generation per year | *Entergy*

Entergy last Monday asked FERC to clarify the deadline for NYISO to complete a final market power review for the deactivation of the Indian Point nuclear plant, or grant the company's request to rehear the commission's approval of a previous ISO compliance filing (ER16-120, EL15-37).

At issue is FERC's November conditional acceptance of NYISO tariff revisions to implement a new reliability-must-run program. (See *FERC Approves NYISO Reliability-Must-Run Plan*.) The ISO in September submitted a compliance filing to implement revisions to its RMR proposal, including adding a 365-day notice period for a generator to tell the ISO it plans to retire. The commission had accepted an earlier compliance filing for the proposal, but in April 2016 directed NYISO to make further changes to the program.

In its Dec. 18 filing with FERC, Entergy said that while NYISO's second compliance filing contained a 90-day deadline for completing reliability studies related to plant shutdowns, it did not contain a provision for a 120-day market power review deadline included in the first compliance filing. As a result, the commission's Nov. 16 order was "arbitrary, capricious, unsupported by substantial evidence and not a result of reasoned decision-making" because FERC conditionally accepted the ISO's compliance filings without requiring it to establish a clear deadline early in the process for deactivating generators, the company argued.

Entergy contended that without a clear deadline for review, the 2,311-MW Indian Point plant lacked certainty about its authorization to exit the market in accordance with NYISO's tariffs.

"At the very least, the NYISO should be held to its own assertions," Entergy said. "Here, the NYISO has emphasized the need to perform any necessary market power review at the start of this process and has expressly confirmed its ability to complete this analysis in the first four months after receiving a completed generator deactivation notice ... [and] a final market power review both in presentations to stakeholders and pleadings before this commission."

The company is seeking a March 13, 2018, deadline for NYISO to complete a market power study for the closure of the Indian Point.

An ISO report earlier this month found that new gas-fired and dual-fuel generation coming online in the next few years, led by the 1,020-MW Cricket Valley plant in Zone G, will provide sufficient capacity to maintain reliability after Indian Point shuts down completely in 2021. (See *New Builds to Cover Indian Point Closure, NYISO Finds*.)

FERC Orders NYISO Changes on Fast-Start Resources

Continued from page 3

NYISO currently applies fast-start pricing logic to online and offline fixed block units that can start in 10 minutes. The ISO defines a fixed block unit as one that, "due to operational characteristics, can only be dispatched in one of two states: either turned completely off, or turned on and run at a fixed capacity level."

The commission noted that in the first pass of the optimization process, NYISO establishes a resource's physical base points (i.e., real-time energy schedules). In the second pass, also called the pricing run, the ISO relaxes the economic minimum operating limit of fixed block units in order to allow them to be eligible to set prices. When pricing offline fixed block units, the price can also include a unit's start-up costs.

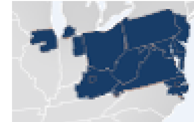
"However, NYISO neither relaxes the economic minimum operating limits of dispatchable resources (i.e., resources that are not block-loaded), nor does it include the start-up costs of these or any online resources for the purpose of setting prices," the commission said.

FERC preliminarily found that NYISO's practice of "differentiating between dispatchable fast-start resources and fixed block units appears to be arbitrary and may result in prices that do not reflect the marginal cost of serving load. NYISO's practice of allowing only fixed block units to participate in fast-start pricing may also create incentives favoring development of block-loaded resources over dispatchable resources. Furthermore, the practice may create incentives for dispatchable resources to withhold their flexibility from the market."

While finding that such practices may be unjust and unreasonable, the commission noted that there are methods to address concerns about the "potential consequences of relaxing the economic minimum operating limit of fast-start resources" by up to 100%.

Continued on page 18

PJM NEWS



MRC Briefs

PJM Wins Examination of Price Formation

WILMINGTON, Del. — PJM's initiative to internalize all generator payments moved forward at last week's Markets and Reliability Committee meeting when stakeholders endorsed the RTO's proposed problem statement and issue charge to examine price formation procedures for its energy markets.

Adam Keech, PJM's executive director of market operations, faced scrutiny during an initial presentation Thursday, but returned later in the meeting with a significantly revised version that was endorsed by acclamation with 12 objections and 14 abstentions.

James Wilson, who consults with consumer advocates for several states within the RTO's footprint, took issue with PJM defining the "price formation goal" as "maximizing the social welfare objective."

"It sounds like the problem statement is trying to narrow what the stakeholder process can focus on," he said.

Keech assured that wasn't the intention. Caveats were added to the endorsed version to explain the objective and indicate that it was "in addition to" other goals.

He also said he was unsure if FERC's order that day for the RTO to clarify or modify its fast-start resource pricing would be part of that evaluation. (See related story below.)

Stakeholders sought assurances for a variety of tangential evaluations that Keech said PJM would undertake, though the endorsed proposal does consider as out of scope any discussions about impacts on and changes to capacity markets, among other things.

"I don't think we have any intention of skipping out on the analysis here," he said, but acknowledged "there may be other changes we'd like to make, but they're not necessarily needed … for this group to move forward."

Calling it a "dramatic change," Independent Market Monitor Joe Bowring proposed an alternative analysis that called for individual examination of energy market components.

"If we're going to do this review, let's do it comprehensively so we come to the right conclusion," he said.

"It's a lot cleaner than PJM's in terms of identifying the problem and what needs to be worked on," Wilson said of Bowring's proposal.

"I think there are some things in here that maybe give us a little bit of concern," Keech said, but "the concept of including operator actions in LMP certainly [does] not."

Because PJM's proposal was endorsed, the

Continued on page 19

FERC Orders PJM Changes on Fast-Start Resources

Continued from page 17

FERC said PJM has special pricing rules only for block-loaded units — resources whose economic minimum operating limits equal their economic maximums, meaning they have no dispatchable range. The RTO seeks to let them set price by relaxing the economic minimum operating limit of online block-loaded resources by up to 10%.

The commission said PJM's practices may not be just and reasonable because they don't allow block-loaded resources' economic minimum to be relaxed by more than 10% and because they limit the relaxation to only block-loaded resources.

"We remain concerned that without allowing relaxation by up to 100%, prices will sometimes be set by the offers from lower-cost flexible units that are dispatched down in order to accommodate the output of fast-start resources," FERC said. "As a result, PJM's practices may not reflect the marginal cost of serving load when a fast-start resource is needed to quickly respond to unforeseen system needs, which may result in inaccurate price signals."

The commission also found fault with PJM's dispatch practices.

"An efficient dispatch can only be reliably determined by modeling the actual system costs and actual system constraints within a market run that minimizes production costs. That is, fast-start pricing logic would ideally not change the dispatch of resources away from the cost-minimizing dispatch but would only alter the manner by which prices are established. PJM does not appear to develop real-time dispatch instructions in this way."

Because PJM's practice does not respect the "power balance constraint," FERC said, the RTO "unnecessarily increases the cost of serving load and puts stress on the frequency regulation resources that are necessary for maintaining system reliability."

In addition, it said PJM should:

- Include in its definition of fast-start resources a requirement that those resources be able to start up within one hour or less (including notification time);
- Apply the relaxation of a resource's economic minimum operating limit to all fast-start resources, not just block-loaded units; and
- Dispatch fast-start resources "consistent with minimizing production costs, subject to appropriate operational and reliability constraints."

PJM stakeholders briefly discussed the order at Thursday's Markets and Reliability Committee meeting. When members considered a proposal from the RTO to evaluate its energy market price formation procedures, American Electric Power's Brock Ondayko asked if the fast-start order would be part of that evaluation.

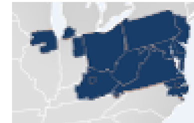
Adam Keech, PJM's executive director of market operations, noted the order's short window for reply comments and said, "Certainly from our perspective, we would prefer discussion [on that issue] earlier [rather] than later."

He said he had not been able to digest the order and had "no idea" if any of the procedures agreed upon for the evaluation are "at odds" with it.

Keech urged stakeholders to endorse the evaluation "to get the discussion started." The proposal received significant revisions but was eventually endorsed.

Continued on page 24

PJM NEWS



MRC Briefs

Continued from page 18

Monitor's was never considered for a vote.

Fuel-Switch Clarifications Endorsed

A debate that escalated at the Dec. 12 Operating Committee meeting was resolved after stakeholders endorsed clarifying text along with manual changes addressing gas pipeline contingency plans. The text box indicates that PJM "may need to direct" switching to an alternate pipeline or fuel on a pre-contingency basis and that it "will use best operator efforts" to move interruptible users off before firm service users. The revisions were endorsed by acclamation with seven objections and four abstentions.

Earlier in the meeting, stakeholders endorsed revisions to Manual 3: Transmission Operations and Manual 13: Emergency Operations, which include processes for addressing gas pipeline disruptions that affect generator reliability.

PJM's Dave Souder announced that his staff are developing a problem statement and issue charge on the topic to be unveiled at the Jan. 10 Market Implementation Committee meeting.

Dave Pratzon of GT Power Group expressed concern that PJM "doesn't have authority to tell a generator which" fuel source to use.

"This is a major expansion of PJM's authority," he said. "We need to think about it in terms of Tariff changes."

O'Connell, who proposed the clarifying text, acknowledged the concern but said it will need to be addressed later.

"There needs to be some kind of bright line. How far inside the fence can PJM go?" he said. "We were in general agreement that trying to address those issues was more than we could bite off in the time frame we had."

