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

ISSN 2377-8016 : Volume 2018/Issue 52 December 25, 2018

# GAO Critical of TSA Pipeline Security Efforts

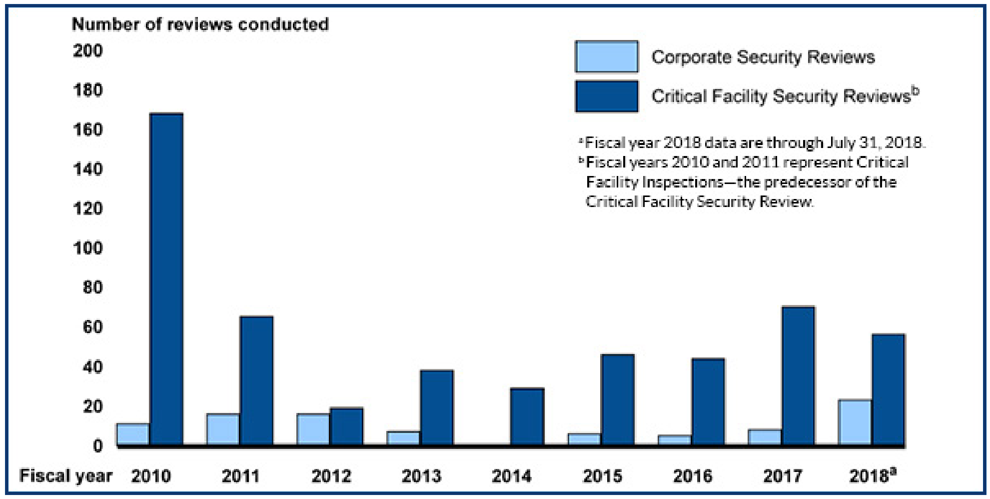
## *Staff of 6 Oversees 2.7 Million Miles*

*By Rich Heidorn Jr.*

The Transportation Security Administration's oversight of natural gas pipeline security is hampered by staffing constraints and vague criteria for identifying critical facilities, the Government Accountability Office *reported* last week.

TSA's Pipeline Security Branch, which is responsible for more than 2.7 million miles of natural gas, oil and hazardous liquid pipelines, currently has only six full-time equivalent employees. Staffing has fluctuated from a high of 14 in fiscal year 2013 to only one in 2014. The agency, part of the Department of Homeland

*Continued on page 4*




Pipeline security reviews conducted, fiscal year 2010 through July 2018 | *GAO Analysis of Transportation Security Administration*



# Chatterjee Pressed on McNamee Resilience Recusal

*By Michael Brooks*

WASHINGTON — Bernard McNamee attended his first open meeting as a FERC commissioner on Thursday, where he was greeted by protests and questions of whether he would recuse himself from the agency's dockets on grid resilience.

McNamee, who was sworn in Dec. 11, declined to vote on the commission's consent agenda for the meeting, which did not feature any discussion items or presentations by staff. Instead, he simply marked himself as "present."

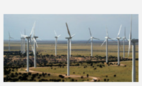
Bernard McNamee | *© RTO Insider*

"Some have asked me what's going to be my agenda here at FERC. That always seems to be the first question I get asked by most people," McNamee said in his opening remarks. "I can sum it up in one word: 'listen.'"

*Continued on page 8*



## Also in this issue:









# NERC Offers Upbeat Long-term Assessment

*By Rich Heidorn Jr.*

NERC offered a mostly upbeat report on the long-term health of the nation's grid Thursday, celebrating results from its first interconnection-wide frequency response studies while highlighting the need to model the increasing volume of distributed resources and supplement variable generation with ramping resources.

The *2018 Long-Term Reliability Assessment*, NERC's 10-year outlook for the North American bulk power system, found that frequency response will remain adequate through 2022 despite the loss of synchronous generators and the increase in inverter-based renewables.

"That gives us some confidence in the resource mix and also the ability to … see whether that performance is degrading out in the future — which is really important, so

*Continued on page 10*

**RTO Insider**

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

**Editorial**

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

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

Art Director
Mitchell Parizer 718-613-9388

Associate Editor / D.C. Correspondent
Michael Brooks 301-922-7687

Associate Editor
Shawn McFarland 570-856-6738

**CAISO/West** Correspondent
Hudson Sangree 916-747-3595

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

**MISO** Correspondent
Amanda Durish Cook 810-288-1847

**PJM** Correspondent
Rory D. Sweeney 717-679-1638

**SPP/ERCOT** Correspondent
Tom Kleckner 501-590-4077

**Subscriptions**

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

Account Executive
Marge Gold 240-750-9423

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

2019 Annual Subscription Rates:

| Plan | Price |
|---|---|
| Newsletter PDF Only | $1,750.00 |
| Newsletter PDF Plus Web | $1,450.00 |

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

# In this week's issue

# FERC Approves NextEra's Gulf Power Acquisition

*By Tom Kleckner*


Gulf Power service truck | *Gulf Power*

FERC on Thursday conditionally approved NextEra Energy's acquisition of Florida utility Gulf Power as being "consistent with the public interest" (*EC18-117*).

Separately, the commission granted Gulf Power's request to make limited market-based rate sales of capacity and energy during the transition ownership period (*ER18-1952*) and accepted the utility's new, standalone tariff, effective upon the transaction's closing (*ER18-1953*). The latter order also established hearing and settlement judge procedures addressing Gulf Power's proposed base return on equity and protocols.

Gulf Power, a subsidiary of Southern Co. in the Florida Panhandle, serves about 450,000 customers in eight counties. The utility owns or controls approximately 2,277 MW of generating capacity, a 2,700-mile transmission system and a 7,700-mile distribution system, and service over its transmission system is currently covered under Southern's tariff.

NextEra announced in May it had reached an agreement with Southern to acquire Gulf Power, Florida City Gas and two gas-fired plants in Florida for almost $6.5 billion. NextEra completed acquisition of the gas plants in December.

Gulf Power will continue to operate in the Southern Company Pool and in Southern's balancing authority area during the transition period, until it can operate on a standalone basis.

FERC said it found no adverse effect to generation markets in its analysis of Florida-based NextEra's acquisition of Gulf Power. It said the applicants' commitment to "indefinite rate de-pancaking" addressed any horizontal market power concerns that might arise, and it noted that Southern-affiliated generation would continue to compete in the Gulf Power balancing authority area, and vice versa.

The commission determined vertical competition would be unaffected as well, pointing to an unconcentrated upstream natural gas delivery market in the existing Southern balancing authority.

It also accepted the transaction's proposed ratepayer protections, which included extending a rate cap period beyond five years, should the transition period take longer than five years, and charging grandfathered transmission customers the lower of Southern's or the new Gulf Power rates during the transition.

In allowing Gulf Power to continue to make limited market-based rate sales of capacity and energy during the transition period, FERC also designated the utility as a Category 2 seller in the Southeast region and a Category 1 seller in the Northeast, Southwest, Northwest, SPP and Central regions.

The commission defines Category 1 sellers as wholesale power marketers and power producers that:

- own or control 500 MW or less of generation in aggregate per region;
- do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been granted waiver of the requirements of Order 888);
- are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets;
- that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and
- that do not raise other vertical market power issues.

Sellers that don't fall into Category 1 are designated as Category 2 sellers and are required to file updated market power analyses.

FERC accepted Gulf Power's proposed tariff, which included a 10.5% ROE, but ordered a public hearing on its justness and reasonableness. The commission held the hearing in abeyance to provide time for settlement judge procedures.

Commissioner Kevin McIntyre did not vote on the orders, while Commissioner Bernard McNamee, who was only sworn in Dec. 11, voted present on each one.

NextEra's share price lost $2.27 at one point during another bloody day on Wall Street, before recovering to close up 16 cents, at $174.91/share, in after-hours trading. ■

## FERC & Federal News

# GAO Critical of TSA Pipeline Security Efforts

Continued from page 1

Security, also lacks a "strategic workforce plan" to identify the skills required of its employees, such as cybersecurity expertise.

GAO also found TSA has not updated its risk assessment methodology since 2014 to reflect current threats to pipelines and that its data sources and underlying assumptions on threats and vulnerabilities are not fully documented. Its risk assessment has not been peer reviewed since it was initiated in 2007, the report said.

Although TSA issued revised guidelines in March 2018 incorporating most of the National Institute of Standards and Technology's "Framework for Improving Critical Infrastructure Cybersecurity," it did not include all of the framework and lacks a formal process for revising the guidelines on a regular basis. "Without such a documented process, TSA cannot ensure that its guidelines reflect the latest known standards and best practices for physical security and cybersecurity, or address the dynamic security threat environment that pipelines face," GAO said.

### Critical Facilities

The guidelines also lack clear definitions to ensure that pipeline operators identify their critical facilities — one reason, auditors speculated, that one-third of the 100 largest pipeline systems have not identified any critical facilities.

TSA's eight criteria lack "additional examples or clarification … to help operators determine criticality," the report said.

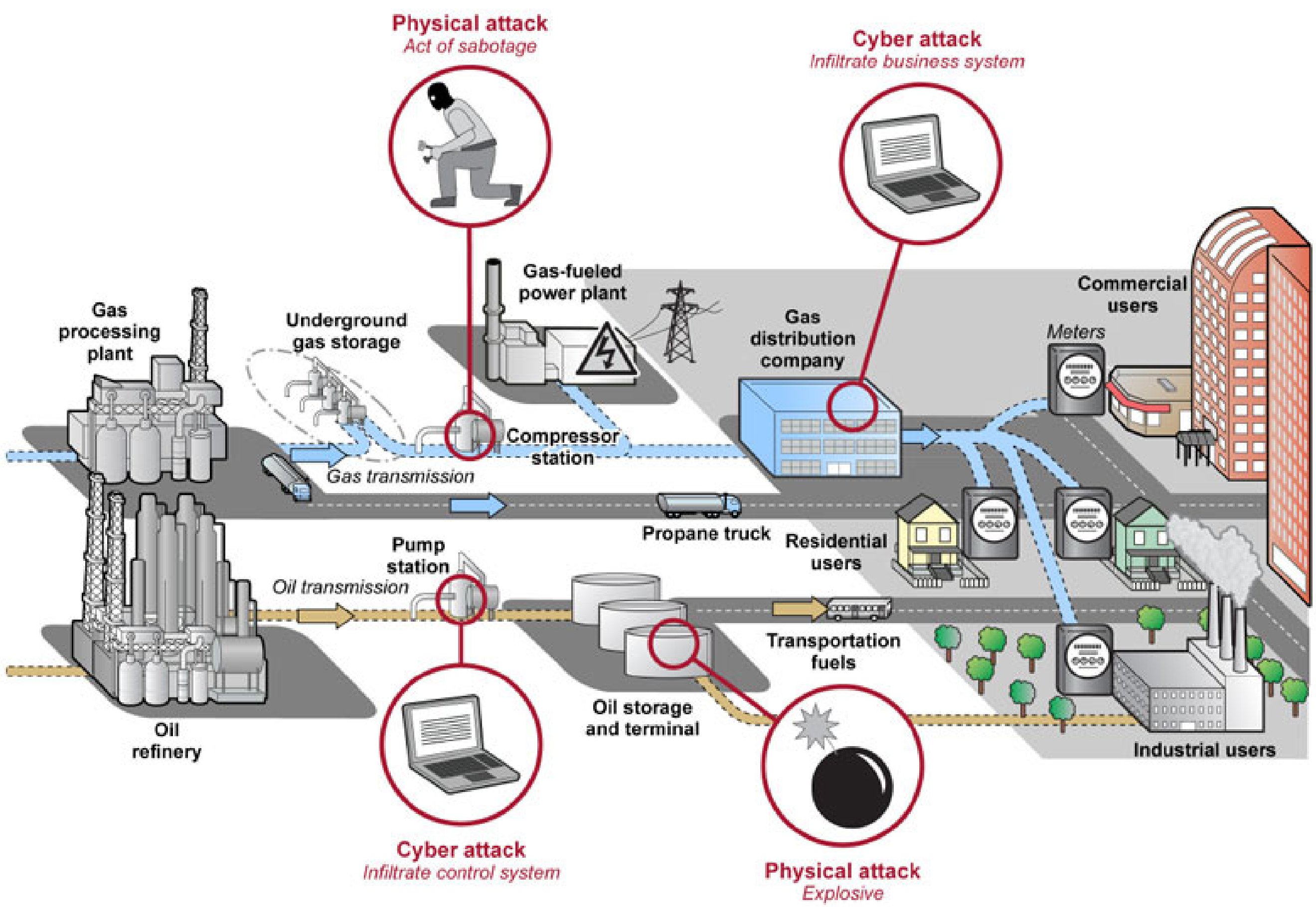
GAO said pipeline operators told it that pipelines may interpret one TSA criterion, "cause mass casualties or significant health effect," differently. "One of these operators that we interviewed stated that this criterion could be interpreted either as a specific number of people affected or a sufficient volume to overwhelm a local health department, which could vary depending on the locality. Another operator reported that because TSA's criteria were not clear, they created their own criteria which helped the operator identify two additional critical facilities."

GAO said one unnamed industry association it met with is working with TSA to develop supplementary guidance for its members to clarify the agency's critical facility criteria.

The American Gas Association (AGA), which represents more than 200 local distribution companies, confirmed it is the group mentioned.

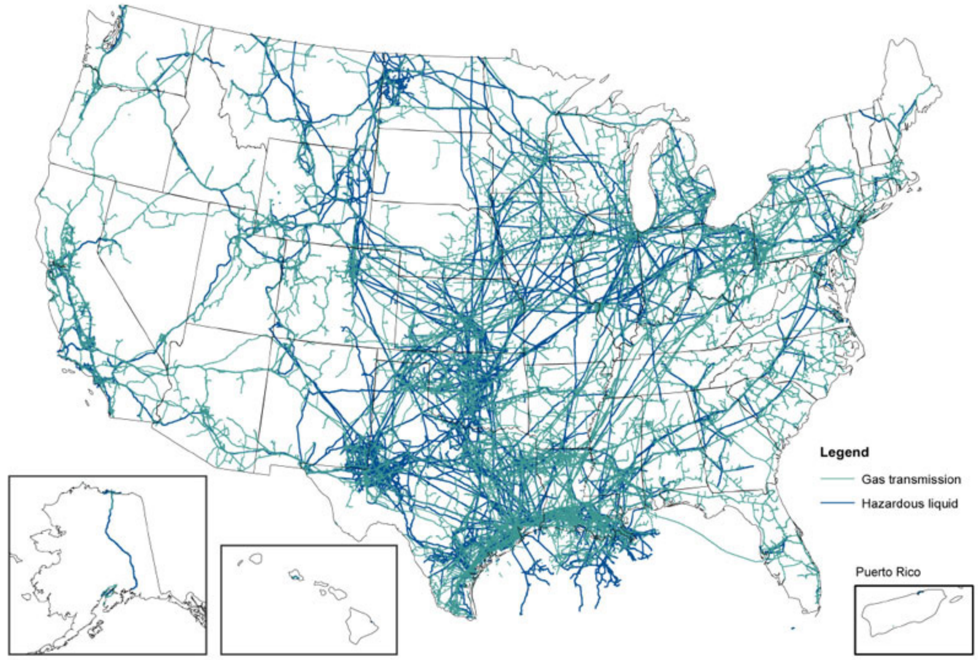
TSA conducts security reviews of the largest 100 companies, but it hasn't checked in the last five years whether its recommended improvements are being followed, leaving it unable to know whether its efforts are reducing risks, the report said.

