RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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ISSN 2377-8016 : Volume 2018/Issue 4 January 23, 2017

McIntyre: Won't Commit to Probe Leak to 'Good Friend'

Mole at 888 First St. NE?

By Rich Heidorn Jr.

| © RTO Insider

WASHINGTON — FERC Chairman Kevin McIntyre declined to say Thursday whether the commission will investigate how attorney William S. Scherman allegedly learned the contents of a pending order before its issuance Jan. 12. McIntyre described Scherman, a former FERC general counsel now with Gibson Dunn, as a "good friend."

Commissioner Neil Chatterjee filed a memo on Jan. 12 reporting that Scherman had attempted to privately lobby him a day earlier on FirstEnergy's request to transfer a struggling coal-fired generator from its merchant unit to a regulated affiliate. The commission's order rejected the request as not in the public interest (EC17-88).

Chatterjee reported that Scherman called him on Jan. 11, "indicating his concern that the commission would shortly issue an order adverse to the interests of [FirstEnergy affiliate] Monongahela Power. Mr. Scherman also stated that he would prefer that the commission set the issue for hearing instead of issue an adverse order. As soon as I realized that Mr. Scherman's communication concerned the merits of the contested proceeding, I terminated the communication and did not respond to Mr. Scherman's

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More FERC & Federal News

Report: Fuel Security Key Risk for New England Grid

By Michael Kuser

A new ISO-NE report finds that New England's grid is vulnerable to a season-long outage of any of several major energy facilities, such as the 688-MW Pilgrim nuclear plant in Plymouth, Mass., which went offline during a recent cold snap after the loss of a power line leading to the plant.

That incident resulted in no reliability issues for the RTO.

"Maintaining reliability is likely to become more challenging, especially if current power system trends continue," the RTO's Operational Fuel-Security Analysis report said.

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Peak, PJM Detail Western Market Proposal

By Jason Fordney

Power industry participants got their first "peak" at a potential organized market that could rival CAISO's efforts to expand its own operations into the rest of the West.

During a conference call Jan. 16, Peak Reliability and PJM Connext sketched out details on their proposed new Western electricity market, possibly setting up a battle with CAISO over who will oversee markets and reliability across the broad region.

Vancouver, Wash.-based Peak has for months been developing a proposal to expand its Reliability Coordinator (RC) services into a new West-wide energy market. It has partnered with PJM, which brings extensive experience and sophisticated knowledge from its Eastern market

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See related story, "'Horse is out of the Barn' for CAISO Reliability Coordinator Effort," p.5.

Also in this issue:

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Subscription Rates:

Payment Frequency	PDF-Only	PDF & Web
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In This Week's Issue

COUNTERFLOW
BY STEVE HUNTOON

The Devil Went Down to Georgia

By Steve Huntoon

"Johnny, rosin up your bow and play your fiddle hard,
'Cause hell's broke loose in Georgia and the Devil deals the cards."

Huntoon

There's a process problem with the Georgia Public Service Commission's Vogtle decision, and there's a substance problem.

Process Problem

Georgia commissioners publicly and vehemently stated that Vogtle should be completed.[1] And *then* they had a hearing on whether Vogtle should be completed. See the problem?

Regulators are supposed to make reasoned decisions based on records. It's hard to do that before you have a record.

"Sentence first! Verdict afterwards," as the Queen said in "Alice in Wonderland."

Substance Problem

Last September, my column showed that the original "need" for Vogtle, in the form of a projected increase in customer demand, had basically disappeared.[2] And with simplifying assumptions favorable to Vogtle, and using Lazard cost estimates, completing Vogtle would impose excess costs of $23.6 billion on Georgia consumers over the next 40 years.

Here's a quick quiz: After eight years of construction, what percent of Vogtle is constructed? Answer in footnote below.[3]

So there was a hearing. Or more like Kabuki theater. The Public Interest Advocacy Staff (PIA Staff) of the Georgia commission showed:[4]

- Because of multiple flaws in Southern Co.'s case, "the project is uneconomic on a going forward basis by $1.6 billion." The commission's Advisory Staff agreed with PIA Staff that completing Vogtle is uneconomic at the cost estimated by Southern.[5]
- "Certain costs [$1.5 billion, excluding Toshiba's parental guarantee] for which the company is seeking recovery from ratepayers resulted from project mismanagement."
- "Had the commission been more accurately informed by the company as to the depth of the problems facing the project, the commission would have had the opportunity to assess the project status and make different decisions earlier on in the construction, when sunk costs were not so daunting an issue."
- Giving Vogtle co-owners "the right to abandon the project if any company costs are disallowed for any reason, including fraud, failure to disclose a material fact or criminal misconduct" was a "threat" and "unconscionable."

Southern, of course, disputed all this.

Given the enormity of these issues and the long-term consequences of a decision to complete or not complete Vogtle, one would have expected a deliberate, careful analysis of the record and a reasoned decision.

Instead, the last day of hearings was Dec. 14, briefs were required five days later and the commission made its decision *two days* after that. Speed readers, I guess.

Are you ready for the decision itself? The Georgia commission *without any explanation at all* simply proclaims:[6]

"Based upon careful consideration of all the evidence in the record, the commission finds as a matter of fact and concludes as a matter of law that it is appropriate to continue construction of Vogtle Units 3 & 4 under the terms set forth in this order."

Georgia, that's all the explanation you get. C'est la vie.[7]

But what should consumers expect from regulators who had announced their decision *before* the hearing? Why waste ink?[8]

More Project Delays Rewarded

Going forward, Georgia consumers have no protection against continuing project delays and overruns.[9] The Georgia commission order claims that it incents performance by reducing return on equity if target dates aren't met.

Unfortunately that is just wrong. Reduced ROE during delays is only for the periods of delay. After the project is in commercial operation, that ROE becomes part of the rate base, upon which Southern gets a generous return for at least 40 years. That is why Southern already will make an *extra* $5.2 billion over the life of the project from the delays to date.[10] Nice work if you can get it.

The longer Vogtle takes to complete, the more Southern makes.

And every electric consumer in Georgia is on the hook for whatever Vogtle ends up costing.

What site selection adviser for a large consumer of electricity will recommend locating a new facility in Georgia? Because there is no competition in Georgia,[11] any

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COUNTERFLOW
BY STEVE HUNTOON

The Devil Went Down to Georgia

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new business would have unlimited exposure to the Vogtle plant. Moody's Investor Service already downgraded JEA because it owns 206 MW of Vogtle.[12]

Customer Refund Gimmick

One last note on the Georgia commission decision: It directed that Southern refund part of the Toshiba/Westinghouse Electric settlement payment to consumers, $25 per customer per month for three months, with a bill line item saying "Vogtle Settlement Refund." Great PR, but this refund money isn't coming from Southern. It's money that otherwise would have been credited against the cost of Vogtle.

So consumers effectively will be paying Southern a generous return on their refunds for decades. Sort of like your credit card company sending you a $75 gift card, but then that $75 shows up on your next bill as a cash advance. Which you can't pay off for the next 40 years.

Oh, sorry, one more thing: The Georgia commission authorized a token 5-MW solar project to be located at, you guessed it, Vogtle. No consideration of whether that project size or location made any sense. But even more rate base for Southern.

The Sad Reality

The sad reality is that Vogtle never made sense, and this became obvious years ago. The Vogtle owners failed to oversee the failures of Toshiba and Westinghouse, failed to report the failures to the Georgia commission, and failed to provide realistic project costs and schedules. The hole became billions deeper as a result, and Southern's past and future profits grew as a result.

Instead of holding the Vogtle owners accountable for their failings, the Georgia commission is more concerned with not appearing to have made consumers pay something for nothing. So the Georgia commission approves continuing an uneconomic project, gives Southern and the new project contractor an even bigger blank check than before, and maintains the incentive of higher profitability from greater delays.

The flogging will continue until morale improves.

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1 "I do want to see this project completed," said PSC Commissioner Lauren "Bubba" McDonald. "I do not like to see failure." http://www.ajc.com/business/georgia-power-told-its-homework-vogtle-nuke-options/mnHqeJ7BdDza0U25xAxfbP/. "As an unabashed supporter of nuclear power," [PSC Chairman Stan] Wise wrote, "I intend to be present for that vote and will resign shortly thereafter so that you may appoint my successor prior to the (candidate) qualifying period for the 2018 elections." http://politics.myajc.com/news/state--regional-govt--politics/psc-wise-quit-after-vogtle-vote-governor-can-appoint-successor/Dv6bJbPTpNupmLUUe83f8J/. Commissioner Tim Echols said: "The last thing I want to do to my ratepayers is to say, 'Look, I spent $4.5 billion of your money, and you have nothing to show for it.' That's a formula for getting unelected, as far as I'm concerned." https://www.greentechmedia.com/articles/read/the-nuclear-power-war-isnt-over-yet#gs.1G0g8AQ. Echols went on to write an op-ed for *The Wall Street Journal* and an article for *Public Utilities Fortnightly* in full-throated advocacy for completing Vogtle, all *before* the hearing on whether to complete Vogtle.

2 http://energy-counsel.com/docs/Vogtle-the-Law-of-Holes-and-Two-Modest-Proposals.pdf. The column also showed that the fuel diversity argument for Vogtle was vacuous.

3 Reportedly, 40%. A shocking audit report on Vogtle's sister nuclear units in South Carolina was prepared by Bechtel in 2016. It was never meant to see the light of day, but the link to it is in the news story here: https://www.postandcourier.com/news/audit-highlighted-problems-with-south-carolina-nuclear-project-a-year/article_9ac96112-9185-11e7-9979-977331ac2233.html.

4 http://facts.psc.state.ga.us/Public/GetDocument.aspx?ID=170562. In this proposed order, the PIA Staff provides a damning "just the facts" recitation of everything wrong about Vogtle.

5 https://www.youtube.com/watch?v=JtycWKqQVk8

6 http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=170765.

7 Adding to the incredulity is that terms of the commission decision were reviewed with Southern in advance of the commission meeting. "Although Echols said he did not want to get into details about his interaction with Georgia Power over the new conditions, he added, 'Ultimately, they were read in and gave feedback' on those restrictions." http://chronicle.augusta.com/news/2017-12-21/georgia-public-service-commission-vote-allows-plant-vogtle-proceed.

8 Not part of the decision is a motion by one of the commissioners on what the decision should be. This motion refers to the uncertainty of future natural gas prices, and how Vogtle can be a hedge against high gas prices. Of course, future energy prices can't be known. But the salient fact is that a forecast of future natural gas prices is effectively a mean. Lower gas prices would mean Vogtle is even more uneconomic. Higher gas prices would mean Vogtle is less uneconomic and might even be economic. But decisions need to be based on the mean, not on one extreme or another. And here's another important point: If the gas price hedging value is significant the right thing to do is suspend Vogtle at a relatively trivial cost of $112 million for up to 10 years, which cost comes from Southern's own consultant. http://facts.psc.state.ga.us/Public/GetDocument.aspx?ID=169459 (Black & Veatch Deferral Study). The Georgia Commission decision makes no mention of this option.

9 The original project completion date was in 2017. In December 2016, Southern promised completion by 2020. Then nine months later, the completion date was pushed back almost two more years. And that date is likely more fantasy than reality. As of late 2016, two AP1000 plants in China were supposed to go into commercial operation in early 2017. https://www.reuters.com/article/us-westinghouse-nuclear/westinghouse-to-start-first-china-reactor-in-2017-sees-tens-more-idUSKCN11M1Q7. Somehow that didn't happen, and last month the China state agency said they "will hopefully begin commercial operation next year." http://www.nicobargroup.com/news-views-1/. "Hopefully"?

10 "As a result of the delays experienced by the project, the company will make considerably more profit over the lifecycle of the units than it would have had the project been completed on time. The company's profit will increase from approximately $7.4 billion to approximately $12.6 billion over the unit's entire lifecycle." http://facts.psc.state.ga.us/Public/GetDocument.aspx?ID=170562 (page 8).

11 As I've pointed out before, Vogtle and the lack of competition are joined at the hip.

12 https://www.moodys.com/research/Moodys-assigns-Aa2-and-Aa3-to-JEA-FL-sr-and--PR_904363490

CAISO NEWS

'Horse is out of the Barn' for CAISO Reliability Coordinator Effort

By Jason Fordney

CAISO said Wednesday there is no turning back on its departure from Peak Reliability in September 2019.

California's grid operator has been studying its recent move to become a reliability coordinator (RC) since early last year, and ISO officials have extensively reviewed the proposal to offer RC services to others, CAISO Vice President of Operations Eric Schmitt said during a Jan. 17 conference call.

"We didn't wake up on that morning" and decide to become a RC, Schmitt said, noting that the ISO on Jan. 2 gave Peak notice that it was departing.

"We were reluctant to do that, to be honest with you," Schmitt said. "But it's pretty evident that the marketplace is changing." He added that the Western Interconnection "is going to be even more complicated as we go forward." Having notified Peak, CAISO must now become its own RC. "The horse is out of the barn," he added.

The ISO hopes other Western balancing authorities will sign up for its RC services. Its timeline calls for comments on the plan by mid-May, a rate proposal to be submitted to its Board of Governors in late June, a FERC filing in August and final approval in October. The effort also requires approval from the Western Electricity Coordinating Council, the Regional Entity that develops the West's reliability standards.

CAISO is asking that potential customers sign nonbinding letters of intent by March 1 that make them part of the implementation process and that in the future they will sign reliability service agreements.

Schmitt said CAISO will continue to work closely with Peak throughout the transition. "We have enjoyed a great relationship with Peak," he said. "We expect that relationship will continue."

When announcing its departure, CAISO cited its expectation that the Vancouver, Wash.-based Peak will be forced to increase its fees because of Mountain West Transmission Group's likely departure from the RC, as well as Peak's recent announcement that it has partnered with PJM to offer competitive market services in addition to reliability services in the West. (See related story, *Peak, PJM Detail Western Market Proposal*, p.1, and *CAISO to Depart Peak Reliability, Become RC*.)

CAISO knows what it takes to obtain certification as an RC and has a transferable skill set for RC services, Schmitt said. The ISO is a registered balancing authority and already performs some reliability functions for its participating transmission owners, such as outage coordination, next-day planning analysis, and real-time grid monitoring and assessment.

CAISO's planned 2018 timeline for offering RC services | *CAISO*

New services in CAISO's RC area would include system operating limit methodology, review of system-wide restoration plans, stakeholder processes and other services. It also plans to offer some non-RC services, such as hosting advanced applications and physical security risk assessment that will involve separate charges. CAISO will need to add personnel to support RC functions such as customer service, NERC/WECC compliance and technology positions. There would be an RC representative in each of the ISO's two control centers located in Folsom and Lincoln.

The ISO had other public meetings on the RC proposal scheduled for Jan. 18 in Phoenix, Ariz., and Jan. 19 in Portland, Ore. Details of the initiative are provided on a new RC website.

FERC Approves CAISO Resource Adequacy, MRTU Revisions

FERC last week issued decisions related to CAISO's resource adequacy program and markets, as well as transmission service in the Pacific Northwest.

The commission approved six tariff revisions related to CAISO's resource adequacy program (ER18-1). The order allows resources in a local capacity area to provide substitute capacity based on how that capacity is reflected in resource adequacy plans. It also accepted the ISO's proposal to cap a load-serving entity's monthly local capacity and system requirements at the same levels.

The order is a follow-up to FERC's October 2015 acceptance of a CAISO filing regarding updates to its reliability services initiative stakeholder process. The filing included criteria for qualifying capacity values of certain resource adequacy resources, must-offer obligations and other modifications.

In another order, FERC (ER17-1459) addressed modifications it had directed CAISO to make regarding its 2006 Market Redesign and Technology Upgrade (MRTU). CAISO's latest compliance filing was on April 21, 2017.

FERC considered six directives it had issued, saying "we find that CAISO has either complied with the outstanding directives in the September 2006 MRTU order or has provided information demonstrating circumstances have changed such that further revisions are not necessary."

In the Northwest-related order, FERC granted Wheatridge Wind Energy's request to direct Umatilla Electric Cooperative to interconnect with Wheatridge's proposed 500-MW project and provide it with transmission service to the Bonneville Power Administration balancing area (TX17-1).

The project would serve a collector substation in the service territory of Columbia Basin Electric Cooperative, which had protested Wheatridge's application, arguing that it must be the exclusive provider of transmission service to the project. Umatilla supported the Wheatridge filing.

— Jason Fordney

CAISO NEWS

Oroville Dam Faces Lawsuit, Relicensing Threat

By Jason Fordney

Controversy is swelling over the February 2017 spillway collapse at the Oroville Dam in Northern California, after local officials last week filed a scathing lawsuit alleging corruption at the state's main water agency and lawmakers called for FERC to delay the facility's relicensing.

"Decades of mismanagement and intentional lack of maintenance" by the California Department of Water Resources led to the federally declared disaster, according to allegations in the Jan. 17 lawsuit filed by the City of Oroville against the department. Filed with the California superior court in Butte County, the suit describes maintenance issues and a culture of poor supervision, fabricated inspection reports and corruption at the agency.

"For years, DWR supervisors were more interested in lining their own pockets than ensuring the safety of the facility and its workers. Important maintenance projects were delayed or never completed, and substandard supplies were used to address vulnerabilities in the dam's armored spillway," the lawsuit alleges.

Oroville is home to the Hyatt and Thermalito power plants totaling 933 MW of capacity, which had to be shut down during the incident. During the dam's 2005 FERC relicensing proceeding, three environmental groups requested that the state pave the hillside below the emergency spillway to avoid erosion. The spillway failure generated criticism of both the DWR and FERC for ignoring the previous warnings. (See *Local Officials Appeal to FERC as Oroville Water Levels Recede*.)

Damage to the Oroville Dam

The court filing alleges a "toxic culture" at the department, describing incidents of racist and sexist behavior, employee theft and other corruption. It describes how events around the incident unfolded, including the interaction of local law enforcement with DWR officials prior to and during the evacuation, which caused chaotic and dangerous road conditions and massive traffic jams. A complaint filed through the state Government Claims Program over the Oroville situation was rejected last July because it was determined it would be better resolved by the courts, the lawsuit says.

The lawsuit does not specify financial damages but does cite physical damage to city infrastructure, equipment and personal property as well as costs related to the evacuation, loss of tax and tourism revenue, and emergency and law enforcement services.

DWR spokesperson Erin Mellon said the department does not comment on pending litigation.

On Friday, U.S. Rep. John Garamendi (D), whose district is near Oroville, petitioned FERC to postpone the pending relicensing of the dam, citing the incident and saying "a failure by FERC to delay relicensing of the Oroville Dam would be a serious abdication of its regulatory responsibility." A week earlier, nearly two dozen California state legislators filed in support of delaying the license.

Blowback over New DWR Director

The DWR has had four directors since the beginning of 2017, when Bill Croyle took over as acting director after Mark Cowin's nearly seven-year stint. Cindy Messer briefly took over from Croyle in July 2017 until Gov. Jerry Brown appointed Grant Davis to the role.

Davis only led the department until this month, resigning after an independent forensics team released its report on the dam failure. (See *Report: Regulatory Failure Caused Oroville Incident*.) He was the signatory to the department's Dec. 20 relicensing application to FERC, and he noted that the spillway incident followed California's wettest January and February in more than a century.

Brown appointed Karla Nemeth to replace Davis on Jan. 10. That decision has stirred controversy, as *The Sacramento Bee* reported last week, because Nemeth is married to Tom Philp, executive strategist of the Metropolitan Water District of Southern California, a key member of a group of public agencies known as the State Water Contractors, which are the main recipients of water stored behind the Oroville Dam.

The City of Oroville's lawsuit alleges the State Water Contractors "lobbied DWR to defer maintenance at [State Water Project] facilities, in order to reduce their own costs" and used their influence to defer needed maintenance at the facility.

Metropolitan Water District is also involved with negotiations around Brown's $17.1 billion water tunnels proposal, a large-scale project opposed by many Northern California officials and environmentalists.

CAISO NEWS

Peak, PJM Detail Western Market Proposal

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covering 13 states and the District of Columbia. (See PJM Unit to Help Develop Western Markets.)

Peak and PJM officials said the market would be nodal, with locational marginal pricing, real-time and day-ahead energy transactions, financial transmission rights, consolidated credit and market settlement, and optional services if desired by participants. These could include ancillary services such as regulation and reserve markets, demand response, a capacity market, and other features.

"Together we have climbed quite a mountain if you will, and this is the next logical step," said Brett Wangen, Peak's chief engineering and technology officer. He added that members would have a direct say in the market design and governance with the goal of reducing operating costs and improving reliability. "We definitely have been hearing the message that the industry is in need of these tools."

Wangen also addressed CAISO's own plans to withdraw from Peak and offer its own reliability services to Western participants. (See 'Horse is out of the Barn' for CAISO RC Effort.) The ISO recently said it plans to allow Peak participants enough time to review its new RC proposal and switch from Peak to CAISO for services by spring 2019.

"This urgency that is being created is a red herring," Wangen said. "People believe they have to make a decision in the next few weeks … clearly that is not the case."

Peak said it is fully funded to provide its current reliability services through August 2019 and it could explore full RTO status after it deploys a new market structure. The organization will continue to be funded at current levels through June 2020, assuming no other members withdraw before September 2019.

Peak pointed out that participants could keep Peak as their RC whether they join the Peak/PJM market, participate in other markets such as SPP or CAISO, or continue with self-scheduling and bilateral contracts. They can also use Peak's balancing authority services or continue with separate balancing authorities regardless of market participation.

Peak said it is developing a straw design for its proposed market and will complete a business case by the end of March or beginning of April. It will then lock in a final design and develop a memorandum of understanding for participation.

CAISO cited increased costs when it announced its plans to depart Peak and provide RC services across the West at much lower costs than are currently charged by Peak. During a conference call earlier this month, ISO officials said they plan to quickly transition current Peak members to CAISO services.

CAISO last month also said it will enhance and expand its day-ahead market across the footprint of its Western Energy Imbalance Market. (See CAISO Plan Extends Day-Ahead Market to EIM.) Peak Reliability member Mountain West Transmission Group is also in discussions to join SPP, and has asked SPP to become its reliability coordinator if it links up with that market.

Peak in 2014 split off from the Western Electricity Coordinating Council, a North American Electric Reliability Corp. Regional Entity based in Salt Lake City, Utah.

Peak last week said that the partnership's existing capabilities will allow a relatively quicker development of a market and that a multiple state/province market "offers public policy balance."