Incremental Auction Revisions Endorsed

Despite some stakeholder frustrations, proposed Incremental Auction revisions received endorsement with a sector-weighted vote of 3.55 that surpassed the necessary 3.33 threshold. They next go for endorsement at the Jan. 25 Members Committee.

> **"In this case, we believe this is actually worse than the status quo at this point. This addresses a lot of other problems, but not the ones that it was initially designed to."**
>
> **Marji Philips of Direct Energy, on PJM's Incremental Auction proposal**

The revisions, which would change in what IAs and for how much PJM can offer excess capacity commitments, received criticism at the Dec. 7 MRC for being presented as if the Incremental Auction Senior Task Force (IASTF) had endorsed them, when in fact the task force vote had fallen seven votes short of endorsement. Exelon's Sharon Midgley moved for the vote.

Bowring criticized the proposal for making it "too easy to get out of your capacity commitment" and voiced support for PJM's original proposal. The endorsed version was a variation of that proposal.

Marji Philips with Direct Energy reiterated previous criticism that "the process was subverted into a lot of other interests" away from the company's original goal when it proposed initiating the IASTF.

"In this case, we believe this is actually worse than the status quo at this point," she said. "This addresses a lot of other problems, but not the ones that it was initially designed to."

"We support this package as a compromise," said Susan Bruce, who represents the PJM Industrial Customers Coalition. "It is not perfect, but in this case, we do not want perfect to be the enemy of good enough. … We look at this as PJM taking on a commitment on behalf of load."

"It's not a benefit for load. It's a benefit for suppliers because those suppliers with excess will be able to undercut PJM's mandated BRA price offer," CPower's Bruce Campbell said. He offered to support anyone who motioned Package D, a competing proposal, but received no takers.

Customers, Competitors Battle TOs on Project Cost Caps

The fight over whether PJM should consider cost cap guarantees on more than construction costs in transmission-development proposals rages on.

PJM's Sue Glatz presented proposed changes to the Operating Agreement that would include caps on construction costs in the RTO's proposal evaluation, but LS Power's Sharon Segner presented a counterargument that cost cap considerations should extend to factors such as return on equity and annual revenue requirements.

The proposal is "very divergent from other FERC-approved tariffs" and "doesn't actually answer the question about how PJM will consider cost estimates versus cost-containment provisions," Segner said.

American Municipal Power's Steve Lieberman "strongly" supported Segner's position, and Bowring also endorsed it.

Representatives of several transmission owners supported PJM's proposal. Alex Stern of Public Service Electric and Gas and Tonja Wicks of Duquesne Light acknowledged they were initially against adding cost cap provisions but eventually changed tack.

"It was a balanced negotiation, so we relented to have cost cap language" included as long as it remained restricted to construction costs, Wicks said.

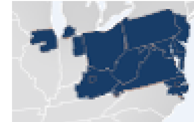
PJM's proposal will be up for endorsement at the January meeting, and Segner will need to make a separate proposal if desired.

Acclamation Votes

Stakeholders endorsed by acclamation several manual revisions and other operational changes:

Continued on page 20

PJM NEWS



MOPR-Ex Faces Uphill Battle as PJM Declines Recommendation

By Rory D. Sweeney

WILMINGTON, Del. — PJM's long-awaited capacity construct redesign will have to wait at least another month for endorsement by a key stakeholder committee, and its path to implementation includes additional hurdles after that.

Stakeholders at last week's Markets and Reliability Committee meeting voted to defer an endorsement vote on the Independent Market Monitor's MOPR-Ex proposal until the committee's Jan. 21 meeting. PJM confirmed that even if it does receive endorsement, staff won't recommend that the Board of Managers approve filing it for FERC approval; they will instead recommend their own proposal, despite not earning stakeholder endorsement.

John Horstmann of Dayton Power and Light made the deferral motion, which was seconded by Bob O'Connell of Panda Power Funds. Horstmann offered that a delay would give stakeholders a chance to review FERC's response to the Department of Energy's Notice of Proposed Rulemaking on price supports for coal and nuclear facilities, which is due by Jan. 11. It also provides additional time, without delaying a scheduled vote at the Jan. 25 Members Committee meeting, to review changes to the proposal requested by stakeholders and incorporated by the Monitor to secure endorsement. (See *PJM Monitor Battles Exelon on MOPR-Ex Proposal*.)

Monitor Joe Bowring at the MRC meeting | © *RTO Insider*

The proposal was developed by the Monitor as an extension of the minimum offer price rule (MOPR) in effect in PJM until FERC rejected it earlier this month on remand from a U.S. appeals court. (See *On Remand, FERC Rejects PJM MOPR Compromise*.) Its critics have been vocal, but it was the only proposal to receive endorsement at the Capacity Construct/Public Policy Senior Task Force (CCPPSTF), which spent the past year considering revisions to PJM's capacity design. As the task force concluded earlier this year, many stakeholders preferred the status quo, but the RTO's rules prevent that from being a voting option. Fearing that, without a clear stakeholder mandate, PJM would file its own two-stage repricing proposal, voters coalesced around the Monitor's proposal, which is seen as having the least impact on the existing design.

But to secure enough votes for endorsement at the MRC, the Monitor revised the version approved by the CCPPSTF. That move has muddied the endorsement process and confused some stakeholders. It has also incensed other stakeholders, who argue that the Monitor is hypocritically picking winners and losers in drafting a rule ostensibly designed to avoid picking winners and losers.

Exelon's Jason Barker questioned Monitor Joe Bowring on revisions to an exemption to the MOPR for resources developed under state renewable portfolio standards. Exelon, which offered its own two-stage repricing proposal in the CCPPSTF, contends that the Illinois zero-emissions credit (ZEC) program, which benefits several of its nuclear facilities, should be included in the exemption.

Bowring argued that he doesn't "get to write the rules," so his proposal must operate within the structures developed by states.

"We are taking those standards as they exist. … We deleted portions that would have resulted in most, if not all, RPS programs being not in compliance with this," he said. "I know you would like to conflate 'zero-emissions' with 'renewable,' but they are not the same thing. This is the RPS, not the ZEC standard."

Continued on page 22

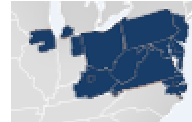
MRC Briefs

Continued from page 19

- Manual 1: Control Center and Data Exchange Requirements. Revisions developed to update NERC references and procedures related to outages and system-restoration planning. PJM members will be required to send the RTO data on transmission megawatt and MVAR flows and bus voltages at greater than or equal to 100 kV, down from 345 kV.
- Manual 10: Pre-Scheduling Operations. Revisions developed to comply with NERC standards as part of a periodic review of the manual. Generators will be required to notify PJM of operating conditions that could result in a single contingency causing an outage of multiple generators.
- Manual 14D: Generator Operational Requirements. Revisions developed as part of a periodic review. Generators will need to be modeled in eDART consistent with the PJM energy management system model.
- Revisions to the Tariff, Manual 28: Operating Agreement Accounting and Manual 6: Financial Transmission Rights resulting from special sessions on FTR issues. The revisions will address changes to long-term FTR modeling for future transmission expansion, streamlining management of overlapping FTR auctions and allocating any surplus funds from day-ahead congestion and FTR auction revenue. Members endorsed the auction surplus proposal endorsed at the Dec. 13 MIC meeting, which allocates all surplus to auction revenue rights holders. The changes will be implemented for the 2018/19 planning period. (See "FTR Changes in the Works," *PJM MIC Briefs: Dec. 13, 2017*.)
- Members will be asked to endorse changes to the procedures for the study of transmission service requests and upgrade requests in the new services queue process. (See "Interconnection Study Process to be Rearranged," *PJM Planning/TEAC Briefs Oct. 12, 2017*.)

— Rory D. Sweeney

PJM NEWS



NJ Nuclear Subsidy Bill Moves Swiftly out of Committee

By Rory D. Sweeney

TRENTON, N.J. — If opponents of nuclear subsidies in New Jersey had an opportunity to sway the opinions of state legislators on the issue, it didn't last long.

During a joint meeting Wednesday of the state Senate Environment and Energy Committee and Assembly Telecommunications and Utilities Committee, members early on indicated their support for a bill that would provide hundreds of millions of dollars in financial support to state nuclear plants. (See Nuke Bailout Bill Introduced in NJ Senate.)

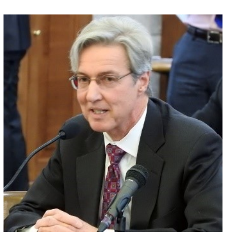
After five hours of testimony, their opinions had not changed. Both committees unanimously voted to move the bills to their respective legislative bodies.

"There's this constant question about 'why now?' The answer is: It's one of the greenest bills we've run into in a long time, and No. 2, we can get it done," said Sen. Bob Smith, who chairs the Environment and Energy Committee.

Opponents argued that the bill required no commitments from Public Service Enterprise Group, such as a plan for a transition to renewable energy when the plants are eventually decommissioned or a mechanism for the company to pay back any money if market conditions change to make its nuclear plants profitable again.

"You're feeding the problem that this country faces right now with Donald Trump. We are losing faith in government, and if you [approve] this bill during lame duck, you are part of the problem," said Doug O'Malley, director of Environment New Jersey. "So hold the bill. Let's do this right in January, February and March."

PSEG CEO Ralph Izzo opened the hearing by assuring legislators that enacting the bill was a vote of confidence for his company to commit years ahead of time to investing as much as $200 million annually for the plants' supply chains.