Based on the company reviews, TSA may also




U.S. natural gas and oil pipeline systems' basic components and examples of vulnerabilities | *GAO Analysis of Transportation Security Administration*

# FERC & Federal News




Map of hazardous liquid and natural gas transmission pipelines in the U.S., September 2018 | *U.S. Department of Transportation*

review the security on a company's critical facilities. Although the reviews are voluntary, TSA told auditors no company has ever rejected an inspection request.

The agency conducted 23 corporate reviews and about 60 facility reviews in fiscal year 2018 (through July 31). In 2014, when the safety unit had only one FTE, it conducted no corporate reviews and about 30 facility reviews.

## Dispute on Mandatory Rules

At FERC's open meeting Thursday, Chairman Neil Chatterjee said the GAO report "reiterated" concerns he and Commissioner Richard Glick expressed in a June *op-ed* calling for mandatory reliability standards for natural gas pipelines like those the commission and NERC enforce on the grid. "Despite having the authority to enforce mandatory cybersecurity standards, the TSA relies on voluntary ones," they wrote.

Glick said TSA performs a valuable role in airport security but is ill-suited for overseeing pipeline security. "I continue to believe that Congress should … consider moving authority over gas pipeline cybersecurity to another agency such as the Department of Energy."

Chatterjee said that although the GAO report identified gaps, he has been pleased by recent efforts by industry and DHS to improve pipeline security, including the creation of a risk assessment program that includes DHS, TSA, DOE and FERC.

In a *press release*, Don Santa, CEO of the Interstate Natural Gas Association of America (INGAA), also cited what he called his group's "partnership" with TSA, DHS and DOE to conduct cybersecurity assessments of pipelines, saying, "This interagency approach will bring to bear the particular expertise of each agency, along with those of the industry itself." INGAA says its 26 members represent most of the interstate natural gas transmission pipeline companies in the U.S. and Canada.

But he rejected the idea of mandatory standards. "In this environment of rapidly evolving cyber threats, it is important that we take an approach that enables flexibility and allows us to quickly adapt and update protocols," he said. "Experience shows that mandatory standards are all too often outdated almost as soon as they are introduced. We need the flexibility and ability to build on our baseline practices to look forward towards addressing the threats of the future."

AGA said in a statement that GAO's criticism "is missing the mark."

TSA officials "understand the industry and have a strong working relationship with natural gas utilities," said AGA CEO Dave McCurdy, who called for expanding the agency's budget and staff "so that they can come into our member companies and make the assessments themselves. In addition to our numerous voluntary programs in the cybersecurity arena, we believe that this is the best way to build upon the success of this public-private partnership." ■

## FERC & Federal News

# GAO: No Consensus on GMD Risk to Grid

*By Rich Heidorn Jr.*

A Government Accountability Office *report* on geomagnetic disturbances released last week found a lack of consensus on how much of a risk they pose to the U.S. electric grid, in part because of limited modeling capabilities.

GMDs, which occur when the sun ejects charged particles that change Earth's magnetic fields, can cause geomagnetically induced currents (GIC) that produce voltage instability and damage connected equipment.

Although such coronal mass ejections occur regularly, GAO said there have been only four GMDs worldwide since 1932 that significantly affected the grid with large-scale service disruptions or equipment damage. The only instances in the U.S. were GMDs in March and September 1989 that damaged four single-phase transformers at one power plant, with no loss in electric service.

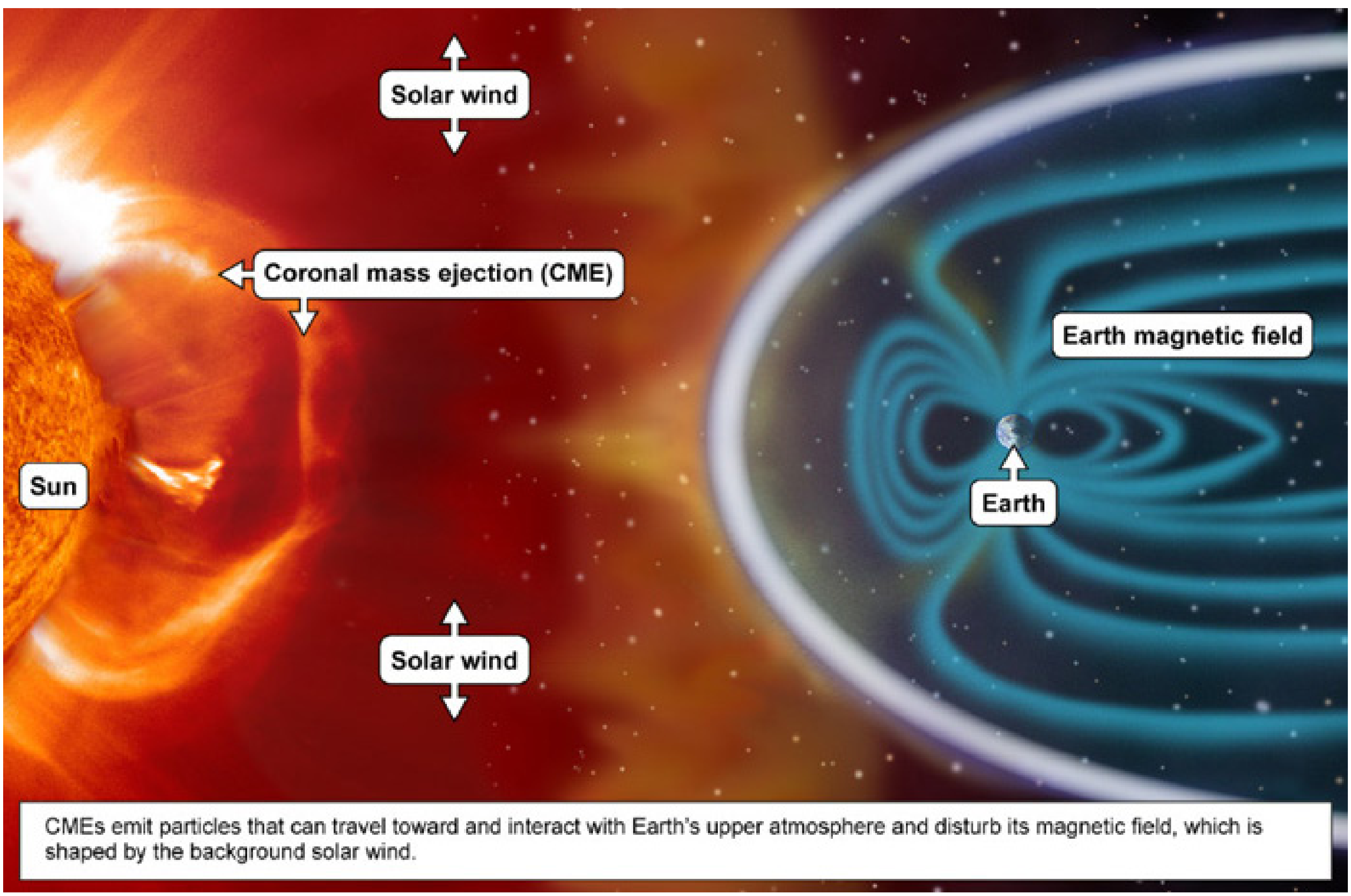
### 'Key Gaps'

"The magnitude of potential damages from a large GMD is not fully understood, in part because there have been few examples worldwide of GMDs that have caused equipment damage or large-scale blackouts," GAO said. "Determining how GMDs will interact with and harm the electric grid is challenging because the magnitude of the ensuing GIC is influenced by several factors. The reaction of specific components of the electric grid to GIC and its secondary effects is also challenging to accurately model."

GAO said there are "key gaps" in the understanding of variables that impact severity, such as data on local geoelectric fields. The U.S. Geological Survey has only 14 ground-based observatories measuring local magnetic fields.

"The relatively sparse coverage of magnetic observatories, particularly in the contiguous United States, limits the ability to monitor GMD in areas without magnetic observatories," GAO said. "Even when the GMD is measured at nearby magnetic observatories, Earth resistivity required to calculate the geoelectric field … is often the dominant source of uncertainty in GIC calculations. … Earth resistivity varies by about a factor of 10,000 within a Midwest region otherwise described by a single, one-dimensional ground resistivity model."

Because extreme GMDs are rare, researchers have attempted to extrapolate the impact of extreme events from available data on moderate events. But GAO said, "Researchers at Los Alamos National Laboratory found that the probability of extreme events is not accurately




Coronal mass ejection (CME) approaching Earth | *GAO-19-98*

# FERC & Federal News

described by statistical models of historical records."

## Worst Case?

The worst-case scenarios from a solar-induced GMD — or an electromagnetic *pulse* produced by the detonation of a nuclear device 25 to 250 miles above Earth's surface — sound like the stuff of disaster movies.

"A large GMD might have long-term, significant impacts on the nation's electric grid," GAO said. "Given the interdependency among infrastructure sectors, such a disruption to the electric grid could also result in potential cascading impacts on fuel distribution, transportation systems, food and water supplies, and communications and equipment for emergency services, as well as other communication systems that utilize electrical infrastructure."

But the auditors said recent research suggests that the worst GMDs might have only limited impact. "The most persuasive studies we reviewed concluded that the most likely effects of a large GMD would be service interruptions that are neither long-term nor large-scale," GAO said.

Two National Laboratory studies that evaluated the impact of an extreme GMD event on the Eastern and Western interconnections concluded "that the disconnection or loss of transformers experiencing high GIC would avoid equipment damage and maintain grid stability. … It is possible to use operating procedures or GIC-blocking technologies to protect transformers and grid stability."

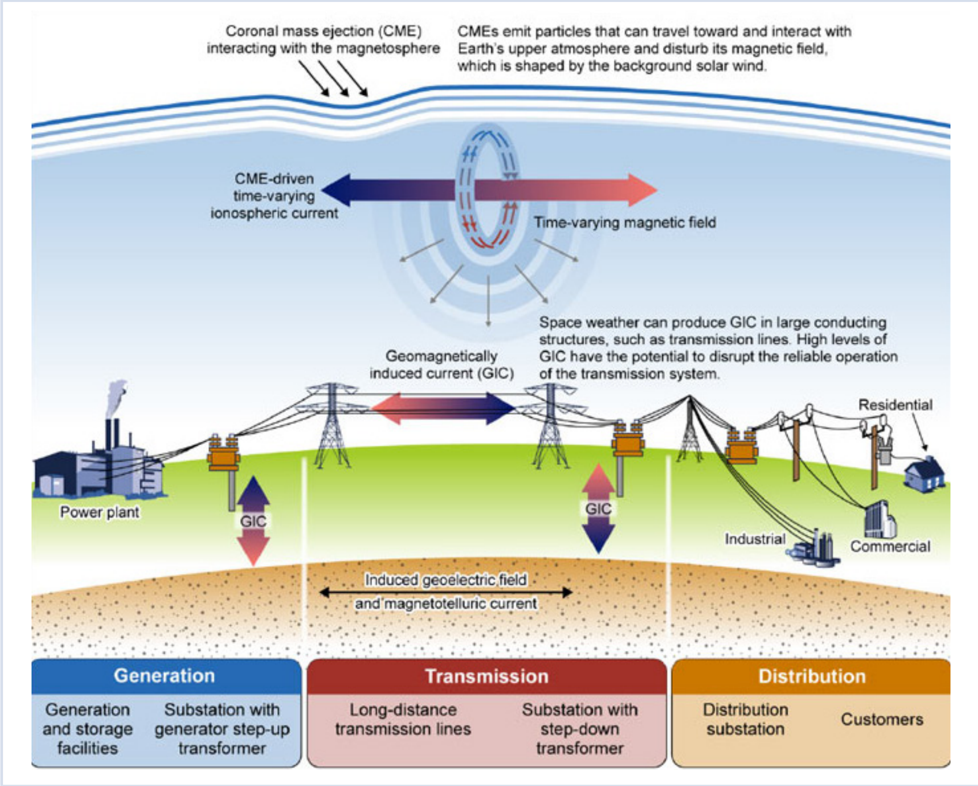
NERC cited operational procedures such as increasing operating reserve margins, modifying protective relay settings and removing vulnerable equipment from service.

A study by an unnamed electric power supplier "concluded that failures in generators or capacitors are unlikely during a 100-year storm," GAO added.

NERC's Geomagnetic Disturbance *Task Force* concluded that the most likely worst-case system impacts from a severe GMD event would be voltage instability and potential blackouts. But GAO noted that "blackouts that originate in the transmission grid in the absence of substantial equipment damage are generally restored within three days and often much sooner."

## FERC, NERC Actions

GAO's findings on the limited data echo frustrations FERC and the Department of Energy have expressed.




Coronal mass ejections cause geomagnetic disturbances that may interact with the electric power grid. | *GAO-19-98*

In 2016, DOE said traditional power system planning models are flawed because they do not include substation grounding or transformer configuration details, which are essential to modeling GIC flows.

In November, FERC approved NERC's revised GMD reliability standard, which broadens the definition of GMDs, requires grid operators to collect certain data and imposes deadlines for corrective actions (*RM18-8, RM15-11-003*). (See *Revised NERC GMD Standard Approved*.)

The standard seeks to create a benchmark for estimating the impact of a large GMD. But GAO said "conducting such estimates is challenging because the wide variety in transformers, including model, age and power capacity, could lead to significant variability in the effects [of] GIC on specific transformers."

At FERC's direction, NERC has joined with the Electric Power Research Institute to develop a research plan to improve the benchmark GMD event and Earth resistivity models.

## Technological Fixes?

An October 2016 executive order by President Barack Obama directed DOE and the Department of Homeland Security to develop a plan to test and evaluate technology that could mitigate the effect of GMDs. The GAO report came in response to a request by the Senate Committee on Homeland Security and Governmental Affairs to examine the availability of such technologies and the challenges of using them.

DOE told the auditors that it completed a plan for a pilot program to test commercially available technology in April and has hired contractors to implement the plan.

The GAO researchers reported that three-phase transformers may be less vulnerable than single-phase units, but it said the larger, heavier three-phase units present shipping challenges.

GAO said series capacitors, used to improve the transfer capability of long transmission lines, can also block GIC. "However, care must be exercised in placing series capacitors in the electric power transmission system because blocking GIC in one section of the grid can affect GIC flow in other sections of the electric power transmission system. Therefore, it is necessary to evaluate the effect of series capacitors in sections of the electric power transmission system on other sections of the electric power transmission system before they are installed," GAO said. ■

## FERC & Federal News

# Chatterjee Pressed on McNamee Resilience Recusal

*Continued from page 1*

He said he is still interviewing potential staff and didn't want to rush his decisions on issues. "I expect to fully participate in the commission's proceedings and decisions soon, but for now, I just plan to listen."