ERCOT NEWS

Texas Regulators Noncommittal After LP&L Hearings

By Tom Kleckner

Texas regulators concluded two days of hearings on Lubbock Power & Light's proposal to move 70% of its load from SPP to ERCOT last week, still debating whether the migration is in the public interest.

A partial settlement between LP&L and consumer groups resolved several issues before the Public Utility Commission's hearing began. Yet to be settled is whether SPP and its members will be compensated for the loss of load and who will pay for the transmission facilities necessary to integrate Lubbock into ERCOT (Docket 47576).

"I don't want anyone to leave here thinking I've approved this," warned PUC Chair DeAnn Walker in drawing the two days to a close Thursday. "I have not made a decision. There are things I'm going to need to have, if we do move forward. Without those things, there's no moving forward."

Walker was joined in her uncertainty by Commissioner Brandy Marty Marquez, who agreed the commission has "a lot to do here."

"I'm not sure where I am on the public-interest finding," she said. "If we get there, that's a big hurdle."

Commissioner Arthur D'Andrea was not as vocal on his position. The PUC will take up the issue again this week during its open meeting, though a final decision is not expected.

The commissioners also asked LP&L and several parties to formalize an agreement in principle reached following a weekend of "diligent" negotiations. The utility announced the agreement during a prehearing conference on Jan. 17.

The utility, Texas Industrial Energy Consumers, the Office of Public Utility Counsel and PUC staff agreed that LP&L's move to ERCOT is in the public interest, with the utility agreeing to paying $22 million annually to hold harmless the ISO's transmission customers over five years.

LP&L also agreed to cover the costs of an SPP study (about $172,000) to determine the effects losing its load would have on its members.

The agreement would also eliminate the proposed South Plains Project, a $247.5 million, 345-kV initiative that overlaps with the facilities necessary to integrate LP&L. Sharyland Utilities has proposed the transmission line as an economic project, but ERCOT's analysis has not been able to justify the project.

The ISO has estimated it will cost approximately $360 million to connect the partial Lubbock load to its system.

LP&L is not an SPP member, but its total load of approximately 600 MW is served through a pair of long-term contracts with Southwestern Public Service. The Xcel Energy subsidiary says it is not opposed to LP&L's efforts to join ERCOT, but it considers the move an economic one.

"Our efforts are focused on protecting the economic interests of our customers, who will bear a greater share of costs for transmission facilities that were built to serve Lubbock," said SPS spokesman Wes Reeves.

For its part, SPP wants to protect its members from incurring additional financial liabilities. "We hope the SPP footprint is held harmless from any costs associated with Lubbock's potential move to ERCOT," General Counsel Paul Suskie said.

LP&L announced in September its intention to integrate 470 MW of its load within ERCOT by June 2021, after its SPS wholesale contract expires. A second SPS deal that expires in 2044 serves the remainder of its load.

The utility is hoping for a decision before March to remain on schedule. City leaders say moving into ERCOT will give most of its citizens access to the ISO's competitive market and lower rates.

"I'm still struggling with the [megawatts] left behind," Walker said. "Lubbock, as a city, is going to have citizens treated differently. I'm concerned about not knowing what the impact of that ultimately is going to be, and us making a decision without knowing what that's going to be."

The commissioners directed staff to prepare a preliminary order. It will include language designed to prevent LP&L from switching back to SPP or another RTO and likely settle the issue of who will build the transmission facilities connected to ERCOT. LP&L has proposed working with Sharyland on that project.

ISO-NE NEWS

Conn. Regulators Signal Public Support for Millstone

By Michael Kuser

Dominion Energy could be one step closer to winning state financial support for its 2,111-MW Millstone nuclear plant in Connecticut.

The Department of Energy and Environmental Protection and Public Utilities Regulatory Authority on Monday issued a draft final report on the economic viability of the plant and signaled their support for state procurement of its energy output under a program reserved for renewable energy resources such as large-scale hydropower, wind and solar (S.B. 106).

The regulators concluded that the public procurement process for Millstone should "go forward" and asked industry stakeholders to submit comments on the report within three days — by Jan. 25 — so they can deliver a final report on Feb. 1.

"The competitive solicitation process created by the legislature is reasonable, and we will propose to the General Assembly that they pursue that process," DEEP Commissioner Robert Klee said in a teleconference with reporters.

The legislature failed to pass a bill last June that would have allowed the Waterford plant to bid into the procurement process, unlike Illinois and New York, which last year voted to support nuclear plants through zero-emission credits.

The regulators said the procurement should go forward "with certain conditions to ensure that the state's ratepayers are protected from paying above-market costs for resources that are not verified to be at risk of retirement."

Conflicting Advice

Gov. Dannel Malloy in July ordered the agencies to assess the current and future viability of the Millstone plant and determine whether the state should provide financial support (17-07-32). In reaching their preliminary conclusion, regulators said they considered confidential documents from Dominion, and stakeholder comments on a study by Levitan Associates that found the plant will likely remain profitable through 2035. (See *Millstone Likely Profitable Through 2035, Conn. Consultant Says*.)

Millstone nuclear plant

In the past few months, state regulators have heard conflicting advice on the issue. The Electric Power Supply Association earlier this month filed comments with the state contending that Millstone's profitability made any ratepayer subsidy unnecessary. EPSA cited a study by Energyzt Advisors that characterized Millstone as "perhaps the most profitable nuclear plant in the United States."

The General Assembly submitted comments in January encouraging PURA and DEEP to "hedge against natural gas by opening a bidding process to receive bids from nuclear generating facilities, including Millstone, to purchase power directly by long-term contract." (See *Conn. Regulators Hear Conflicting Advice on Millstone*.)

DEEP Analysis

The draft report said the current and projected economic viability of Millstone hinges on energy market revenues and plant operating costs.

PURA Chair Katie Dykes said the Levitan study used the best available public information to develop cost assumptions for the two Millstone units but lacked precision because of the absence of cost information from Dominion. The company submitted a two-page summary of short-term, forward financial projections in November and a longer, redacted document on Jan. 10.

While Millstone's retirement would not trigger the need for new capacity in Connecticut specifically, it would spur a need for new generation capacity in New England as a whole. Replacement capacity procured through ISO-NE would likely be natural gas-fired, exacerbating security and system reliability issues because of the region's heavy reliance on gas for power generation.

"It's important that we are issuing this report just a few days after ISO New England released their own evaluation of the region's exposure to risks of rolling blackouts if facilities like Millstone or Seabrook or LNG facilities were to be offline for a prolonged period or retire," Dykes said. (See *Report: Fuel Security Key Risk for New England Grid*.)

A Regional Issue

If Millstone's two units stopped operating, CO_2 emissions for the entire New England electric sector would increase by 80 million short tons, or 25%, through 2035, according to the regulators' report. Replacing at least 25% of Millstone's output with hydropower, demand reduction, energy storage and zero-emission renewable energy would be necessary for Connecticut not to backslide on its statutory greenhouse gas emissions reductions targets, and would cost the state's ratepayers an estimated $1.8 billion, it said.

Even with that investment, regional emissions would increase by 20%. Replacing 100% of Millstone's output with zero-carbon resources would cost Connecticut ratepayers approximately $5.5 billion, the draft report said.

In theory, regulators could use a variety of mechanisms to provide revenue stability for new and existing zero-carbon resources, including long-term power purchase contracts and ZECs.

At present, there are no mechanisms to retain Millstone and allocate the costs regionally. The RTO has indicated in this proceeding that Millstone would not be eligible for a reliability-must-run contract on a transmission security basis. And FERC earlier this month rejected the U.S. Energy

Continued on page 10

ISO-NE NEWS

Report: Fuel Security Key Risk for New England Grid

Continued from page 1

The most concerning trend: the increasing reliance on natural gas for power generation, which has led to supply constraints during times of peak load. Under normal conditions, New England relies on natural gas for about half its electric power generation, up from 15% in 2000.

The grid operator began the study in late 2016 to quantify the region's future fuel security risk. It planned to issue the report last fall but delayed publication until the furor died down over Energy Secretary Rick Perry's proposed rulemaking to financially support coal and nuclear generators (RM18-1). (See DOE NOPR Rejected, 'Resilience' Debate Turns to RTOs, States.)

"The goal was to understand the future implications of several significant trends already affecting grid operations," ISO-NE CEO Gordon van Welie said. "The results aren't a prediction, but they do shine a light on the potential reliability consequences of retirements of generators with stored fuels and the significance of liquefied natural gas, imports, renewables and oil inventories at dual-fuel power plants."

The study grew out of the RTO's experiences operating the system through challenging winter conditions and was undertaken to ensure that power plants have, or are able to procure, the fuel they need to meet demand and maintain power system reliability.

Scenarios and Risks

The study created 23 scenarios and focused on five key variables: retirements of coal- and oil-fired power plants; availability of LNG; oil tank inventories at dual-fuel generators; electricity imports from neighboring power systems; and the addition of renewable resources.

The report highlighted the concern that New England's system reliability is heavily dependent on LNG and electricity imports. While dual-fuel capability for plants can provide a key contribution to reliability, permitting for construction and emissions is difficult. All but four scenarios resulted in fuel shortages requiring rolling blackouts, indicating the trends affecting the system may intensify the region's fuel security risk.

RTO planners concluded that developing renewable resources could help reduce the fuel security risk but will also likely drive more coal- and oil-fired generators into retirement, requiring increased LNG imports to counteract the loss of stored fuels. At the same time, higher levels of LNG, electricity imports and renewables can minimize system stress and maintain reliability. But delivery assurances for LNG and electricity imports, and transmission expansion, will be needed to attain those levels, the report said.

Recent and impending retirements of oil, coal and nuclear power plants will translate into 4,600 MW of retirements by June 2021, representing more than 10% of the region's total installed capacity, the report said.

The RTO noted that about 13,500 MW of new generation was in its interconnection queue as of Dec. 1.

"Proposed wind farms make up just over half the proposals, or about 7,300 MW," the report said. "The queue also includes 1,000 MW of proposed solar (8% of the total) and 400 MW of battery storage (3% of the total). Not all these projects will be constructed; historically, about 68% of the megawatts proposed are never built."

Massachusetts Sierra Club Director Emily Norton took issue with those numbers.

The report "inexplicably underestimates the amount of renewable energy — i.e. solar and wind — that we know will be coming online in coming years," Norton said in a statement." Yet even a report rigged against clean energy shows that New England can affordably and reliably replace most of its old, dirty, dangerous and uneconomic power plants without spending billions of dollars on unnecessary gas pipelines."

ISO-NE plans to discuss the results of the analysis with stakeholders, regulators and policymakers throughout 2018 to determine the level of fuel security risk they are willing to tolerate.

| ISO-NE

Conn. Regulators Signal Public Support for Millstone

Continued from page 9

Department's Notice of Proposed Rulemaking that would have required RTOs to compensate nuclear and coal-fired facilities on a cost-of-service basis.

"It's been unfortunate that the regional discussions at [the New England Power Pool] and at the ISO have not produced any actionable mechanisms to date that could ensure that the region's ratepayers would be able to do their share in paying to retain these kinds of critical facilities, given that the entire region shares an incentive," Dykes said.

Klee said the General Assembly would have 30 days to respond to the agencies' proposal and that details of any forthcoming request for proposals would be worked out in the standard regulatory process.

ISO-NE NEWS

ISO-NE Seeks Path to Mass. GHG Cost Recovery

By Michael Kuser

Massachusetts generators are worried they won't be able recover the costs of purchasing additional greenhouse gas allowances after state regulators last month implemented stricter limits on emissions from fossil fuel plants.

ISO-NE is floating a proposed solution.

In a memo issued Friday to the New England Power Pool Markets Committee, the RTO said the early January cold spell has provoked concern among some generators "that they may consume all of their initial allocation of allowances and emit beyond that allocation before the end of the year."

The generators are questioning their ability to recover costs for buying more allowances through bilateral trading once they exhaust their initial allowances from the state. The new rules require the utilities to purchase at least 16% of their electricity from clean energy sources in 2018, stepping up by a minimum of 2 percentage points annually until 2050. (See *Massachusetts Tightens GHG Limits for Generators*.)

ISO-NE is proposing a possible recovery mechanism for instances when allowance costs cannot be reflected in a participant's energy market supply offer. The proposal hinges on a waiver request that GenOn Energy Management filed with FERC earlier this month.

Immature Market

While generators can purchase additional GHG allowances from other participants through secondary markets, the Massachusetts program is only in its first year, and secondary trading is not mature — nor are there reasonably forecasted price ranges, ISO-NE said.

That contention mirrors one made by GenOn, an NRG Energy subsidiary, in its FERC filing requesting a limited, one-time waiver enabling it to seek additional cost recovery for purchases of emissions allowances required under the Massachusetts rule. The company said the waiver would allow purchases that might be needed for the continued operation of its 1,113-MW Canal Generating Station in Sandwich, Mass., "including operation this winter, if and as they become available from other allowance holders later in 2018 and into 2019 or, as a last resort, in an auction for 2019 Massachusetts GHG allowances (which could be used to cover a 2018 shortfall on a three-to-one basis)."

GenOn asked the commission to issue an expedited order on its request by Feb. 2 and sought a shortened comment period of 14 days (with comments due on Monday).

Both ISO-NE and its Internal Market Monitor support the company's request.

Possible Remedy

GenOn worked with the Monitor last fall to devise an additional GHG cost recovery mechanism under an ISO-NE rule that permits a participant to request additional cost recovery in the event its supply offer is mitigated in the energy market, leaving it unable to recover variable production costs.

The provision requires the participant to initiate a cost recovery request within 20 days of receipt of the first invoice for allowances for the applicable operating day. If additional allowances are bought more than 20 days after operation, the regulatory timing requirements would preclude their use for cost recovery of the additional allowances.

The RTO said it would support such a waiver, provided it can review the waiver request in advance and ensure it is limited only to an extension of time to file for cost recovery. The grid operator also clarified that the additional cost recovery must only cover the cost of purchasing additional allowances.

The Monitor and RTO added a final condition: that cost recovery would only be appropriate to the extent that energy market revenues earned for operation during the period covered by the purchased allowances are insufficient to cover the cost of those allowances, and only to the extent the revenue deficiency resulted from mitigation.

Legal Challenge

GenOn last week also joined with the New England Power Generators Association to file suit in Suffolk County Superior Court against the state for "regulating emissions from the electric generation sector in the same manner as all other sectors of the Massachusetts economy."

The suit alleges that the state's GHG rules "are arbitrary and capricious because they will increase statewide greenhouse gas emissions in direct contravention of the express purposes of the Global Warming Solutions Act."

GenOn cited ISO-NE modeling of the impact of the rules on statewide GHG emissions demonstrating that generators in the region would maintain reliability by shifting electricity production from power plants in Massachusetts to other states. Relatively efficient clean-burning facilities in Massachusetts would therefore operate less, while inefficient and less clean resources in other states would run more.

Finally, the suit alleged that the state agencies exceeded their statutory authority in promulgating mass-based emissions regulations that remain in effect 30 years beyond the sunset date for any such regulations.

Canal Generating Station | *EPA*

ISO-NE NEWS

FERC Denies New England Tx Owners ROE Rehearing

By Michael Kuser

FERC on Thursday denied requests by New England transmission owners and the Edison Electric Institute for rehearing of its September 2016 ruling regarding complaints over the TOs' base return on equity.

Since September 2011, numerous parties have filed complaints seeking reductions in the New England TOs' base ROE.

The commission's 2016 order established hearing and settlement judge procedures and a refund effective date for a complaint filed by an ad hoc group of municipal utilities, Eastern Massachusetts Consumers-Owned Systems, which contended that the New England TOs' 10.57% base ROE (11.74% including incentives) should be reduced to 8.78% and 11.38%, respectively.

The commission's Jan. 18 order rejected every argument made by the TOs, saying it "has repeatedly rejected the assertion that every ROE within the zone of reasonableness must be treated as an equally just and reasonable ROE in [a Federal Power Act] Section 206 proceeding" (EL16-64-001).

| Avangrid

FERC in October rejected a bid by the TOs to increase their ROEs to the levels before they were lowered by a 2014 commission order vacated by an appellate court in April 2017. The commission said it would address the actual rate in a later remand order (ER15-414, EL11-66). (See *FERC Rejects New England Tx Owners on ROE*.)

The TOs also argued that constant litigation over the ROEs introduces risk and uncertainty in the ratemaking process.

They contended that the 15-month refund limitation in Section 206, as amended by the 1988 Regulatory Fairness Act, requires the commission to deny a complaint when a similar complaint is already pending.

"While Congress' adoption of a 15-month refund limitation in the Regulatory Fairness Act gave public utilities some rate certainty in FPA Section 206 proceedings, the New England TOs misinterpret the level of certainty that Congress provided," the commission said.

Following such logic "would prohibit any party from challenging a utility's ROE as long as there is another complaint involving that utility's ROE pending before [FERC], the commission said. "The language of FPA Section 206 does not support such a finding."

The commission also rejected the TOs' assertion that it had ignored "countervailing evidence regarding the cost of equity capital and the fact that the capital markets continue to remain unusual," insisting it "had reviewed the pleadings and evidence submitted by all parties and found that the evidence raises issues of material fact that could not be resolved based upon the record before the commission. The hearing and settlement judge procedures established in the September 2016 order are the product of that review and are the appropriate vehicle to resolve the dispute."

ISO-NE NEWS

DC Circuit Rejects New England Scarcity Pricing Challenge

By Rich Heidorn Jr.


Dynegy's 827-MW Lake Road combined cycle plant, Dayville, Conn. | *Alstom*

The D.C. Circuit Court of Appeals on Friday rejected New England generators' challenge to FERC orders on scarcity prices, saying the commission had properly considered their complaints (16-1023, 16-1024).

The New England Power Generators Association had asked the court to review two FERC orders related to ISO-NE's scarcity pricing rules and the peak energy rent (PER) adjustment, which is used to claw back some revenues earned by capacity suppliers when prices in the real-time energy market are very high.

Adjustment Events

ISO-NE each day calculates a strike price set just above the marginal cost of the RTO's most expensive generation. It also estimates PERs — essentially the difference between the real-time energy price and the strike price — for any hour in which the real-time price exceeds the strike price ("adjustment events," the court called them).

The PER value is deducted from each capacity supplier's monthly payments, regardless of whether it sold energy in the real-time market at the high price. NEPGA says most capacity suppliers clear their electricity offers in the day-ahead market, receiving the day-ahead market price, rather than the real-time price on which the adjustment is based.

The commission has acknowledged that this is a "potential inefficiency" and has approved elimination of the adjustment for the 2019/20 capacity commitment year.

Procedural Failure

The D.C. Circuit dismissed on procedural grounds NEPGA's challenge to FERC's May 2014 order rejecting a joint filing by ISO-NE and the New England Power Pool Participants Committee.

That "jump ball" filing contained two alternate proposals to address generator performance problems. The commission said neither proposal was sufficient alone, ordering ISO-NE to submit a modified version of its proposal along with increased scarcity prices suggested by NEPOOL (ER14-1050, EL14-52).

The D.C. Circuit said NEPGA lacked standing to seek review of the order because it had not previously sought rehearing from the commission.

Not Arbitrary or Capricious

The court did act on the merits of NEPGA's complaint alleging that the interaction between the scarcity prices and the PER is unjust and unreasonable.

FERC said the group had not met its burden under Section 206 to prove that the existing Tariff provisions were unjust and unreasonable (EL15-25). The commission said NEPGA's evidence — data from a Dec. 4, 2014, adjustment and a back-cast analysis — failed to consider the likelihood and size of future adjustments. It also said NEPGA did not address whether increases in day-ahead energy prices and capacity price floors might offset expected increases to the PER. (See *FERC Upholds ISO-NE New Entry Pricing; Rejects Challenges by Generators*.) The commission also rejected NEPGA's rehearing request on the complaint. (See *FERC Denies Rehearings on ISO-NE Pay-for-Performance*.)

The court said the commission's rejection of the complaint was not arbitrary and capricious, noting that "because we are dealing here with technical and policy-based determinations, the commission's judgment is entitled to judicial respect."

Second Complaint

NEPGA said the court should overturn the commission's rejection of its complaint because of the outcome of the group's second complaint challenging the PER, filed in September 2016.

In that filing, NEPGA provided an additional 20 months of data in arguing that the PER had become unjust and unreasonable because of the increased scarcity rates.

The commission granted the complaint in part in January 2017 and set the case for hearing and settlement proceedings (EL16-120). (See *ISO-NE Scarcity Rules Unfair to Generators, FERC Says*.)

An uncontested settlement in that docket is pending before the commission. It would require ISO-NE to increase the daily PER strike price hourly based on the difference between actual five-minute reserve shadow prices and the pre-December 2014 scarcity prices for 30-minute operating reserves and 10-minute non-spinning reserves ($500/MWh and $850/MWh, respectively). The adjusted PER strike price would be effective Sept. 30, 2016, through May 31, 2018, when the PER is abolished.

"We note that any settlement would not fully moot this case because the second complaint proceeding has a refund effective date of Sept. 30, 2016, whereas the complaint in this case requested a refund effective date of Dec. 3, 2014," the court said.

ISO-NE NEWS

FERC Denies FirstLight Hydro Capacity Change

By Michael Kuser

FERC on Thursday denied FirstLight Hydro Generating's request to change reservoir levels this winter at a Massachusetts hydroelectric plant, citing inadequate time to assess the impact on the endangered shortnose sturgeon (P-2485-076).

Shortnose sturgeon

FirstLight requested the temporary amendment to increase operational flexibility at its 1,167-MW Northfield Mountain Project in anticipation of potential reliability challenges in New England this winter. ISO-NE supported the request but did not say the extra capacity would be critical to reliability.

FERC sympathized with FirstLight's intentions, but ultimately sided with the shortnose.

"While we are very sensitive to the need to take all feasible steps to ensure the reliability of the electric grid, and accordingly have approved previous amendment requests by FirstLight, the presence of an endangered species in the project reservoir that may be affected by the amendment is a significant new circumstance," the commission said. "We could not lawfully approve the current amendment before completing consultation with the [National Marine Fisheries Service], a process that would require the gathering of information, followed by NMFS review and action."

In comments filed with FERC last October, NMFS indicated the sturgeon had been found in Northfield Mountain's lower reservoir, which was historically above the recognized upstream extent of the species' range.

The commission ordered that "any future proposal of a similar nature should be filed a sufficient time before the winter season such that any necessary efforts with respect to [Endangered Species Act] consultation can be completed in a timely manner."

Under federal regulations, NMFS has 135 days to complete a consultation. The commission said that "it did not appear possible" that the consultation process could be completed before March 31, the end of the period for which FirstLight requested the temporary amendment.