PSEG CEO Ralph Izzo | © RTO Insider

"There's been a lot of discussion about this being an automatic handout to utilities. That is not true," Izzo said, noting that it will be at least 300 days until PSEG will know if its plants qualify for the subsidies proposed under the bill. "Over that time, we will have to decide whether or not to invest between $100 [million] and $200 million in those plants and make an estimate as to whether or not those plants will continue to operate for the remaining 20 or 30 years of their life to make that money back."

PSEG currently has $275 million in commitments for fuel-related expenses until 2025, he said, and must decide over the next year whether it will commit to keeping the plants open through 2021.

"This is not a rush. This has been an eight-year discussion," Izzo said. "I encourage you to recognize that driving the vehicle by exclusively focusing on the rear-view mirror is not the safest way to proceed. Most companies look forward on the prospects of their assets."

Izzo's comments were rebutted by Stefanie Brand, director of the New Jersey Division of Rate Counsel, who argued that the bill is unclear on how much money PSEG should make or how unprofitable the plants will be without support. Izzo said they will remain profitable at least until next year when a number of PSEG's energy contract hedges expire.

"There are offramps for the company. There are no offramps for the ratepayers," she said. ""I'm not advocating for [the plants] to close. I'm advocating for a system that doesn't allow a single company to hold us hostage in this way."

Senate President Stephen Sweeney grilled Brand on her concerns, asking whether she thought the state Board of Public Utilities, which would oversee distribution of the plan's nuclear diversity certificates (NDCs), is capable of fulfilling that role. Brand said it was impossible to know because eligible plants could submit information confidentially without public review. She noted that the subsidized plants would also likely be subject to PJM's minimum offer price rule (MOPR).

"The rest of us don't have the information that PSEG does to claim they'll close. … The consumer protections in this bill are really a delusion," Brand said. PSEG is "deregulated, so there is no set cost of capital that they are set to earn."

Exelon Vice President Joe Dominguez testifies as PJM Market Monitor Joe Bowring listens. | © RTO Insider

She added that out-of-state plants, such as Exelon's Three Mile Island plant in Pennsylvania, might be eligible for the subsidy the way the bill is currently written.

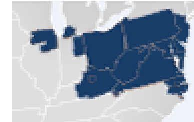
Industry analysts also traded opposing studies on the issue. Dean Murphy with The Brattle Group outlined a study sponsored by PSEG and Exelon that argues it would be cheaper to pay to keep the plants running than to develop replacement power. Tanya Bodell with Energyzt said that report is "flawed" and includes substantial "uncertainty." She challenged Izzo's assertion that they might close within two years if they become uneconomic.

"The plants are committed to operate through 2021," she said. "It would be more costly to retire before 2021."

Joe Dominguez, Exelon's executive vice president of governmental and regulatory affairs and public policy, said that while his company can't decide whether to close the nuclear plants, it can stop investing in them. Exelon can nix any investment over $5 million into the plants, he said, and has come to an agreement with PSEG to begin deferring capital projects "in anticipation of

Continued on page 22

PJM NEWS



NJ Nuclear Subsidy Bill Moves Swiftly out of Committee

Continued from page 21

the closure of" the Salem facility.

"As we looked at the market forwards … our concern was that we could no longer invest in the machine given what we were looking at in terms of future energy prices," he said. "We are already acting on the belief that if adequate attribute payments aren't provided for nuclear energy in New Jersey, we're going to take the unit out of service, or at least from Exelon's perspective, stop investing in the machines."

One significant opponent to the bill received short shrift from legislators.

NRG CEO Mauricio Gutierrez | © *RTO Insider*

After calling NRG Energy CEO Mauricio Gutierrez to testify, Smith referred to him as "Maurice" and declined to attempt his surname, asking him to instead introduce himself. Gutierrez argued that the bill "creates only one winner and many losers, including my company."

NRG owns no nuclear assets in New Jersey and has a portfolio of mostly gas-fired units. Substantial supplies of natural gas have kept commodity prices low and helped gas-fired generation offer into PJM's markets at prices below nuclear units. The shift in generation economics has prevented some nuclear units from clearing auctions and denied them payments they say they need to remain profitable.

Gutierrez told the committees that had the subsidies existed before he decided to base his company in Princeton, N.J., he would have placed the headquarters elsewhere. The legislators asked no questions about his testimony, and Gutierrez appeared visibly frustrated as he returned to the audience.

MOPR-Ex Faces Uphill Battle as PJM Declines Recommendation

Continued from page 20

In a subsequent email to *RTO Insider*, Bowring added that FERC has ceded regulatory authority over RPS programs and that the U.S. Supreme Court provided additional leeway for states in setting renewables standards in its decision rejecting Maryland's plan to subsidize generation. (See *Supreme Court Rejects MD Subsidy for CPV Plant*.)

As a result, there is only a limited ability for FERC-approved rules to affect the market participation of generation developed under RPS programs. The MOPR-Ex is intended to respect existing programs while introducing an element of competition, Bowring said.

"I can tell you most of the [state] advocate offices would not vote for the other version, but with this modification made … I think you gained the support of most of the advocate offices," said Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS). "Status quo is the preferred option, but this is the next best option because of the RPS exemption."

Monitor's Lead

The situation is further confused by PJM taking a back seat in developing necessary revisions to its governance documents.

"We are trying to facilitate at this point," said PJM CFO Suzanne Daugherty.

Carl Johnson, who represents the PJM Public Power Coalition, took the RTO to task for what he saw as the "extraordinary" situation in which it would "not actively draft the Tariff language" for a proposal endorsed by a task force and said he plans to address it in the future.

Staff defended themselves, saying they "didn't decline" to write the language but "engaged with the IMM staff and legal counsel" to determine that it might be better for the Monitor to write the first draft to ensure its intentions are accurately reflected.

"PJM is continuing to do its legal analysis, but PJM has been in close connection with the IMM," PJM attorney Chris O'Hara said.

He noted that analysis might determine that applying the MOPR to any qualifying facility under the Public Utility Regulatory Policies Act isn't defensible, "but that would entail a complete rewrite to what the stakeholder group did."

PJM Recommendation

PJM's Stu Bresler announced that staff's "recommendation to the board would be that we not file that proposal" because "it does not accommodate state public policy decisions" and raises discriminatory concerns.

Bowring responded that in the event of a "super-majority" stakeholder endorsement, "we would then consider making that filing ourselves, so one way or the other, we expect the proposal to get to the commission."

Such a filing would be under Section 206 of the Federal Power Act, he confirmed.

Poulos asked whether PJM would recommend the status quo; Bresler clarified that is the pre-2012 MOPR rule, which was in place prior to the filing FERC recently rejected.

"No, that would not be our recommendation to the board," he said, adding that PJM would recommend its repricing proposal to replace the existing MOPR rule.

MOPR Status

FERC's rejection also muddies PJM's capacity auction schedules. The RTO asked FERC for a waiver on its deadline for filing MOPR exemptions for its Feb. 26 Incremental Auction, PJM's Jen Tribulski said. Generators will have until Jan. 12 to request exemptions for the third IA for delivery year 2018/19. Unit-specific exemptions for the Base Residual Auction for 2021/22 will be due on Jan. 10. All exemptions are based on the pre-2012 rule.

SPP NEWS

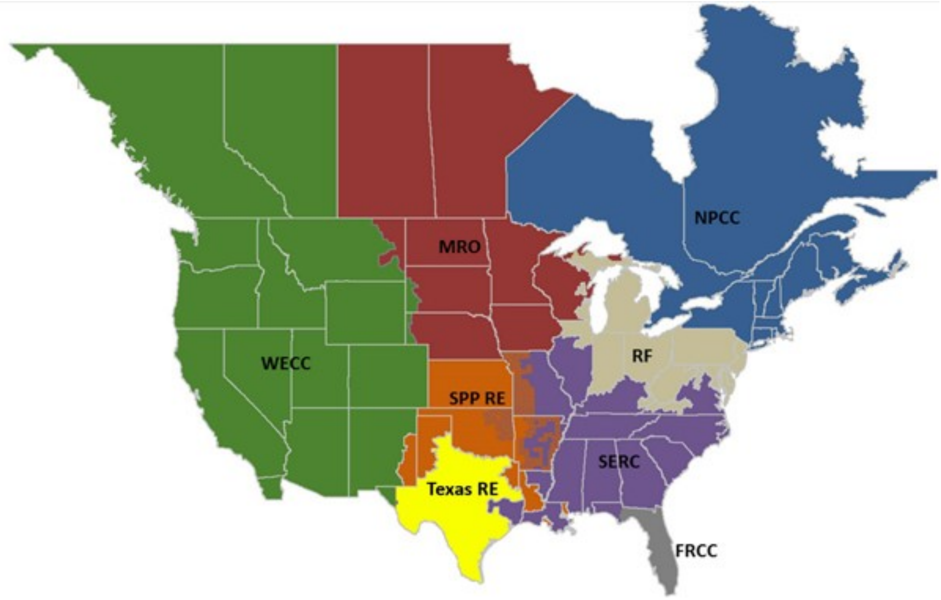
NERC Assigns SPP RE Entities to MRO, SERC

By Tom Kleckner

NERC is offering SPP's 128 registered entities a chance to comment after assigning them all to a new Regional Entity.