McNamee left the room almost immediately after the meeting ended, declining to answer a reporter's question. It fell to Chairman Neil Chatterjee to address multiple calls for McNamee's recusal from the resilience dockets. Those calls have come from Senate Democrats, environmental groups, the Harvard Law School's Electricity Law Initiative and several protesters at Thursday's meeting — though the last group did not say from what he should recuse himself. (See *Enviros Seek McNamee Recusal in Resilience Dockets*.)

FERC Commissioner Bernard McNamee gives his opening remarks at the commission's open meeting Dec. 20, his first since being sworn in. | *© RTO Insider*

Chatterjee said, "All I know is, on his very first day at the commission, [McNamee] went and received ethics training and sat down with our legal counsel here at the commission to discuss these matters, as we all did on our first days at the commission." He repeatedly emphasized that the decision to recuse lies with individual commissioners, and that the chairman has no say in the matter. "I don't have the capacity to deny another commissioner their vote or their ability to participate in a proceeding. That is between Commissioner McNamee and ethics" staff.

"And I have complete confidence in the lawyers in this building to ensure on all these fronts that whatever actions we take will be with an eye toward ensuring the maximum ability to withstand legal scrutiny," Chatterjee said.

But Chatterjee also noted that upon his own arrival at FERC, there were also questions concerning his ability to be impartial given his previous job as energy adviser to Senate Majority Leader Mitch McConnell (R-Ky.), "and I probably wasn't always helpful to dissuade those." He said he felt that his record at FERC has proven he can make impartial decisions based on the record.

"So all I would ask is that he be given an opportunity to demonstrate that, like myself, [McNamee] will be an earnest public servant," Chatterjee said. "And I think that based on my getting to know him and his remarks today, I truly feel he will be that earnest public servant."

Chatterjee was referring to McNamee's closing remarks at the meeting, after the commission had honored two retiring staff members.

McNamee said agency staff are "sometimes not given the due that they should be given. ... Public service is a calling, and often people don't respect it the way they should. You don't get paid as much as you could in the private sector, but ... you come each day to do what's right for the country and give your best advice. And that's something that's very noble. Personally, I'm grateful for it, and I'm looking forward to working with all of you."

### Tension over LNG; No Update on McIntyre

Meanwhile, the partisan divide at the commission over natural gas facilities continued, as Chatterjee struck from the consent agenda a vote on Venture Global LNG's application to build its Calcasieu Pass LNG export facility in southwestern Louisiana's Cameron Parish (CP15-550).

In her opening remarks, Commissioner Cheryl LaFleur (D) said she was "disappointed we are not voting on the project today. Based on the record before us today, and my assessment of the legal requirements under the Natural Gas Act and the National Environmental Policy Act, I was prepared to cast a vote on the project. Without getting into internal deliberations, I think I made clear what I believe is required of us when considering whether to authorize this LNG project."

Both LaFleur and fellow Democratic Commissioner Richard Glick have repeatedly disagreed with their Republican colleagues about the consideration of greenhouse gas emissions in gas infrastructure approvals. If the vote on Calcasieu Pass had been like previous votes, Chatterjee would have been outnumbered without McNamee and Commissioner Kevin McIntyre, who was again absent from the monthly meeting and has not voted on any items since stepping down from the chair in October because of what he called a "serious setback" in his battle with a brain tumor.

Chatterjee has previously poked fun at LaFleur at previous open meetings for her reversal on the issue, as she only recently began to vote against gas infrastructure over GHG concerns. (See *FERC Says Farewell to Powelson*.)

But speaking to reporters on Thursday, he was subtly critical of her.

"I appreciate my colleague's concerns, but also, when she was chairman she had a reputation of being a strong supporter of LNG exports. The policy was fine then," he said, before moving on.

Chatterjee declined to give an update on McIntyre's status. The commissioners in their opening remarks wished him and his family well for the holidays. But unlike at earlier meetings, none of them offered hopes of him soon returning to work. ■

## FERC & Federal News

# Enviros Seek McNamee Recusal in Resilience Dockets

*By Rich Heidorn Jr.*

Environmental groups last week asked that new FERC Commissioner Bernard McNamee recuse himself from the commission's resilience dockets because of his advocacy for coal and nuclear plants during his time at the Department of Energy.

The motion by the Natural Resources Defense Council, Sierra Club and Union of Concerned Scientists echoed concerns Senate Democrats expressed during McNamee's confirmation hearing in November (*RM18-1, AD18-7*). McNamee was sworn in on Dec. 11 after winning confirmation on a 50-49 party line vote.

McNamee's role in DOE's Notice of Proposed Rulemaking and the agency's second proposal, to save at risk generators under the Defense Production Act, "create the appearance that Commissioner McNamee has prejudged central matters of law and fact that remain at issue in these proceedings," the environmental groups wrote.

As Deputy General Counsel for Energy Policy at DOE, McNamee signed the NOPR, which asserted that "the resiliency of the nation's electric grid is threatened by the premature retirements of power plants that can withstand major fuel disruptions caused by natural or manmade disasters." The NOPR proposed eligible fuel-secure units within PJM, NYISO, MISO and ISO-NE receive "full recovery of costs," including a return on equity, arguing wholesale pricing in organized markets "does not adequately consider or accurately value" resilience benefits of fuel-secure generators.

McNamee also worked on DOE's second proposal, which asserted that "retirements of fuel-secure electric generation capacity across the continental United States are undermining the security of the electric power system because the system's resilience depends on those resources."

The environmental groups cited a series of court rulings outlining the circumstances in which recusal is required. "Due process considerations require that an adjudicator 'who participates in a case on behalf of any party, whether actively or merely formally by being on pleadings or briefs, take no part in the decision of that case by any tribunal on which he may thereafter sit,'" they wrote, quoting from a 1958 D.C. Circuit Court of Appeals ruling.

The groups also noted FERC's rejection of the DOE NOPR (RM18-1) is still subject to rehearing request by the Foundation for Resilient Societies. "McNamee's participation in these rehearing requests would violate the venerable prohibition against a man standing in judgment of his own cause, and due process," the groups said, adding that McNamee also should recuse himself from the resilience docket the commission opened in January when it rejected the NOPR (AD18-7).

### 'Same Factual Questions'

"The resilience docket therefore encompasses the very same factual questions that were answered by the department, and by Commissioner McNamee on behalf of the department, in the DOE NOPR: whether the grid is threatened by retirements of so-called 'fuel secure' power plants and whether and to what extent such 'fuel secure' resources are necessary to the reliability and resiliency of the grid. … The mere technicality that the two proceedings have different docket numbers, where the substantive matters at issue are materially the same, does not make the resilience docket a sufficiently distinct matter for the purposes of the due process inquiry."

The groups cited *comments* filed Dec. 6 by Harvard Law School's Electricity Law Initiative, which also questioned McNamee's impartiality. "His recusal must extend beyond these two dockets," wrote Ari Peskoe, the director of the law project. "The NOPR's sweeping conclusions prejudge issues that could appear before the commission in ratemaking proceedings. This prejudgment is substantially different from a commissioner's public statements about policy issues, which the commission has recently determined were not a basis for recusal."

In his confirmation hearing, McNamee said he would consult ethics lawyers on whether he should recuse himself from the resilience dockets. (See *Democrats Urge McNamee's Recusal from Resilience Docket*.)

Democrats also were alarmed by comments McNamee made in a videotaped speech in February after briefly leaving DOE and working for a conservative think tank's project to "reframe the national discussion" about fossil fuels. McNamee said renewables are disruptive to "the physics of the grid" and described environmentalists' activism against fossil fuels as a "constant battle between liberty and tyranny."

FERC Commissioner Bernard McNamee told Senators at his November confirmation hearing that he would consult with ethics lawyers on whether he should recuse himself from the commisison's resilience dockets. | *© RTO Insider*

After the video became public, Sen. Maria Cantwell (Wash.), the ranking Democrat on the Energy and Natural Resources Committee, questioned McNamee in writing about his comments, asking: "How can environmental groups possibly expect a fair shake from you as a FERC commissioner?"

McNamee responded: "I understand the difference between being an advocate and an independent arbiter."

McNamee and FERC Chair Neil Chatterjee declined to comment on the recusal motion.

### Comments Filed

McNamee replaced former Commissioner Robert Powelson, who joined in FERC's 5-0 vote rejecting the DOE NOPR and opening the new resilience docket in January. The commission has received two rounds of comments in the new docket, including a June request by FirstEnergy for an emergency order to preserve fuel-secure generating resources. (See *RTO Resilience Filings Seek Time, More Gas Coordination* and *Don't Rush on Resilience, Commenters Urge*.) The commission has given no indication of what it will do, if anything, in response.

The Trump administration reportedly dropped DOE's second proposal this fall. (See *Chatterjee Dodges as DOE Spins on Coal Bailout*.)

But the resilience concerns the department raised haven't gone away. On Dec. 17, PJM issued a report calling for payments for fuel-secure generation. (See *Full PJM Study Makes Case for Fuel Security Payments*.) On Dec. 18, NERC issued a warning that quicker-than-expected retirements of coal and nuclear plants could undermine reliability. (See *NERC Releases 'Stress Test' Analysis of Gen Retirements*.) ■

## FERC & Federal News

# NERC Offers Upbeat Long-term Assessment

Continued from page 1

that if there are issues, you can put [in] policies or build new resources," said John Moura, director of reliability assessment and system analysis, during a press briefing on the report.

John Moura, NERC | *© RTO Insider*

Moura noted that FERC Order 842, issued in February, requires all new resources seeking interconnections be able to provide frequency response, calling the requirement "really, really important for reliability." (See *FERC Finalizes Frequency Response Requirement*.)

The report said dynamic stability analysis showed both the Eastern and Western interconnections' generation "sufficiently supports frequency after simulated disturbances despite reductions in inertia" from the loss of synchronous generation. It said ERCOT has operational procedures to address risks from "degraded inertia."

"My optimism is not only based on the current mechanisms in place but the ability of the industry to respond and adapt to the changes. And so, while today we don't have really what I would call excellent frequency response modeling capability, we've got pretty good [capability]. We're able to see it," Moura said. "And I have confidence that we'll be able to have that excellent frequency response model in by the time we really need it."

### Load & Reserves

The report predicts North America will see compound annual load growth of only 0.57% for summer and 0.59% for winter, with five areas — New York, New England, the Maritimes, Manitoba and the California-Mexico region (most of California and a northern sliver of Baja California) — expecting reductions in peak demand. The fastest growing regions are ERCOT and the Rocky Mountains region of the Western Electricity Coordinating Council, both projected to grow about 1.8% annually.

The report did identify concerns, noting that ERCOT's anticipated reserve margins are below targets for the next five years, with MISO and Ontario foreseeing reserve shortfalls beginning in 2023. (See *ERCOT Predicts Tight Reserve Margin for 2019*.) But it said the shortfalls could be filled by accelerating construction of additional Tier 2 resources — those that have met milestones such as completing feasibility, system impact or facilities studies.


| Top 3 States | Projected Capacity (2023) |
|---|---|
| California | 18,000 MW |
| New Jersey | 4,000 MW |
| Massachusetts | 4,000 MW |

| *NERC*

The report includes new probabilistic evaluations — loss-of-load studies that evaluate all hours of the year — which found the California-Mexico assessment area of WECC at risk of 2.3 loss-of-load hours in 2022, with an expected 152 MWh of unserved energy. "These are not significant numbers … but it's a faint signal that tells us about risk that may not be occurring in the peak hour," Moura said.

### Following Florida, California

The report projects 100 GW of new generation in the next decade, including about 41 GW of gas and 60 GW of solar. ERCOT and the California-Mexico region expect gas generation to contribute more than 60% of on-peak capacity, while Florida expects gas' share to rise from 70% to 80%.

"When you do have this level of natural gas resources, you have to plan differently," Moura said. "There are things that, for example, Florida does that other areas may need to do in the future, such as procuring more firm gas … or ensuring we have more dual-fuel capabilities."

California is leading the way in addressing reliability risks from increasing solar, with CAISO's three-hour ramping needs hitting a record 14,777 MW last March and expected to rise to 17,000 MW by 2022.

"As solar generation continues to increase in California and elsewhere across North America, system planners should ensure sufficient flexible ramping capacity, including large-scale energy storage," the report said.

More than 30 GW of new distributed solar PV generation is expected by the end of 2023, with California expected to reach 18 GW of capacity, almost 40% of its projected peak. New Jersey, Massachusetts and New York are projected to each have 3.5 to 4 GW of distributed solar by 2023.

"There's more [distributed energy resources] coming online faster than we've really ever seen any type of resource coming on. … If that's not represented in models, we're going to be modeling the system completely inaccurately. And if we don't have flexibility in our resources, we really won't be able to meet the challenges of the daily demand curves," Moura said.

"In areas that may not have a lot of DER, or only starting to get DER, it's perhaps common for planning studies to negate them or net them out or mostly ignore them. However, as we get a larger penetration of DERs, it's really important that their characteristics are modeled," Moura said. "Engineers and planners need to prepare data specifications and data exchanges that are needed now so that we have a better understanding of what the sys-

# FERC & Federal News

tem's going to look like in the future."

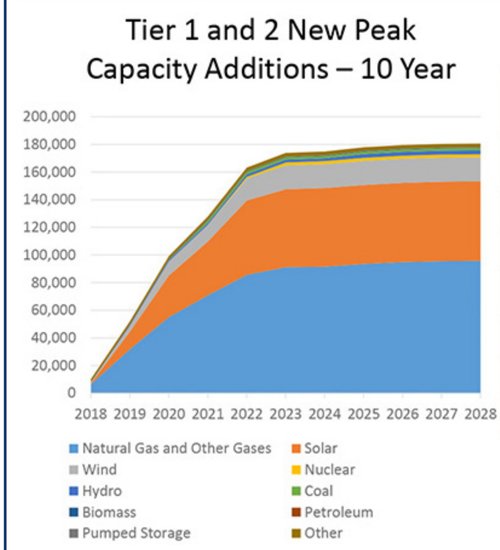
This fall, NERC created a new *working group* to guide its efforts: System Planning Impacts of DER (SPIDER).

## Recommendations

Among the report's recommendations was a call for NERC's Reliability Assessment Subcommittee to lead development of common metrics to assess energy adequacy. "Additional analysis is needed to determine energy sufficiency, particularly during off-peak periods and where energy-limited resources are most prominent."

Similarly, it urged NERC's Planning Committee to develop a common framework for assessing fuel disruptions, saying "system planners should identify potential system vulnerabilities that could occur under extreme, but realistic, contingencies and under various future supply portfolios." The assessments could be used to develop regulations or market mechanisms to promote fuel assurance.