Technical Limits

FirstLight proposed reducing Northfield Mountain's minimum reservoir elevation from 938 mean sea level (msl) feet to 920, and bumping up the maximum from 1,000.5 msl feet to 1,004.5, increasing the potential operating range from 62.5 feet to 84.5 and available storage from 12,318 acre-feet to 15,327. The company also sought unrestricted use of the extra capacity.

According to FirstLight, the additional 3,009 acre-feet of storage would increase the facility's maximum daily generation by 2,050 MWh, or an additional 1.8 hours of generation at full load. Within current limits, it is capable of generating 8,729 MWh/day during peak load conditions.

But FERC signaled that it would seek limits on the flexibility offered by the adjustments. In its decision, the commission ordered that "any future proposal should be restricted to use during ISO-NE discretionary actions taken during emergency operations ... unless FirstLight can provide sufficient evidence why a broader amendment is appropriate."

The commission has previously granted six temporary amendments for the facility. The first three allowed FirstLight to modify operations only when ISO- NE declared an energy emergency, triggered by a forecast showing electric demand could exceed capacity reserves. The fourth and fifth did not restrict FirstLight's use of the additional storage, but the sixth, most recent amendment also restricted the use of the additional storage to declared emergencies.

Northfield Mountain includes an upper reservoir, an underground powerhouse containing four reversible pump-turbine generators and an intake/outlet structure in the Turners Falls reservoir. The 22-mile-long reservoir on the Connecticut River serves both Northfield Mountain and the Turners Falls Hydroelectric Project, for which FirstLight also holds the license.

Northfield Mountain, Turners Falls and three other hydroelectric facilities directly upstream are all currently undergoing relicensing. As part of that process, the licensees are required to conduct studies for the five facilities to analyze interrelationships in project operations and environmental effects.

Connecticut River at Turner Falls

ISO-NE NEWS

Planning Advisory Committee Briefs

LMP Data Show Congestion-Free Interface Flows

Region	Mean	Standard Deviation	Minimum	Maximum	Mean: Difference from Hub
Hub	33.94	31.16	-126.82	703.60	0.00
Boston	34.75	33.72	-125.90	701.10	0.82
CMA/NEMA	34.09	31.46	-126.46	710.14	0.16
WMA	33.84	30.78	-128.03	696.70	-0.10
SEMA	33.99	31.39	-125.90	691.01	0.05
CT	33.85	30.73	-127.70	694.43	-0.09
SWCT	33.97	30.62	-129.49	686.57	0.03
NOR	34.06	30.70	-129.94	689.56	0.13
VT	33.21	30.22	-126.18	705.44	-0.72
NH	32.60	30.61	-126.21	709.84	-1.33
RI	33.81	31.08	-126.67	693.32	-0.12
BHE	27.68	34.66	-130.45	669.50	-6.25
SME	32.14	32.11	-124.59	701.37	-1.80
ME	31.73	31.48	-123.09	687.19	-2.21

Real-time LMPs 2017 summary ($/MWh) | *ISO-NE*

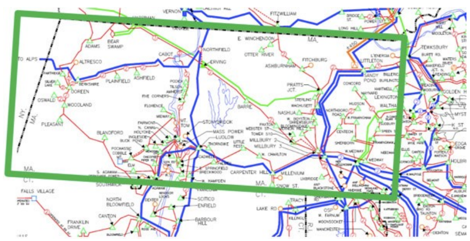
Real-time price data from 2018 indicate the ISO-NE grid is nearly free of congestion, stakeholders learned during a Planning Advisory Committee teleconference last week.

ISO-NE System Planning Engineer Victoria Rojo presented the PAC with an analysis of historical market and operational data, saying "the small congestion component of the locational marginal prices suggests there is little congestion on these interfaces."

The analysis showed that interface flows typically operate closer to the limit during on-peak hours and that portions of the system far from load centers — especially northern Maine — have high negative loss components. Rojo attributed the Maine negative line losses to new wind energy resources.

"We are effectively close to a congestion-free system," said Michael Henderson, the RTO's director of regional planning and coordination.

West Central Mass 2027 Tx Needs Assessment



West Central Mass Study Area | *ISO-NE*

ISO-NE will conduct a 2027 needs assessment for the Western and Central Massachusetts (WCMA) study area to examine any potential transmission needs 10 years out and determine their time sensitivity.

The study will consider future load distribution; resource changes in the area based on Forward Capacity Auction 11 results; 2017 solar and energy-efficiency forecasts; reliability over a range of generation patterns and transfer levels; and all applicable NERC, Northeast Power Coordinating Council and ISO-NE transmission planning reliability standards.

Comments on the preliminary draft study are due by Feb. 4 and the study should be complete in the second quarter.

Critical Load Level and Need-by Date Determination

Senior transmission planning engineer Pradip Vijayan presented staff analysis to determine the critical load level (CLL) and a need-by date (NBD) for steady-state, peak-load needs on short circuits.

The study noted that in past needs assessments, a "year of need" was used to denote summer peak load needs likely to be required within three years. However, for time-sensitive needs, the Tariff requires a specific NBD.

The RTO performs a CLL analysis for each identified need, and the results inform market participants about the quantity and general location of resources that would either satisfy the need or defer it for regulated transmission solutions.

For a time-sensitive need, the calculated CLL signals at what load level an identified need would be eliminated — which may call for additional reduction in New England load.

— Michael Kuser

FERC Denies Bear Swamp Waiver on Affiliate Info

FERC on Thursday denied Bear Swamp Power's request for a waiver of the requirement to include certain affiliate information in its market-based rate filings (ER17-603).

Bear Swamp, which is controlled by Brookfield Renewable Energy Group, operates the 600-MW Bear Swamp Pumped Storage Development and the 10-MW Fife Brook Development on the Deerfield River in northwestern Massachusetts.

In December 2016, Bear Swamp filed a notice of change in status, reporting that Nova Scotia-based Emera had acquired an indirect 50% ownership in the company. Bear Swamp requested a waiver of the requirement to include Emera generation and transmission assets in its change-in-status notice and future market-based rate filings.

Bear Swamp argued that Emera's affiliates should not be included in its horizontal market power analysis and other filings because its generation capacity is fully attributed to Brookfield, and Brookfield is not privy to Emera's acquisition activities. Emera affiliates include Emera Maine and Tampa Electric.

"Bear Swamp has not presented any compelling reason for its request," the commission said in its Jan. 18 order. "The facts that Brookfield and its affiliates are not privy to the acquisition activities of Emera and its affiliates, and that a Brookfield affiliate controls day-to-day operations of Bear Swamp's generation facility, [do] not affect the affiliate relationship between Emera and Bear Swamp."

The commission directed Bear Swamp to submit an updated market power analysis including Emera affiliates within 30 days.

Under FERC's market-based rate regulations, any company controlling 10% or more of another company is considered an affiliate.

— Michael Kuser

MISO NEWS

MISO Looks to Align Load Forecasting, Tx Planning

By Amanda Durish Cook

The MISO Planning Advisory Committee meets on Jan. 17. | *© RTO Insider*

CARMEL, Ind. — MISO is seeking to more closely harmonize its load forecasting process with the four 15-year future scenarios it creates to support long-term transmission planning, but stakeholders are wary of two ideas being floated by the RTO.

"I think it's time we move to where the ... load forecast is future-dependent," John Lawhorn, MISO senior director of policy and economic studies, said at a Jan. 17 Planning Advisory Committee meeting.

Lawhorn said that the futures created for the MISO Transmission Expansion Plan could link up with the load forecast in one of two ways: require load-serving entities to supply detailed planning-level data for each of the futures; or use the RTO's "independent" load forecast as a starting point to create forecasts for each future.

"In both cases, the level of information would be the same; it would include a 20-year forecast, energy efficiency, demand response [and] distributed generation," Lawhorn said.

"It's a paradigm shift," he said. "It's becoming increasingly evident that a long-term forecast is needed to study the futures," citing the potential for MISO to swing from summertime peak planning to possible hour-by-hour planning for a future in which smaller distributed generators provide scatterings of energy.

The biggest hitch with the current forecasting approach is that MISO can't get a clear picture of demand-side management programs, which will be instrumental in forecasting future demand, Lawhorn said.

"This is driving our planning process to areas that we haven't yet been forced to look at in this level of detail," he added.

Developed by Purdue University's State Utility Forecasting Group, MISO's independent load forecast does not draw on any of the futures, which include "limited," "continued" and "accelerated" fleet change predictions, as well as a scenario in which distributed generation and emerging technologies gain popularity. The independent forecast also does not account for individual load forecasts produced by MISO's LSEs, but instead relies only on publicly available information to predict summer and winter peak energy demand for the RTO's 10 local resource zones along with systemwide peaks.

Unlike the 10-year forecasts produced by LSEs, the Purdue forecast is for informational purposes only — not tied to any official MISO predictions — with an Applied Energy Group study lending the independent load forecast its projections for EE, DR and DG. But the RTO now thinks either the Purdue or LSE forecasts could perform a larger role in transmission planning.

MISO says its pace of fleet evolution "highlights the need to create a new source of load forecasts tailored for long-term economic planning."

"Our process lacks transparency and it lacks ... the detail needed to effectively and efficiently move energy to all areas of the MISO footprint," Lawhorn said. He also said the 140-plus separate LSE load forecasts currently lack a common set of assumptions.

Two Approaches

If the RTO decides to have LSEs prepare more detailed forecasts, they would have to ready four separate 20-year forecasts, a total of 8,760 hourly load shapes, 20 years' worth of demand-side management growth predictions, and four iterations of program penetration for EE, DR and DG.

MISO could adopt the LSE-centered approach by the 2021 MTEP at the earliest, Lawhorn said, noting that it would take a minimum of two years to modify the RTO's member website to accept more detailed information.

Currently, LSEs submit 10-year demand and energy forecasts, extrapolated for another 10 years to develop a 20-year forecast.

"By having a 20-year forecast, you might be outrunning the headlights of state regulators and local planners," said David Harlan, president of consulting firm Veriquest Group.

"That level of specificity is where the industry is heading," Lawhorn replied.

MISO's second load forecasting option involves a third-party consultant like Purdue developing a 20-year demand and energy forecast for each local resource zone by future scenario. Such a system could be in place by MTEP 19.

PAC Chair Cynthia Crane asked whether MISO plans to calibrate a long-term third-party forecast against the shorter forecasts furnished by LSEs if it takes the second route.

"Oh, absolutely," Lawhorn said.

LSE Ability to Forecast

Stakeholders are divided over how difficult

Continued on page 17

MISO NEWS

MISO Seeks Stakeholder Input as Queue Timeline Lengthens

By Amanda Durish Cook

CARMEL, Ind. — Amid growing complaints about the sluggishness of its redesigned interconnection queue, MISO is rolling out a new way for stakeholders to voice their concerns about the process.

RTO staff last week introduced a new feedback form designed specifically to capture stakeholder opinions on issues discussed during Interconnection Process Task Force (IPTF) meetings, in addition to other advice related to the queue.

"If there are any areas of the process that you see need improvement, we want to make sure that we have a channel for stakeholder voices to be heard," Arash Ghodsian, MISO manager of economic studies, said during a Jan. 16 IPTF meeting.

MISO will accept stakeholder submissions for about three weeks after IPTF meetings and post responses to the feedback on its public website, Ghodsian said.

Developer EDF Renewable Energy on Jan. 4 filed a FERC complaint against MISO's year-old interconnection queue process, contending that the procedure is still too slow to ensure the company's wind projects will beat the 2020 federal production tax credit deadline.

EDF argued that its projects can only meet the tax credit deadline if MISO completes interconnection studies by June 2019 to allow for the average 18-month construction of a wind farm. Otherwise, wind developers could risk forfeiting "tens of billions" of dollars, the company said. It urged FERC to consider a fast-tracked queue progression for vetted projects. (See *Renewables Developer Escalates MISO Queue Design Dispute*.)

"MISO will file a response to that complaint in the coming days or weeks," Corporate Counsel Michael Blackwell said.

Meanwhile, the RTO has updated its timetable for when it expects projects that entered the queue's definitive planning phase (DPP) during the past two years to execute generator interconnection agreements. The most recent predictions, divided by region, have projects clearing the DPP as late as July 3, 2019, in the wind-heavy MISO West region. In all other regions, the August 2017 cycle of projects are expected to wrap up in February or March 2019, except in the Upper Peninsula area of MISO East, where projects are slated to finish this December.

MISO's queue reform was intended to reduce the number of days that interconnection customers spend in the DPP from an average of 589 days to 460. Customers that entered the August 2017 cycle of projects are currently predicted to spend an average of 579 days in the DPP before entering an interconnection agreement.

RTO staff and IPTF leadership will also assess the need for a February task force meeting based on stakeholder requests. Wind on the Wires consultant Rhonda Peters campaigned for the additional meeting, saying a conference call was needed between now and the next scheduled meeting on March 13, considering the queue's tight timeline.

MISO will accept new generator interconnection requests until March 12 for the April 2018 DPP cycle of projects and until Jan. 22, 2019, for the March 2019 cycle.

MISO Looks to Align Load Forecasting, Tx Planning

Continued from page 16

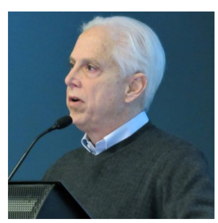
it would be for LSEs to provide more detailed forecast data.

Indianapolis Power and Light's Lin Franks said there's no reason MISO couldn't begin now to use more detailed LSE information for load forecasts.

Lawhorn responded that it's a "fairly considerable task" to coordinate forecast information from more than 140 LSEs, noting that not all of them are prepared to offer that level of detail. MISO will instead issue a survey to determine the feasibility of producing 20-year forward-looking data, he said.

Customized Energy Solutions' Ted Kuhn pointed out that forecasts are only worthwhile if MISO develops a process for historically assessing their accuracy. He said the RTO must be able to compare forecasts with actual demand.

Minnesota Public Utilities Commission staff member Hwikwon Ham said he thinks "the independent load forecast is as good as the input used."



John Lawhorn | © RTO Insider

American Electric Power's Kent Feliks said it's a "daunting amount of work to require all 140-plus LSEs to provide 20-year forecasts."

"It seems like an awful lot of resources spent … for little improvement," he said.

Other LSE representatives at the meeting said creating a load forecast would be a nominal challenge, as they already collect the data needed to prepare forecasts for each MTEP future.

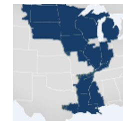
WPPI Energy's Steve Leovy asked MISO to be more specific about what kind of forecasting information LSEs will be asked to provide. "I'm concerned with what I see, to be blunt, is a half-baked proposal," he said.

Other stakeholders questioned what came of a 2017 presentation aimed at blending Purdue's independent load forecasting with LSEs' 10-year forecasts. (See *Bigger Role Seen for Independent Forecast in MISO Tx Plan*.)

Madison Gas and Electric's Megan Wisersky said that LSEs will not be able make an informed choice between the two approaches until they research the costs of preparing more in-depth forecasts.

Lawhorn said MISO is collecting input on the new pair of proposals, and that he would return to the PAC in June to discuss the RTO's take on the prevailing stakeholder opinion.

MISO NEWS



Louisiana Regulators Question MISO South Max Gen Event

By Amanda Durish Cook

Louisiana regulators are questioning why MISO called a maximum generation event and issued instructions for conservative operations in its South region during an extreme cold snap last week.

Eric Skrmetta, chair of the Louisiana Public Service Commission, told *The Advocate* that he'll seek an investigation into last week's actions in MISO South, saying there was "no reason in the state of Louisiana for electricity to become short." Commissioner Craig Greene said the agency would examine the electricity supply during the cold snap and look to identify ideas for better utility response in future frigid weather.

Reached by phone, a member of the PSC's staff told *RTO Insider* that they were in the process of reviewing the event and declined to comment further.

MISO spokesperson Mark Brown said the RTO was able to maintain grid reliability even as extreme temperatures gripped the South and multiple generation outages posed challenges.

The RTO declared conservative operations and a cold weather alert for MISO South — which spans Arkansas, Louisiana, portions of Mississippi and part of eastern Texas — beginning Jan. 15, when most of Louisiana was under a winter weather advisory. It cautioned operators in the natural gas-heavy region to prepare for fuel restrictions.

| Entergy

The region set a new winter demand record of 32.1 GW on Jan. 17 as temperatures dipped to about 30 degrees Fahrenheit below normal and winter storm warnings were issued in Louisiana. The region's all-time summer peak is 32.6 GW.

That same day, Entergy Louisiana reported that about 32,000 homes and businesses had lost power because of the winter storm, and it later thanked customers for responding to the conservation plea.

The South region resumed normal operations late on Jan. 18, after the Louisiana PSC had issued a public appeal on behalf of MISO and Entergy Louisiana asking customers to conserve energy by lowering thermostats, sealing households against outside air as much as possible and postponing laundry and bathing during the unusually cold temperatures.

Louisiana tops all other U.S. states in energy consumption per capita, in part because of the number of oil refineries and manufacturing plants on the Gulf Coast, according to a report last year by the U.S. Energy Information Administration.

MISO South Executive Director of External Affairs Kent Fonvielle said the RTO shared the Louisiana PSC's concerns about reliability.

"In extreme conditions such as this week's bitter cold in the South, MISO delivers the value of a large footprint with a diverse energy mix and greater redundancies to address various challenges to operations," Fonvielle said in an email to *RTO Insider*. "As the generation resources available to serve these extreme load conditions become strained, MISO has a set of procedures to ensure adequate supply and to keep the transmission grid stable."

He added that, in such situations, MISO South calls on support from MISO Midwest and makes purchases from other RTOs. It's also common for MISO to request that members activate their load control programs and issue public appeals for conservation, he said.

"It is rare for MISO to ask for conservation efforts, but ultimately those conservation efforts help protect the larger grid," Fonvielle said. "Our role is to coordinate the best use of the power resources available across the MISO footprint so that it is reliable and cost-effective."

Fonvielle said MISO appreciated the cooperation it received from South members, stakeholders and consumers to conserve energy during the peak conditions. He added that the RTO would perform its own review of the week's events and have staff discussions on possible areas of improvement.

FERC OKs Extended Window for MISO Capacity Auction

MISO obtained a one-time waiver of the deadline for its 2017/18 capacity auction after FERC last week agreed that technical difficulties on the RTO's market platform was reason enough to extend the offer window.

While MISO normally closes the three-day offer window for its Planning Resource Auction at 11:59 p.m. ET, it said last year network connectivity issues caused by a hardware failure forced it to extend the window until 12 p.m. on April 1. Without the extension, at least one market participant would have been unable to submit or modify its offers during the final hours of the auction on March 31, according to MISO.

In its ruling last week (ER17-2113), FERC said that extending the offer deadline ensured "all market participants had the requisite time under the Tariff to submit their auction offers." The additional time "provided sufficient, but not excessive, time for market participants to submit or modify offers," the commission said.

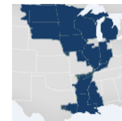
MISO had assured the commission that the waiver will "not have undesirable consequences and that no third parties are harmed."

All 10 zones in MISO cleared at $1.50/MW-day during the 2017/18 Planning Resource Auction, a result of new supply and lower demand in the Midwest. (See *All Zones at $1.50/MW-day in 5th MISO Capacity Auction*.)

Consumer rights watchdog Public Citizen questioned the waiver, claiming MISO failed to adequately describe what caused the connectivity issues or to explain what corrective actions it has planned "to avoid such disruptions in the future." FERC disagreed with the group's contention that MISO should have to provide additional evidence or detail any future plans stemming from the mishap.

— Amanda Durish Cook

MISO NEWS



MISO Readies Retirement Change

By Amanda Durish Cook

CARMEL, Ind. — MISO is close to completing a plan that would give generators three years to submit a decision to retire after signaling their intention, but some stakeholders think the changes could allow unit owners to "game the system" for allocating transmission costs.

Joe Reddoch of MISO's retirement planning group said the proposal — slated for a March filing with FERC — will close out a longtime recommendation from the Independent Market Monitor to allow generators to time their retirements according to Planning Resource Auction timelines.

Under the proposal, generation owners considering or planning a shutdown will still submit an Attachment Y notice to MISO, but the RTO will now treat all such notices as a request for suspension. Owners would no longer have to decide between a permanent retirement and a temporary shutdown with an estimated return-to-service date.

Instead, they would have three full planning years to prepare a return to service or decide to make the suspension permanent, providing additional time to decide whether to participate in the capacity auction. Suspended generators would lose interconnection service after three planning years if they don't resume operations.

"By removing the return date [requirement], we can actually consider them in our planning processes," Reddoch said during a Jan. 17 Planning Advisory Committee meeting.

Reddoch said MISO plans to continue its practice of passing *pro rata* transmission upgrade costs needed to maintain baseline reliability to unit owners who rescind their decision to retire.

Wind on the Wires' Natalie McIntire pointed out that unit owners cause unnecessary costs for new interconnection customers by deciding to suspend and then come back online after an interconnection customer has shouldered the entire cost of interconnecting to make up for the lost generation.

"We have concerns about this," McIntire said. "This treatment sort of creates an opportunity to game the system."

"They could play games right now, but they don't. They're simply looking at the viability of their assets," Reddoch said. "Right now, we create a false sense of security by modeling their return date when most of them never return."

Reddoch said the proposal will not require changes to the planning process, as planning models already assume all retiring and formerly suspended units will be offline within 36 months. MISO last year deferred the proposal while it looked into possible modeling implications stemming from the change. (See *MISO Defers Retirement Process Changes*.)

MISO Director of Planning Jeff Webb said the plan improves the auction because owners uncertain about retiring a generator can still choose to participate in auctions, but the RTO's Interconnection Planning Task Force could still explore the possibility that interconnection customers could be left holding the tab on an ultimately ineffectual network upgrade.

Other stakeholders said generation owners could potentially game the system by vacillating in and out of three-year suspensions. Reddoch pointed out that MISO's Tariff limits total suspension times to three years in a five-year period.

MISO NEWS

FERC Denies Louisiana PSC Clarification on Entergy ROEs

By Tom Kleckner

FERC last week denied the Louisiana Public Service Commission's request for clarification on one matter related to a sprawling Entergy-related case before the federal commission.

The PSC was seeking to learn what specific proceeding would determine the return on equity that would apply to amended power purchase agreements that were the subject of an August 2016 order (ER16-1251). It requested the clarification following a January 2017 FERC order denying its request for a rehearing of the 2016 ruling. FERC had said the proceeding regarding the amended PPAs was not the right forum for determining the appropriate ROEs to be applied under a replacement tariff, finding the issues raised by Louisiana regulators to be outside its scope.