The reassignments became necessary when the SPP RE announced its dissolution in July, addressing NERC and FERC concerns over its reliability oversight role. (See *SPP to Dissolve Regional Entity*.) Responses are due back to the organization by Jan. 5.

NERC said it received 122 transfer requests spanning five REs, with six entities expressing no preference for a "transferee" RE. The organization placed most of the registered entities into the Midwest Reliability Organization (MRO), with 13 Arkansas, Louisiana, Mississippi and Missouri entities assigned to SERC Reliability.



NERC Regional Entities | *NERC*

Arkansas Electric Cooperative Corp., which provides power to Arkansas' 17 distribution cooperatives, was placed in both MRO and SERC.

In a message to the registered entities, SPP RE President Ron Ciesiel said it was the RE's "understanding" that NERC is on target to present final transferee recommendations to the organization's Board of Trustees at its February meeting.

"We believe there is a high probability the transfer can be completed in the July time frame," Ciesiel said.

After an initial review and analysis of entity requests, NERC said it determined that granting all the requests "would neither result in effective and efficient administration of compliance and enforcement activities, nor a cohesive functional alignment to support and promote BPS [bulk power system] reliability and security."

In reviewing the requests, NERC considered the location of an entity's BPS facilities in relation to the geographic and electrical boundaries of the transferee RE. The agency also assessed the impact of a proposed transfer on other BPS owners, operators and users, including affected reliability coordinators, balancing authorities and transmission operators, as appropriate.

NERC said it recognized that its procedural rules do not contain criteria for "the allocation of multiple registered entity transfers" when an RE dissolves, so it used criteria from another rule for considering requests. The organization reviewed each transfer request using that criteria and other "entity-specific circumstances."

When NERC's recommendations differed from the entities' requests, it contacted the entities and explained its rationale, the agency said.

Created in 2007, the SPP RE is responsible for auditing and enforcing NERC reliability rules in three balancing authorities: SPP, the Southwestern Power Administration and parts of MISO.

SPP said it is dissolving the RE in part because the RTO's expanded footprint no longer aligns with the RE's territory. However, FERC criticized SPP in a 2008 audit for failing to ensure the RE's independence from the RTO.

Calling 2017 a "tumultuous year for SPP RE," Ciesiel told its registered entities that RE staff, while working at reduced levels, achieved its highest ever metrics performance.

"A good way to close out the year for us," he said.

The dissolution is expected to be completed by the end of next year.

FERC OKs Changes to SPP's Tx Planning Process

By Tom Kleckner

FERC last week accepted Tariff revisions to streamline SPP's Integrated Transmission Planning (ITP) process, despite opposition from wind developers.

The commission's Dec. 21 order accepted the revisions as consistent with the transmission planning requirements under FERC Orders 890 and 1000 (ER17-2027).

SPP's filing drew protests from the American Wind Energy Association, the Wind Coalition and four renewable energy companies. They contended that SPP's ITP process did not meet Order 890's transparency principle because it lacked details of the process currently found in the ITP Manual.

AWEA and the Wind Coalition also argued that the Tariff should "specify the transmission elements and voltage levels to which the ITP assessment applies; more clearly provide opportunities for stakeholder input on economic transmission needs; include additional details on the inputs SPP plans to incorporate into its planning studies and how SPP will determine the inputs to use; and explain how SPP will coordinate its aggregate transmission study, generation interconnection and ITP processes."

The wind developers added that the Tariff, rather than the ITP Manual, "should detail how SPP determines the variable operations and maintenance cost for wind and solar resources; incorporate reasonable, objective standards to identify the amount of wind generation that SPP will use in its planning models; include triggers to address economic market conditions; and specify the criteria for identifying persistent operational issues.

FERC said the concerns "relate to elements of the ITP process that SPP does not propose to change, and thus are beyond the scope."

"SPP's proposed Tariff revisions implement this proposal without otherwise modifying the existing ITP process," the commission said.

The protesters further argued that SPP should hold two planning summits per planning cycle, rather than the proposed annual summit. FERC agreed with the RTO's argument that reducing the number of required planning summits "will not affect stakeholders' ability to provide input."

"Stakeholders may participate at the working group level and throughout the transmission planning process," the commission noted, saying SPP could always schedule additional planning summits as needed.

Stakeholders approved the process changes, which were developed by a member task force, in July 2016. Under the new process, SPP will combine the ITP's near-term and 10-year assessments and NERC transmission planning assessments into a single 10-year study. It also modified the 20-year assessment's timing from at least once every three years to five years.

The changes will result in an annual transmission expansion plan addressing reliability, economic and policy needs. The first study under the new process began in September, and results will be unveiled in October 2019.

FERC Orders SPP Changes on Fast-Start Resources

Continued from page 18

The commission found SPP's approach to pricing quick-start resources to be "inconsistent with minimizing production costs."

FERC said SPP's real-time balancing market practices for quick-start resources begins with a "screening run" that identifies a set of resources to be excluded from the binding solution. The screening run identifies an economic dispatch solution under the assumption that quick-start resources may be dispatched below their economic minimum operating limit, the commission said.

Any resources that are dispatched below their economic minimum operating limit are treated as "off" and excluded from consideration in the binding pricing and scheduling run. "This means quick-start resources are only considered for dispatch in the pricing and scheduling run if they are dispatched to at least their economic minimum operating limit in the screening run," FERC said.

A second optimization pass (pricing and scheduling run) is used to determine both the binding resource dispatch levels and energy and operating reserve prices.

The commission noted two other rules that distinguish SPP's treatment of quick-start resources from other RTOs' fast-start pricing practices:

- It provides an option for quick-start resources to submit an enhanced energy offer that includes commitment costs (start-up and no-load costs) as part of the incremental cost curve to be used both in the screening run and in the real-time balancing market's pricing and scheduling run.
- SPP does not have any minimum run time requirement for eligibility as a quick-start resource.

The commissioners said SPP's practices are not in its Tariff, pointing to the Federal Power Act's requirement that all practices significantly affecting rates, terms and conditions of service be on file with FERC and included in a commission-accepted Tariff.

"For example, the Tariff does not describe the process by which quick-start resources are screened out within the screening run from participating in dispatch, which appears to have a material effect on electric power rates," the commission said. "Therefore, our preliminary review indicates that SPP's practices related to quick-start pricing significantly affect the rates, terms and conditions of service and as such, must be filed with the commission as part of the SPP Tariff."

The commission said SPP should:

- Commit and dispatch quick-start resources in real time consistent with minimizing production costs, subject to operational and reliability constraints;
- Remove the option for enhanced energy offers for quick-start resources that incorporate commitment costs in the incremental energy curve; and
- Consider both registered and unregistered quick-start resources in quick-start pricing to ensure prices reflect the cost of the marginal resource.

FERC & FEDERAL NEWS

FERC to Review Gas Pipeline Approval Process

Continued from page 1

The policy statement details how the commission grants developers of proposed pipelines a certificate of public convenience and necessity — allowing them to exercise eminent domain — under the Natural Gas Act of 1938. It came at a time when the gas industry, much like the electricity industry, was being restructured, and demand in the northeastern U.S. was expected to increase — somewhat of an understatement in hindsight.

"At a time when the commission is urged to authorize new pipeline capacity to meet an anticipated increase in the demand for natural gas, the commission is also urged to act with caution to avoid unnecessary rights of way and the potential for overbuilding with the consequent effects on existing pipelines and their captive customers," the statement concludes. "This policy statement is intended to provide more certainty as to how the commission will analyze certificate applications to balance these concerns."

Since the statement was issued, FERC has granted a certificate to virtually every proposed pipeline submitted to it; Commissioner Richard Glick noted that the amount of new pipeline capacity approved by the commission has grown by more than 500% in the past six years alone.

This has raised the ire of environmentalists and landowners, who charge that FERC "rubber-stamps" pipelines and point to the number of former staffers who have gone on to work in the natural gas industry. Protesters interrupting commission meetings have become a regular occurrence over the past two years. (There were, ironically, no interruptions at Thursday's meeting.) Members of Congress have also written FERC on behalf of constituents to complain about inadequate public notice for commission hearings on pipelines in their jurisdictions, or a lack of time to accommodate all who wanted to speak.

But there is also a growing concern in the energy industry about the potential for overbuilding pipeline infrastructure as renewable, distributed and storage resources are becoming increasingly relied upon for electricity generation. Just before his resignation in February, former Chair Norman Bay called on the commission to analyze its reliance on signed agreements with shippers to determine the need for pipelines. (See *Bay Calls for Review of Marcellus, Utica Shale Development*.)

"Overbuilding may subject ratepayers to increased costs of shipping gas on legacy systems," Bay said. "If a new pipeline takes customers from a legacy system, the remaining captive customers on the system may pay higher rates."

McIntyre said he did not share any of those concerns, instead citing the policy's statement age as a factor for his decision to examine it. "The fact of my having proposed this should not be read as … a complaint about our current policy. It is not," he told reporters after the meeting. "1999 was quite a while ago, particularly in the natural gas pipeline industry. So much has changed" across all energy industries, "but it would be hard to point to an area that has changed more than natural gas."

His fellow commissioners — it was the first time FERC has had five commissioners in two years — all expressed support for the review.


Cheryl LaFleur | © *RTO Insider*

Commissioner Cheryl LaFleur said she would like the review to focus on how FERC determines economic needs for proposed pipelines, as well as the environmental impacts.