"A common approach for what kind of contingencies to study would be very valuable to the industry," Moura said. ■




**Assessment Areas with More Than 50% Natural Gas as a Percent of Total Capacity**

| Assessment Area | 2022 (MW) | 2022 (%) |
|---|---|---|
| FRCC | 42,003 | 78.1% |
| WECC-CAMX | 42,536 | 68.2% |
| Texas RE-ERCOT | 51,867 | 63.3% |
| NPCC-New England | 16,308 | 52.3% |
| WECC-SRSG | 16,774 | 51.8% |
| WECC-AB | 8,514 | 51.8% |

| NERC

## FERC & Federal News

# NERC Releases 'Stress Test' Analysis of Gen Retirements

*By Michael Brooks*

NERC last week warned that faster-than-expected coal and nuclear plant retirements could jeopardize reliability if grid operators are not prepared.

"If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur," NERC said in a special reliability assessment *report*. "Therefore, resource planners at the state and provincial level, as well as wholesale electricity market operators, should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be developed and placed in service."

Calling it a "stress test" of the bulk power system, the organization used data from the U.S. Energy Information Administration to identify generators set to retire through 2025 in 10 areas where coal-fired and nuclear generation make up a significant portion of the resource mix. It then analyzed the impacts of those generators retiring earlier, in 2022.

The analysis found four areas — SPP, SERC-East, WECC-RMRG and WECC-SRSG — in which currently planned generation resources would not be sufficient to make up for the accelerated retirements. NERC determined this by comparing projected planning reserve margins for 2022 under the scenario to projected peak load levels for the year. The organization used data from its 2017 Long-Term Reliability Assessment to determine projected reserve margins under currently confirmed retirements through 2022, to which it factored in the accelerated retirements. It also used the LTRA to determine the projected peak loads.

### 'Unlikely' Scenario

Both the report and John Moura, NERC director of reliability assessment and system analysis, repeatedly emphasized that the analysis was not a prediction.

"I think it's really important that stakeholders understand that this is a stress-case scenario," Moura said in a conference call with reporters last Tuesday morning. "We're not necessarily making any recommendations or calls for any additional financial support beyond that which market operators think are required. We completely acknowledge that the scenario as tested is unlikely."

He noted the organization also analyzes the impacts of geomagnetic disturbances and simultaneous, highly coordinated physical and cyberattacks on the grid. "These are things that we don't believe will happen, but we think it's instructive, when we break a system, to understand what are the potential mitigations and see how to get it working."

"NERC's stress-test scenario is not a prediction of future generation retirements nor does it evaluate how states, provinces or market operators are managing this transition," the report says. "Instead, the scenario constitutes an extreme stress-test to allow for the analysis and understanding of potential future reliability risks that could arise from an unmanaged or poorly managed transition."

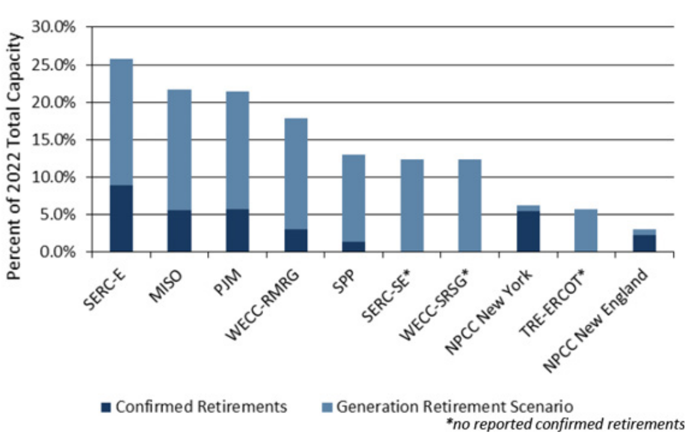
Moura also noted that the report doesn't criticize capacity markets or out-of-market subsidies. "We're simply saying that these tools need to be monitored and tested in planning," he said.

### Fears of Politicization

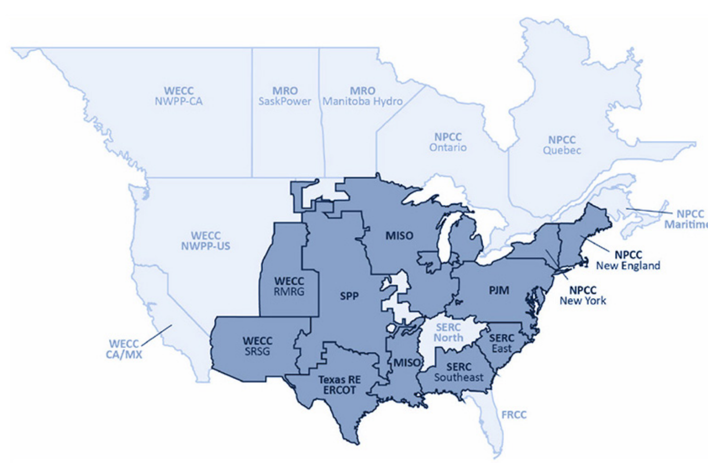
NERC was criticized by some stakeholders, including FERC Commissioner Cheryl LaFleur, in early November, when it briefed its Members Representatives Committee on a draft of the report. They feared it would be politicized, and that the press and public would misunderstand it as a warning of things to come. (See *LaFleur, Stakeholders Anxious over NERC Retirement Study*.)"

Policymakers and regulators should not interpret this study as justifying interventions to artificially retain unprofitable power plants, as these actions deter the economic transition in the power generation fleet, undermine innovation and raise costs to America's businesses and families," Devin Hartman, CEO of the Electricity Consumers Resource Council, said in a statement Dec. 18.

"As NERC itself states, the report looks at unlikely scenarios that go far beyond either announced or projected power plant retirements to determine at what point there might

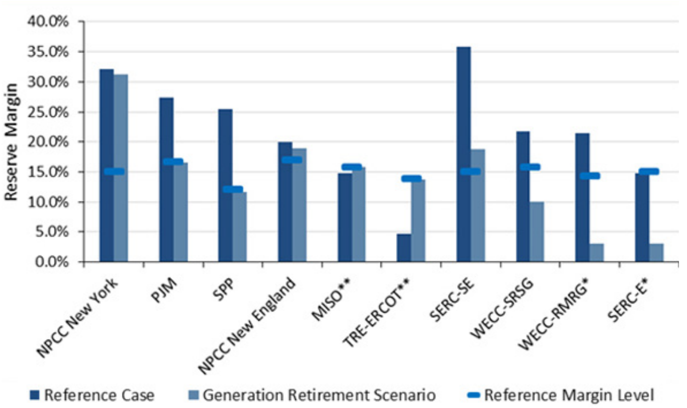



Projected retired capacity as a percent of total capacity in 2022, both currently confirmed and under NERC's "stress test" scenario | *NERC*




NERC analyzed the 10 regions where coal-fired and nuclear generation make up a significant portion of the resource mix. | *NERC*

# FERC & Federal News




Under the "stress-test" scenario, SPP, SERC-East, WECC-RMRG and WECC-SRSG would not have enough new generation to make up for the accelerated retirements. PJM, MISO and ERCOT are just slightly above or equal to the reference levels. (SERC-East and WECC-RMRG's margins are actually zero or in the negative.) | *NERC*


Natural gas-fired generation's contribution to the fuel mix in each region | *NERC*

be some risk for reliability," said Jeff Dennis, general counsel for regulatory affairs at Advanced Energy Economy. "The report does not provide evidence of any imminent threat to the reliability of the bulk power system. Nor does it suggest that competitive wholesale energy markets aren't up to the job of ensuring reliability as the resource mix changes."

The report "relies on too many extremes to be enlightening about real-world grid reliability," the Natural Gas Supply Association said.

At FERC's open meeting Dec. 20, LaFleur repeated her criticism, saying the report has a "fundamental flaw" in assuming baseload retirements beyond that currently anticipated but only counting new resource that have been announced. "So there's an asymmetry in what's coming out and what's coming on," she said. "It's like saying, 'What if I gave up 45% of my income and I kept my expenses the same. … You'd have a mismatch by definition."

LaFleur said it was "noteworthy" that even under NERC's extreme scenario "there's not that many resource problems [that] pop up."

"It's a big deal … making sure we have enough resources in the future," she concluded. "But I think we have to make sure that we rely on fact and not projections."

NERC spokesman Marty Coyne declined to respond to LaFleur's comments. "We don't have anything further to say other than what's in our media *release*," he said.

Speaking to reporters after the open meeting, FERC Chairman Neil Chatterjee said he thought "NERC put a lot of work into it, and it was a thorough document. It is one data point amongst many, and I think as it pertains to our actions here at the commission and our resilience docket, my colleagues and I will analyze the myriad of data points that we have before us."

Last week's report did not include a detailed analysis of natural gas infrastructure; however, NERC said "additional midstream natural gas infrastructure could be required" to respond to early retirements.

In a November 2017 assessment, NERC had recommended industry consider the loss of key natural gas infrastructure in their planning studies under NERC reliability standard TPL-001-4. (See ***NERC: Natural Gas Dependence Alters Reliability Planning***.)

Although NERC sees risks to increasing dependence on renewables and gas-fired generation, last week's report said that "successfully managed, the changing resource mix can provide … potential benefits to reliability and security of the BPS. Less reliance on large, centralized generation stations and greater use of dispersed networks comprised of smaller diversified generation resources can provide operating and planning flexibility. Additionally, some fuel assurance risks diminish with the changing resource mix. The effects of adverse weather on coal stockpiles or fossil fuel resupply infrastructure may be reduced when natural gas pipelines supply a greater proportion of the generating fleet. Attaining reliability enhancements associated with the changing resource mix is possible when the different challenges to fuel assurance and [essential reliability services] are addressed."

## Recommendations

NERC included several suggestions to stakeholders, regulators and policymakers in the report, among them a recommendation to incorporate fuel assurance analyses in generator retirement assessments. This would mean factoring in fuel supply infrastructure, new infrastructure requirements for replacement resources, and firm vs. non-firm fuel delivery contracts.

It also recommended that regulators and policymakers consider ways to speed up approvals of infrastructure. "When a generator's planned retirement is delayed to allow for completion of transmission system upgrades, expedited regulatory proceedings can help minimize the delay," the report says. "Where more natural gas generation is needed, more natural gas pipeline capacity will likely also be needed."

But Moura also noted that the report doesn't make any specific recommendations for the four areas identified by the report as being at risk under the scenario. "We have a lot of confidence in how these areas plan their systems," he said. ■

## FERC & Federal News

# FERC Proposes Market Screen Exemptions

By Michael Brooks

WASHINGTON — FERC on Thursday proposed to exempt market participants in ISO-NE, MISO, NYISO and PJM from its indicative horizontal market power screens (*RM19-2*).

Under the Notice of Proposed Rulemaking issued at the commission's monthly open meeting, entities in the four regions would no longer be required to submit the pivotal supplier and wholesale market share screens to qualify for market-based rate authority.

"We believe that this proposal would reduce the filing burden on market-based rate sellers in RTO/ISO markets without compromising the commission's ability to prevent the potential exercise of market power in RTO/ISO markets," the commission said.

The new rule would presume that the grid operators' commission-approved monitoring and mitigation rules provide adequate protection against market power abuse.

"The existence of market power mitigation in an organized market generally results in a market where prices are transparent, which disciplines forward and bilateral markets by revealing a benchmark price, keeping offers competitive," FERC said.

CAISO and SPP are excluded from the NOPR because they do not have centralized capacity markets, FERC said. Bilateral capacity sales in these markets are overseen by state regulators, not by the grid operators' market monitoring units.

"We recognize that there is state regulatory oversight of the capacity costs and/or prices incurred in CAISO and SPP," FERC said. "However, we do not believe that it is appropriate to exempt sellers from filing the indicative screens ... in markets that lack commission-approved monitoring and mitigation programs. Capacity markets are distinct from energy markets ... so monitoring and mitigation of energy prices in day-ahead and real-time markets does not ensure that capacity prices will be just and reasonable."


FERC issued the Notice of Proposed Rulemaking at its monthly open meeting on Dec. 20, 2018. | © *RTO Insider*

Both screens were created in 2007 by FERC's Order 697, which simplified the commission's analysis for determining whether a market participant qualifies for MBRA into a two-part test examining the participant's horizontal and vertical market power.

The pivotal supplier screen tests whether peak demand in the participant's balancing authority area can be met without the participant's supply. The market share screen ensures a participant's share of the total capacity of the market is 20% or less.

All market-based rate sellers would still be required to file vertical market power analyses.

"The commission has long relied on RTO market monitoring and mitigation to address any market power concerns," FERC Chairman Neil Chatterjee said Thursday. "So, limiting these submissions is a common-sense change that will reduce regulatory burdens without diminishing protections for ratepayers."

"I support the general gist of the proposal," Commissioner Richard Glick said. "If we are imposing unnecessary burdens on jurisdictional utilities, we should eliminate them." But he also said he was looking forward to reviewing the comments "to consider whether there are additional measures the commission or regions could adopt to offer added protections against market power."

Comments on the NOPR are due 45 days after its publication in the *Federal Register*. ■

# FERC OKs Transcos' Revised Tax Calculations

FERC on Thursday approved tariff filings by more than a dozen transmission owners to correct how they calculate accumulated deferred income tax balances.

The commission issued orders regarding: Ameren Illinois, Ameren Transmission Company of Illinois and Northern States Power (*EL18-155*, *et al.*); Public Service Company of Colorado and Southwestern Public Service (*ER18-2319*, *et al.*); ALLETE, Montana-Dakota Utilities, Northern Indiana Public Service Co., Otter Tail Power and Southern Indiana Gas & Electric (*EL18-138*, *et al.*); International Transmission Co., ITC Midwest and Michigan Electric Transmission Co. (*EL18-159*, *et al.*); American Transmission Co. (*EL18-157*); TransCanyon DCR (*EL18-165*); Virginia Electric and Power Co. (*EL18-167*); GridLiance West Transco (*EL18-158*); and Southern California Edison (*EL18-164*).

The companies' filings came after the commission ordered Section 206 proceedings, finding that their use of the "two-step" averaging methodology used to calculate ADIT balances in the projected test year calculations or annual true-up calculations for formula transmission rates may no longer be just and reasonable.

The commission had previously permitted TOs to use a two-step averaging methodology to calculate ADIT balances based on the understanding that the methodology was necessary to comply with IRS rules. But after guidance that IRS provided in an April 2017 private letter ruling, the commission said it now believes the two-step method could lead to overstated rate bases and unreasonably higher rates.

Earlier this year, the commission issued a series of orders to ensure ratepayers benefit from the savings energy companies received through the Tax Cuts and Jobs Act, which reduced the maximum corporate income tax rate to 21% from 35%. (See *FERC Acts on Tax Cuts* and *FERC Orders Pipelines to Pass Through Tax Savings*.) ■

*— Rich Heidorn Jr.*

## CAISO/WECC News

# New Mexico Regulators Say PNM Can Join EIM

The New Mexico Wind Energy Center is among the resources that PNM could bring to the Western Energy Imbalance Market. | *PNM*

New Mexico regulators on Thursday gave Public Service Company of New Mexico (PNM) permission to join the Western Energy Imbalance Market, clearing the way for the state's largest electric utility to begin participating in the interstate real-time market in April 2021.

The Public Regulation Commission voted 5-0 to allow the move by PNM, which declared its intent to join the EIM in August. (See *PNM Seeks to Join Energy Imbalance Market*.)