The PSC said "that if the appropriate ROE … is outside the scope of the instant proceeding, it does not appear the ROE will be addressed in any [FERC] proceeding."

In its Jan. 18 ruling, FERC told the PSC it had explained in the 2016 order that issues concerning the application of ROE under Entergy's unit power sales and PPAs are pending in the massive ER13-1508 docket. FERC also noted that it had already dismissed concerns by the PSC about applying a generic ROE to the amended PPAs.

FERC last week also approved an uncontested partial settlement related to adjustments in MISO Tariff transmission formula rate templates for Entergy's operating companies (ER17-2579), directing the company to file a revised rate template in eTariff and terminating four related dockets (ER17-2579, ER16-1528, ER15-1453 and ER15-1436).

Entergy Services had objected to FERC trial staff's October 2017 recommendation that it file a revised rate template for Entergy Gulf States Louisiana, but a settlement judge in November certified the partial settlement as uncontested.

The settlement memorializes adjustments to three items in the Entergy operating companies' rate templates: excess accumulated deferred income taxes; certain permanent differences in income taxes; and the Entergy operating companies' post-retirement benefit costs other than pensions for 2014 and 2015.

MISO NEWS

OMS Urges FERC to Pass Tax Cut Benefit to Ratepayers

By Amanda Durish Cook

The Organization of MISO States on Monday called on FERC to order the nation's utilities to cut rates in response to a recent reduction in federal corporate taxes.

OMS board members last week unanimously approved sending the commission a letter outlining their position after Executive Director Tanya Paslawski introduced the idea during a conference call.

"I don't think it's anything controversial here … but we want to make sure everyone is comfortable," Paslawski said. "We're looking to file this fairly quickly."

North Dakota Public Service Commissioner Julie Fedorchak was the first to express her support.

The letter, signed by OMS Chairman Ted Thomas (also chair of the Arkansas Public Service Commission), encourages FERC to move quickly to ensure customers receive the maximum benefits associated with the recent reduction in the federal corporate tax rate. The tax reduction "directly impacts the cost of service for regulated utilities across the country," the letter said.

OMS noted that many of its members have already taken steps "to preserve the value of these cost reductions" for ratepayers within their own jurisdictions and that it is in the public interest that the savings be realized by all customers, including those for electric transmission.

"As such, the OMS members join the chorus of parties urging FERC to take all necessary action to preserve the benefits of the cost reduction from lower corporate tax rates for customers in the form of lower transmission rates for entities within its jurisdiction," the organization said.

Ever since President Trump last month signed the Tax Cut and Jobs Act, reducing the corporate tax rate from 35% to 21%, state officials across the country have called on utilities to pass the savings to their ratepayers — and some utilities have vowed to do so. The Organization of PJM States Inc. has already sent a similar letter to FERC. (See *Utilities Likely to Pass Tax Bill Gains to Customers*.)

Several OMS associate members elected to join in the letter, including the Indiana Office of Utility Consumer Counselor, the Office of Consumer Advocate of Iowa, the Michigan Agency for Energy, the Minnesota Office of the Attorney General and the Citizens Utility Board of Wisconsin. The Alliance for Affordable Energy in Louisiana also said it supported the letter.

At Thursday's open meeting, Commissioner Robert Powelson expressed his support for a measure. "I hope we do our part to make sure these tax benefits are accrued to energy users here in America," he said.

Chairman Kevin McIntyre told reporters after the meeting that he agreed with Powelson's sentiment and that the commission was considering its options.

FERC: Ameren Illinois Formula Rate Stands

FERC on Thursday again rejected a challenge to Ameren Illinois' formula rate while tamping down a rehearing request from Ameren itself (EL16-1169-001).

The ruling denying rehearing lays to rest a challenge by Southwestern Electric Cooperative and Southern Illinois Power Cooperative to Ameren's 2015 $214.4 million projected net revenue requirement. FERC largely upheld the rate in a September 2016 order while ordering Ameren to change how it accounts for contributions in aid of construction; include net operating loss carryforward in its rate base; and exclude some charges for allowance for funds used during construction from its 2016 true-up. (See *FERC Finds No Significant Problems in Ameren Rate Filing*.)

Both Ameren and the cooperatives sought rehearing of the 2016 ruling, with Ameren arguing that FERC should have dismissed the cooperatives' first challenge outright because of "nebulous and undocumented assertions." The cooperatives said FERC had broken with commission precedent that allows "parties to challenge the inputs to the formula rate in the same way as they can challenge costs in a stated rate case" because the commission declined to investigate whether the challenged costs were recoverable.

FERC rejected both arguments. "The commission's power to dismiss a pleading summarily is discretionary, and declining to exercise that power here is therefore not legal error," it told Ameren. It told the cooperatives that their interpretation of commission precedent was inapplicable because they were challenging the rate itself and not seeking "after-the-fact corrections and updates." Finally, the commission refused the cooperatives' request to expand the proceeding into a broader investigation of Ameren's expenses. Initiating such an investigation, FERC said, would be beyond the scope of the complaint.

— Amanda Durish Cook

| *Ameren Illinois*

NYISO NEWS

NYPSC Approves New CCA, 4th VDER Tranche

By Michael Kuser

New York regulators last week approved the state's third community choice aggregation (CCA) program, authorizing energy consultant Good Energy to provide five upstate municipalities with bulk purchasing of electricity and natural gas.

The Public Service Commission's Jan. 18 order allows the new CCA to serve the villages of Fayetteville and Minoa in central New York, along with the village of Coxsackie and the towns of Cairo and New Baltimore near Albany.

Authorized by the PSC in 2015 under Gov. Andrew Cuomo's Reforming the Energy Vision, CCAs can provide communities with lower energy prices as well as clean energy options, according to the PSC.

"Residential and small-business customers can reduce their energy bills, take advantage of renewable energy choices and enjoy other money-saving services thanks to the leverage enabled by the bulk purchasing available through these community-based associations," PSC Chair John B. Rhodes said.

While the five towns represent Good Energy's first programs in New York, the company has helped create CCAs for more than 60 communities in other states, serving nearly 400,000 households and providing 3.3 billion kWh annually.

The commission previously allowed 20 municipalities in Westchester County to form a CCA (14-M-0224), and last year it approved a CCA by the Municipal Electric and Gas Alliance for several towns in central and upstate New York.

Commissioner Diane Burman supported the measure, but she urged that all stakeholders affected by the decision be heard, especially low-income residents and consumer advocates.

"Out of the seven states that have done community choice aggregation, New York is the only state that has done this outside of the legislative process," Burman said.

Communities can pass local laws to join or establish a CCA, but they must ensure that residents and small businesses can choose to remain a customer of a utility or energy service company (ESCO). Good Energy will help each of the five communities select an ESCO to manage its CCA, which could begin operating during the second quarter of 2018.


PSC Chair John B. Rhodes

PSC Approves 4th Tranche of VDER

The commission last week also approved implementation of the fourth tranche in its Value of Distributed Energy Resources (VDER) tariff, continuing the transition away from net energy metering (NEM).

The PSC's VDER Phase I order of March 2017 (Case 15-E-0751) directed that distributed energy resources be compensated through the "value stack," a methodology that bases compensation on the benefits provided by the resources. (See *NYPSC Adopts 'Value Stack' Rate Structure for DER*.)

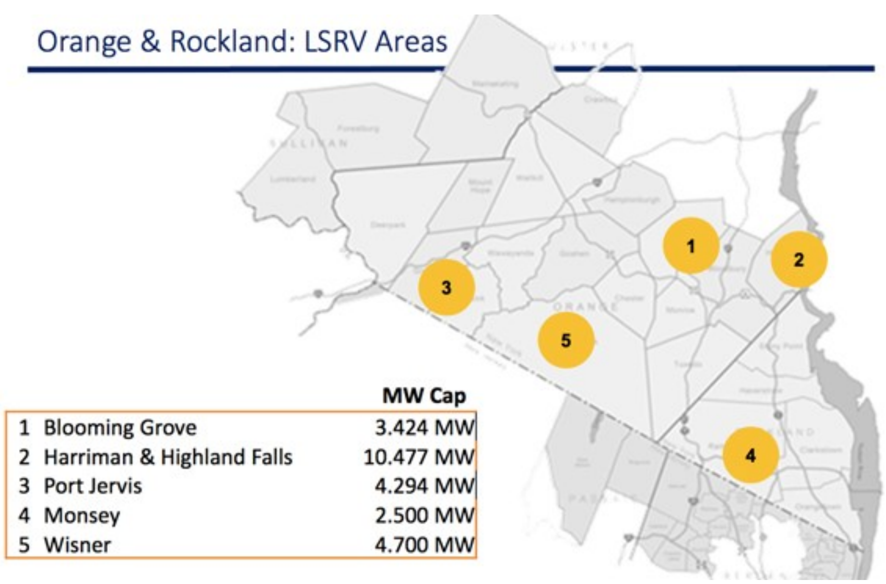
"Several transition mechanisms were in that order," Ted Kelly, assistant counsel for the Department of Public Service, told the commission. "Onsite mass market customers such as rooftop solar continue to receive net metering for all projects built before Jan. 1, 2020. Mass market customers — that's residential customers as well as small businesses —participating in community-generated distribution projects, community solar for example, receive a market transition credit, or MTC, on top of the value stack."

The commission's Jan. 18 order recognized that several utilities had exceeded the limits of their capacity allocations under the program. Orange and Rockland Utilities last April filed a letter notifying the commission that 85% of the total megawatt capacity for its tranches had been allocated, but the utility continued to assign projects to Tranche 3, which is now 28 MW over its original 12-MW size.

In December, Central Hudson Gas and Electric told the PSC that it had reached 85% of its total allocation, and then subsequently filed an update that Tranche 3 had exceeded its 19-MW capacity, with 29.7 MW currently allocated.

Burman supported the measure but said, "I continually have felt that we are doing a delicate dance of being unwilling to admit that we may have a problem in going from net metering to [VDER] and the transition of that and what that means for when we lift and completely get rid of NEM and the grandfathering issue."

Burman nonetheless said she supported the majority position of not disrupting the distributed generation effort and agreed that REV should ultimately decide alternatives to net metering.



Business Issues Committee Briefs

Natural Gas Prices Surge 260% in December

NYISO power prices jumped sharply in December on the back of sharp gains for natural gas stemming from extreme cold weather at the end of the month.

Locational-based marginal prices (LBMPs) averaged $52.63/MWh for the month, up 58% from November and nearly 20% from the same period a year ago, Robert Pike, NYISO director of market design and product management, told the ISO's Business Issues Committee (BIC) on Wednesday.

The ISO's year-to-date monthly energy prices averaged $36.56/MWh in December, a 7% increase from a year earlier. The average daily sendout was 444 GWh/day, compared with 403 GWh/day in November and 433 GWh/day a year earlier.

New York natural gas prices surged 260% over the previous month, averaging $7.59/MMBtu at the Transco Z6 hub. Prices were up 73% from a year ago. Natural gas prices for the month peaked at $31.16/MMBtu on Dec. 29, five days into a severe cold snap.

Distillate prices gained 20.1% year on year, with Jet Kerosene Gulf Coast averaging $13.47/MMBtu, up from $13.04 in November. Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $13.91, compared with $13.70 a month earlier.

The ISO's local reliability share was 9 cents/MWh, down from 20 cents/MWh from the previous month, while the statewide share dropped 18 cents/MWh from the previous month to -78 cents/MWh. Total uplift costs were lower than in November.

Ongoing JOA Dispute with New Jersey

Reviewing the Broader Regional Markets report, Pike noted that the New Jersey Board of Public Utilities last month filed a complaint with FERC against PJM, NYISO, Consolidated Edison, Linden VFT, Hudson Transmission Partners and the New York Power Authority. The complaint challenges the implementation of the mutual benefits provisions of the Joint Operating Agreement between NYISO and PJM and requests amendments to it.

Pike said the ISO last month jointly filed with the other respondents to request an extension of the Jan. 11 answer deadline to Feb. 23. The commission granted the extension, which was unopposed by the BPU.

The report also noted the ISO is taking further steps to improve modeling consistency between real-time commitment (RTC) and real-time dispatch (RTD) and examine changes to look-ahead evaluations to improve scheduling and price convergence. The ISO published a white paper on the topic last month and will further explore RTC-RTD convergence this year.

BIC Recommends ICAP Manual Revisions

The BIC also recommended revisions to the Installed Capacity (ICAP) Manual covering deliverability requirements for capacity imports from PJM, effective May 1.

Zachary Smith, NYISO manager of capacity market design, told the committee that the ISO finished modifying the documentation requirements for capacity imports across the PJM AC ties. His report outlined changes that would require PJM-based ICAP suppliers to provide NYISO with evidence of firm transmission service for all capacity import obligations on the day Spot Market Auction results are posted.

Suppliers that fail to provide documentation by the deadline would be subject to penalties and deficiency charges. Monthly deadlines, which will be posted on the ICAP event calendar, would be the same for all imports.

The committee will continue evaluating deliverability requirements for other interfaces and imports.

New Price Correction Deadlines

The committee also approved modifying price-correction deadlines by using business days rather than calendar days in the period calculation. If approved by NYISO's Management Committee and Board of Directors, the Tariff revision would reset deadlines to four business days after the market day for real-time prices, and two business days after the market day for day-ahead prices. The change is subject to FERC approval.

Michelle Gerry, the ISO's price validation supervisor, told the BIC that ISO-NE allows five business days for real-time price corrections and three days for day-ahead, while PJM stipulates 10 calendar days for both categories.

NYISO would continue to provide notice as soon as any price correction is processed and post a detailed correction within 10 days of each correction, as well as the quarterly price correction report recapping all corrections for each quarter.

NYISO Applies Wind Forecast Fee to Solar

The BIC voted to recommend Tariff changes that would charge New York's utility-scale solar facilities for acquiring solar forecasts, similar to how the ISO currently recovers the costs for wind forecasts.

The changes would be implemented in mid-2018 and would also apply to meteorological data requirements. The ISO will next year pursue Tariff modifications for the economic dispatch of solar.

In a report on solar integration, David Edelson, NYISO operations performance and analysis manager, explained that the grid operator procures a centralized solar forecast for each of its 11 load zones, for both behind-the-meter and individual utility-scale resources.

Edelson said the new cost recovery mechanism is modeled on the ISO's wind forecasting fee, which is $500/month for each resource, plus $7.50/MW (nameplate) per month. The proposed Tariff changes would modify the forecasting fee rate to $6.20/MW (nameplate) per month for both wind and solar resources so that the fees remain in line with the costs NYISO incurs to develop the forecasts.

Applying these rules to front-of-the-meter solar resources will improve NYISO's ability to reliably integrate higher levels of solar onto the grid, Edelson said.

— Michael Kuser

NYISO News

‘Transformation’ Focus of NYISO 5-Year Plan

By Michael Kuser

NYISO’s new five-year strategy calls for the ISO to align its competitive markets with New York’s efforts to promote clean energy and the “wave of change” sweeping the power industry.

All while keeping an eye on long-term reliability for the state’s grid.

“Our [2018-2022] Strategic Plan reflects an approach of continuous adaptation to shifting market dynamics and a different industry paradigm,” NYISO CEO Brad Jones wrote in the foreword to the plan, released Jan. 11. “It reaffirms our commitment to enhancing our markets, operations and planning activities.”

Jones noted that “ongoing industry transformation” and New York’s “ambitious” energy policies will “redefine” the electricity system and wholesale markets.

“Long-term reliability depends upon finding ways to harmonize the competitive wholesale markets with the state’s actions to promote clean energy,” he said.

The broadly defined plan outlines several initiatives intended to help the ISO meet that goal over the next five years:

- Enhancing energy and capacity markets to maintain reliability and improve the efficiency of markets;
- Developing the tools necessary to operate the grid with increased numbers of distributed energy resources;
- Assuming a pivotal role in integrating public policy objectives while maintaining fair and competitive markets;
- Managing the increasingly “complex, costly” systems needed to run the grid and wholesale markets; and
- Becoming equipped to manage costs “in an environment of decreasing [megawatt-hour] throughput.”

The plan also lays out more concrete steps for NYISO.

To ensure reliability and competitive markets, NYISO will upgrade its energy management and business management systems and automate the interconnection queue. The ISO also plans to improve cyber security by improving security operations and enhancing perimeter defenses as well as overall security resiliency. (See RTO CEOs Discuss Cybersecurity, Integrating Renewables.)

Grid and market operations will incorporate new capabilities to support the integration of DERs and improvements in wide area situational awareness in smart grid applications, the report said.

The plan also highlighted NYISO’s key accomplishments in 2017, which included publishing its DER Roadmap describing how the ISO expects DERs to integrate into wholesale markets and working with the New York Department of Public Service on pricing carbon into its wholesale electricity market. (See NYISO Readies Market for Energy Storage, State Targets.)

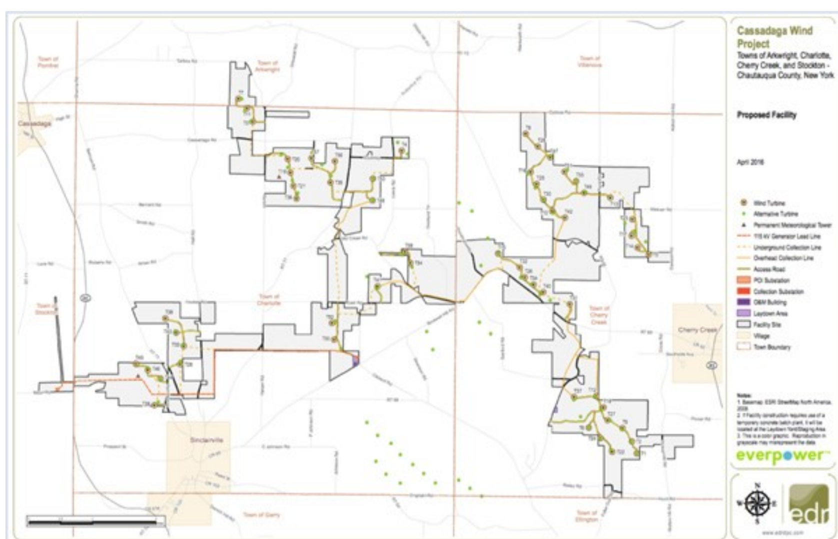
NY Siting Board Approves 126-MW Cassadaga Wind Farm

The New York Board on Electric Generation Siting and the Environment last week approved a 126-MW wind farm to be built and operated by EverPower Wind in the state’s westernmost county.

The Cassadaga Wind project will occupy about 77 acres in Chautauqua County and consist of up to 48 high-capacity, 500-foot-tall wind turbines. The wind farm would interconnect to the state’s electrical grid along the 115-kV Dunkirk-Moon transmission line.

EverPower had proposed installing up to 62 turbines but lowered the number during the public review process, which included opposition comments from Amish residents and local equestrians. Many Amish do not use electricity from the grid, and the equestrians argued that siting huge wind turbines near their riding trails could spook horses, potentially injuring both animals and riders.

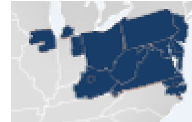
In May 2016, EverPower was the first company to apply for a siting certificate from the multiagency Siting Board, which was established under the Power NY Act of 2011 to streamline the permitting process for power plants 25 MW or greater. John B. Rhodes, chair of the Public Service Commission, also chairs the board.



The board said that the wind farm will improve fuel diversity, grid reliability and modernization of grid infrastructure, as well as benefit the host communities. The developer said the new wind farm will create “nearly 470 construction and full-time jobs with an annual payroll of more than $80 million, while paying more than $10 million to local governments and school districts over a 20-year period.”

— Michael Kuser

PJM NEWS



PJM Going it Alone on Capacity Repricing Plan

Rejects IMM, Stakeholder Requests

By Rory D. Sweeney

PJM staff will recommend that the RTO's Board of Managers approve its own capacity repricing proposal next month, ignoring an endorsement vote scheduled for Jan. 25 on an alternative proposal that had garnered more stakeholder support.

PJM CEO Andy Ott announced the decision Jan. 16 in a letter to stakeholders.

In addition to describing revisions to PJM's proposal, Ott made the case for why the RTO's proposal needs to be filed for FERC approval now and is superior to the proposal from PJM's Independent Market Monitor.

"I do not make this recommendation lightly, recognizing valid concerns arise with any course of action PJM may take, including capacity repricing," Ott wrote. "Despite all of our collective efforts in the stakeholder process, a workable consensus solution — or even a shared agreement on the nature and extent of the problem to be solved — appears unlikely."

The filing would be the culmination of the Capacity Construct/Public Policy Senior Task Force (CCPPSTF) that dominated PJM stakeholder work in 2017. PJM said its plan would accommodate generator offers from state-subsidized plants by allowing them to bid into capacity auctions but ensure they don't suppress competitive prices by removing those offers in a second "repricing" stage of the auction.

Several proposals like PJM's arose to address perceived flaws in the concept, but the IMM's proposal — fueled by concerns that PJM would unilaterally file its proposal without a clear stakeholder mandate — was the only one to receive endorsement to move forward, albeit slowly. The IMM's "MOPR-Ex" proposal would extend the minimum offer price rule to all units indefinitely. (See *MOPR-Ex Faces Uphill Battle as PJM Declines Recommendation*.)

Ott's Argument

Ott said PJM needed to seek approval quickly because of growing threats to PJM's markets. He cited FERC's rejection of the RTO's 2012 MOPR compromise, the failure of a court challenge to Illinois' zero-emissions credits program, and the "distinct potential" for additional state subsidies this year — likely a reference to New Jersey legislators' consideration of a ZEC-style program. (See *On Remand, FERC Rejects PJM MOPR Compromise* and *NJ Lawmakers Pass on Nuke Bailout in Lame Duck Session*.)

Ott said he agrees with the Monitor that MOPR-Ex "offers the most economically sound response to the issue" and "the most direct and effective means to preserve price integrity" necessary for the capacity market to work. But he said PJM's proposal is superior to MOPR-Ex because it is "substantially less punitive and less likely to frustrate the operation of state programs."

PJM CEO Andy Ott (left) and Monitor Joe Bowring at FERC | *© RTO Insider*

"PJM believes it is vital for the regional market design to respect individual state interests while protecting consumers in other states from potential cost shifts," Ott wrote. "While MOPR-Ex would not prevent state programs from providing support to individual generators, it would most likely exclude generators obtaining this support from clearing the PJM Capacity Market. PJM believes this approach is not sustainable and does not strike an appropriate balance between legitimate state interests and wholesale market integrity."