"The policy statement … actually holds up quite well. It outlines a very broad range of factors we could look at to review need. Over time our practice has coalesced around a reliance on precedent agreements as a determiner of market need. And as I recently stated in dissents in Atlantic Coast (CP15-554, *et al.*) and Mountain Valley (CP16-10, *et al.*) pipelines, I think our review of pipeline applications would benefit from a broader consideration of need," she said.

"Secondly, I think it's appropriate for us to consider how we do our environmental reviews … [to consider] the downstream impacts on greenhouse gases or other downstream impacts," she continued.

"I was already looking forward to 2018 with all you fine folks, and I now am even more."

In August, the D.C. Circuit Court of Appeals ruled that FERC's environmental impact statement (EIS) for the Southeast Market Pipelines Project should have included "reasonable forecasting" of the project's impact on GHG emissions.

As interim chairman, Commissioner Neil Chatterjee said in October that he didn't expect the ruling to have a "significant" impact on the agency's pipeline licensing. (See *FERC Chair: Court Ruling Won't Change Pipeline Reviews*.)

"Although I am supportive of our current policies, I wholeheartedly agree with the chairman that it's important the commission takes a look at how it exercises its statutory obligations," Chatterjee said Thursday.

He emphasized that he wanted input from all stakeholders. "I particularly want to speak to those who feel frustrated that their voices are not heard throughout this process. I want you to know that I empathize with that frustration."

Commissioner Robert Powelson agreed with Chatterjee's sentiments, but he also defended FERC's record. "We don't rubber-stamp interstate pipelines here," he said. "People should have peace of mind that, one, we don't site pipelines on speculation here at the FERC. There is due diligence. … This is about giving everybody an opportunity to be heard."

"It's not just that we're approving a lot of pipeline capacity; that may be OK," Glick said. "It's that these pipelines are increasingly traversing populated areas, and thus have potentially greater impacts on individuals and communities, in addition to their impacts on the environment."

McIntyre told reporters that any outcome of the review would affect the pipelines currently before the commission.

"I am approaching this topic with an open mind and want the staff and the commission to take a fresh look at all aspects of the issue," he said.

FERC & FEDERAL NEWS

FERC Orders Tightened Cyber Reporting Rules

Continued from page 1

FERC Commissioners Neil Chatterjee (left) and Richard Glick | *© RTO Insider*

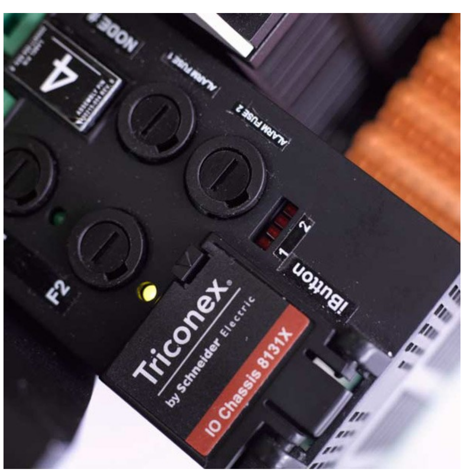
the current reporting requirements."

In a Notice of Proposed Rulemaking, the commission said the standard should be revised to require reporting of incidents "that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS)."

FERC cited NERC's 2017 State of Reliability report, which noted that "while there were no reportable cybersecurity incidents during 2016 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cybersecurity incident is low."

The current "mandatory reporting process does not create an accurate picture of cybersecurity risk since most of the cyber threats detected by the electricity industry manifest themselves in … email, websites, smart phone applications … rather than the control system environment where impacts could cause loss of load and result in a mandatory report," NERC said.

The organization recommended redefining reportable incidents "to be more granular and include zero-consequence incidents that might be precursors to something more serious."



Schneider Electric acknowledged this month that its Triconex control system, which is used by power plants worldwide, was the target of an attack by nation-state hackers. | *Schneider Electric*

NERC noted that the 2016 annual summary of the Department of Energy's electric disturbance reporting form OE-417 included two suspected and two actual cyberattacks. In addition, the Department of Homeland Security Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) responded in 2016 to 59 cybersecurity incidents within the energy sector, which includes the electric subsector.

"Based on this comparison, the current reporting threshold in reliability standard CIP-008-5 may not reflect the true scope and scale of cyber-related threats facing responsible entities," FERC said.

Deadlines, Data Requirements

FERC said NERC's revision should set a deadline for filing a report following a cyberattack attempt and specify the information required in the reports to "improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information."

Current rules require responsible entities to provide the Electricity Information Sharing and Analysis Center (E-ISAC) with initial notification within an hour of determining a "reportable" incident, which may be made by phone call, email or web-based notice. The rules do not specify what should be included in the report, nor do they set a deadline for completing the full report.

FERC said the reporting timeline "should reflect the actual or potential threat to reliability, with more serious incidents reported in a more timely fashion."

The commission suggested requiring information on three "attributes," as used in DHS' multisector reporting and summarized in its annual report: the functional impact that the incident achieved or attempted to achieve; the attack method or "vector" (such as a phishing attack for user credentials or a virus designed to exploit a known vulnerability); and the level of intrusion that was achieved or attempted.

In addition to being filed with the E-ISAC, as is now required, the incident reports also would be sent to ICS-CERT. NERC also must file an annual — and public — summary of the reports with FERC with identifying details anonymized. "We believe that the ICS-CERT annual report, which includes pie charts reflecting the energy sector's cybersecurity incidents by level of intrusion, threat vector and functional impact, would be a reasonable model for what NERC reports to the commission," the NOPR said.

Continued on page 27

FERC Orders Tightened Cyber Reporting Rules

Continued from page 26

Comments Sought

Comments on the NOPR will be due 60 days after publication in the *Federal Register*. The commission specifically sought comment on whether to exclude EACMS from the new standard and establish the ESP as the minimum reporting threshold instead.

NERC defines an ESP as the "logical border surrounding a network to which BES cyber systems are connected using a routable protocol." EACMS include firewalls, authentication servers, security event monitoring systems, intrusion detection systems and alerting systems.

"Therefore, EACMS control electronic access into the ESP and play a significant role in the protection of high- and medium-impact BES cyber systems. Once an EACMS is compromised, an attacker could more easily enter the ESP and effectively control the BES cyber system or protected cyber asset," FERC said.

"The EACMS … are the systems that control access to the ESP. … You could consider it being the doorway," Kevin Ryan, an attorney in the General Counsel's office, explained during a presentation at the commission's open meeting Thursday. "This … limits the proposal to high- and medium-impact BES cyber systems so we can see what happens in the future. But we're not touching on low-[impact systems] at this point."

The commission also asked for comment on alternatives to modifying the mandatory reporting requirements, such as whether a request for data or information pursuant to Section 1600 of the NERC Rules of Procedure "would effectively address the reporting gap … and satisfy the goals of the proposed directive."

Safety 'Pyramid'

The NOPR was approved unanimously.

"One thing that has been observed and studied across many industries — not just electricity but in aviation, medicine and other industries — is a well-established … statistical correlation between minor issues or near misses that are far more frequent and … rare major events," said Commissioner Cheryl LaFleur, referring to what is known as "the safety pyramid."

"We need to learn from the things that don't happen but that could have happened in order to prevent the big thing that you're afraid of happening," she continued. "I think it's important that we identify and track attempted incursions into the grid's cyber defenses to help us learn from them, study the trends [and] see what we might need to do to standards."

FERC Chairman Kevin McIntyre chats with Commissioner Robert Powelson (left) and Terry Turpin, director of the Office of Energy Projects (right) before the start of Thursday's open meeting. | *© RTO Insider*

Commissioner Richard Glick, attending his first meeting, said, "We've been pretty lucky in the United States so far — at least on the electric side — in not having any significant consequences from cyber efforts.

"But we've seen it around the world already," he added, noting the 2015 and 2016 attacks in Ukraine and Schneider Electric's Dec. 14 disclosure that one of its control systems — used by power plants worldwide — was the target of an attack.

Malware

The attack, believed to be the work of nation-state hackers, targeted Schneider's Triconex industrial safety technology, which is used by nuclear generators and oil and gas plants.

Investigators said the hackers used malware to take remote control of a workstation running Triconex's safety shutdown system, then sought to reprogram controllers used to identify safety issues. One investigator called it a "watershed" attack that will likely be repeated.

The malware, which security firm FireEye named Triton, is the third type of computer virus known to be able to disrupt industrial processes. It was preceded by Stuxnet, which the U.S. and Israel allegedly used to attack Iran's nuclear weapons program, and CrashOverride (also known as Industroyer), believed to have been used in the December 2016 attack in Ukraine. (See *Experts ID New Cyber Threat to SCADA Systems*.)