CAISO, which administers the EIM, welcomed PNM in a news release, saying the utility's participation would increase the EIM's efficiency in trading resources across the West. New Mexico is fast becoming one of the West's largest producers of wind power, and California has a legal mandate to gather an increasing share of its electricity from renewable resources.

PNM generates about 2,580 MW of electricity, including 800 MW from low- or zero-carbon resources, CAISO said.

"The diversity and location of PNM's resources, along with the transmission connectivity to the rest of the EIM footprint will provide significant benefits to their customers," CAISO said in its statement.

The EIM has generated a half-billion dollars in benefits for its members since its founding in November 2014, including $100 million in the third quarter of 2018 alone, CAISO has said.

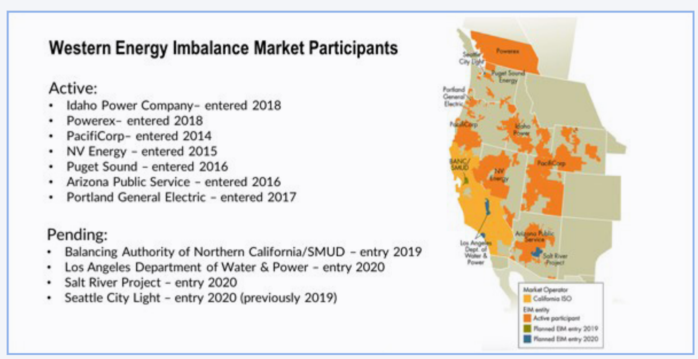
The EIM's current members include Arizona Public Service, Idaho Power, NV Energy, Portland General Electric, Puget Sound Energy and Powerex. The Los Angeles Department of Water and Power, the Sacramento Municipal Utility District and several other entities are scheduled to join between 2019 and 2021. ■

*— Hudson Sangree*

# BPA Stays on Track to Join Western EIM

*By Hudson Sangree*

The Bonneville Power Administration last week continued its series of discussions with stakeholders about joining CAISO's Western Energy Imbalance Market, with a possible activation date in 2022.




The Energy Imbalance Market currently has seven participants in addition to CAISO. | *CAISO*

Last Tuesday's talks revolved around EIM settlements, with *detailed presentations* about invoices, charges and metering. The calculations may have appeared daunting but ultimately came down to familiar math, said Steve Kerns, BPA's director of grid modernization.

"I want to make sure you don't find this to be too scary," Kerns told the dozens of stakeholders on the call and in BPA's Rates Hearing Room in Portland, Ore. "There's a lot of stuff going on here, but at the end of the day, it's adding, subtracting [and] multiplying."

Prior meetings that were part of BPA's EIM stakeholder initiative have covered subjects such as market power, transmission and governance. Future meetings will deal with resource sufficiency and carbon obligations, with the next session scheduled for Jan. 16 in Portland.

BPA is targeting next September for issuing a final record of decision authorizing it to sign an implementation agreement with the EIM, which would allow the agency to begin spending on implementation projects without obligating it to join the market.

So far there has been little opposition among BPA stakeholders to joining the EIM, though details of the move are still being worked out. Joining would ease short-term trading of Pacific Northwest hydro power for solar energy from the desert Southwest and wind power from Rocky Mountain states.

*Continued on page 16*

## CAISO/WECC News

# FERC Denies Oakland Complaint Against PG&E

By Hudson Sangree

FERC denied a complaint Thursday by the city of Oakland against Pacific Gas and Electric for charging retail instead of wholesale power and transmission rates at the Port of Oakland, which maintains an extensive distribution network. The city claimed PG&E violated the Federal Power Act by charging the higher rates and failing to file a wholesale service agreement with FERC (*EL18-197*).

The city, acting through the port, asked for a refund of the difference between the retail rates PG&E charged and the wholesale rates the city argued it should have paid for electricity it had received through its Cuthbertson substation between 1997 and 2017, when it signed a wholesale agreement with PG&E. The city said that since 1997, it had resold virtually all the electricity it received from PG&E to metered electricity end-use customers, and that PG&E should have been aware of the situation and charged wholesale rates.

FERC rejected the city's argument and request for relief, saying it hadn't provided evidence, such as invoices, of its resale of electricity to end users. Moreover, the city never specifically asked PG&E to change its rates from retail to wholesale at the substation, and PG&E did not have an obligation to do so on its own, the commission said.

"We do not believe that Port has substantiated its general claim that PG&E violated Section 205c of the FPA by failing to file a wholesale transmission and power sale agreement for the Cuthbertson substation," the commission said. "Port's statements to the contrary are speculative, not supported by the record evidence, and insufficient to meet its FPA Sections 206 and 306 burdens."

The commission added that "even if we were to find that PG&E violated FPA Section 205c as alleged by Port, we would not direct refunds here. As noted above, Port had ample opportunity over roughly two decades to clarify the nature of the service it took from PG&E and failed to do so. We therefore do not think requiring refunds from PG&E would be appropriate." ■

Continued from page 15

BPA controls the Pacific Northwest's largest hydroelectric resources — including the Grand Coulee, The Dalles and Chief Joseph dams on the Columbia River — and operates about 70% of the region's transmission. Its balancing area covers most of Oregon, Washington, Idaho and western Montana, along with smaller portions of California, Nevada and Wyoming.

If BPA signs an agreement with the EIM, it would bring a territory the size of France into CAISO's real-time market. The EIM has been expanding rapidly, with entities joining or seeking to join from Canada to the Mexican border.

Idaho Power and Powerex began transacting in the market in April, bringing the number of members participating to eight. (See *Idaho, Powerex Began Trading in Western EIM*.) That expansion equipped the EIM to serve imbalances for about 55% of load in the Western Interconnection, according to the ISO.

NV Energy, Arizona Public Service, PacifiCorp, Puget Sound Energy and Portland General Electric are already participants.

The Sacramento Municipal Utility District plans to begin participating in the EIM in April 2019. The Los Angeles Department of Water and Power, Arizona's Salt River Project and Seattle City Light are scheduled to go live in April 2020. Public Service Company of New Mexico recently received state regulators' permission to join the EIM by 2021. (See *PNM Seeks to Join Energy Imbalance Market*.)

In debates about establishing a Western RTO led by CAISO, the EIM has often been held up as a better alternative because, unlike an RTO, the market's transmission-owning entities retain operational control over their assets, while member generators participate in the real-time market on a voluntary basis.

The EIM has conferred a half-billion dollars of benefits on participants since its founding five years ago, with $100 million realized in the third quarter of 2018 alone, CAISO officials said in October.

The Dalles Dam on the Columbia River is one of the major hydroelectric resources that the Bonneville Power Administration could bring to the Western Energy Imbalance Market. | © *RTO Insider*

(See *Western EIM Reports Record Benefits*.)

Moreover, the EIM's board consists of members from multiple states, while CAISO's board is appointed by California's governor and confirmed by the State Senate. Industry leaders and officials from other Western states don't want to cede control to California, and California politicians don't want to give up authority over CAISO.

A series of CAISO regionalization measures that would have broadened its governance to include out-of-state representatives have failed in the State Legislature in recent years, largely because of this impasse. Proponents of a single RTO for the West say they will likely introduce another bill in January when California lawmakers reconvene for the start of another two-year session. (See *Western RTO Proponents Vow to Keep Trying*.)

In the meantime, CAISO officials and EIM participants have been pushing ahead to add day-ahead trading to the EIM's current real-time-only market, bringing it closer to conferring many of the benefits of a regional RTO without the perceived drawbacks. ■

## ERCOT News

# Texas PUC Briefs

### Commission Approves Revised 345-kV CenterPoint Project

The Texas Public Utility Commission last week preliminarily approved a certificate of convenience and necessity for CenterPoint Energy's proposed 345-kV project in the industrial Freeport area south of Houston, but not before quibbling over the wide range of cost estimates (*Docket 48629*).

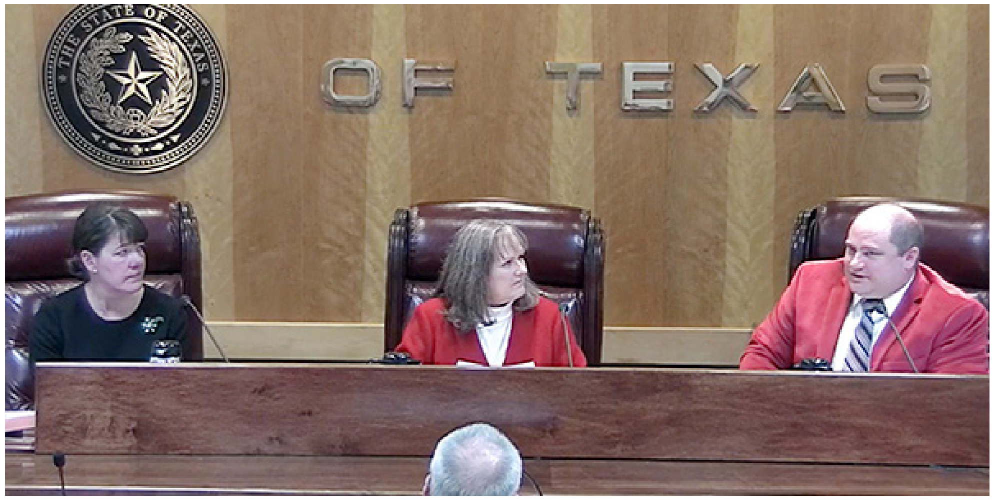
CenterPoint provided ERCOT a revised estimate of $481 million to $695 million for a new 345-kV double-circuit transmission line over its preferred route connecting two substations and upgrading an existing 345-kV double circuit line. The grid operator filed a revised *study* with the PUC on Dec. 14 that still recommends CenterPoint's preferred route.

"The range of cost estimates is still not terribly satisfying," Commissioner Arthur D'Andrea said. "It's no one's fault but the ambiguity and uncertainty of doing these [studies]."

"Unsatisfying is an understatement for me," PUC Chair DeAnn Walker said, "especially when the low end — the $481 million — depends on using state land that I'm not sure is even an option."

In September, the commission had asked ERCOT to take a second look at the project in the face of rising costs.

ERCOT reviewed five options in its original study and 10 in the second. Its Board of Directors approved the project, which was estimated at $202 million, in December 2017. (See "Board Approves $246.7M Freeport Transmission Project," *ERCOT Board of Directors/ Annual Meeting Briefs*.)




Texas commissioners got in the holiday spirit for December's open meeting.

### PUC Slashes NRG's Nuke Decommission Costs

The commission *approved* a 65.2% reduction in the decommissioning costs for NRG South Texas' share of the South Texas Project (STP) nuclear plant (*Docket 48447*).

With the order, NRG's annual funding amounts will drop from $758,791 to $264,351.

The PUC "substantially reduced" the annual funding requirement in its last review in 2013, assuming a 20-year license extension for STP's twin units from the original 2027 and 2028 expirations. The Nuclear Regulatory Commission approved the extensions last year.

NRG's share of the decommissioning fund was $691.8 million at the end of 2017. The plant faces total decommissioning and dismantling costs of an estimated $2.5 billion.

The company owns a 44% share of STP. The plant's other two owners are the city of San Antonio (40%) and the city of Austin (16%).

The nuclear plant's two units have a combined capacity of almost 2.6 GW. They have been online since the late 1980s.

South Texas Project

### Hearing Schedule Set for Sempra-Oncor-Sharyland Deal

The commission will hold hearings April 10-12 on proposed transactions involving Sempra Energy, its Oncor subsidiary, Sharyland Utilities and Sharyland Distribution & Transmission Services (*Docket 48929*).

Staff filed a *procedural schedule* following a Dec. 18 prehearing conference.

In October, the parties announced deals worth $1.37 billion, with Sempra buying a 50% stake in Sharyland D&T and Oncor acquiring transmission owner InfraREIT. (See *Sempra, Oncor Deals Target Texas Transmission*.)

The transactions would result in Sharyland T&D becoming an indirect, wholly owned subsidiary of Oncor, owning transmission and distribution lines in central, north and west Texas. Sharyland Utilities would remain in South Texas, with Sempra owning an indirect 50% interest. The real estate investment trust (REIT) structure that holds Sharyland and Sharyland T&D would be terminated.

InfraREIT and Sharyland are both owned by Hunt Consolidated, which failed in a 2016 attempt to acquire Oncor. ■

*— Tom Kleckner*

## ISO-NE News

# ISO-NE CSO Penalties Approved by FERC

*By Michael Kuser*

FERC on Thursday approved new ISO-NE penalties for market participants that fail to cover their capacity supply obligations (CSOs) when a new resource is delayed.

The commission's Dec. 20 order agreed with the RTO "that the failure-to-cover charge rate mechanism establishes a just and reasonable penalty rate for capacity resources that do not cover their CSO in advance of a capacity commitment period and fail to demonstrate the ability to fulfill all or part of their CSO" (*ER19-169*).

The new Tariff provisions were scheduled to go into effect Dec. 24.

The rule *changes* are designed to shift the responsibility for covering CSOs to market participants, which ISO-NE says have the best information about project development schedules and potential delays. (See *NEPOOL OKs Penalty for Delayed Capacity Resources*.)

The changes stipulate that for delivery years before June 1, 2022, the monthly dollar/kilowatt-month failure-to-cover charge will be the higher of the capacity clearing price and the clearing price in any Annual Reconfiguration Auction (ARA) for that year. After that time, the charge will be based on the outcome of a second run of the third ARA, using the unproven CSO quantities as a demand bid. Market participants will still be compensated for their CSOs and continue to face Pay-for-Performance risk.

### Two Protests Denied

Public Service Enterprise Group *filed* a protest seeking "staggered effective dates" to incorporate a three-month grace period beginning in June 2019, June 2020 and June 2021 for resources awarded CSOs in the Forward Capacity Auctions associated with those capacity commitment periods.