IMM Response

In an emailed response, the Monitor said it agrees with PJM that there is a conflict between state subsidies and competitive wholesale power markets.

"But the IMM disagrees with PJM's conclusion that PJM must reflect state interests even when state subsidies conflict with the operation of a competitive wholesale power market," Monitor Joe Bowring said. "PJM's capacity repricing proposal would permit state subsidized resources to push competitively offered resources out of the capacity market. That outcome is inconsistent with competition."

Bowring took issue with Ott's characterization of MOPR-Ex, saying that it's not punitive to require competitive offers and "prevent subsidized, uneconomic resources from pushing competitive, economic resources out of the market."

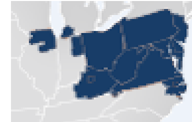
He reiterated his oft-repeated refrain that "subsidies are contagious."

"If one subsidy program is permitted to undermine the PJM capacity market, others will follow," Bowring wrote. "The MOPR-Ex approach would provide a disincentive for subsidies and would require individual states to bear the costs of state subsidies rather than spreading the costs across the other states in PJM."

Next Steps

Ott said PJM would request FERC approve its proposal for an effective date after the 2021/22 Base Residual Auction in May. He promised that "PJM will actively listen, consider, and engage on alternative design suggestions that stakeholders might offer in the course of the FERC proceeding."

PJM NEWS



FERC Rejects Challenge to PJM CP Rules on Coal Plants

By Rich Heidorn Jr.

FERC on Thursday rejected an Illinois Municipal Electric Agency challenge to PJM's Capacity Performance rules for coal plants, saying it had dealt with IMEA's concerns in its June 2015 order approving the program (ER15-623-010, *et al.*).

IMEA asked for rehearing on two aspects of the commission's May 2016 follow-up CP order on compliance, arguing that the order will "unduly disadvantage coal-fired generation owners like IMEA who separately bid in their minimal level of output and megawatts," according to FERC's summary.

Created in 1984, IMEA comprises 32 municipal electric systems and one cooperative in Illinois. It owns a 15% stake in two 800-MW supercritical units at the Prairie State Generating Co. in Southern Illinois, and 12% of Trimble County 1 (a 514-MW coal-fired unit) and Trimble County 2 (a 750-MW super-critical, pulverized coal-fired unit) located between Louisville and Cincinnati.

Nonperformance Charge Exemption

IMEA said FERC should have approved PJM's compliance filing — a response to the June 2015 order — proposing to exempt generators from nonperformance charges "if the relevant resource is not scheduled by PJM, or is online but scheduled down, subject to a determination by PJM that such an action is appropriate" under its economic dispatch.

Trimble County 1 | *LG&E and KU*

The agency said the May 2016 order was thus inconsistent with commission precedent recognizing the longer ramp-time needs of coal units.

But FERC ruled that "IMEA effectively seeks rehearing of the initial June 2015 order, not the May 2016 order."

"Having failed to seek rehearing of the June 2015 order on this issue, IMEA may not raise these issues on rehearing of the May 2016 order addressing PJM's compliance filing," the commission said.

Operating Parameter Constraints

The commission also rejected IMEA's argument that PJM's compliance proposal on operating parameter constraints failed to provide sufficient specificity or transparency.

IMEA said "it is critical that PJM be required to explicitly document the specific operating limitations it will impose on a given resource and the reasons justifying those limitations," FERC explained.

In response, the commission reiterated its May 2016 order, finding that PJM's provision of timelines and details specifying how the RTO will implement its process for reviewing unit-specific parameter limited schedules is sufficient.

The commission cited "provisions of PJM's Tariff allowing for an annual review of unit-specific parameter limitations and a case-by-case procedure through which a resource can justify operating outside of its unit-specific parameters for purposes of receiving make-whole payments. The May 2016 order further interpreted PJM's obligation to notify a seller in writing regarding PJM's determination as a commitment to provide sufficient detail regarding its determination."

Chairman Kevin McIntyre and Commissioner Robert Powelson did not participate in the ruling.

'Creative' Settlement Approved in VEPCO Revenue Spat

Despite complaints from PJM's Independent Market Monitor, FERC last week approved a settlement in a yearslong fight over how much revenue Virginia Electric and Power Co. should receive for its reactive energy supply fleet.

The commission's ruling said "the IMM's concerns are too attenuated to outweigh the bargained-for benefits of the settlement, which include rate certainty and reduced litigation costs" (EL16-89, EL17-40, ER06-554, ER17-512).

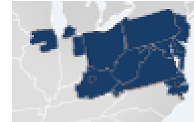
The settlement between VEPCO, North Carolina Electric Membership Corp., Old Dominion Electric Cooperative and Northern Virginia Electric Cooperative came after FERC initiated a review in July 2016 of VEPCO's rates for reactive services under Section 206 of the Federal Power Act.

The settlement maintains VEPCO's fleet-wide annual revenue requirement of $27.5 million but maintains a list compiling the revenue requirements for each generating unit totaling nearly $40 million. When VEPCO files to retire a unit, it will remove the unit's associated revenue from the compiled list. However, its fleetwide revenue requirement will remain the same, and the other parties agreed not to contest the filing until the compiled list totals less than $27.5 million.

The Monitor argued that VEPCO, a Dominion Energy subsidiary, should have to itemize how much of the $27.5 million is attributable to individual units each year. The Monitor said the information would help with calculating several of the plants' market positions, including their cost-based offers, but FERC dismissed the requests.

In a separate case, FERC also approved a settlement in the reactive rate requirements for Talen Energy's West Deptford facility (EL16-100, ER14-1193).

— Rory D. Sweeney



FERC Sides with Incumbent TOs; OKs Limits on Competition

By Rory D. Sweeney

In a win for PJM's incumbent transmission owners, FERC ruled Thursday that transmission projects driven by TOs' individual planning criteria are exempt from competitive bidding.

It also ruled against a competitive transmission developer's request to allow bidding on some immediate-need projects (ER16-2401, EL16-96).

The order approved Tariff and Operating Agreement revisions PJM proposed in response to FERC's July 2016 show cause order initiating a Section 206 proceeding over inconsistencies in the OA. (See *FERC Rejects PJM Cost Allocation on Dominion Project*.)

PJM made revisions suggested by the commission to clarify that projects driven solely by a TO's Form 715 local planning criteria are not subject to PJM's competitive process because all the costs are allocated to the zone of the TO. PJM's competitive process is limited to regionally allocated projects.

In the revisions, PJM also said it will identify local planning criteria transmission needs at the monthly Transmission Expansion Advisory Committee meetings so stakeholders can review and comment on them. The RTO will present its solutions to the issues, identifying applicable criteria, the project's zone, alternatives it considered and an explanation of the decision to assign the project to the incumbent TO.

LSP Challenge

LSP Transmission, an LS Power subsidiary, challenged both the 206 proceeding and PJM's filing in response. It said the RTO's proposed revisions stifle competition and overlap with issues outstanding in other dockets, including a request for rehearing on an order that Form 715 projects aren't eligible for regional cost allocation (ER15-1387). It also cited a show cause order in August 2016 questioning whether PJM TOs' procedures for planning supplemental projects provided stakeholders opportunity for "early and meaningful input and participation," as required by Order 890 (EL16-71).

Neither has been decided. In December 2016, the commission did reiterate an earlier ruling that Form 715 projects are not eligible for regional cost allocation. (See *FERC Rejects Challenges on Local Tx Cost Allocations*.)

Defining 'Immediate Need'

LSP also argued that FERC "got it backwards" in directing PJM to clarify the three-year threshold for immediate-need reliability projects. LSP said immediate-need projects should only be exempt from competition if the *in-service date* of a solution is within three years, rather than also exempting those with a *need date* within that period.

PJM responded that it "makes no sense" to delay a project that cannot be built within three years to conduct bidding.

FERC agreed, saying, "The fact that it may take longer than three years to build a solution to an immediate reliability need is not a persuasive justification for potentially further delaying the solution."

RTEP Approvals

In a related order, FERC on Thursday confirmed its approval of PJM's cost allocations for projects added to its Regional Transmission Expansion Plan in March 2017 (ER17-1236). Commission staff had approved the allocation tentatively in June 2017 while the commission was without a quorum.

FERC denied a protest and request for rehearing from Dominion Energy, which had argued it shouldn't be allocated all costs for two 500-kV facilities in its zone to address its Form 715 criteria. Dominion is appealing the order that allocated all Form 715 project costs to zones in which the criteria apply (ER15-1387).

Commissioner Cheryl LaFleur issued a separate concurrence, pointing out that she had dissented on the order Dominion is appealing.

"As explained in that dissent, I believe the commission should have retained regional cost allocation for transmission projects that are double-circuit 345 kV and 500 kV and above," she wrote.

FERC Approves Transfer of New Jersey Plants

FERC on Thursday gave energy investment firm Ares EIF Management the go-ahead to transfer its ownership in two New Jersey cogeneration facilities to Excalibur Power (ER16-2217, ER17-2515).

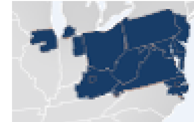
Ares owns a 242-MW facility in Logan Township and has a 60% stake in the 285-MW Chambers cogeneration facility in Carneys Point. Atlantic Power owns the other 40% of the latter plant. Both plants have FERC-approved rate schedules to provide reactive power to PJM.

The commission also granted a request to waive the 90-day notice period for transferring the plants, although Ares and Excalibur had sought to obtain the waiver by Dec. 15.

— Rory D. Sweeney

Ares' 242-MW power plant in Logan Township, N.J. | © *RTO Insider*

PJM NEWS



FERC Nixes SMECO Request to Pre-empt Md. Solar Rules

FERC last week denied a request by Southern Maryland Electric Cooperative (SMECO) to rehear a petition asking it to rule that Maryland Public Service Commission regulations on acquiring power from community solar facilities run afoul of the federal Public Utility Regulatory Policies Act (EL16-107).

SMECO and Choptank Electric Cooperative had asked FERC in 2016 to issue a declaratory order that the PSC's rules covering from which facilities and at what price state utilities must buy solar is pre-empted by PURPA. FERC declined at the time, arguing that the action was premature because the program was voluntary and neither cooperative had indicated it planned to enter into the program.

The cooperatives in December 2016 then asked the commission to grant a rehearing of the request or otherwise clarify that the ruling was without prejudice so that they could bring their complaint again if the PSC failed to address their concerns. They also requested that the filing fee be waived the second time around. Last October, SMECO filed a motion to supplement the record to include a proposed solar tariff it had filed with the PSC, along with the PSC's recommendations in response and subsequent letter denying the proposal.

SMECO argued this showed its intent to enter into the program and that it had exhausted all of its state law remedies, but FERC was not persuaded.

"SMECO's motion does not allege any change to the facts relied upon by the commission in dismissing the petition, particularly, that the community solar systems program remains voluntary and that SMECO is not subject to the program's regulations," the commission wrote in denying the rehearing.

The order did clarify that the denial was without prejudice but did not waive the filing fee. Commissioner Robert Powelson didn't participate in the order.

— Rory D. Sweeney

MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the Markets and Reliability and Members committees Thursday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage.

RTO Insider will be in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

2. PJM Manuals (9:10-9:50)

Members will be asked to endorse the following proposed manual changes:

A. Manual 14F: Competitive Planning Process. Revisions developed to incorporate construction cost caps, the subject of special Planning Committee sessions. (See "Cost Cap Discussion Continues," *PJM PC/TEAC Briefs: Jan. 11, 2018*.)

B. Manual 38: Operations Planning. Revisions developed from periodic review to include protection system/relay communication outages and PJM assessment of impact.

C. Manual 40: Training and Certification Requirements. Revisions developed to accommodate new exams and other training changes.

3. Gas Pipeline Contingencies (9:50-10:20)

Members will be asked to approve a problem statement and issue charge at their first reading to address how gas-fired generators should be compensated if PJM orders them to switch to alternative fuel sources, such as oil or a different pipeline. (See "Emergency Pipeline Switching Instructions Sparks Rights Debate," *PJM MIC Briefs: Jan. 10, 2018*.)

4. RERRA Review of EE Participation (10:20-10:40)

Members will be asked to endorse Tariff and Reliability Assurance Agreement revisions associated with the Demand Response Subcommittee proposal for the relevant electric retail regulatory authorities (RERRA) review of energy efficiency resource participation in the capacity market. (See "Rules Endorsed for Enforcing Regulator Requirements on EE," *PJM MIC Briefs: Jan. 10, 2018*.)

5. CCPPSTF (10:40-11:30)

PJM management will discuss its recommendation to the Board of Managers that the RTO file with FERC a capacity repricing proposal. Members will be asked to endorse proposed Tariff revisions for the Independent Market Monitor's MOPR-Ex proposal to extend the minimum offer price rule to all resources. (See *PJM Going it Alone on Capacity Repricing Plan*.)

Members Committee

Consent Agenda (1:20-1:25)

Members will be asked to endorse:

B. Tariff revisions related to the procedures associated with 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*.)

1. FTR Modeling, Performance & Surplus (FTRMPS) (1:25-1:40)

Members will be asked to endorse 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. (See "FTR Changes in the Works," *PJM MIC briefs: Dec. 13, 2017*.)

2. CPPSTF (1:40-2:10)

Members will be asked to endorse proposed Tariff revisions associated with the proposal developed by the CCPPSTF. (See MRC item 5 above).

3. Incremental Auction Senior Task Force (IASTF) (2:10-2:25)

Members will be asked to endorse proposed Tariff and Operating Agreement revisions for proposal A", which would reduce the number of Incremental Auctions from three to two following each Base Residual Auction. PJM says the change will reduce the opportunities for BRA sellers to "shop" for the cheapest replacement capacity while allowing them to cure a physical inability to satisfy their commitments. (See "Incremental Auction Revisions Endorsed," *PJM Markets and Reliability Committee Briefs: Dec. 21, 2017*.)

4. RERRA Review of Energy Efficiency Participation (2:25-2:40)

Members will be asked to endorse proposed Tariff and Reliability Assurance Agreement revisions for the RERRA review of energy efficiency resource participation in the capacity market. (See MRC item 4 above).

— Rory D. Sweeney

SPP NEWS

Strategic Planning Committee Briefs

Committee to Lead Response to FERC's 'Resilience' Request

OKLAHOMA CITY — SPP's Strategic Planning Committee last week decided it will respond to FERC's request for a definition of "resilience," rather than losing valuable time turning the effort over to a newly created task force.

The commission on Jan. 8 rejected Energy Secretary Rick Perry's call for cost-of-service payments to coal and nuclear generators, instead creating a new docket (AD18-7) requiring RTOs and ISOs to answer two dozen questions about how they define and assess resilience. FERC said it will use the response to determine whether additional action is necessary. (See *DOE NOPR Rejected, 'Resilience' Debate Turns to RTOs, States*.)

Grid operators must respond by March 9.

American Electric Power's Richard Ross, stressing the importance of stakeholder feedback, asked, "Will the creation of a task force end up consuming two-thirds of the time needed to get feedback?"

During the SPC's Jan. 18 meeting, SPP staff initially suggested creating a forum in which they could solicit member concerns and input on resiliency issues, but they eventually yielded to the SPC's management role to save time.

"Let's start the discussion and see what happens," SPP CEO Nick Brown said. "Using the whole Strategic Planning Committee is the best approach. Let's let our team of experts put straw comments together, and see where they fly."

Nick Brown | © RTO Insider

Brown assured the committee he is, and will be, in "constant contact" with his counterparts to track progress at other RTOs, and said there was little appetite for asking FERC for an extension.

"I suggest we move ahead as best we can, using our existing stakeholder process," he said.

Asked whether this was the commission's effort to end up with resiliency standards, Brown said he didn't know. "I think FERC is just looking for guidance on this. It's a new commission, and there's a lot of different thoughts on that commission."

FERC has started the dialogue by inviting feedback on its suggested definition of resilience: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or rapidly recover from such an event."

SPC Chair Mike Wise, with Golden Spread Electric Cooperative, said he would work with the committee's staff secretary Michael Desselle and SPP General Counsel Paul Suskie to create a timeline and process for gathering input.

| © RTO Insider

Energy-only Resources Report Leads to Discussion, not Results

A staff report on including energy-only resources in SPP's transmission planning process generated significant debate but did not result in an action item.

Staff reminded the committee several times that it was only presenting a status report, and that it would provide more information in the future.

Mike Wise | © RTO Insider

"It's pretty clear from the discussion we have some concerns," Wise said. He and Desselle "want to spend some time looking at this before we get back to you."

Staff said they are attempting to develop and adopt policies that better align SPP's generation interconnection, transmission service and integrated transmission planning processes to "provide value proportional to cost when considering capacity and energy-only resources."

Jay Caspary | © RTO Insider

Jay Caspary, SPP's director of research, development and special studies, said this will address a perception that there is an "inequity of costs associated with market access and transmission expansion" allocated to load-serving entities when compared to non-LSE interconnection customers.

As the discussion dug deeper into the weeds, it was evident that stakeholder concerns ranged in many different directions, from the meaning of firm and non-firm transmission service to the length of time it takes proposed projects to get through the interconnection queue.

Caspary highlighted one equity issue as the "big one": LSEs or merchants with energy resources compete equally in the market with those that have capacity resources and typically incur lower costs with associated

Continued on page 30

SPP NEWS

Commission OKs SPP Price Corrections

FERC last week approved SPP's request to issue price corrections and resettlements for a two-week period in December 2016, stemming from Omaha Public Power District's retirement of its Fort Calhoun nuclear plant (ER17-2495).

After OPPD deregistered Fort Calhoun from SPP's Integrated Marketplace on Dec. 1, 2016, the RTO established a replacement settlement location to recognize previously awarded transmission congestion rights (TCRs) at the plant. However, the market software did not model the replacement location's correct shift factors, resulting in an overstated marginal congestion component and understated TCRs. The error was not corrected until Dec. 14.

In a September 2017 filing with FERC, SPP said the error did not affect other settlement locations. It requested commission approval for the repricing because it did not notify market participants of the contemplated price correction within five calendar days of the operating day, as required by its Tariff.

SPP told FERC the modeling errors were associated with the Fort Calhoun deregistration and were "human performance anomalies that have since been corrected." The RTO said it can recalculate the prices "with accuracy," ensuring that market participants that "unfairly suffered" from the error will be made whole and creating only a "minor monetary impact" for other participants.

The resettlements will amount to $145,000 in net payments to TCR holders at the location, and a net charge of $400 to the virtual transactions.

— Tom Kleckner

ERCOT, SPP Extend Winter Peak Records

Just as it projected a day earlier, ERCOT set a new winter peak of 65.73 GW Wednesday morning. The demand was almost 3 GW higher than the previous record of 62.86 GW on Jan. 3. (See *SPP Resets Winter Peak Record, ERCOT Set to Follow*.)

The ISO said historic low temperatures in Texas resulted in multiple new peaks before demand settled on the new record between 6 and 7 a.m. Single-digit temperatures extended from North Texas to the Gulf Coast overnight, stranding trucks on icy highways.

ERCOT said it has sufficient generation resources to meet forecasted demand, but it also issued a news release Wednesday offering conservation tips to consumers.

SPP also set yet another winter peak when it recorded demand of 43.58 GW at 7:23 a.m. Wednesday. That surpassed the Jan. 16 record of 42.71 GW.

MISO tweeted late Wednesday night that MISO South had also set a new winter peak but did not say the exact figure.

— Tom Kleckner

Strategic Planning Committee Briefs

Continued from page 29

market access.

"We could determine all network load in the footprint is firm," Wise said. "That's one way to eliminate much of this issue."

"That may be very well where we end up," said Lanny Nickell, SPP vice president of engineering. "We were trying to limit our creative thinking to what we felt we could accomplish. These are just ideas, not the end-all, be-all solutions to all the concerns we've been hearing."

Staff said they would narrow a list of "modification considerations" — and "not proposals," Nickell clarified — and incorporate the SPC's feedback into a whitepaper, to be presented to the committee in the future.

Until then, much of the project's burden could fall onto the Generator Interconnection Improvement Task Force (GIITF), which has been asked to address the overloaded interconnection queue and new requirements from FERC's proposed rulemaking initiatives.

The GIITF in April intends to share with the Markets and Operations Policy Committee details on its three-stage process to clear the queue's backlog. The group expects its next major issue to be rules accommodating battery storage, following a "dozen or so" requests for storage in the latest queue.

"That's a bigger and bigger item for us to deal with," said SPP's Steve Purdy, the GIITF's staff secretary. "We have a lot to accomplish by October."

The MOPC recently granted the task force a one-year extension to develop a replacement for SPP's current interconnection process. (See "Generator-Interconnection Task Force Extended for 1 Year," *SPP Markets and Operations Policy Committee Briefs*.)

Governance Committee Reviewing SPP's Committee Structure

Brown told the SPC that the Corporate Governance Committee is reviewing SPP's governance structure to ensure it still matches where the RTO is today — and will be soon with the possible integration of the Mountain West Transmission Group.

SPP's footprint touches 14 states, stretching from East Texas to the Canadian border, having added Nebraska utilities and the Integrated System since 2009.

"We need to put some thought into the governance structure as we continue to grow," Brown said. "Is a committee structure we put in place in 2003, and changed incrementally, appropriate for where we are today? It's time. We just haven't sat down and taken a detailed look."

The Finance Committee is also moving forward with changes to increase transparency into SPP's budget, which Brown said raises questions about the RTO's withdrawal fee.

"All those things fit together," he said, promising the SPC and Board of Directors will stay informed of the progress.

— Tom Kleckner

SPP NEWS

SPP Stakeholders Still Struggling on BTM Reporting

By Tom Kleckner

OKLAHOMA CITY — SPP's Markets and Operations Policy Committee last week continued to hash through the difficulties of reporting behind-the-meter (BTM) load, a holdover issue from its previous two meetings.

In July, the committee directed a stakeholder group to address "inconsistency and uncertainty" over which BTM generation qualifies as network load. In October, the committee rejected the Regional Tariff Working Group's proposal of a 1-MW threshold for reporting BTM network load, and the Board of Directors declined to reverse the decision on an appeal by Southwestern Public Service. (See "Stakeholders Unable to Reach Consensus on Network Load," *SPP Markets and Operations Policy Committee Briefs*.)

SPP staff shared with the MOPC and the Strategic Planning Committee initial results of a survey of network integration transmission service (NITS) customers. The survey focused on NITS load reporting, with an emphasis on grandfathered agreements (GFAs), BTM generation and "special circumstances."