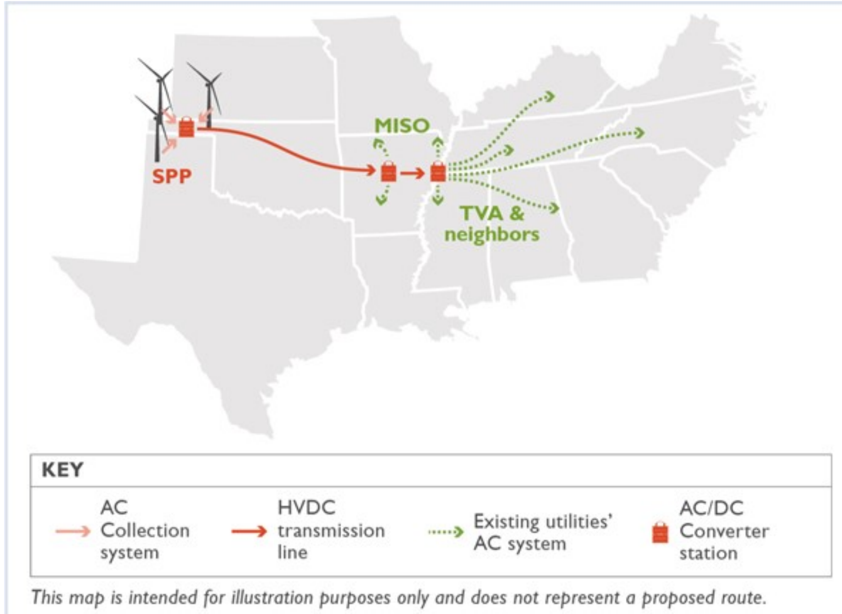
In proposing tighter disclosure rules, FERC also rejected The Foundation for Resilient Societies' January 2017 petition asking the commission to set new standards for malware detection, mitigation and reporting (AD17-9).

The commission said new standards were not necessary based on existing reliability standards and ongoing efforts.

"For example, provisions of currently effective reliability standards, including CIP-005-5 and CIP-007-6, address malware detection and mitigation. Ongoing efforts described by NERC and other commenters, such as the development of a supply chain risk management standard, should also address malware concerns," FERC said.

Clean Line Sells Okla. Portion of Plains & Eastern to NextEra

By Tom Kleckner



Plains & Eastern Clean Line | *Clean Line Energy Partners*

Clean Line Energy Partners announced Friday that it has sold all the assets of the Oklahoma portion of the multistate Plains & Eastern Clean Line transmission project to NextEra Energy for an undisclosed sum.

In a press release, Clean Line said the transaction would continue the "forward momentum" of the Plains & Eastern project and "install a new sponsor to a transmission solution to the burgeoning wind sector in Oklahoma" and SPP. Under the agreement, the company will retain its assets east of Oklahoma.

NextEra, which bills itself as the world's largest generator of wind and solar energy, is the largest owner of wind generation in the Oklahoma, with 1.7 GW of operating capacity.

Clean Line spokesperson Sarah Bray told *RTO Insider* that while the Plains & Eastern's goal is to "deliver low-cost renewable energy … to communities where there is substantial demand," the market has evolved and eastern Oklahoma "now presents a strong delivery point for Plains & Eastern." Alluding to NextEra's financial strength and operational capabilities, Bray said, "We believe that they are the right owner to take the project over the finish line."

Officials from the two companies have not disclosed the transaction's terms, though it apparently includes the transfer of the "significant portion" of the Oklahoma right of way Clean Line has already acquired.

The Plains & Eastern is a proposed 720-mile HVDC transmission project that would move 4 GW of wind energy from the Oklahoma Panhandle through Arkansas to Memphis, Tenn., with a 500-MW drop-off in Arkansas. Clean Line has been involved in commercial negotiations with potential customers, both wind generators and load-serving entities seeking power.

Clean Line has said the project's construction would begin once developers have contracts for 2 GW of capacity.

The project has been under development for eight years and has regulatory approvals from the Oklahoma Corporation Commission and the Tennessee Regulatory Authority. The U.S. Department of Energy issued a "record of decision" in 2016 after nearly six years of study and evaluation, saying it would participate in the project's development under Section 1222 of the 2005 Energy Policy Act. (See *DOE Agrees to Join Clean Line's Plains & Eastern Project*.)

However, Clean Line has yet to receive a go-ahead from regulators in Arkansas, where the project has met stiff resistance from landowners and the state's all-Republican congressional delegation. The lawmakers in March asked Energy Secretary Rick Perry to "preserve states' rights" and reverse the department's decision to partner on the project. They also are sponsoring a bill that that would prevent DOE from using eminent domain for Section 1222 transmission projects without the approval of both the governors and utility commissions of affected states.

But on Thursday, a federal judge in Arkansas rejected a lawsuit by two landowner groups challenging the department's authority to partner with Clean Line. In his order, Judge D.P. Marshall Jr. of the U.S. District Court for the Eastern District of Arkansas overruled Downwind LLC and Golden Bridge LLC's contention that the federal government exceeded its authority and denied landowners a chance to participate in the process.

"In the circumstances presented, Arkansas doesn't get to decide where the transmission line is located," Marshall wrote. "And the state doesn't have a veto over whether this line gets built."

Clean Line Executive Vice President Mario Hurtado applauded the decision.

"This critical decision confirms the strong legal basis for the Department of Energy's decision to participate in the Plains & Eastern project, and keeps the door open for future infrastructure projects and the use of Section 1222," he said.

COMPANY BRIEFS

FERC OKs 30% Cut in Reactive Supply Rates for Talen Units

Brandon Shores power plant

PJM will reduce its reactive service payments to nine Talen Energy generators by 30% under a settlement approved by FERC last week. The nine fossil-fueled units will have a reactive service annual revenue requirement of $5.14 million, a reduction of $2.23 million from existing rates (EL16-116).

Affected are Talen's Bayonne (165 MW), Camden (145 MW), Elmwood Park (71 MW), Newark Bay Cogeneration (123 MW) and Pedricktown Cogeneration (118 MW) plants in New Jersey; Mount Bethel (538 MW) and York (47 MW) in Pennsylvania; and H.A. Wagner (976 MW) and Brandon Shores (1,273 MW) in Maryland.

The settlement was prompted by FERC's September 2016 order that questioned whether the reactive power rates were just and reasonable because of the "degradation" of the units' reactive capability.

FERC Orders Settlement Talks on Chehalis Refund

FERC last week ordered settlement talks between Chehalis Power Generating and the Bonneville Power Administration over the company's efforts to recoup refunds paid to the agency (ER05-1056).

The dispute stretches back to 2005 over rates for reactive power service Chehalis provided BPA from a 520-MW plant in Washington state. In 2015, the commission found in favor of Chehalis but also determined it could not order return of the refunds because of a lack of jurisdictional authority over BPA. The D.C. Circuit Court of Appeals in May remanded FERC's order, saying the commission must evaluate the relevant equities to determine the amount of the refunds.

In last week's ruling, the commission found "it is appropriate to further develop the record to determine the amount Chehalis should be permitted to recoup," establishing a briefing schedule to develop the record on how it should "weigh the equities." But it held the briefing in abeyance in the hopes that the parties could settle the issue themselves.

FERC Approves APS-Navopache Settlement

FERC last week approved a settlement agreement between Arizona Public Service and Navopache Electric Cooperative that resolved differences over APS' proposed tariff revisions that reduced post-employment benefits other than pension expense used in calculating transmission charges under APS' formula rate (EL17-51).

"The settlement agreement resolves all issues in dispute in this proceeding," FERC said.

Navopache is a nonprofit distribution cooperative serving more than 33,000 members in eastern Arizona and western New Mexico.

SC PSC Denies SCE&G Request To Dismiss Summer Cases

The South Carolina Public Service Commission on Wednesday denied South Carolina Electric & Gas' request to dismiss two cases related to the failed attempt by the utility and state-owned Santee Cooper to expand the V.C. Summer nuclear plant.

One case seeks to eliminate charges that the SCANA subsidiary's customers are paying for the failed project. The other seeks refunds of the money its customers have paid. The PSC plans to hold a hearing next year to determine the merits of eliminating the charges and granting refunds.

Meanwhile, the state's 20 electric cooperatives have asked state legislators to form a special committee to evaluate offers for Santee Cooper. The cooperatives' contract to buy power from Santee Cooper gives them veto power over any attempt by the state to sell it. Gov. Henry McMaster has pushed to sell Santee Cooper to raise funds to repay ratepayers.

More: The State; The State

FirstEnergy Promotes Blair to Davis-Besse GM

Blair

FirstEnergy has promoted Barry Blair to general plant manager of the Davis-Besse Nuclear Power Station in Oak Harbor, Ohio.

In his new role, Blair will be responsible for overseeing the plant's operations, radiation protection, chemistry and maintenance activities. He will report to Davis-Besse Site Vice President Mark Bezilla.

Blair succeeds David Imlay, who is retiring after 30 years at FirstEnergy.

More: FirstEnergy

German Co. Buying US Wind Development Business

German energy company innogy said Friday it has agreed to buy U.S. wind development business EverPower Wind Holdings from Terra Firma Capital Partners, a British private equity firm, for an undisclosed sum.

Innogy said it expects the deal, which must be approved by the U.S. Committee on Foreign Investment, to close in the second quarter of next year.

The deal will give innogy ownership of more than 20 projects with more than 2 GW of capacity in various stages of development in seven states. It was announced three days after Peter Terium stepped down as CEO of the company, which cut its profit forecast .

More: innogy; Reuters

Volkswagen Installing EV Charging Stations as Part of Settlement

Volkswagen subsidiary Electrify America said last Monday that it will install more than 2,800 electric vehicle charging stations at roughly 500 sites in 17 of the 19 largest U.S. cities by June 2019.

The company said 75% of the charging stations will be set up at workplaces, and the other 25% will be installed at multifamily properties. EV charging station companies SemaConnect, EV Connect and Greenlots will work with Electrify America on the installations.

Continued on page 30

COMPANY BRIEFS

Continued from page 29

Volkswagen promised to spend $2 billion on EV infrastructure in the U.S. to settle its diesel-emissions cheating scandal.