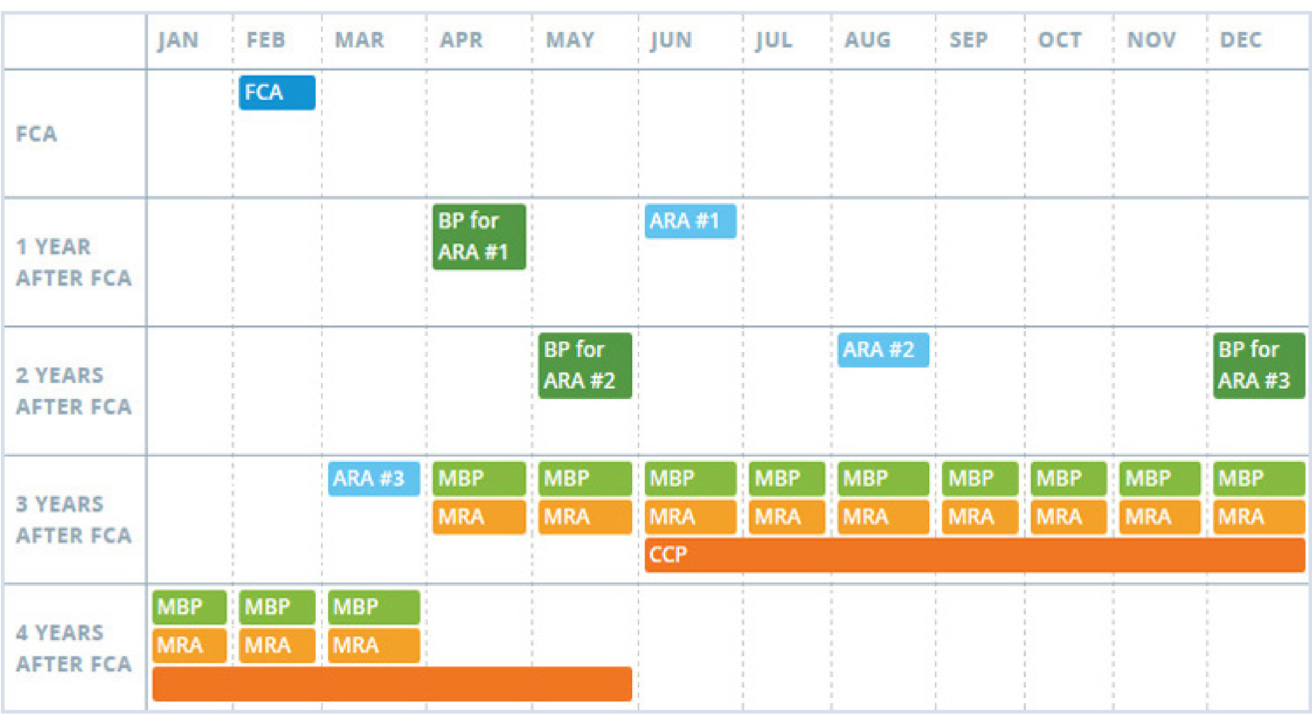
The company argued that allowing the filing to take effect this month would impose new and unexpected risks and costs on resources that obtained CSOs under the existing rules, in particular its Bridgeport Harbor 5 plant scheduled to go into operation next June.

The commission disagreed "that the proposed effective date violates the filed rate doctrine and rule against retroactive ratemaking. ... PSEG fails to quantify or detail the extent to which the risk profile for Bridgeport Harbor 5 is altered or otherwise to support its argument that any such change is unjust and unreasonable."

Northeastern Massachusetts Consumer-Owned Systems (NEMACOS) also *filed* a protest expressing concern that load-serving entities may be paying arbitrage margins to suppliers that obtain a higher clearing price in the FCA and cover their capacity obligations in the reconfiguration auctions at a lower price.

The commission found the Tariff provisions that NEMACOS addresses in its protest are not at issue in the proceeding, but it noted that "under both the current Tariff and the proposed revisions, a resource that obtains a CSO in the FCA would have an opportunity to cover its CSO in a subsequent reconfiguration auction and potentially garner an arbitrage margin."

"Because the failure-to-cover charge rate is designed to always be greater than or equal to the third Annual Reconfiguration Auction clearing price, the proposed revisions will offer no additional arbitrage incentives beyond those already available to resources under the current Tariff," the commission said. ■




The general timeline for Forward Capacity Market events for a single capacity commitment period. The specific dates for 2019 can be found at *iso-ne.com/static-assets/documents/2018/03/2019_fcm_ra_art_bil_cal.pdf.* | *ISO-NE*

## ISO-NE News

# FERC Approves Mystic Cost-of-Service Agreement

### *Commissioner Glick dissents*

*By Michael Kuser*

FERC last week voted 2-1 to approve ISO-NE's cost-of-service agreement with Exelon for its Mystic Generating Station Units 8 and 9, including payments to the company's Distrigas LNG facility. It also ordered a paper hearing on the issue of return on equity for the plants.

FERC Chairman Neil Chatterjee and Commissioner Cheryl LaFleur approved the order — issued after the commission's open meeting Thursday — with Commissioner Richard Glick dissenting (*ER18-1639*). The agreement becomes effective June 1, 2022.

The RTO sought the agreement after Exelon said in March that it would retire the 2,274-MW plant when its capacity supply obligations expire on May 31, 2022 (*ER18-1509*).

The commission tentatively accepted the agreement in July while ordering an expedited hearing on unresolved issues. (See *FERC Advances Mystic Cost-of-Service Agreement*.)

The agreement would allow the gas-fired units in Massachusetts an annual fixed revenue requirement of almost $219 million for capacity commitment period 2022/23 and nearly $187 million for 2023/24. But the commission found the information Exelon provided to support those figures insufficient and ordered the company to submit a compliance filing within 60 days of the order.

In the most recent order, the commission directed Mystic to adopt Exelon's capital structure for ratemaking purposes, include an amortization of excess deferred income taxes and amend the agreement to state that it will recover 91% of the costs of Distrigas as Mystic fuel costs, determining that other New England beneficiaries of the LNG terminal should bear some of its operational costs.

View from the control room at Exelon's Distrigas LNG terminal in Everett, Mass. | *ENGIE*

### Glick's Dissent

In his dissent, Glick argued the commission "cannot and should not use its authority over wholesale sales of electricity to bail out an LNG import facility. ... The commission concludes that it can use the [Federal Power Act] to bail out an LNG import facility simply because that LNG import facility has an undefined and unexplained 'extremely close relationship' to the Mystic facility."

The commission is attempting to regulate the costs incurred and sales made by a non-jurisdictional facility, he said.

"A more reasonable construction of the commission's jurisdiction would be to limit its reach to the entities that can or actually do participate directly in the wholesale market for electricity," he said.

"The jurisdictional puzzle in which the commission now finds itself only reinforces the fundamental mistake that the commission made in rushing to seize control of the debate over fuel security in New England and dictate a particular outcome. That outcome, 'individual, ad hoc contracts with particular resources whose retirement might, under the most conservative assumptions, create a fuel security concern,' is no way to address a region's long-term fuel security," Glick said, quoting from his previous dissent in the commission's July tentative acceptance of the agreement.

FERC on Dec. 3 approved ISO-NE's interim proposal to use an out-of-market mechanism to address concerns about fuel security (*ER18-2364*). (See *ISO-NE Fuel Security Measures Approved*.) The RTO's Tariff had previously only allowed cost-of-service agreements to respond to local transmission security issues, with the interim proposal developed in response to FERC's July denial of a request for waiver to allow for the Mystic agreement. (See *FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes*.) ■

Mystic power plant

## MISO News

# MISO Probing South and SPP Seams Tx Needs

By Amanda Durish Cook

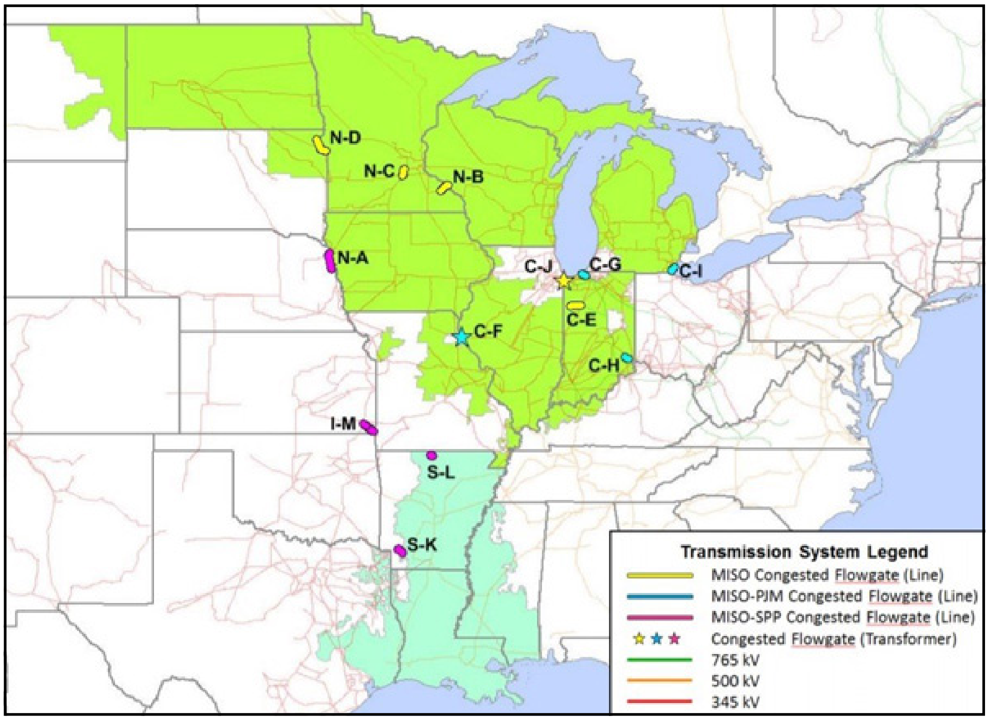
MISO last week opened the floor to stakeholders' ideas on transmission projects to relieve congestion in MISO South and near the SPP seam.

During a Dec. 18 South Subregional Planning Meeting, MISO Planning Manager Matt Ellis asked for stakeholder help in identifying project candidates for the South region as part of the RTO's annual Transmission Expansion Plan cycle. The MTEP 19 solution submission window will close March 1.

MISO has compiled a preliminary *list* of four congested flowgates with upgrade potential in and around South and the SPP seam, though the RTO is telling stakeholders to expect lower congestion in 2019 and beyond.

MISO Economic Studies Engineer Karthik Munukutla said several top congested areas in South have already been addressed with MTEP projects that are coming online as early as this month and as late as mid-2023. Munukutla also said congestion will subside because of low energy demand and potential distributed resources further reducing those needs. However, he said some local resource zones expecting high renewable penetration may experience higher congestion.

MISO predicts future flowgate congestion at the Bullshoals-Midway Jordan 161-kV line near the Missouri border in northern Arkansas and the Fulton-Patmos 115-kV line in southwestern Arkansas. The RTO also predicts seams congestion around the Raun-Tekamah 161-kV line on the Iowa-Nebraska border




Top congested flowgates in MTEP 19 | *MISO*

and the Neosho-Riverton 161-kV line on the eastern Kansas-Nebraska border.

RTO officials said a complete list of South and seams issues and a formal request for ideas will be sent via email to stakeholders in early January.

Project ideas will be analyzed under the MTEP's 2019 Market Congestion Planning Study (MCPS), the first such footprint-wide study since Entergy's five-year transition period began in 2013. The transition period, which expires at the end of 2018, has limited the cost-sharing of transmission projects.

Going forward, MISO will discontinue its practice of creating separate studies for Midwest and South, though the MCPS will continue to focus on subregional needs. In another first, the MCPS will also contain congestion analyses of the PJM and SPP seams that could produce an interregional congestion-relief project. ■

## MISO News

# MISO, SPP Tweak Interregional Criteria

By Amanda Durish Cook

MISO and SPP plan to file a slightly revised version of proposed changes to their joint operating agreement aimed at making a first interregional project between the two more attainable.

Targeted for the first quarter of 2019, the RTOs' filing will still eliminate the $5 million cost threshold for the projects, add avoided costs and adjusted production cost benefits to project evaluation, mandate coordinated system plan studies, and remove the joint modeling requirement in favor of individual RTO regional analyses. (See *MISO, SPP to Ease Interregional Project Criteria*.)

But with recent changes, the proposal will now require that a coordinated system plan (CSP) — the joint study used to identify interregional transmission needs — take place once every two years instead of the originally proposed three years.

MISO and SPP also restored the JOA's original opt-in instead of an opt-out approach for the CSP study agreement. The RTOs had proposed that the two would have to agree not to perform a study in order to skip a CSP, but now they will actually have to agree to initiate a CSP before undertaking one.

"I think SPP and MISO's intent is still to do a study annually," SPP's Adam Bell said during a Dec. 20 conference call held by the RTOs' Interregional Planning Stakeholder Advisory Committee (IPSAC).

But multiple stakeholders pointed out that the CSP study process is historically an 18-month process and doesn't fit well into the annual time frame. However, RTO staff said the studies, now evaluated regionally, will probably take less time to complete.

Entergy's Jennifer Amerkhail said her company opposed the study frequency minimum. She reminded the RTOs of their "fiduciary responsibility" to not expend resources on CSP studies that aren't ultimately necessary.

### JPC Review

The RTOs have also added to the proposal both a study model review and project review by the Joint Planning Committee (JPC), an interregional group comprising representatives from both RTOs. The JPC will also vote on a project's proposed interregional cost allocation.

Some stakeholders questioned the need for a JPC review and vote, saying the RTOs may be introducing another interregional project hurdle.


A MISO-SPP JOA meeting last year | © *RTO Insider*

Bell said the JPC review isn't for "leverage" purposes but to ensure that projects "have more certainty" before they are decided on by the RTOs' boards of directors. He said it's best for the JPC to meet and ensure all project expectations can be realized.

"It's so we're not operating blindly," Bell said. "It's not to second-guess assumptions or cost allocations."

Stakeholders questioned what the impact of a JPC vote would be, asking whether the vote was a recommendation or binding vote, which could lead to re-evaluation of projects and delay before projects are put to either board.

Officials said the RTOs' already-approved regional processes will be used by the JPC to evaluate the projects.

"There would be no reason for the JPC to deviate from the regional process and the study findings," Bell said.

LS Power's Pat Hayes asked for the RTOs to develop criteria to guide the JPC in its votes on projects.

But RTO officials reiterated that their regional processes will guide JPC decisions, with some noting the committee already reviews project candidates under the current interregional process.

### Negative APC Consideration

SPP and MISO also agreed to evaluate adjusted production costs and avoided costs for all potential interregional projects regardless of whether the projects are driven by economics, reliability or public policy.

The two also said they have "tentatively" agreed to include negative adjusted production cost values to evaluate reliability and public policy projects.

However, Bell said the RTOs will craft language that would still allow for otherwise beneficial projects that happen to have negative adjusted production costs. Bell said MISO and SPP legal teams are still deciding whether to include the caveat in the JOA.

Adam McKinnie, chief economist with the Missouri Public Service Commission, asked if projects with negative values must be pursued through special FERC filings to find a different cost allocation methodology. Bell said that would probably be the case. ■

## MISO News

# FERC OKs Mich. Wind GIA, Leaves Open Funding Issue

*By Amanda Durish Cook*


Crescent Wind Farm interconnection site map | *MISO*

FERC last week accepted a revised generator interconnection agreement (GIA) between MISO and a Michigan wind farm, avoiding complex analysis from the fallout of a vacatur of the commission's previous orders covering transmission owners' ability to fund network upgrades.

The Dec. 20 order allows Invenergy's 150-MW, 60-turbine Crescent Wind Farm near the Michigan-Ohio border to interconnect to the MISO system under a revised agreement that eliminates TO Michigan Electric Transmission Co.'s (METC) "unilateral right to elect to provide initial funding for network upgrades" (*ER18-2340*). The new GIA allows METC to provide initial funding for network upgrades "only upon mutual agreement with the interconnection customer."

In approving the GIA, FERC focused on the requested effective date, not the issues still in flux around agreements executed between mid-2015 to mid-2018, after the D.C. Circuit Court of Appeals early this year vacated FERC orders dealing with TOs' rights to fund upgrades.