"It was unclear to us in whether all the behind-the-meter gen was identified, and then netted with the load," said SPP COO Carl Monroe. "There was some controversy as to whether you can net the load with behind-the-meter generation."

Monroe said staff are reviewing the survey responses and asking follow-up questions, such as:

- What load and BTM generation is netted versus added?
- Why are some grandfathered megawatts not being included in resident load? (Resident load is a term SPP uses to ensure all load is paying Tariff rates.)
- What are the details of the "special circumstances"?

Monroe said the aim is to foster continued discussion and education, and to determine the consistency of members' NITS reporting practices. He hopes to produce a final report in April.

"One of the real concerns is that stakeholders with network load may not really understand what needs to be reported. Your survey results may indicate a lack of knowledge," said Golden Spread Electric Cooperative's Mike Wise. "That is what I was hopeful of finding. You are really highlighting some of the folks in our footprint don't understand the rules and don't understand FERC's requirements."

"We just asked what people were doing. We didn't proclaim what needed to be done," Monroe responded.

At the same time, SPP's legal staff met with FERC to gain a better understanding of what is and what isn't net metering.

"As we thought, since SPP has a *pro forma* Tariff, all load, if reported, can't be netted," said General Counsel Paul Suskie. "If somebody thinks they have a good case because of behind-the-meter load, it can be filed at FERC. To our knowledge, no SPP member has ever done that."

Suskie said his department is working to further clarify for members what the BTM rules are today, and "what it would be tomorrow if we make a filing at FERC."

"Once we get the results finalized and understood, we can see which ones don't line up with what we believe FERC has said through its pronouncements," Monroe said.

MOPC Chair Paul Malone, of Nebraska Public Power District, pushed unsuccessfully for a face-to-face educational meeting to help bring some consistency to network load reporting and "make sure we have a legal understanding of what FERC requires."

"That's critical, because that's what billing is based on," he said. "I think some of it is just different interpretations," he said. "Looking at the [survey] items, it's no wonder. 'GFAs'? Lots of issues there. 'Special circumstances'? I think we're getting murkier, rather than clearer."

Kansas City Power & Light's Denise Buffington pressed both the MOPC and the SPC as to whether the 1-MW exemption would go before the Board of Directors next week. Monroe reminded members the board took no action on SPS' appeal; Suskie said SPS could still place the issue on the agenda.

"I thought we made a commitment that it should be on the agenda in January," said Board Chair Jim Eckelberger.

An agenda and meeting materials for the board's Jan. 30 meeting had yet to be posted as of Monday.

Suskie said staff will present the board with draft reporting rules based on its "pretty extensive" discussion with FERC and the survey results "later this month."

Separately, MOPC approved a revision request (RR 251) from the Supply Adequacy Working Group that addresses three issues FERC used in once again rejecting SPP's resource adequacy package last year. (See *FERC Again Rejects SPP's Resource Adequacy Revisions*.)

The commission said:

- SPP's proposal failed to include requirements that all power purchase agreements are backed by verifiable capacity to meet the RTO's resource adequacy requirement (RAR), and that provisions to allow SPP to verify the agreements are backed by capacity;
- the proposed treatment of firm power purchases and sales in determining net peak demand is unduly discriminatory; and
- SPP has not supported as just and reasonable its proposal to publicly post a list of load-responsible entities that had not met their RAR.

The motion was opposed by the Kansas Municipal Energy Agency, while 10 other members abstained.

| *Sunrun*

SPP NEWS

MOPC Briefs

Market Working Group Resolves Mitigation Improvement Issues

OKLAHOMA CITY — SPP's Markets and Operations Policy Committee unanimously approved a Market Working Group (MWG) revision request (RR 245) that adds a major maintenance cost in mitigated start-up and no-load offers, resolving pushback from the RTO's Market Monitoring Unit.

The MWG said the change allows market participants to include major maintenance costs associated with the number of starts or run hours in their mitigated start-up and no-load offers, resulting in the recovery of true variable costs.

The revision received a thumbs-up from MMU Executive Director Keith Collins, who said he was aware the Monitor had opposed previous versions of the change.

"The Market Monitor believes that changes made to 245 … are substantial differences that allow the Market Monitor to find this approach acceptable," he said. "One, we're not moving down the variable maintenance approach we tried last time, and two, we are talking specifically about major maintenance for start-up and no-load. This approach is consistent with how other RTOs address major maintenance."

The MOPC's endorsement allowed the MWG to recommend closing several action items and withdrawing two other revision requests it had been working on: RR 231, which addressed fuel-cost changes, and RR 214, which removed locally committed resources from the economic mitigation tests. The latter revision request, which also created a 10% cap for resources committed for local reliability, had been remanded back to the working group by the committee for additional review.

The MMU opposed RR 214, saying it discovered resources were "self-mitigating" to pass the conduct threshold test and avoid possible mitigation.

RR 245 "takes a little of what PJM is doing and what MISO is doing, and puts them together," Collins said. "We like driving in the middle of the road."

MWG Vice Chair Jim Flucke, of Kansas City Power & Light, said, "Given everything else we passed, 214 as written is no longer the right approach to the remaining issues we have."

Golden Spread Electric Cooperative's Mike Wise thanked the MWG for its work, saying, "This is taking SPP substantially forward."

The MOPC approved the recommendation to withdraw the revision requests with three abstentions.

Members unanimously endorsed two other revision requests brought forward by the MWG:

- MWG-RR247: Clarifies language to reflect how the market-clearing engine treats contingency reserves in the real-time balancing market when a contingency reserve event is deployed.
- MWG-RR257: Responds to a FERC compliance requirement (EL16-110) requiring SPP to limit the eligibility for auction revenue rights and long-term congestion rights of network customers with service subject to redispatch. The changes will ensure network service subject to redispatch is treated comparably with point-to-point service subject to redispatch. (See FERC Again Rejects SPP Rules on ARRs, LTCRs.)

| © RTO Insider

SPP Pays MISO $2.25M After M2M Resettlements

SPP has reimbursed MISO more than $2.25 million after resettlements of several market-to-market (M2M) flowgates and will continue to perform "limited" resettlements because of a memorandum of understanding between the two RTOs.

The resettlements stem from binding events on three flowgates along the SPP-MISO seam. SPP has accumulated $32.73 million in M2M payments through November since the two RTOs began the process in March 2015.

"Large dollars are transferring between SPP and MISO on a daily basis," said David Kelley, SPP's director of interregional relations. The resettled payments "shouldn't have been paid to us to begin with, but we didn't have a lot of criteria around it. We needed to ensure [M2M coordination] is grounded in some of [the MOU's] principles."

The RTOs executed the MOU last summer to improve M2M coordination after what Kelley called a "significant" amount of time and negotiation. They then revised the MOU to address power swings and capping its firm-flow entitlement provisions. FERC accepted the revisions in December (ER18-150).

Kelley reminded members that the commission directed the RTOs to begin M2M coordination with the implementation of SPP's Integrated Marketplace in 2014. FERC cited the success of a similar process between MISO and PJM.

"We knew we had some room for improvement almost immediately because of the way the system operated," Kelley said. "From the moment we threw the switch, we saw significant oscillations and power swings on some flowgates. We knew this wasn't how it was supposed to work."

"It's all because Iowa wind is impacting our

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SPP News

SPP, Mountain West Resolving 'Contentious' Issues

By Tom Kleckner

OKLAHOMA CITY — SPP COO Carl Monroe told the Markets and Operations Policy Committee last week that the RTO's integration of Mountain West Transmission Group is on track to meet its October 2019 consummation timeline, pending reaching final agreement among the various parties.

A small negotiating team tasked with resolving a subset of five "real contentious" issues has reduced the list to two after an initial meeting, Monroe said. He would not elaborate on the issues at play, but Mountain West entities have suggested several governance changes that would emphasize the differences between the two interconnections. (See *SPP, Mountain West Integration Work Goes Public*.)

Monroe said the team is "intent" on coming up with a recommendation that can be brought back to the Board of Directors and Members Committee here next week. "It does look like we're getting closer," he said.

Complicating matters somewhat, Monroe said, was Peak Reliability's recent announcement that it would work with PJM to offer market services, and CAISO's desire to offer reliability coordination in its footprint for half the price of Peak. (See related story, *Peak, PJM Detail Western Market Proposal*, p.1, and *CAISO to Depart Peak Reliability, Become RC*.)

"That's created a whole bunch of ripples in the West on the reliability side, and market side too," he said. "We continue to have conversations as to what this means to Mountain West going forward."

SPP's Strategic Planning and Corporate Governance committees have been meeting with Mountain West representatives behind closed doors since October. Monroe assured members they would have a chance to add their input to any protocol and Tariff changes as they bubble up through the RTO's normal stakeholder process.

SPP working groups will handle the Tariff changes, while the CGC will be responsible for the governance changes. Monroe said financial obligations won't be discussed until both parties "are comfortable with the policy level."

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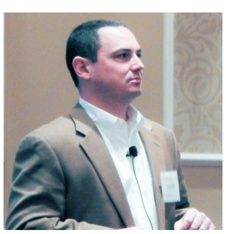
system," SPP COO Carl Malone said, issuing a refrain familiar to many of his colleagues.

"I think we've ended up in a good place where the process should work much better," Kelley said.

SPP and MISO will both file waivers with FERC to complete the resettlements.



David Kelley | © *RTO Insider*

Kelley also said SPP will "take a run at another filing" with FERC over two potential seams projects with Associated Electric Cooperative Inc. The commission last year rejected both projects, saying SPP had not shown its proposed cost allocations on a load-ratio share basis were "roughly commensurate" with the projects' benefits. (See *FERC Rejects Cost Allocation for SPP-AECI Seams Project*.)

SPP staff have met with FERC staff to gain further insight as to why their filings were rejected. "It's not a for-sure slam dunk [for SPP]," said General Counsel Paul Suskie, "but it's worth another try."

In the meantime, Kelley has kept open the lines of communication with AECI.

"We've reiterated our support and commitment, and they've reiterated their support and commitment as well," Kelley said.

MOPC Agrees to Pull Basin Electric Project's NTC-C

The committee unanimously agreed with staff's recommendation to withdraw a notification to construct with conditions (NTC-C) for a Basin Electric Power Cooperative transmission project in North Dakota.

Staff said their updated load projections indicated there was no longer a need for the 33-mile, 345-kV Kummer Ridge–Roundup line. Staff studied winter and summer peak scenarios in 2022 and 2027 before making their decision.

The project began as a 115-kV line in SPP's 2016 near-term assessment, but its NTC-C was modified by the Board of Directors in July 2016 to reflect the change in voltage to 345 kV. It has an estimated cost of $52.3 million.

The MOPC and board both approved Basin Electric's request for an expedited re-evaluation in April 2017. (See "MOPC Endorses Re-evaluation of Basin Electric Project," *SPP Markets and Operations Policy Committee Briefs*.)

Staff also alerted MOPC about a change in a New Mexico project that came out of its 2014 High-Priority Impact Load Study. Tapping an existing 115-kV line to build a new 115-kV substation at Ponderosa Tap had been approved at a cost of $4.9 million. However, staff said the project costs were incorrectly designated as "direct assigned" and should be "base plan" funded instead. The cost was reduced slightly.

Stakeholders separately unanimously endorsed the 2018 Transmission Expansion Plan, sending it to the board for its approval. Members completed 36 projects costing $246 million in 2017, while SPP issued 71 NTCs for an additional $263.2 million in spending.

North Dakota Sponsored Upgrade Study Approved

The MOPC endorsed SPP's sponsored upgrade study performed for Central Power Electric Cooperatives, a member company in North Dakota that purchases power from Basin Electric to serve its own six-member cooperative.

CPEC proposed changing a 115-kV breaker status from "normally open" to "normally closed" and completing a 115-kV loop between two Western Area Power Administration substations to correct a potential thermal violation in the 2026 summer models. Staff said CPEC would have to bear

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the costs of the upgrade and any mitigations.

SPP issued a report to CPEC, Basin Electric and WAPA in November.

NERC Stakeholder Teams to Review, Reduce Standards

Charles Yeung, SPP's executive director of interregional affairs, told members they face a Feb. 2 deadline for submitting input to NERC on its standards streamlining effort.

The agency has formed three teams to review long-term planning, operations planning and real-time operations standards. The teams will provide recommendations on reducing the number of NERC standards — not including critical infrastructure protection standards — by the third quarter of this year.

The teams, which still have open seats, have scheduled one-hour webinars Jan. 24-25 for orientation and to discuss scope, timelines and other matters.

Consent Agenda Clears 10 Revision Requests

The MOPC approved a measure that documents market import service (MIS) as a transmission product in the Tariff; it has been offered in SPP's Integrated Marketplace since 2014. RR 250 places all information related to reserving and scheduling MIS in one location as a new business practice.

Malone pulled the revision from the consent agenda, pointing to language that said MIS had not been implemented through Tariff language.

"The Tariff language being added is brand new," he said. "I read that it didn't exist until today. It looks like new service to me."

Malone was joined in opposing RR 250 by the Municipal Energy Agency of Nebraska. ITC Holdings abstained from the vote.

The MOPC unanimously approved nine other revision requests on its consent agenda:

SPP COO Carl Monroe addresses the committee, with MOPC Chair Paul Malone to his right. | © RTO Insider

- CPWG-RR249: Corrects, updates and clarifies unclear or outdated letter of credit language to make it more acceptable to financial institutions.
- MWG-RR182: Removes the term "control area," which is no longer used by SPP, from the market protocols and the Tariff.
- MWG-RR200: Removes bilateral settlement schedules (BSS) at hubs and generation settlement locations from the over-collected losses (OCL) distribution calculation. The revision allows only BSS at a withdrawal point to be included in the OCL distribution calculation. It caps the BSS at the maximum amount of the real-time withdrawal minus any amount of grandfathered agreements and federal service exemptions.
- MWG-RR246: Clarifies language explaining SPP's congestion management efforts when declaring transmission loading relief (TLR) and removes a reference to an old system name. SPP does not have an active TLR for every congestion management event, but the protocol language will be updated to read "as soon as practicable," and adds provisions for market-to-market coordinated curtailments in lieu of TLR market flow curtailment targets when appropriate.
- MWG-RR253: Changes how dispatchable variable energy resources (DVERs) provide regulation down service. SPP said the change will lower structural barriers to DVERs providing regulation service and allow the system to operate more efficiently in times of high wind when SPP could use online turbines rather than requiring uneconomic commitments of other resources.
- MWG-RR254: Updates the data requirements requested from SPP's forecasting vendor to improve the wind and solar power forecast. Additional data requirements include individual wind turbine coordinates, turbine model characteristics, cold-weather packages, and turbine availability and de-rate submissions.
- MWG-RR258: Recommends modifications to the list of frequently constrained areas (FCAs) and resources from the Market Monitoring Unit's 2017 study. FCAs are electrical areas with one or more transmission constraints or reserve zone constraints that are expected to be binding for at least 500 hours during a given 12-month period and within which one or more suppliers are pivotal.
- MWG-RR265: A compliance filing in response to FERC's order on handling ramp shortages under Order 825. (See *FERC Approves SPP Shortage Pricing Changes*.) Modifies the methodology through which scarcity pricing reflects the value of regulation and operating reserves. The Tariff language was filed in October (ER17-772).
- ORWG-RR162: Requires phasor measuring units (PMUs) at new generator interconnections to aid in oscillation detection, generator model validation and post-event analyses, as has become common practice among SPP's peers.

The consent agenda's approval also resulted in MOPC's endorsement of:

- A 34.9% decrease in SPS' escalated baseline cost of $17.67 million to rebuild 22.1 miles of 115-kV line and a 115-kV circuit.
- A 23.2% decrease, to $58.8 million, in the escalated baseline cost for SPS to build a new 47.2-mile, 345-kV line and a 345-kV substation.
- A 23.4% decrease, to $28.5 million, in the escalated baseline for Nebraska Public Power District to build a new 35-mile, 115-kV line and complete various upgrades.
- Charter revisions to the Reliability Compliance Working Group reflecting the SPP Regional Entity's dissolution.

— Tom Kleckner

SPP NEWS

SPP Working to Respond to FERC's Quick-Start Directive

By Tom Kleckner

OKLAHOMA CITY — SPP told members last week it and its Market Monitoring Unit will file separate reply briefs in response to FERC's December order that found the RTO was suppressing investment signals by not allowing quick-start resources (QSRs) to set LMPs.

The commission issued a Section 206 order requiring SPP to change its Tariff to address quick-start pricing (RM17-3). FERC said it found the RTO's approach to the resources' pricing to be "inconsistent with minimizing production costs" and suggested several changes it could implement. (See *FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes*.)

Richard Dillon | *© RTO Insider*

Under a 206 filing — "fairly new to SPP," said Market Design Director Richard Dillon — FERC can unilaterally make changes to an RTO's or ISO's rates, terms or conditions. The reply briefs are due by Feb. 12, with a final order expected within six months of that. The MMU will file its brief after the RTO. Neither Dillon nor MMU Executive Director Keith Collins revealed what they will say in their briefs.

"A quick-start unit provides a product other [resources] can't," Dillon said. FERC "wants the value of the product to be reflected in the LMP itself."

In the meantime, SPP staff said it will continue its work on three open revision requests addressing QSRs. Securing the Markets and Operations Policy Committee's unanimous approval last week of a revision request that corrected and clarified a previous revision was a first step.

Staff developed RR 256 as it began working on the previous revision request's implementation details. It said the revision addresses a market inefficiency "inadvertently" created in RR 116 and eliminates a potential gaming opportunity. RR 116 was approved in October 2015 but has yet to be filed with FERC. Two other quick-start related Tariff changes, RR 137 and RR 142, have also been approved by SPP stakeholders but not yet filed.

Dillon said the revision requests are built on top of each other and reflect stakeholders' "desires and corrections," but they will not be filed with FERC until the commission rules on the Section 206 docket.

- RR 116: Provides the primary language for the new QSR logic and replaces "quick-start resource" with "offline supplemental reserve resource" for those resources supplying offline supplemental reserve.
- RR 137: Updates previously removed enhanced combined cycle language referencing QSR limits and the Tariff's Appendix G for QSR changes.
- RR 142: Clarifies that QSRs are ineligible to register as multiconfiguration combined cycle resources.

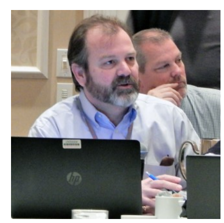
In its order, FERC said SPP should:

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

Golden Spread Electric Cooperative's Mike Wise said the revision requests are unresponsive to the FERC order and "come very short of the mark." Dillon admitted the changes do not cover everything in the 206 order, "but they're moving in the same direction."

Dillon said addressing all of FERC's directives in the 206 filing would result in significant market changes for SPP. He pointed out SPP's pricing is *ex ante* (planned), and that an *ex post* market (actual outcomes) would require major software changes.

"We don't know what the final order will look like," he said. "When we get an actual order from FERC, we'll have another RR incorporating additional direction from FERC."



Greg McAuley | *© RTO Insider*

Oklahoma Gas & Electric's Greg McAuley said his company would prefer SPP file the revision requests, rather than wait on FERC. "The concern is stakeholders have already indicated a willingness to do this. As an entity with brand new quick-start resources coming online and available, what we've been working on is very important to us."

"A bigger issue is credibility," Dillon countered. "We used to have a reputation of knowing what we were doing and being really sharp. If we make some filings inconsistent with the very 206 filing FERC gave us, that calls into question we know what we're doing. We don't want to dig that hole any deeper."

Complicating matters is SPP does not yet have a definition for QSRs in its Tariff, as do the other RTOs. Stakeholders have suggested a minimum run time of one hour or less to qualify as a QSR.

"We used to have a reputation of knowing what we were doing and being really sharp. If we make some filings inconsistent with the very 206 filing FERC gave us, that calls into question we know what we're doing. We don't want to dig that hole any deeper."

Richard Dillon, SPP

FERC & FEDERAL NEWS

Congress Votes to Reopen Government After Weekend Shutdown

Congress on Monday afternoon voted to approve a short-term spending plan, funding the federal government through Feb. 8 after a nearly three-day shutdown.

The first shutdown since 2013 began midnight Friday after the Senate failed to reach agreement on a spending plan. Negotiations continued until Monday, when Senate leaders reached an agreement.

The House of Representatives approved the plan shortly after the Senate, which had added an amendment to the original House bill paying federal employees who worked during the shutdown.

FERC had said it would furlough all but 49 of its 1,465 employees if it runs out of money before the government reopened.

The commission's contingency plan says it would continue normal operations until its funds from prior year appropriations are exhausted. After that, it would continue only "excepted" activities, such as protecting life and property (e.g., inspections of LNG facilities), monitoring for physical and cyber threats to infrastructure, and market monitoring. "The excepted staff will perform a minimum level of these oversight roles, to monitor for urgent matters," the plan says.

Because the five commissioners continue working through any hiatus, FERC also would keep some legal staff working to provide advice.

The commission would stop accepting filings from the public and postpone deadlines and due dates for all pending matters not related to excepted activities. It would seek stays from all cases pending in federal courts. "If the courts deny the stay and explicitly or implicitly rule that FERC participation in these matters is authorized under the protection of life and property exceptions provided in 31 U.S.C § 1342 or some other applicable provision of law, FERC staff will be required to meet obligations established by these courts."

In addition to retaining 49 staffers (3.4% of the total), the commission would also maintain 18 contract workers to provide physical security for FERC facilities and information technology support.

The Interior and Energy departments expected to furlough about three-quarters of their workforces. EPA said it had "sufficient resources to remain open for a limited amount of time."

— Rich Heidorn Jr.

McIntyre: Won't Commit to Probe Leak to 'Good Friend'

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statements. I then drafted this memorandum to memorialize the *ex parte* communication for the record."

McIntyre Press Conference

RTO Insider asked McIntyre at his press conference following Thursday's open meeting whether the commission would investigate who may have leaked the information to Scherman.

"I read that in [Chatterjee's] statement and I am going to be discussing that with my staff," McIntyre responded. "In the meantime, I just want to say that the system that we have in place for situations just such as that where there's an *ex parte* communication worked perfectly. We have a system in place. Commissioner Chatterjee did exactly the right thing and the system worked. So as far as I'm concerned, I'm very satisfied with where it came out."

Commissioners Cheryl LaFleur, Robert Powelson and Richard Glick told *RTO Insider* on Jan. 16 that Scherman had not attempted to contact them on the case. McIntyre said Thursday that he also had not been contacted.

"Bill Scherman and I are old friends. I consider him a terrific lawyer and a good friend," McIntyre said. "In this instance, I had no contact with him about the matter."