More: Reuters

Alliant Buys 170-MW Wind Project from Tradewind

Alliant Energy has bought the 170-MW English Farms Wind Project from Tradewind Energy for an undisclosed sum, the companies said last Tuesday.

Alliant plans to start construction next year on the project, which it will build and own. The project is located 60 miles east of Des Moines in Poweshiek County, Iowa.

Alliant last year received permission from the Iowa Utilities Board to add up to 500 MW of wind energy in the state and has made a similar request this year.

More: Alliant Energy; Tradewind Energy

PG&E Suspends Dividends over Potential Wildfire Liability

PG&E Corp. said Wednesday it will stop issuing dividends because it could be held liable for the wildfires that swept through California Wine Country in October, causing more than $9 billion in damages.

The parent company of Pacific Gas and Electric will suspend dividends on its common stock beginning this quarter. It didn't say when it might resume them.

PG&E's most recent quarterly dividend was 53 cents/share.

More: San Francisco Chronicle

Georgia Power Must Provide Answers on Airport Outage

The Georgia Public Service Commission has given Georgia Power 30 days to answer questions about the fire that caused an 11-hour power outage at Hartsfield-Jackson International Airport on Sunday.

The PSC asked the Southern Co. subsidiary to provide the cause of the outage, what it did to restore service and what it plans to do to prevent a similar outage from occurring

Hartsfield-Jackson International Airport

in the future, among other things.

Separately, Delta Air Lines CEO Ed Bastian said his company will talk to the airport and Georgia Power about being reimbursed for the revenue it lost as a result of the outage.

More: Atlanta Journal-Constitution; Atlanta Journal-Constitution

Prevailing Winds to Build South Dakota Wind Farm

Prevailing Winds plans to move ahead with a $240 million, 200-MW wind farm in the Avon-Tripp area of South Dakota.

The company made the decision after receiving notification that it can connect the wind farm to SPP's grid and reaching an agreement to sell its power to a purchaser it didn't identify.

The company hopes to start construction on the facility in nine to 18 months and have it completed in spring 2019.

More: Yankton Daily Press & Dakotan

AMS to Build Storage Facility At Water Treatment Plant

Advanced Microgrid Solutions

Advanced Microgrid Solutions has been selected to build a 500-kW/3-MWh energy storage system at the Long Beach Water Department's Groundwater Treatment Plant.

The storage system is expected to increase the plant's operational efficiency and lower its energy costs by up to $150,000 a year, as well as provide grid services to Southern California Edison.

More: Energy Storage News

No Competing Bids for Bankrupt Exelon Unit's Plant

Bankrupt merchant generator ExGen Texas Power canceled an auction last week for a Fort Worth power plant after failing to receive any competing bids for the unit.

The move means parent company Exelon Generation will own and operate the 1,265-MW Handley Generating Plant, paying lenders $60 million to do so. Exelon's "stalking-horse" bid was the only offer ExGen received. A stalking-horse bid is the initial bid on a bankrupt company's assets, chosen by the company to avoid low bids on an asset.

ExGen filed for Chapter 11 bankruptcy in November, giving up four other gas-fired plants in the state to its lenders. Exelon said the filing was necessary to offload most of a $675 million loan due in 2021.

More: Exelon Gives up 4 of 5 Plants to Lenders in Chapter 11 Filing

PNM Resources Retires 2 San Juan Units

PNM Resources said Wednesday that its Public Service Company of New Mexico subsidiary has completed shutting down two of the four generating units at its San Juan Generating Station near Farmington.

PNM was required to retire the units by Dec. 31 as part of the Revised State Implementation Plan, which resulted from an agreement between it, the New Mexico Environment Department and EPA.

The company shut down the units earlier than expected because of mechanical problems with them.

More: PNM Resources

Xcel Energy Moving Stock to Nasdaq

Xcel Energy said last Tuesday that its stock will begin trading on the Nasdaq Global Select Market on Jan. 2.

Xcel's stock has been trading on the New York Stock Exchange. Its last day trading there will be Dec. 29.

The stock will retain its "XEL" ticker symbol.

More: St. Paul Business Journal

Continued on page 31

Company Briefs

Continued from page 30

Motion Filed to Stop SCANA From Paying Dividends

A lawyer who represents South Carolina Electric & Gas customers has filed a motion asking a judge to stop its parent, SCANA, from paying $87 million in dividends on New Year's Day.

Attorney Ed Bell filed the motion as part of a lawsuit that seeks refunds for SCE&G customers, who have paid about $1.8 billion toward the construction of two nuclear reactors that SCANA and South Carolina-owned utility Santee Cooper tried to build at the V.C. Summer Nuclear Station.

South Carolina utility regulators are considering how much SCE&G customers should pay for the reactors, which SCANA and Santee Cooper gave up trying to build in July after spending $9 billion on them.

More: *The Post and Courier*

GridWise Alliance Announces New Board Members

The GridWise Alliance last Tuesday announced its board of directors, all of whom will serve two-year terms.

Elected to their second terms were Stephen Callahan of IBM and Kerrick Johnson, founder of Utpous Insights. Elected to their first terms were former FERC Chair Joseph T. Kelliher, now with NextEra Energy; Lee Karvat of PXiSE Energy Solutions; Dan Pfeiffer of Itron; and Gil Quiniones, president and CEO of the New York Power Authority.

Additionally, Baltimore Gas and Electric CEO Calvin G. Butler Jr. joins the board as vice chair, replacing Terry Oliver of the Bonneville Power Authority.

More: *Gridwise Alliance*

Federal Briefs

McIntyre Addresses DOE NOPR After 1st Open Meeting

FERC Chair Kevin McIntyre (left) and Commissioner Neil Chatterjee before Thursday's open meeting | © *RTO Insider*

Speaking to reporters after his first open meeting as chairman, Kevin McIntyre made his first public comments regarding the Department of Energy's proposed grid resiliency pricing rule.

McIntyre's first act as chair after being sworn in on Dec. 7 was to request an extension on the Notice of Proposed Rulemaking from Energy Secretary Rick Perry.

"I arrived here I think less than 48 business hours before the [previous Dec. 11] deadline was to be upon us for action, and I didn't regard that as realistic at all for me to try to get something done in that kind of a quick fashion," he said. "I think it would by necessity end up being slapdash and that's not my style and not what the process deserves." He did not anticipate the commission needing longer than the new Jan. 10 deadline to respond.

Previous Chair Neil Chatterjee had been working on what he called an "interim" solution to the NOPR by the December deadline. McIntyre said he was "aware" of the plan but declined to comment on it. He also said that he had "zero complaints" about Chatterjee's picks for chief of staff and general counsel — Anthony Pugliese and James Danly, respectively — and "nothing but praise for everything they've done."

McIntyre also addressed the monthlong delay between his confirmation by the Senate in early November and his swearing in. While both he and Commissioner Richard Glick had to wait some time before President Trump signed their official commissions, Glick was sworn in a week earlier than McIntyre, leading some to speculate that the White House was intentionally dragging its feet on McIntyre to give Chatterjee time to work on his interim solution.

McIntyre said the delay was because it took time for him to transition cases and other matters at law firm Jones Day, where he was the global energy practice coleader, to his colleagues.

How Much Energy Does Bitcoin Use?

Fad, fraud or the next big thing, the cryptocurrency bitcoin is a big energy hog. Just how big is uncertain.

A recent *Newsweek* article said that bitcoin computer operations could consume "all of the world's energy by 2020." The website Digiconomist claims that bitcoin operations use as much energy as Denmark — enough to power 3 million U.S. households.

"Other analysts say the true figure is smaller, albeit hard to measure because it is spread around the world, generated by an unclear mix of machines and comingled with other sources of electricity demand," reports *The Washington Post*. Several experts told the *Post* that bitcoin uses as much as 1 to 4 GW, the output of one to three nuclear reactors.

More: *Newsweek*; *The Washington Post*

EPA Advisory Board Members Sue Agency over Adviser Policy

Current and former members of EPA's advisory boards sued the agency Thursday over Administrator Scott Pruitt's decision to prohibit scientists who receive agency grants from serving as advisers to it.

Continued on page 32

FEDERAL BRIEFS

Continued from page 31

The board members were joined by environmental advocacy and public health organizations as plaintiffs in their lawsuit, which was filed in the D.C. District Court.

The lawsuit argues that Pruitt did not have the authority to change EPA's ethics rules and says the policy he implemented is "unlawful, arbitrary and capricious." More than 700 people, including more than 200 scientists, have left EPA since President Trump took office, putting his administration nearly one-fourth of the way to its goal of reducing the agency's staff to levels last seen in the Reagan administration.

More: *The Washington Post*; *The New York Times*

NRC Investigating Event At Clinton Nuclear Plant

The Nuclear Regulatory Commission said Wednesday it has launched a special inspection to review the circumstances surrounding a transformer failure and the subsequent manual shutdown of the reactor at Exelon's nuclear power plant in Clinton, Ill.

The event didn't affect public health or safety, the commission said. Its two-member inspection team arrived at the plant last Monday.

More: *Nuclear Regulatory Commission*

EPA Seeks Public Input on Replacing Clean Power Plan

EPA last Monday issued an Advanced Notice of Proposed Rulemaking seeking public input on how to replace the Clean Power Plan.

The agency said that it is "soliciting information on the proper and respective roles of the state and federal governments" in setting greenhouse gas emission limits.