MISO in July submitted a pre-emptive Section 205 filing to retain the option to allow new generators to self-fund interconnection transmission upgrades. (See *MISO Files Revised Upgrade Funding Provisions*.) FERC dismissed that filing as moot after deciding TO initial funding should be included in MISO's *pro forma* GIA only prospectively as of Aug. 31, 2018. It instituted a briefing schedule to determine how to address GIAs, facility construction agreements and multiparty facility construction agreements that were entered into between June 24, 2015, and Aug. 31, 2018.

FERC said because MISO and Crescent Wind filed for an Aug. 15, 2018, agreement effective date, MISO's previous pro forma GIA should be followed, which allows TOs to provide initial funding for network upgrades "only upon the mutual agreement of the interconnection customer."

"We find the amended agreement to be just and reasonable because such language was not included in MISO's pro forma GIA as of the effective date of the amended agreement," FERC said.

METC had requested FERC reject the amended agreement, arguing that MISO's removal of the funding language is premature because the commission is still working through whether to include language allowing the initial TO funding of network upgrades for all GIAs executed between June 24, 2015, and Aug. 31, 2018. METC also pointed out that the agreement does not contain any network upgrades that would be subject to TO initial funding. FERC did not address the argument.

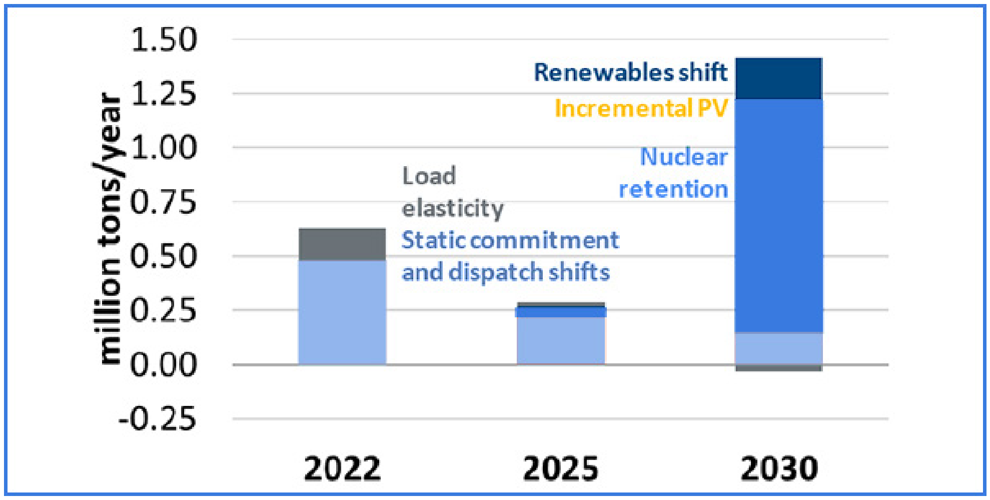
The Crescent Wind GIA is also exempt from FERC Order 842 primary frequency response requirements because MISO requested an exemption for all projects having reached at least the second decision point in its interconnection queue before May 15, 2018. ■



## NYISO News

# IPPTF Hands off Carbon Pricing Proposal to NYISO

*By Michael Kuser*




The Brattle Group projects that carbon charges will lead to incremental internal emissions reductions of 6% by 2030. Most reductions would come from price-responsive load, renewable shifts and possible nuclear retentions. | *The Brattle Group*

RENSSELAER, N.Y. — The *Integrating Public Policy Task Force (IPPTF) on* Dec. 17 *met for the last time* before handing its final carbon pricing proposal to NYISO's stakeholder governance process. The ISO will pick up work on the market design in January through its Market Issues Working Group.

The ISO and the New York Public Service Commission created the task force last October to explore ways to price carbon into the wholesale electricity markets to align them with state decarbonization policies, including the zero-emission credit program for struggling nuclear plants.

NYISO published the *IPPTF Carbon Pricing Proposal* on Dec. 7 after recommending it no longer include a mechanism that would make emissions-free resources with existing renewable energy credit contracts pay the carbon component of locational-based marginal prices (LBMPc). (See *IPPTF Updates Carbon Charge Analysis, Treatment of RECs*.)

### Social Cost of Carbon

The key metric to be used in calculating a wholesale charge on emissions is the gross social cost of carbon (SCC), which the PSC would set "pursuant to the appropriate regulatory process," according to the proposal. The state Department of Public Service based its calculations on that of the federal government's Interagency Working Group on Social Cost of Greenhouse Gases.

Couch White attorney Michael Mager, who represents Multiple Intervenors, a coalition of large industrial, commercial and institutional energy customers, asked whether there had been any discussions with state regulators about the timing of the PSC's process

"I assume that the commission is not going to have any regulatory process on setting the social cost of carbon unless and until there's a vote at the ISO, but doing it that way creates difficulties for stakeholders because then we're being forced to vote on a carbon pricing proposal without having any guarantees on how the social cost of carbon will be set, how it will be updated [and] when it will be updated," Mager said.

"The policy of the state of New York is very obvious, and I clearly stated where we got the social cost of carbon used in this analysis," said Warren Myers, DPS director of market and regulatory economics. "There are no guarantees in life, but you sure have a heck of a lot of information." (See *NY Looks at Social Cost of Carbon, Modeling*.)

"The ISO and DPS staff have had a few conversations on this subject" and continue to have conversations on how to structure the rules to accommodate the PSC's ruling, said Michael DeSocio, NYISO senior manager for market design.

"At the end of the day, if there's a public policy that establishes a value for carbon, that would be the value that we need to incorporate into the wholesale market," DeSocio said. "How that value has been established is public policy. I don't know that we'd create bookends for what the maximum or minimum should be."

### External Transactions

Under the proposal, suppliers would be expected to embed the carbon charge into their energy offers and would continue to receive the full LBMP and be debited their carbon charges during settlement. NYISO would calculate and publish the LBMPc to provide market transparency, adjust payments for import and export transactions, and allocate carbon residual revenues.

"As we discussed along the way, the ISO put forth a proposal that would allow imports and exports to continue to compete on a status quo basis with internal suppliers," DeSocio said. "As we get experience with it, if we see there are ways to make it more efficient, let's do that."

Several stakeholders questioned how NYISO planned to deal with the possibility that FERC might not accept in full the impact of a state-mandated carbon charge on wholesale electricity rates.

"We're looking at the potential in the very near future to have gigawatts of offshore wind coming into New England and PJM, so this concern may be on us much sooner than you think," said Seth Kaplan of EDP Renewables. "I refer you specifically to the work done by the Massachusetts Department of Environmental Protection for implementation of the Global Warming and Solutions Act, where they got into this exact issue in terms of customers in Massachusetts that were buying clean energy and wanting to make sure that it was credited in the emissions mix."

DeSocio said the ISO will release a forecast LBMPc an hour before real-time dispatch. "What we're not going to do is guarantee that that forecasted price is what we're going to charge you, and instead will charge you the actual price," he said.

### Update on Analysis Requests

DeSocio gave an *update* on NYISO's actions on several stakeholder requests for additional analysis, saying it would not study using buyer-side mitigation as a replacement for carbon pricing.

"Seemingly small adjustments to assumptions have wild differences in what the analysis

# NYISO News

shows," he said. "That tells us whatever number we put out, we know [it] will be wrong, and most likely will be wrong in a big way."

"The reason we wanted to see this study performed is that part of the reason we're here is because FERC is concerned with the impact state policies are having on the markets, specifically price formation," said Matt Schwall of the Independent Power Producer of New York. "One of the tools FERC has in its box is mitigation. I don't know what the likelihood is that FERC could subject state-supported resources to mitigation; I do know that's an option, and that carbon pricing is one way to protect against that."

Bob Wyman of Dandelion Energy referred to recent rulings by the PSC that will double New York's existing 2025 storage goal to 3,000 MW by 2030 and require the state's utilities to reduce building energy use by an additional 31 trillion British thermal units (TBtu) to meet an energy efficiency target of 185 TBtu by 2025. (See *NYPSC Expands Storage, Energy Efficiency Programs*.)

"It's important to note that in that order [Case *18-M-0084*], they called for 5 [trillion] Btus in savings from heat pumps," Wyman said. "Increasing the price of electricity relative to gas and oil is going to discourage people from accomplishing that goal, as with any of the beneficial electrification stuff, if we have a single-sector carbon price. And that really should be taken into consideration."

| | Gross SCC | RGGI, Inc. | Net SCC |
|---|---|---|---|
| | $nominal/US-ton | $nominal/US-ton | $nominal/US-ton |
| 2020 | 47.30 | 6.56 | 40.74 |
| 2021 | 48.30 | 6.98 | 41.32 |
| 2022 | 50.48 | 7.39 | 43.09 |
| 2023 | 52.74 | 7.81 | 44.93 |
| 2024 | 55.07 | 8.45 | 46.62 |
| 2025 | 57.48 | 9.09 | 48.39 |
| 2026 | 59.96 | 9.73 | 50.23 |
| 2027 | 62.52 | 10.35 | 52.18 |
| 2028 | 65.17 | 10.96 | 54.20 |
| 2029 | 66.54 | 11.58 | 54.96 |
| 2030 | 69.32 | 12.55 | 56.77 |

The New York Department of Public Service derived the gross SCC from the federal government's Interagency Working Group on Social Cost of Greenhouse Gases. The expected RGGI price is based on the August 2017 base case forecast for RGGI prices (in dark blue). The light blue values are interpolated. | *NY DPS*

"Climate change is occurring, it's clearly related to carbon dioxide emissions and it's not tip-toeing in on little cat's feet anymore; that time is past. It's coming like a freight train," Myers said. "As an economist, I am convinced that the most economical way to address this problem starts with — it may not be sufficient — but starts with a universal, economy-wide price on carbon."

Myers said, however, that, "unfortunately, we do not currently have a federal government willing to work on such a universal, economy-wide carbon price. And the proposal we have here put forth by the NYISO is not that. Context matters, and the context here is that we are evaluating a single-state, single wholesale market carbon price."

DeSocio said he expects stakeholders will be meeting on the carbon pricing proposal several times a month in the first half of the year and that the ISO will soon release a schedule for those meetings. ■

# NYISO Management Committee Briefs

RENSSELAER, N.Y. — Interim CEO Robert Fernandez told the Management Committee on Wednesday the Board of Directors this month had "reached a unanimous decision" on the AC Public Policy Transmission Project approved by the committee last summer and would release its decision no later than Dec. 27.

The MC in June backed joint proposals by North America Transmission (NAT) and the New York Power Authority to build two 345-kV transmission projects that could cost $900 million to $1.1 billion and would address persistent transmission congestion at the Central East interface and Upstate New York/Southeast New York interface. (See *NYISO MC Supports AC Transmission Projects*.)

The MC selected project T027, a double-circuit 345-kV line from Edic to New Scotland, along with project T029, a standard 345-kV line from Knickerbocker to Pleasant Valley.

### Winter Outlook

Vice President of Market Operations Emilie Nelson reprised the winter *outlook*, saying the ISO will have adequate capacity on hand to meet its forecasted peak demand of 24,269 MW for the 2018/19 winter season, well under last winter's peak of 25,081 MW. (See *NYISO Forecasts Adequate Capacity for Winter*.)

### Balancing Energy Tariff Revisions OK'd

The MC approved Tariff changes clarifying real-time market settlements and their interaction with energy storage resources (ESRs), subject to approval by the board in January.

ISO staffer Christopher Brown *told* the committee the changes do not affect calculations or require software modifications. (See "Real-time Market Settlements Clarifications," *NYISO Business Issues Committee Briefs: Dec. 12, 2018*.)

Energy imbalance payments and charges address the differences among actual energy injections or withdrawals and real-time and day-ahead energy schedules. The changes apply to the injections and withdrawals of ESRs and include terms introduced and defined in the ISO's FERC Order 841 compliance filing submitted Dec. 3 (*ER19-467*). (See *RTOs/ISOs File FERC Order 841 Compliance Plans*.) ■

— *Michael Kuser*

## NYISO News

# NYISO Ordered to Revise DR Meter Rules

*By Michael Kuser*

NYISO must revise its rules governing the installation and reading of demand response meters for participants in its Installed Capacity (ICAP) market, FERC ruled Thursday (*EL18-188*).

The commission partly granted NRG Curtailment Solutions' July *complaint* alleging the ISO's Tariff provisions are unjust because they require curtailment service providers (CSPs) and responsible interface parties (RIPs) seeking to participate in the ICAP market to use the services of meter service providers (MSPs) or meter data service providers (MDSPs) certified by the New York Department of Public Service to install and read non-revenue grade interval meters.

The ruling denied NRG's request for waiver of the rules, instead convening a paper hearing to determine replacement provisions.

The commission found the rules unduly discriminatory to the extent they require CSPs and RIPs that are not transmission owners to be certified by the DPS, which certifies only entities that also provide metering services for the state's retail electric market.

"The result, even if not so intended, is that retail market participation is a prerequisite for demand response resource participation in NYISO's wholesale market," the commission said. "Indeed, in this proceeding, the New York [Public Service] Commission disavows the role ascribed to it through NYISO's requirements and explicitly states that its certification program was designed to facilitate retail billing service, not for participation in wholesale markets or for measuring load reductions."

FERC noted the PSC "has issued a notice proposing to eliminate the state MSP and MDSP programs and the certifications related to these programs."

The PSC filed *comments* in favor of granting NRG the relief it sought, saying "the future of competitive metering services is presently in question in New York. Upon information and belief, there are no known utility customers today who avail themselves of competitive metering services, nor have there been for some time."

NYISO *answered* NRG's complaint Aug. 13 and filed a *supplemental* answer Oct. 22, saying it is examining its metering requirements as part of its broader DER Roadmap. But FERC found the current metering requirements "in need of immediate remedy."

The commission established a paper hearing with initial briefs due within 45 days of the order and reply briefs due within 30 days thereafter. It ordered parties participating in the hearing to address the following issues:


The New York PSC told FERC that the future of competitive metering services is presently in question in New York.

- What metering requirements could be implemented in NYISO, would not be unduly discriminatory and yet would effectively evaluate, measure and verify customer meter data?
- How would such metering requirements address the verification of meter data and auditing of metering service providers?
- How would such metering service eligibility criteria ensure that metering services are available to customers in all geographic areas of NYISO?
- Would such metering requirements allow self-certification for DR providers in NYISO? If not, please explain why.

FERC said it expects to be able to render a decision within four months of receiving reply briefs, or by May 31, 2019. ■

## PJM News

# PJM Members Balk at Price Formation Deadline

*By Rory D. Sweeney*

PJM CEO Andy Ott responds to concerns about a recent deadline issued by the RTO's board on revising energy market issues. | © *RTO Insider*

VALLEY FORGE, Pa. — PJM CEO Andy Ott attended last week's Markets and Reliability Committee meeting to respond to concerns about the Board of Managers' recent ultimatum around price formation — and members were more than happy to offer additional ones.

Under the gun of the board's Jan. 31 deadline to revise six characteristics of PJM's energy market price formation, stakeholders last week heard first reads of three alternative proposals. (See *PJM Moving Quickly to Make Board's Price Formation Deadline*.)