FirstEnergy merchant affiliate Allegheny Energy Supply had requested permission to transfer ownership of the 1,159-MW Pleasants Power Station to regulated affiliate Mon Power, with the latter assuming a $142 million obligation for pollution controls Allegheny installed at the plant. The commission's unanimous Jan. 12 order concluded the deal was not in the public interest because it resulted from an "overly narrow" solicitation. (See *FERC Blocks FirstEnergy Sale of Merchant Plant to Affiliate*.)

Ex Parte Communications Common

Ex parte communications (one side only) are quite common at FERC — so frequent, in fact, that FERC's secretary publishes a list of disclosures about every two weeks (RM98-1).

Most of the dozens of communications reported in the last year concerned pipeline projects and involved letters or flyers sent to commissioners rather than filed as formal comments in the dockets. Residents near the projects were the most frequent offenders, but chambers of commerce, economic development authorities and labor unions also were listed. The communications are filed in the dockets to document them but are not considered part of the evidence before the commission.


William Scherman | *Gibson Dunn*

The commissioners also hear frequently from state and federal elected officials, but such communications are exempt from *ex parte* rules.

No Foul?

Ex parte phone calls to commissioners by members of the energy bar are not common, however.

"Everyone else in the FERC bar manages to follow the rules. FERC shouldn't let cheaters get away scot-free," said a former member of the commission's general counsel's office who asked not to be identified to protect his working relationships. "And Commissioner Chatterjee's description gives the lie to the assertion that this was a gray area. Setting a matter for hearing as opposed to denying it

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is about as substantive as it can get."

Scherman told *RTO Insider* last week that he had done nothing wrong and said the commission should change its *ex parte* rules, which prohibit private communications with commissioners in contested case specific proceedings. "Based upon my experience, I do not believe I engaged in any *ex parte* communications," Scherman said in an email. (See FirstEnergy Lawyer Sought to Lobby Chatterjee on Plant Deal.)

Scherman declined to answer additional questions Monday morning but later asked that the story include comments on an unrelated matter (see Editor's Note, below). First Energy has declined to comment.

Rule 2201, revised by FERC Order 718 in 2008, states that "in any contested on-the-record proceeding, no person outside the commission shall make or knowingly cause to be made to any decisional employee, and no decisional employee shall make or knowingly cause to be made to any person outside the commission, any off-the-record communication. … Commission employees who are found to have knowingly violated this rule may be subject to the disciplinary actions prescribed by the agency's administrative directives."

Who is the Mole?

FERC draft orders are typically circulated among the commissioners' aides and staffers in divisions who are responsible for writing the legal and technical language of the ruling. The drafts are generally not secured with any kind of watermark that would indicate where a leaked copy originated.

The commission's ethics rules state that staff "may not disclose nonpublic information, including draft orders and internal discussions, to the public." Staff are also barred from disclosing "the nature or the time of any proposed action by the commission to anyone outside the commission."

But Washington's revolving door culture means that those who depart FERC leave behind former colleagues able to share information with them — carelessly or maliciously — in social settings.

A former FERC policy adviser who now works as a consultant said he thinks such disclosures are "very rare."

"I feel like it would harm relationships to even put staff in that position by asking a question" regarding a pending matter, he said. "But clearly others do, and somebody [on FERC staff is] playing ball."

The former adviser speculated that Chatterjee, a former aide to Senate Majority Leader Mitch McConnell (R-Ky.), was slow to realize what he had gotten into when he agreed to talk to Scherman. "In the legislature, intelligence is the coin of the realm. And sharing intelligence is how you get intelligence. It wouldn't surprise me if he started to get into that game a little bit and realized his entire reputation could be damaged" by sharing information.

An industry analyst agreed that improper disclosures are rare.

"The commission goes out of its way not to discuss matters with parties to a case," the analyst said. "I tell my clients, 'If you bring this up [in a meeting with FERC officials], you can expect to be shut down.' FERC is fairly discreet. I think they are cognizant that [their comments] can move a stock.

"You can talk in hypotheticals [with FERC officials], but then you may find that what you have been told is not something you can

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take to the bank. I've had conversations where someone says, 'Commissioner so-and-so told me X.' It's just one person's opinion. A staffer close to one commissioner saying, 'I think this is going to happen.' That's only one of five votes.

"My guess is somebody probably tipped Bill and that was inappropriate," the analyst said. But FERC's "pretty aggressive" deficiency letter, filed in the docket in June, indicated the commission's skepticism of the Pleasants deal, the analyst added.

"The commission should be investigating whether Scherman did in fact obtain non-public information," Tyson Slocum, director of Public Citizen's Energy Program, said in an email. "If FERC refuses, the Senate Energy and Natural Resources Committee should step in."

The Department of Energy's Inspector General also has authority to investigate the commission. (See *DOE IG Warns FERC Information Security 'Severely Lacking.'*)

An IG spokeswoman on Monday declined to say whether it was investigating the Scherman incident. "We are an independent organization. We take a number of factors into consideration when deciding to initiate an investigation," she said.

Penalties, Prior Incidents

Rule 2201 allows the commission to bar Scherman from practicing before it: "If a person knowingly makes or causes to be made a prohibited off-the-record communication, the commission may disqualify and deny the person, temporarily or permanently, the privilege of practicing or appearing before it, in accordance with Rule 2102 (Suspension)." [See 18 CFR section 385.2201 (i)(2).]

Rule 2102 permits FERC to disqualify a person who is found "to have engaged in unethical or improper professional conduct."

This is not the first time Scherman has been accused of flouting the commission's *ex parte* rules. In 1992, congressional investigators suggested Scherman — then FERC general counsel — had whitewashed an *ex parte* meeting at which FERC staff discussed with sponsors of the Iroquois Gas Transmission System pipeline project ways to expedite the commission's approval without notifying opponents of the project.

The meeting, on March 15, 1990, was requested by commission staff, according to an account in the *Energy Law Journal*, which said the applicants also met with at least one commissioner about the status of the application.

Martin Fitzgerald, special assistant to the general counsel at the General Accounting Office, told the House Government Operations Committee panel in 1992 that the discussions involved amendments to the application, the timetable for the commission's review of new aspects of the project and a change in the project's gas capacity, according to the *Journal of Commerce*.

Scherman, who was assigned to investigate the issue, reported on June 29, 1990, that the meeting dealt only with procedural matters and thus did not violate FERC rules.

But Environment, Energy and Natural Resources Subcommittee Chairman Mike Synar (D-Okla.) released a memo Scherman had written to FERC Chairman Martin L. Allday weeks before that report was issued — and before the investigation was complete — indicating Scherman had already reached that conclusion. A second GAO investigator told the subcommittee that FERC employ-

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ees who were at the meeting said Scherman asked them only perfunctory questions about it, according to a *Washington Post* account.

The commission's ruling on the pipeline application sided with Scherman on the characterization of the meeting (CP89-634), as did the D.C. Circuit Court of Appeals.

Second Incident

Scherman also was criticized for not disclosing that Transcontinental Gas Pipe Line Corp. had asked him and the commission's deputy general counsel for oral argument prior to commission action on a rehearing request. A divided commission ruled in January 1992 that the request should have been treated as an *ex parte* communication and made public.

According to the order, the request was made following the commission's September 1990 order denying Transco's request for an oral argument. "Counsel for Transco orally asked the general counsel and the deputy general counsel of the commission for an oral argument prior to the commission acting on rehearing in this case. That oral request was not disclosed to the parties or to the commission. Subsequent to these communications, the general counsel and the deputy general counsel recommended to the commission that it grant an oral argument."

Citing the *Iroquois* opinion, the majority said, "this is the kind of doubtful situation that should be treated as involving comments related to the merits in order to protect the integrity of the decision-making process."

The dissenting commissioners concluded the request for oral argument was procedural and thus permissible (TA85-3-29).

Editor's Note from Rich Heidorn Jr.

After saying Monday morning that he had no further comment on the Chatterjee incident, Scherman emailed *RTO Insider* in the afternoon, saying he wanted to go on the record with criticism of me over my role as a FERC whistleblower in a 2006 incident.

The incident occurred after then-FERC Chief of Staff Daniel Larcamp negotiated a settlement to end an investigation by the commission's Office of Administrative Law (OAL) under circumstances that suggested that Southern Co. and FERC management had engaged in *ex parte* communications.

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Pleasants Power Station

As a staffer in FERC's Office of Enforcement, I had been loaned to OAL's trial staff to aid in the investigation, which concerned whether Southern was improperly sharing nonpublic information with the company's marketing affiliate.

When I confirmed with my superiors that Larcamp's settlement would have improperly allowed Southern to continue sharing nonpublic information — but was unable to persuade them to block it — I consulted with an attorney with the Government Accountability Project, an organization that represents whistleblowers.

Based on my attorney's advice, I went public with my concerns through Rep. Henry Waxman, then the ranking Democrat on the House Oversight and Government Reform Committee. I also was quoted in the press. The commission ultimately rejected the settlement Larcamp negotiated and imposed tougher conditions.

Larcamp's Entry

Larcamp entered the case in September 2005, after trial staff had obtained evidence indicating that Southern's subsidiary, Southern Power, attended meetings at which sensitive information (i.e., plant retirements, present and future load characteristics, expected resource additions and industrial energy sales) was exchanged. This is information that Southern Power would not have been allowed to receive were it properly classified as a "marketing" affiliate under FERC's regulations.

On Sept. 21, 2005, Larcamp declared himself "non-decisional," meaning that, like trial staff, he was *not* prevented from talking to Southern under *ex parte* rules. Doing so, however, meant he could not discuss the matter with any commissioners or other "decisional" FERC staff.

Larcamp never met with the trial team to discuss the evidence in the case before beginning his settlement talks with Southern. The team did not even know Larcamp was talking to Southern until he abruptly informed OAL managers in November, while team members were deposing Southern officials in Birmingham and Atlanta. Staff were ordered to cancel the remaining depositions and return to D.C.

Larcamp said he was settling the case at the behest of then-Chairman Joseph Kelliher, who took the gavel two months after the case was initiated under Chairman Pat Wood.

"[Larcamp] said Southern thinks it has two votes on the commission in its favor on this issue," according to an internal memo I provided to Waxman. "He said that if that didn't work, Southern would likely apply political pressure. … But he said that even if the case goes forward, the chairman would not be eager to expedite it, and it would likely languish through 2007."

Scherman's Statement

Here is Scherman's statement in full:

> "In your short time at FERC, it was public information that you engaged in unethical and unlawful actions. As you know, at that time, I, along with others, publically [sic] stated that on the record. As you know, I, along with those who were at the FERC at that time, were highly critical of your improper and unethical conduct. As a result, you should recuse yourself from any potential story where I am involved given your obvious prejudice and bias. Seeking to settle an old score is unethical and unscrupulous conduct that exhibits actual malice. Any reputable 'journalist' would be disreputable by failing to include fully this on-the-record comment in any story that might run."

For the record, I worked for FERC for eight years, from 2002 to 2010 (and had frequent contact with Scherman on matters concerning his client, Entergy). FERC never took any disciplinary action against me for my role. In October 2006, the commission unanimously rejected the settlement Larcamp negotiated and imposed tougher conditions (EL05-102).

Commissioner Suedeen G. Kelly, writing in a concurring statement, said, "It is well-known that the process leading up to the filing of this settlement was highly unusual and caused great controversy."

Kelly cited comments that Administrative Law Judge Edward M. Silverstein made to a member of the commission's trial staff during oral arguments following the settlement. "I've been here almost 15 years, and I've never been involved in a case in which somebody representing the commission — other than trial counsel — negotiated a settlement. And so, I think your position is unique and maybe even dangerous," Silverstein said.

Six months after FERC's ruling, Larcamp left the commission for a new job — with Southern's law firm, Troutman Sanders.

Rich Heidorn Jr.
Editor and Co-Publisher

FERC & FEDERAL NEWS

FERC Backs NERC Supply Chain Standards

By Michael Brooks

WASHINGTON — FERC on Thursday proposed to adopt several reliability standards intended to mitigate cybersecurity risks posed by the global supply chain of grid operation tools.

Multiple entities around the world may participate in the development of software or technology used by utilities to manage their reliability duties, exposing them to potential corruption.

In a Notice of Proposed Rulemaking (RM17-13) FERC indicated its intention to approve a NERC critical infrastructure protection standard (CIP-013-1) that would require utilities to consider several cybersecurity issues when procuring these products for their medium- and high-impact systems. These issues include:

- disclosure of known vulnerabilities in the products;
- security event notifications;
- coordination of vendor remote access;
- notification when vendor employee remote or onsite access is terminated;
- coordinated response to vendor-related cybersecurity incidents; and
- verification of integrity and authenticity of all software and patches.

NERC noted that the standard does not "require that every contract with a vendor include provisions for each of the listed items." Rather, utilities would need to "ensure that these security items are an integrated part of procurement activities, such as a request for proposal or in the contract negotiation process."

The actual terms and conditions of utilities' contracts with vendors are outside the scope of the standard, as are the activities of the vendors themselves. "A responsible entity should not be held responsible under the proposed reliability standard for actions (or inactions) of the vendor," NERC said.

Reliability officials would evaluate and reapprove utilities' procurement processes every 15 months under the standard.

FERC also proposed to adopt two additions to existing NERC standards, both to support the requirements in CIP-013-1. One (CIP-005-6) would require utilities to develop a method for identifying active remote access sessions by vendors. The other (CIP-10-3) would require utilities to verify the source of all software and patches before installing them.

Broader Scope, Tighter Deadline

NERC developed the standards in response to a FERC directive in July 2016, marking only the third time the commission has taken such initiative. (See *FERC Orders NERC to Develop 'Flexible' Supply Chain Standard*.) The organization submitted the proposed standards last September.

FERC found that NERC had generally satisfied the four objectives it had laid out in its order: software integrity and authenticity; vendor remote access; information system planning; and vendor risk management and procurement controls. The commission had also directed that the standard be flexible, leaving it to utilities to determine the best way to comply.

However, the commission directed NERC to include Electronic Access Control and Monitoring Systems (EACMS) —firewalls, authentication servers, security event monitoring systems and intrusion detection systems, for example — as part of the scope of the standard.

It also instructed NERC to evaluate the risks posed by Physical Access Control Systems (PACS) — such as motion sensors, badge readers and electronic locks — and Protected Cyber Assets (PCAs) — networked printers, file transfer servers and local area network switches — as part of a supply chain cybersecurity study the organization's Board of Trustees ordered last August.

FERC also proposed to tighten the implementation deadline for the standards, shortening NERC's proposed 18 months after commission approval to 12.

Commissioners: Good First Step

Commissioner Cheryl LaFleur, who had dissented from FERC's earlier order, issued a lengthy concurrence to explain her vote. She had called the July 2016 directive too broad and lacking in guidance. She had also said the timeline for developing the standards was too short given the lack of stakeholder input.

At the commission's open meeting Thursday, LaFleur said she still had some of those concerns, calling the standards "quite general." But, she said, "I agree that they are an improvement over the status quo.

"I do not believe that remanding these standards or the larger supply chain issue to the NERC standards process would be a prudent step at this point," she said. "Rather, I believe the better course of action at this time is to move forward with these standards and … improve them over time as needed."

Her colleagues had similar sentiments.

"While the standard is not a panacea, it is an important step forward to tackle a tough problem," Commissioner Neil Chatterjee said.

"It will be particularly important to revisit the standard after several years of experience to see what is working and what aspects could be improved. But again, today's order is a good step in the right direction."

Commissioner Richard Glick also called the standards "an important first step," but "I think more needs to be done."

Comments on the proposal to adopt the standards are due 60 days after its publication in the *Federal Register*.

EOP Reliability Standards

FERC on Thursday also approved several updates to emergency preparedness and operations reliability standards proposed by NERC last March (RM17-12).

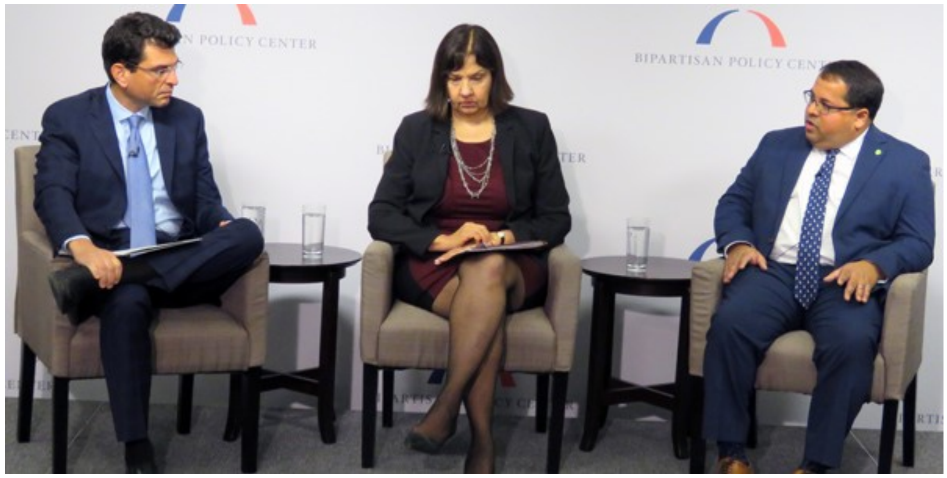
The revisions streamline existing standards and remove redundant language. The commission said they will ensure accurate reporting of events to NERC's event analysis group; delineate the roles and responsibilities of entities involved in system restoration processes; and identify the elements required in plans for continuing operations when primary control functionality is lost.

FERC did not make any changes to the EOP standards since it proposed to adopt them last September, nor did stakeholders propose any. (See *FERC OKs Rules on Balancing, Interconnection, Remedial Actions*.) They will go into effect 60 days after their publication in the *Federal Register*.

FERC & FEDERAL NEWS

LaFleur, Chatterjee Discuss NOPR Ruling, Resilience Proceeding

By Rich Heidorn Jr.



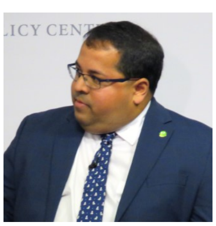
Left to right: Bipartisan Policy Center President Jason Grumet, and FERC Commissioners Cheryl LaFleur and Neil Chatterjee. | *© RTO Insider*

WASHINGTON — FERC Commissioner Neil Chatterjee acknowledged last Tuesday he has suffered some growing pains in his transition from Capitol Hill partisan to FERC commissioner, saying he hadn't fully appreciated the commission's "fact-based, evidence-based approach."

In a panel discussion, Chatterjee and Commissioner Cheryl LaFleur discussed the commission's Jan. 9 ruling dismissing Energy Secretary Rick Perry's Notice of Proposed Rulemaking (RM18-1) and previewed the docket the panel created to investigate RTOs' resilience practices (AD18-7).

The session, sponsored by the Bipartisan Policy Center, attracted an audience that included the heads of groups representing the nuclear and coal industries, merchant generators and state regulators. (See DOE NOPR Rejected, 'Resilience' Debate Turns to RTOs, States.)

Chatterjee, a Kentuckian and former energy adviser to Senate Majority Leader Mitch McConnell (R-Ky.), had pushed for "interim" financial relief for struggling coal and nuclear generators pending further proceedings but ultimately joined LaFleur and their three colleagues in the unanimous ruling.



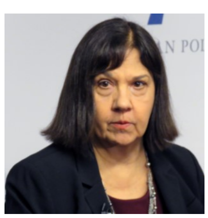
Neil Chatterjee | *© RTO Insider*

"During my time in the legislative branch, I had spent time with lawmakers of all political stripes who stressed the importance of fuel diversity and the need for an all-of-the-above energy strategy," Chatterjee, a Republican, said. "And so initially I did express some sympathy for what the secretary had laid out. ... That said, I was also very clear that if the commission were to take any action, it would have to be legally justified, and that it would not distort markets.

"As we went through the process, I came to really appreciate the fact-based, evidence-based approach that the commission takes. I was aware of it prior to my confirmation, but once you really get in there and start doing the work, you realize we do things in a cautious, steady, legally defensible manner. As we ... went through the record and did the analysis, I came to the conclusion that my colleagues did, which is that while I feel Secretary Perry asked the right question, he proposed the wrong remedy."

Chatterjee said he was pleased that all five commissioners also agreed "that resilience is something that needs to be explored further. The commission has looked at these kinds of issues throughout the last number of years, but we've never had a really hyper-focused analysis on resilience."

LaFleur, a Democrat, said, "I disagree with Neil a little bit on how much we've done on this issue in the past.



Cheryl LaFleur | *© RTO Insider*

"Since I've been on the commission for seven and a half years, a large percentage of our work has been driven by relentless changes in the nation's resource mix. ... And I would say that's been driving our market work, our reliability work, and our transmission work for much of the last decade."

She said that although the resiliency proceeding is important, "I think we shouldn't let this swallow everything the commission is doing. We have to continue on all fronts."

LaFleur said she opposed interim subsidies for coal and nuclear plants because the commission lacked robust factual basis for the action. She likened it to the high burden of proof required of those seeking a preliminary injunction, who must show they have a likelihood of ultimately prevailing.

She also parted with Chatterjee on definitions, saying she believes resilience is part of reliability.

"I think resilience is distinct from reliability," Chatterjee said. "Perhaps the threats of a loss of resilience aren't as dire as some generators are making them out to be. But they're certainly not as insignificant as some proponents of new generating sources are making it out to be."

BPC President Jason Grumet, who moderated the talk, praised the commission and Chairman Kevin McIntyre for their response to the NOPR. "I think for anyone who mistrusts government action, the rigor, the integrity and the independence, and the unanimity that FERC was able to show is really, I think, one of the brightest moments in basic public service that I've seen in a while," Grumet said.

On McIntyre's handling of the NOPR, Chatterjee and LaFleur were in agreement. "He threaded the needle very well," Chatterjee said.

House Panel Considers Bills on PURPA, LNG Exports

By Michael Brooks

A House Energy and Commerce Committee panel Friday heard testimony from federal officials and stakeholders on Republican legislation to expand LNG exports and revise the Public Utility Regulatory Policies Act. Support for the bills, introduced late last year, fell along party lines at the hearing.

From left to right: Travis Kavulla, Montana PSC; Timothy Sparks, CMS Energy; Karl Rabago, Pace Energy and Climate Center; Paul Cicio, Industrial Energy Consumers of America; and Charlie Riedl, Center for Liquefied Natural Gas. | *Travis Kavulla*

PURPA Modernization

The PURPA Modernization Act of 2017 (H.R. 4476), introduced by Rep. Tim Walberg (R-Mich.) in November, would substantially reduce the number of PURPA qualifying facilities from which utilities would be forced to buy power.