EPA took the first step toward repealing the rule in October, but doing that would generate a host of legal challenges, as the Supreme Court has ruled that it is required to regulate greenhouse gas emissions.

More: *InsideClimate News*

EPA Cancels Controversial Oppo Research Contract

EPA is canceling a $120,000 contract it gave to Definers Public Affairs, a Republican public affairs and opposition research firm.

The agency said it had hired the firm merely to act as a news-clipping service, but *The New York Times* reported that a vice president at the firm had filed at least 40 Freedom of Information Act requests with the agency this year and that many sought correspondence of employees who had criticized the Trump administration.

Joe Pounder, the company's president, said the decision to end the contract was mutual.

More: *The Washington Post*

DOE Providing $12M to Boost Solar Forecasting Technologies

The Department of Energy announced last Tuesday that it will provide $12 million in new funding for eight projects meant to advance solar forecasting technologies.

The projects will be carried out by partnerships between national labs, universities and the power industry. CAISO, MISO and ERCOT will be involved in three projects looking at integrating forecasting technologies with grid planning and operating systems.

Cost-sharing requirements will result in an additional $2.6 million in funding from the private sector, bringing the total funding for the projects to $14.6 million.

More: *Department of Energy*

STATE BRIEFS

RGGI States Finalize Agreement to Boost Emissions Reductions

The nine Northeast states in the Regional Greenhouse Gas Initiative last Tuesday finalized an agreement reached in August to reduce their cap-and-trade program's annual allowances for power-sector carbon dioxide emissions by 30% between 2020 and 2030. (See *RGGI States Agree to Increased Emission Reductions*.) The allowances had been falling by 2.5% annually and will continue to do so through 2020.

More: *The Baltimore Sun*

ARKANSAS

Commission Accepts SPP-AECC Pseudo-Tie Proposal

Rejecting Entergy Arkansas' protest, FERC last week approved a revised pseudo-tie agreement among the company, SPP and Arkansas Electric Cooperative Corp. (AECC), effective Jan. 1 (ER18-208). The agreement revises a 2014 pact by removing AECC's Avoca load as one of four points of pseudo-tie interconnection for AECC load located in SPP seeking to be pseudo-tied to MISO.

Entergy Arkansas, the external balancing authority under the revised agreement, was a standalone BA before being integrated into MISO in December 2013. Entergy Arkansas protested SPP's proposal, saying the RTO and AECC were making unilateral changes to the agreement, and that it could not fulfill all the obligations under the new proposal, such as including the real-time pseudo-tie value in its calculation of area control error and treating energy consumed by the AECC pseudo-tied loads as BA interchange.

The commission found Entergy Arkansas' argument to be without merit, saying the proposed changes to the revised 2014 agreement did not alter its terms and conditions "other than to remove the … interconnection point." It added that the utility can contract with MISO to provide any BA functions that it no longer performs itself.

DELAWARE

State to Hold Meeting on EPA's Plan for CPP

The Department of Natural Resources and Environmental Control said it will host a public meeting next month to give East Coast residents a chance to comment on EPA's proposal to repeal the Clean Power Plan.

Continued on page 33

STATE BRIEFS

Continued from page 32

The meeting is not one of the public hearings that EPA itself plans to hold on the CPP. Those are slated for the Midwest and West Coast.

The meeting will be held at 10 a.m., Jan. 8, at the Chase Center on the Riverfront. Speakers need to register by Jan. 5 and will get no more than five minutes.

More: Delaware

DISTRICT OF COLUMBIA

Pepco Seeks $66.2M Rate Increase

Pepco last Tuesday filed a request with the Public Service Commission to increase its rates by $66.2 million for capital expenditures in 2016 and 2017.

The Exelon subsidiary said the increase would hike the monthly bill of its average residential customer by 9.24%, or $7.54.

Pepco said it spent $89.9 million in 2016 to improve its customer service and the safety and reliability of its distribution system, and plans to spend $96.4 million in 2017 on reliability projects.

More: Pepco

ILLINOIS

Invenergy Applies for County Permit for 250-MW Wind Farm

Invenergy has applied for a permit from McClean County for a 250-MW wind farm on more than 100 parcels covering 13,000 acres in five townships.

The company expects to begin construction in 2018 or 2019 and have the wind farm operational in 2019 or 2020.

The permit will be the subject of a public hearing at the county's next zoning board of appeals meeting on Jan. 2. EDP Renewables has expressed interest in building a wind farm in the same area.

More: The Pantagraph

MAINE

FERC Denies Rehearing on Northern Maine Settlement

FERC on Thursday dismissed a rehearing request on a commission-approved settlement regarding capacity obligations in an area of Northern Maine separate from ISO-NE (ER17-192-002). The settlement allowed the Northern Maine Independent System Administrator (NMISA) to amend its rules defining resources eligible for meeting capacity obligations.

The original rule permitted a market participant to designate a resource "outside of Northern Maine Transmission System" as eligible unforced capacity if it could prove deliverability through firm transmission reservations or other means. Under the revision, the deliverability requirement was limited to resources located outside the New Brunswick balancing authority area. NMISA said the change was justified by an upgrade that removed constraints from the Tinker transformer at the New Brunswick-Northern Maine interface. NMISA's transmission system is not directly connected with the rest of New England.

The commission ordered settlement hearings in December 2016 after ReEnergy Biomass Operations, the owner of two generating plants in the NMISA control area, protested that the system administrator hadn't provided sufficient backing for the rule change. (See FERC Orders Hearing in Maine Dispute over Capacity Rules.) ReEnergy dropped its opposition after NMISA provided additional information, leading to an uncontested settlement, which FERC approved in July.

Merlin One, the owner of the 0.8-MW Caribou Generating Station, sought rehearing on the settlement. But FERC ruled Thursday that because it had not filed as in intervenor in the proceeding, the company had no standing to seek rehearing. The commission also said that Merlin One's concerns "are not errors in the delegated letter order and are beyond the scope of rehearing."

MASSACHUSETTS

Clean Energy Employment Grew 4% in 2017

The state's clean energy sector employs 109,226, up 4% from 2016, according to the Massachusetts Clean Energy Center's "2017 Massachusetts Clean Energy Industry Report." The number of clean-sector workers in the state has grown 81% since 2010, the report said.

The report found that the number of clean energy jobs grew in every region of the state last year. Southeastern Massachusetts had the largest growth at 5.9%, followed by Western Massachusetts with 5.1%.

Northeast Massachusetts, which includes Boston, accounted for nearly half (48%) of the total clean energy employment in the state, according to the report.

More: Massachusetts Clean Energy Center

MICHIGAN

State Approves $34.8M Local Tax Capture for Gas Plant in Niles

The state's Strategic Fund last Tuesday approved a request by the City of Niles Brownfield Redevelopment Authority to capture $34.8 million in local and school taxes to ready a site in Niles for a 1,000-MW gas turbine combined cycle power plant.

Indeck Niles, a subsidiary of Indeck Energy Services, plans to build the plant on 276 acres of contaminated land in Niles. Money from the tax capture will be used to alleviate brownfield conditions on the land and prepare it for development.

More: Kalamazoo News

Lansing Announces $500M Natural Gas Plant

The Lansing Board of Water and Light last Monday announced plans for a $500 million natural gas-fired power plant that will replace a coal plant slated for retirement in 2020.

The utility said it plans to break ground on the power plant a year from now and have it online in the first quarter of 2021.

More: Michigan Radio

MINNESOTA

PUC Denies Local Hiring Request on Wind Project

The Public Utilities Commission last

Continued on page 34

STATE BRIEFS

Continued from page 33

Tuesday denied a request to require EDF Renewable Energy to prioritize hiring local workers on the Stoneray Wind Project, a 105-MW wind farm it plans to begin building in Pipestone and Murray counties early next year.

The wind farm will create more than 150 construction jobs and local unions fear they will be filled by out-of-state workers.

More: *The Globe*

NEBRASKA

PSC Rejects TransCanada's Keystone Route Change

The Public Service Commission last Tuesday denied a request by TransCanada to amend its route application for its proposed Keystone XL pipeline.

The PSC late last month approved a route for the pipeline through the state, but the route was not the one TransCanada specified in its application.

Opponents of the pipeline said the commission violated state statutes by approving the alternative route. TransCanada filed to amend its route application to avoid lawsuits from the pipeline's opponents.

More: *Reuters*

NEW MEXICO

PNM Granted Rate Increase, But not for Coal Plant

The Public Regulation Commission has granted Public Service Company of New Mexico a rate increase that works out to about 8% for its average customer over the next two years.

At the same time, the commission prevented the utility from recovering nearly $150 million it spent improving the coal-fired Four Corners Power Plant, calling the spending "imprudent."

The utility and other parties in the rate case have until next week to accept or reject the commission's ruling. If they reject it, the case gets sent back to the commission for a new round of hearings.

More: *The Associated Press*

SOUTH DAKOTA

PUC Approves MidAmerican's Plan to Repower Wind Turbines

The Public Utilities Commission has approved a plan by MidAmerican Energy to spend more than $1.3 billion "repowering" its wind turbines.

The approval will allow MidAmerican to apply for a second set of production tax credits on the wind turbines from the federal government.

The wind turbines are based in Iowa, but MidAmerican provides power to customers in Alcester, Dakota Dunes, Fairview, Hudson, Jefferson and North Sioux City.

More: *Rapid City Journal*