Currently, QFs of 20 MW or larger are presumed to have nondiscriminatory access to the wholesale competitive markets and are thus ineligible to invoke utilities' must-purchase obligation. The bill would reduce this threshold to 2.5 MW.

It would also make it harder for QF developers to game FERC's 1-mile rule — the presumption that QFs located 1 mile or more apart from each other are separate facilities — by making that presumption rebuttable.

State regulators also would be allowed to exempt utilities from having to purchase from QFs if they determine that the utilities have no need for their power, or if utilities use integrated resource planning and conduct competitive procurement processes.

The provisions in the bill mirror solutions that critics suggested at a subcommittee hearing in September. (See *Witnesses Offer Alternate Realities on Need for PURPA Reform*.)

Testifying on behalf of the National Association of Utility Regulatory Commissioners, Montana Public Service Commission Vice Chairman Travis Kavulla praised the bill. "This legislation is an important and significant leap forward in providing us with the ability to secure a reliable and affordable energy future for the nation," he said.

Kavulla said PURPA forces state commissions to essentially guess a utility's avoided costs, which usually results in overstated rates. Responding to a question by Rep. Bill Flores (R-Texas), Kavulla said, "The smaller the consumer base of the utility, the greater the potential magnitude of erroneous price forecasting from the regulator would be." In the case of small municipalities and cooperatives, the city or county councils that regulate them "are probably even in less of a good position than I am to try to guess about the future market prices of energy for the purpose of establishing a rate."

Karl Rabago, executive director of the Pace Energy and Climate Center, said the bill "proposes three significant and problematic changes to PURPA and should be rejected in favor a more measured and competition-friendly approach to addressing perceived concerns about electricity markets."

"The real problem today is the need for modernization of the utility business model that is now more than 100 years old," Rabago said.

LNG Exports

The Unlocking Our Domestic LNG Potential Act (H.R. 4605), introduced by Rep. Bill Johnson (R-Ohio), would amend the Natural Gas Act of 1938 to eliminate the Department of Energy's role in approving requests to export and import gas. The NGA requires the department to determine whether import/export agreements are in the public interest before approving them. Trades with countries that have free-trade agreements with the U.S. are automatically considered in the public interest.

The bill leaves intact FERC's jurisdiction over siting LNG terminals, as well as the president's power to prohibit trade with countries under U.S. sanctions.

Republicans repeatedly emphasized the need to capitalize on the country's supply of natural gas.

"We literally have more natural gas production capability in the United States than we know what to do with," Rep. Joe Barton (R-Texas) said. The legislation "is simply an acknowledgement of that and says, 'let's use this economic resource that we have to benefit the rest of the world and create more economic benefit in the United States.'"

Democrats were less enthusiastic.

"I fail to see the need for almost any of the policy changes," said Rep. Frank Pallone (D-N.J.), ranking member of the subcommittee. The bill "removes longstanding consumer protections and prevents DOE from ensuring exports of liquefied natural gas to non-free-trade-agreement countries are consistent with the public interest."

So was Paul Cicio, president of the Industrial Energy Consumers of America, who said domestic gas supplies are not as abundant as commonly thought. Increased LNG exports could harm U.S. consumers by raising prices, he said. He called DOE studies used to determine whether trades with non-FTA countries were in the public interest "woefully inadequate."

Cicio's claims about the amount of domestic supply were challenged by Charlie Riedl, executive director of the Center for Liquefied Natural Gas, who said Ohio alone added 5 Tcf of proved reserves in 2016. (See *No Agreement on Tipping Point for LNG Exports*.)

"When we talk about a supply situation, it's driven by market demand," Riedl said. "As market demand continues to increase, we're able to respond to that with supply."

The other members of the panel, including those who only came to testify on the PURPA bill, agreed that there was no short-term threat to gas supply.

Steven Winberg, DOE assistant secretary for fossil energy, told the subcommittee that the Trump administration has taken no position on the bill. President Trump, however, has repeatedly emphasized expediting LNG exports, and Energy Secretary Rick Perry and EPA Administrator Scott Pruitt have traveled abroad to promote U.S. natural gas.

COMPANY BRIEFS

Phoebe Wood Elected To PPL Board

PPL said Jan. 18 that Phoebe Wood, the principal of investment firm CompaniesWood, has been elected to its board of directors.


Wood

Wood is "an executive with three decades of international, financial and operational management experience," PPL said.

Wood was the chief financial officer of Brown-Forman from 2001 to 2008, as well as an executive vice president from 2001 to 2006 and a vice chairman from 2006 to 2008.

More: PPL

Work on Biggest Solar Array in Texas Begins

Hanwha Energy's 174 Power Global subsidiary said Jan. 18 it has begun constructing a 236-MW solar project in Pecos County that will be the largest in Texas when it's completed.

The company plans to own and operate the Midway Solar project for 25 years. It will sell all its power to Austin Energy, Austin's municipal utility.

174 Power Global said Midway Solar will cost $260 million to build.

More: Solar Power World

Dominion Putting 9 Generating Units into Cold Reserve

Dominion Energy said Wednesday it plans to place nine generating units at five Virginia power plants into "cold reserve" status.

The units, which account for less than 1% of Dominion's generation capacity, won't run but can be restarted if necessary. All but one burn coal; the other was converted from coal to gas.

Dominion said it will maintain the necessary environmental permits for the units and continue paying local taxes on them.

More: The Washington Post

FERC Approves Hydro One, Avista Deal

FERC last week approved Ontario-owned Hydro One's $5.3 billion acquisition of Avista, the companies announced.

The companies said FERC's order noted the commitment by Hydro One to insulate Avista's transmission customers from costs associated with the deal.

It still must be approved by utility regulators in Washington, Idaho, Oregon, Montana and Alaska, as well as the Federal Communications Commission and the Committee on Foreign Investment in the United States. It also must pass antitrust muster.

More: Hydro One; Avista

Siemens Gamesa to Supply 95 Wind Turbines to 2 Facilities

Siemens Gamesa Renewable Energy said Thursday it has signed contracts to supply 95 of its G132-3.465 MW wind turbines to two wind farms being built in the U.S.

The company will supply 47 of the turbines to the Midway Wind project in San Patricio County, Texas, which is scheduled to be completed late this year.

| Siemens Gamesa

The remainder of the turbines will go to a customer Siemens is not disclosing for a project scheduled to come online next year.

More: Siemens Gamesa

Dominion not Interested in Buying Santee Cooper, CEO Says

Dominion Energy CEO Thomas Farrell II on Jan. 16 told a panel of South Carolina state senators that his company is not interested in buying Santee Cooper.

Farrell was before the panel to testify about Dominion's agreement to buy SCANA, which paired with the state-owned Santee Cooper in a failed attempt to build two additional nuclear reactors at the V.C. Summer power plant.

Dominion has agreed to buy SCANA for $14.6 billion and has said that if the deal goes through, it will cut the electric rates of SCANA's South Carolina Electric & Gas subsidiary by $7/month and immediately refund $1.3 billion to SCG&E customers, who have paid $1.8 billion for construction of the reactors that were never completed. Dominion still plans to charge SCG&E customers another $2.8 billion over 20 years for work performed on the reactors.

More: Post and Courier; The State

FEDERAL BRIEFS

NEMA CEO Calls for Infrastructure Modernization Strategy

National Electrical Manufacturers Association President and CEO Kevin J. Cosgriff said Jan. 18 that Congress and the Trump administration need to "develop a broad-based infrastructure modernization strategy that includes not only roads and bridges but also ports, water systems, buildings and the electric grid."

Cosgriff's organization, a trade group for makers of electrical and medical imaging equipment, joined other business groups, business executives, policymakers and investors at the U.S. Chamber of Commerce America's Infrastructure Summit to discuss how the country's infrastructure can be modernized.

"Plans that utilize advanced, digitized electrification technologies will grow the economy, create new jobs and improve our competitive position in a global economy," Cosgriff said.

More: NEMA

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Federal Briefs

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API CEO Jack Gerard Stepping down in August

American Petroleum Institute President and CEO Jack Gerard said Jan. 17 he would step down when his contract ends in August.

Until then, Gerard will continue to direct API's work and help it search for a new CEO.

Gerard joined API in 2008 after serving as president and CEO of the National Mining Association and the American Chemistry Council. Under his leadership, API's membership grew nearly 50%, as the organization added members from every sector of the petroleum industry.

More: American Petroleum Institute

Uranium Producers Ask Commerce Department for Import Relief

Two Colorado uranium companies, Energy Fuels and Ur-Energy, on Jan. 16 jointly submitted a petition to the U.S. Department of Commerce asking for relief under Section 232 of the Trade Expansion Act of 1962 from "imports of uranium products that threaten national security."

The companies said they are seeking a quota on uranium imports and to have at least 25% of the U.S. nuclear market reserved for U.S. uranium companies.

The companies said domestic uranium producers fulfill less than 5% of U.S. demand, while imports from businesses owned or subsidized by governments in Russia, Kazakhstan and Uzbekistan fulfill nearly 40% of it.

More: Denver Business Journal

Big Power CEOs Tried to Convince Entergy, NextEra to Stay in NEI

The CEOs of American Electric Power, Dominion Energy, Exelon and Southern Co. earlier this month tried to convince Entergy and NextEra Energy to remain members of the Nuclear Energy Institute, according to an email by NEI Board Chairman Don Brandt that was obtained by *Politico*.

"We implored [Entergy CEO Leo Denault] to reconsider his decision" at an Edison Electric Institute board meeting, Brandt wrote in the email.

NextEra CEO Jim Robo, Brandt wrote, "appears more hardened on his decision" to take his company out of NEI.

More: Politico

Trump Imposes 30% Tariff On Imported Solar Panels

President Trump on Monday imposed a 30% tariff on the import of solar panels, following a recommendation by the International Trade Commission.

The tariffs, less severe than those sought by solar panel manufacturers Suniva and SolarWorld, will gradually decrease to 15% over the next four years. The solar industry and environmentalists criticized the decision.

Trump acted under a provision of trade law that, after an examination by the ITC, leaves the final decision on tariffs to the president. The provision has not been used since 2002, when President George W. Bush imposed tariffs on imported steel. Trump also imposed a 20% tariff on imported washing machines.

More: The Washington Post

Leaker of Perry-Murray Photos Seeking Whistleblower Protection

Simon Edelman, who as a Department of Energy photographer took and subsequently leaked photographs of a meeting last March between Energy Secretary Rick Perry and Murray Energy CEO Robert Murray, has filed a complaint with the department's inspector general and is seeking whistleblower protection.

In his complaint, Edelman said he became alarmed during the meeting, in which Perry agreed to implement Murray's "action plan," which called for, among other things, "immediate action … to require organized power markets to value fuel security, fuel diversity and ancillary services that only baseload generating assets, especially coal plants, can provide." (See Photos Show Murray's Role in Perry Coal NOPR.)

He said he decided to leak the photos to *In These Times* (which provided them to *RTO Insider*) and *The Washington Post* after the department issued its Notice of Proposed Rulemaking to FERC calling for RTOs with energy and capacity markets to pay generators with 90-day supplies of onsite fuel their full operating costs.

The day after the photos were published by *In These Times*, Edelman was placed on administrative leave without pay and later declined to renew his employment contract. Edelman also has recorded a conversation, heard by *The New York Times*, with a former colleague who told him to transfer ownership of the Google Drive folder in which the photos were stored to the department.

More: The New York Times

State Briefs

CALIFORNIA

SoCal Edison Named Defendant in Mudslide Suit

Residents of Montecito have filed a lawsuit alleging that Southern California Edison could have prevented the Thomas Fire with better maintenance and infrastructure and so bears responsibility for the mudslides earlier this month that killed at least 20 people, destroyed 100 homes and damaged hundreds more.

The lawsuit, which also names the Montecito Water District as a defendant, says the fire wiped out the vegetation on the upper slopes of the Los Padres National Forest, reducing the amount of water they could absorb and leaving the town vulnerable to floods and mudslides from heavy rains, such as the ones that hit it Jan. 8-9.

Neighborhood in Santa Barbara County affected by mudslide, Jan. 9

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STATE BRIEFS

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One of the law firms that filed the suit in the Superior Court of Santa Barbara County previously filed a lawsuit in Ventura Superior Court alleging that malfunctioning SCE transformers triggered the Thomas Fire, which was the largest fire in modern state history.

More: The Tribune

Stern Calls for Regulations in Response to Gas Storage Report

Stern

State Sen. Henry Stern (D) on Thursday called for new regulations and possible legislative action concerning the state's major natural gas storage fields.

Stern was responding to a report released Thursday by the California Council on Science and Technology that analyzed the gas storage fields' safety, viability and operational risks. The report was a response to the 2015 leak that resulted in the closure of Southern California Gas' Aliso Canyon gas storage field.

Stern represents the communities in the north San Fernando Valley impacted by the 2015 leak. He introduced SB 801, which requires publicly owned utilities in the Los Angeles Basin to support deployment of distributed energy resources and energy storage and reduce the region's reliance on gas-fired generation. The bill was passed last September and signed into law the following month. (See CAISO Regionalization, 100% Clean Energy Bills Fizzle.)

More: Sen. Henry Stern

PG&E Begins Installing EV Chargers At Apartments, Condos, Offices

Pacific Gas and Electric on Jan. 17 began installing 7,500 electric vehicle chargers at apartment buildings, condominiums and workplaces throughout the state under its EV Charge Network Program.

The utility will continue installing chargers through 2020 under the program, which has a $130 million budget and is funded by a charge on PG&E customers' bills of about 22 cents/month.

More: San Francisco Chronicle

KENTUCKY

Big Rivers Files Paperwork for 3.3-Mile Portion of 30-Mile Tx Line

Big Rivers Electric has filed preliminary paperwork with the Public Service Commission for a proposed 3.3-mile transmission line in Hancock County.

The line would be part of a 30-mile, 345-kV line between Big Rivers' substation in Hancock County and Vectren's substation in Huntingburg, Ind. Big Rivers said in its filing that MISO in 2015 determined the line was necessary to relieve congestion in the region.

The estimated cost of the whole line is nearly $54 million.

More: Messenger-Inquirer

MASSACHUSETTS

Generators Challenge Carbon Emissions Caps in Court

The New England Power Generators Association and NRG Energy filed a motion in Suffolk Superior Court on Jan. 16 to force the state to rescind the carbon emission caps that took effect this month.

The administration of Gov. Charlie Baker established the emission caps after the Supreme Judicial Court ordered the state to set specific limits to comply with the 2008 Global Warming Solutions Act, which requires the state to cut greenhouse gas emissions 25% below 1990 levels by 2020 and 80% below them by 2050.

Nearly 90% of emission reductions under the caps will come from the power sector, even though it already has reduced its emissions 60% since 1990, more than any other sector over that time, NEPGA President Dan Dolan said.

More: The Boston Globe

CLF Seeks Pause in Appeal of Power Plant Expansion Decision

The Supreme Judicial Court is scheduled to hear a motion by the Conservation Law Foundation on Jan. 30 to pause consideration of its appeal of an Energy Facilities Siting Board decision approving the expansion of NRG Energy's Canal Generating Plant in Sandwich, an attorney for the foundation said.

| NRG Energy

The foundation wants the motion paused pending resolution of two Superior Court cases in which the New England Power Generators Association and Calpine are challenging emissions regulations.

More: Cape Cod Times

NEW MEXICO

PRC Votes to Allow PNM Rate Increase

The Public Regulation Commission voted 3-2 Wednesday to allow Public Service Company of New Mexico (PNM) to collect an additional $4.7 million from customers.

The amount is what PNM asked to be allowed to recover from customers for improvements at the Four Corners Power Plant after the commission last week rejected its request to be allowed to recover more than $9 million for the improvements. In that ruling, the commission said PNM shouldn't be allowed to recover any money for the improvements.

More: Santa Fe New Mexican

OKLAHOMA

Bill to End Renewable Energy Tax Credits Introduced

State Rep. Bobby Cleveland (R) has introduced a bill to repeal a 2001 law allowing zero-emission energy facilities to collect tax credits.

A law enacted last spring required wind farms to be operational by last July to qualify for the tax credits. Cleveland's law apparently would completely eliminate the credits, which he said cost the state $66.9 million in the 2015 tax year.

Continued on page 47

Calls Grow for Capturing Utilities' Tax Savings

The number of state officials and utilities announcing actions because of the Tax Cut and Jobs Act signed by President Trump last month keeps growing.

The bill cut the federal corporate tax rate from 35% to 21%, and many public officials want to make sure utilities pass their savings from the bill on to their customers.

As of Jan. 8, regulatory bodies in at least 11 states had opened proceedings or taken other actions related to the tax bill, and elected officials in at least two other states had called for them to. Also, at least nine electric and gas utilities had said they planned to pass their savings on to their customers. (See *Utilities Likely to Pass Tax Bill Gains to Customers*.)

Since then, a coalition of elected officials, consumer advocacy officials and utility regulators from 18 states has written FERC a letter calling for an investigation into the "justness and reasonableness" of utility rates considering the tax act. (See "States Asking FERC to Investigate Rates in Light of Tax Cut," *Federal Briefs*.)

The Organization of MISO States joined the chorus on Monday. (See related story, *OMS Urges FERC to Pass Tax Cut Benefit to Ratepayers*, p.21.)

At Thursday's open meeting, Commissioner Robert Powelson expressed his support for a pass-through of utilities' savings. "I hope we do our part to make sure these tax benefits are accrued to energy users here in America," he said.

Chairman Kevin McIntyre told reporters after the meeting that he agreed with Powelson's sentiment and that the commission was considering its options.

Also, the Texas Public Utility Commission has taken its first steps in determining how to share the tax cuts with ratepayers. (See *PUCT Briefs: Regulators Begin Addressing Utility Tax Savings*.)

Ameren Illinois plans to file a petition with the Illinois Commerce Commission to be allowed to pass its tax-bill savings on to its electric customers. | *Ameren Illinois*

Here's a round-up of other recent actions by regulators and companies:

Midwest

The North Dakota Public Service Commission on Jan. 10 ordered Montana-Dakota Utilities, Otter Tail Power and Xcel Energy to let it know by Feb. 15 their savings from the tax bill so it can return the money to ratepayers.

Ameren Illinois said it filed a petition with the Illinois Commerce Commission to be allowed to pass its tax bill savings on to its natural gas customers and planned to file one to be allowed to pass them on to its electric customers too.

Oklahoma Gas & Electric said savings it realizes from the tax act will cover about $68 million of a $72 million rate increase it asked for on Jan. 16.

Kansas City Power & Light and Westar Energy said they will file requests with their state regulators to be allowed to pass their savings on to their customers. Kansas City Power & Light's parent, Great Plains Energy, and Westar Energy are continuing to pursue their merger. (See *Great Plains, Westar File Revised Merger Plan*.)

East

The Delaware Public Service Commission on Jan. 16 approved a petition filed by the state's Public Advocate to make sure

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STATE BRIEFS

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Adrienne Gautier, who belongs to Ready for 100, a group advocating 100% renewable energy, said the "tax incentives for wind are a drop in the bucket compared to the breaks that big oil and gas receive in this state."

More: *The Norman Transcript*

RHODE ISLAND

Invenergy Withholds Impact Fee from Town

Rather than paying Burrillville a $500,000 impact fee Jan. 15 for a power plant it wants to build in the town, Invenergy put the money in escrow because the town has used money from previous impact fee payments to fund an effort to prevent the company from building the plant.

Invenergy has paid Burrillville $1.175 million in impact fees under an agreement it signed with the town in November 2016. "It is our intention to use Invenergy's own money to finance our fight to keep them out of Burrillville," Town Council President John F. Pacheco III said after the agreement was signed.

Invenergy's chief legal officer, Michael Blazer, said Burrillville is violating the agreement by spreading "misleading information" about the Clear River Energy Center, a 1-GW power plant that would mainly burn natural gas.

More: *Providence Journal*

WISCONSIN

PSC Approves ATC's Riverside Transmission Line Project

American Transmission Co. said Thursday the Public Service Commission has approved its Riverside Transmission Line Project, which is needed to connect Alliant Energy's expanded West Riverside Energy Center to the grid.

The 4.2-mile, 345-kV, double-circuit transmission line will run from a planned substation near the center to an existing 345-kV transmission line in the Town of Beloit.

ATC anticipates it will cost $42 million to build and be in service in 2019.

More: *American Transmission Co.*

Calls Grow for Capturing Utilities' Tax Savings

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consumers receive the benefits of any savings realized by utilities. The order directs utilities to estimate the impact of the new tax law on their cost of service, and to propose procedures for reducing their rates to reflect those impacts by March 31.

Delmarva Power, which had already committed to pass along its savings from the tax bill to Maryland ratepayers, said it would adjust its natural gas and electric rate increase requests in Delaware to reflect its savings from the bill.

Dominion Energy said Jan. 2 if its deal to purchase SCANA goes through, it will reduce the rates of SCANA's South Carolina Electric & Gas subsidiary by more than $7/month with some of the money coming from savings from the tax bill.

Public Service Enterprise Group said in an 8-K filing Jan. 11 that it will realize a one-time benefit of $660 million to $850 million from the tax bill. A day later its Public Service Electric and Gas subsidiary asked New Jersey regulators to approve a 1% increase in its base electric and gas rates, which it said reflects the fact that it is "passing along savings from recent tax law changes."

National Grid said on Jan. 11 it would reduce its request for an electric and gas base distribution rate in Rhode Island from $71 million to $45 million because of savings from the tax bill.

The company on Monday said its Niagara Mohawk Power subsidiary has filed a request with the New York Public Service Commission to boost its revenue by $206 million in 2018-2019, before the impact of deferred credits. The request includes an estimated customer savings of $76 million from the tax cuts.

West

Pacific Power said Jan. 3 it will work with its regulators and stakeholders to pass its savings from the tax bill on to its customers.

Arizona Public Service said Jan. 9 it wants to use its savings from the tax bill to reduce its average residential customer's monthly bill by about $4.70.

Green Mountain Power CEO Mary Powell said Jan. 10 that the company would pass along all its savings from the tax bill to its customers.

South

The Mississippi Public Service Commission has asked its Public Utilities Staff to consider possible rate reductions available to residents.

The Georgia Public Service Commission on Jan. 16 ordered Georgia Power to submit a report to it by Feb. 20 detailing how the utility will be affected by the tax bill.

Florida Power & Light said Jan. 16 it plans to use its savings from the tax bill to cover its $1.3 billion in Hurricane Irma restoration costs and may be able to use them to delay future rate increases.

— Peter Key