Ott said the board felt several of the revisions for which it intends to request FERC approval are "no-brainers" in that they have already proven successful in solving other problems for PJM.

"We feel we are correctly criticized as a region for not addressing known price anomalies," Ott said. "There is a very strong opinion by the board that we are long overdue for these changes."

He said PJM staff could provide additional data for stakeholder analysis after the revisions have been implemented, but "we're not in that mindset right now" to wait for additional data to validate the revisions. "As a board, we felt that these issues had been discussed for years."

Responding to concerns about whether the board was fully apprised of activity in the Energy Price Formation Senior Task Force (EPFSTF), Ott said they are "well aware" and have had a "complete discussion of where the stakeholders were." Instead of asking to slow down changes, stakeholders should be helping PJM speed them up, he said.

"The pace of the industry is not going to slow down for us. In fact, it's going to accelerate," he said. "On some of the very big and broad issues, we struggle on how to get them through in a way that's timely. ... These are so obvious that we need to get it through to FERC. ... We don't feel it's rushed; we feel it's actually delayed."

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said he is fielding questions from his members asking why this is happening now when major changes are already imminent for other PJM markets, including capacity and financial transmission rights.

"It seems like everything is happening at once," he said.

"The fact that the votes haven't happened, it's not delay. It's truly trying to do the right things by the market," said Susan Bruce, representing the PJM Industrial Customer Coalition. "We have almost a fiduciary responsibility" to understand the full impacts of the proposal before going to FERC, particularly if stakeholders are going to be asked to endorse it.

Ott acknowledged that some issues, such as alignment of day-ahead and real-time reserves, haven't been discussed and hoped that they could be addressed in January.

### Collapse the Process

The call to immediate action left some stakeholders questioning the value of debating the issues within PJM.

"You have stated that the stakeholder process is antiquated and of no real use to you," said Ruth Ann Price of the Delaware Division of the Public Advocate. "Perhaps we need to collapse the stakeholder process and just go directly to FERC."

Ott admitted that the board did discuss making a unilateral filing under Section 206 of the Federal Power Act rather than issuing its Dec. 5 letter to stakeholders, but he said he "feels very strongly that stakeholder input is vital."

"Time and time again, the stakeholder process has improved proposals, and we believe that," he said. "I think it's of tremendous value."

While PJM comprehensively outlined its *proposal* to meet the board's demands, it was unclear which member company would be motioning or seconding it for consideration. The proposal includes increasing the penalty factor for pricing reserve scarcity in the operating reserve demand curve (ORDC) to $2,000/MWh.

Still a work in progress, a second *proposal* from the D.C. Office of the People's Counsel mainly focuses on maintaining the current $850/MWh ORDC penalty factor.

PJM's Independent Market Monitor presented its *alternative*, which remained unchanged from its EPFSTF proposal that would, among other things, delineate smaller subzones and create an ORDC "based on analysis of actual operator demand for additional reserves." Monitor Joe Bowring said the ORDC is "overstated" in PJM's proposal.

Finally, Calpine's David "Scarp" Scarpignato *proposed* to implement PJM's proposal without a "transitional mechanism for the energy and ancillary services (E&AS) revenue offset to reflect expected changes in revenues in the determination of the net cost of new entry." Spark spreads have been "coming down," Scarp said, but a "high variance" remains between expected and actual E&AS revenues.

Stakeholders will vote on the issue at the Jan. 24 MRC meeting. ■

## PJM News

# PJM MRC Briefs

| © RTO Insider

### Board's GreenHat Investigation

VALLEY FORGE, Pa. — PJM Board of Managers member Susan Riley asked RTO members for continued patience with the board's ongoing investigation into the historically large default of GreenHat Energy's financial transmission rights portfolio. (See *PJM Board Investigating GreenHat's Record FTR Default*.)

Speaking via phone to attendees at the RTO's Markets and Reliability Committee meeting Thursday, Riley said the Special Board Committee is progressing — having completed 30 interviews — but has little to offer yet publicly. It anticipates preparing a draft for board members to review in early January.

The final report, targeted for publication in early February, is intended to provide "a great deal of confidence" about what happened and ensuring it doesn't happen again, Riley said.

"If it takes a little longer, I hope that you'll bear with us," she said. "Our goal here is to be comprehensive ... complete and unbiased."

### FTR Mark-to-Auction Credit Requirements Endorsed

Members approved without discussion a *proposal* endorsed by the Market Implementation Committee to increase FTR credit requirements with the addition of a "mark-to-auction" provision. (See "FTR Collateral," *PJM Market Implementation Committee Briefs: Dec. 12, 2018*.)

The vote, taken by acclamation, included one objection.

### Must-offer Exception Process Deferred

Members voted to defer consideration of a *proposal* endorsed by the MIC to revise the capacity market must-offer exception process. The changes would allow participants to specify multiple auctions when making exception requests. Resources that cannot be made Capacity Performance-capable by the start of the delivery year will be permitted to seek an exception. (See "Must-offer Exception Changes," *PJM Market Implementation Committee Briefs: Nov. 7, 2018*.)

Susan Bruce, representing the PJM Industrial Customer Coalition, requested deferring the vote until the April 29 MRC meeting and remanding the issue back to MIC to discuss resources wanting to move between capacity- and energy-only status. Despite the request, Bruce said the issue "feels like something to get wrapped up before [capacity market] auctions start."

Asked to specify which member company made the deferral motion among those she represents, Bruce named industrial gas producer Praxair. Old Dominion Electric Cooperative, via Carl Johnson as the representative of the PJM Public Power Coalition, seconded the motion. It was approved in a sector-weighted vote with 3.74 in favor.

Asked by Marji Phillips of Direct Energy whether the Independent Market Monitor could address any withholding issues if the proposed rule passed, Monitor Joe Bowring responded that strong and clear rules are needed in order to be enforceable and that the Monitor would not be able to prevent the exercise of market power through withholding if the proposed rule were implemented.

### FTR Forfeiture Rule Deferred

A second long debate, on a proposed change to the FTR forfeiture rule, ended in another vote deferral after some stakeholders expressed fear it could unintentionally create exploitable market loopholes.

The *proposal*, endorsed by the MIC, would revise the trigger for forfeiture of FTRs from virtual trades that create a penny's worth of impact on the value of an FTR to those whose impact exceed 10%. (See "FTR Forfeiture Proposal Endorsed," *PJM Market Implementation Committee Briefs: Nov. 7, 2018*.) Bruce said certain physical suppliers have been very vocal about wishing to revise the trigger, but stakeholders haven't heard from others about how "endemic" the issue is. Several financial-only traders responded.

"I think that there is a broader impact than just [on] companies like [proposal co-sponsors] Exelon and NextEra [Energy]," Appian Way Energy Partners' Abram Klein said.

"We don't think we're striking the right balance today," PJM's Stu Bresler said in support of the proposal. As evidence of the revision's necessity, proponents had provided an example of issues around taking positions at the RTO's Western Hub.

"I think that the Western Hub is the most liquid location in the system," Bresler said. "If there isn't enough liquidity there, we should probably all pack our bags."

The Monitor continued its longstanding defense of the current rule, including the so-called "penny test," pointing out that the existing rule has a 10% test for the impact of a company's portfolio on a constraint and that the penny test is simply a test for a positive impact on the value of an FTR. That test could reasonably have been zero, but a penny was implemented.

In response to assertions by Exelon and NextEra that the proposal would improve

# PJM News

market efficiency, Bowring pointed out that "there is no evidence that the rule would improve the efficiency of the market. … The proposed rule would substantially weaken the FTR forfeiture rule and permit the exercise of market power."

Exelon's Jason Barker said such logic suggests it would also be more efficient to send people directly to jail when arrested, but that such a bypassing of due process ignores important nuances like intent and tenet of being "innocent until proven guilty."

"We don't have those things in our system because we have to judge the reasonableness of those actions," Barker said. "[The penny test] is efficient, I'm sure, for Joe to monitor and for PJM to apply, but it's not fair."

"I didn't quite get that, but it sounded pretty dramatic, pretty draconian. That's not what we're doing here," Bowring said. He questioned why "10% is a good threshold for guilty but a penny is not?"

Gabel Associates' Mike Borgatti, representing NextEra, motioned for deferral to the MRC's Feb. 21 meeting to discuss a compromise of a 5% threshold for triggering forfeiture. The motion passed without objection or abstention.

## PFR Task Force on Hiatus

Members agreed to a PJM *proposal* to put the Primary Frequency Response Senior Task Force on hiatus for one year to gather data and subsequently determine whether to reconvene. The hiatus was suggested after stakeholders in the task force failed to come to consensus on any proposals to require existing units to provide primary frequency response. (See *PJM SHs Seek End to Frequency Response Debate*.)

Many generators already provide the service such that there is no additional need for it in PJM, and those that don't argue that being forced to install the necessary equipment would be a financial hardship that isn't supported by reliability needs. PJM staff anticipate that outreach to unit owners will result in performance improvements over the next year and that NERC might issue enhanced standards.

The motion was endorsed by acclamation.

## Transmission Replacement

Transmission owners remain at philosophical odds with load interests and merchant transmission operators about end-of-life (EOL) and replacement procedures for aging infrastructure.

American Municipal Power's Ed Tatum and

| © RTO Insider

Lisa McAlister presented proposed *revisions*, developed in concert with ODEC to Manual 14B in a package that retains the position as the first option to receive a vote on the topic. The proposal would add language in section 1.5.4 of the manual to provide sufficient information to enable stakeholders to replicate transmission owners' results on the need for proposed supplemental projects, as well as strike the word "useful" throughout in manual references to "end of useful life."

"We don't need folks replacing well-maintained assets simply because they are at the end of their depreciable life," Tatum said.

PJM's Aaron Berner, who presented the RTO's alternative proposal endorsed by TOs, worried the slight wording difference could lead to reliability issues.

"Getting rid of 'useful' is going to leave us with 'end of life.' It means something failed," he said.

The PJM *proposal* was moved for consideration by FirstEnergy and seconded by Public Service Electric and Gas.

LS Power's Sharon Segner proposed a friendly amendment to either proposal that would limit the ability for supplemental projects — which are developed by TOs based on their own internal needs criteria — to supplant competitively bid projects accepted by PJM to address regional reliability violations or other criteria. She said LS is concerned about an apparent "blur" of the lines between such projects.

"We accept that some supplemental projects are needed. We accept that FERC has made the decisions that they have made," Segner said. "But supplemental projects cannot be displacing regional projects."

Stakeholders will vote on the issue at the Jan. 24 MRC meeting.

## Resilience and Fuel Security

PJM's Jonathon Monken presented an *update* on the RTO's efforts to increase system resilience, noting several initiatives planned for 2019. Among them are an infrastructure interdependency analysis, a pilot to test distributed energy resources for resilience and identification of resilience attributes for fuel-secure generation resources.

The latter was the topic of a special session of the MRC that followed the normal committee meeting, in which PJM's Dave Souder *reviewed* the fuel security *report* the RTO released earlier this week. (See *Full PJM Study Makes Case for*

Continued on page 29


PJM's Dave Souder discusses PJM's fuel-security report and plans going forward. | © RTO Insider

## PJM NEWS

# FERC OKs PJM Plan to Prevent Shortchanging of DR

*By Rory D. Sweeney*


East Kentucky Power Cooperative headquarters | *EKPC*

FERC last week approved PJM's proposal to revise its Reliability Assurance Agreement (RAA) to exclude atypically low usage winter peak days from load-serving entities' winter peak load (WPL) calculations (*ER19-142*). The revision, which was requested by East Kentucky Power Cooperative, eliminates the potential that demand response resources might be shortchanged in the load curtailment they can provide. (See "Now is the Winter of Our Discontent (with DR Rules)," *PJM Market Implementation Committee Briefs: Sept. 13, 2017*.)

PJM calculates an end-use customer's DR capability by taking the lesser of its total peak load contribution, which measures summer capability, or its WPL.

The WPL, which is usually lower, is calculated by averaging the customer's peak hourly loads during traditional daytime hours on the five days with the highest daily unrestricted peak loads from December through February, known as the five coincident peaks (5CPs).

However, one or more of the 5CPs can have little or no load because of load-management actions, offline factories or meter malfunctions. Such reductions reduce the WPL, which will likely reduce the calculation for the resource's potential load reduction.

To avoid this, PJM will allow customers to exclude up to two CP days when the peak hourly loads for each of those days are individually below 35% of the average peak hourly load for all the location's winter 5CP day. The 35% threshold represents 1% of all submitted peak load days.

The commission's Dec. 17 order said the new rules "should more accurately reflect end-use customers' actual loads during peak winter periods." It rejected the Independent Market Monitor's argument that the proposal would arbitrarily increase the calculated WPL.

"Similarly, we are unpersuaded by the Market Monitor's argument that failure to also eliminate high-load days renders the winter peak load calculation arbitrary. There is no evidence in the record that identifies any particular circumstances or events that may cause abnormally high-load days that are not representative of actual peak loads and, when used to calculate winter peak load, lead to an inaccurate representation of a demand resource's capability to reduce its winter load." ■

*Continued from page 28*

*Fuel Security Payments*.)

Responding to stakeholder questions, Souder acknowledged that the units included in the report's retirement scenarios were just the least-profitable units rather than "underwater" facilities. He said scenario templates for each of the 324 analyzed scenarios are expected to be published in mid-January. Staff also plan to introduce a problem statement and issue charge on the issue for stakeholder consideration in the first quarter.

That would precipitate creating a senior task force to examine the topic with any potential market rule changes targeted to be filed with FERC in early 2020. A third phase of the initiative is occurring in parallel to consider expanding beyond just gas contingencies would be longer than the 14-day outage scenario examined in the report.

### Manual Approvals

Stakeholders endorsed two manual revisions by acclamation:

- Manual 14D: *Generator Operational Requirements*. Revisions developed to revise information input deadlines for the Resource Tracker application. (See "Resource Tracker," *PJM Operating Committee Briefs: Nov. 6, 2018*.)
- Manual 14E: *Upgrade and Transmission Interconnection Requests*. Revisions developed as part of a triennial cover-to-cover review. The revisions include changing the manual name to align it with the structure of Manuals 14A and 14G and explaining how to apply to the interconnection queue via Queue Point.
- *Clarifications* of market participation rules for DERs in Manuals 11 and 14D and the Open Access Transmission Tariff. Among the changes are a consistent definition of on-site generators. ■

*— Rory D. Sweeney*

## PJM News

# GT Power Group's Dave Pratzon Retiring

*By Rory D. Sweeney*

It's the end of an era at PJM: Following the Dec. 20 Markets and Reliability Committee meeting, GT Power Group's Dave Pratzon called it a career after 45 years.

Over that time, Pratzon has seen many of the biggest changes to the electricity industry from the trenches, having been involved in developing a number of the processes and rules that would eventually make up the grid and its markets as they are today.

"I care about the success of the enterprise. I want to deploy myself to the end," said Pratzon, who turns 68 later this month.

### A Fate-full Career

Pratzon describes his career as "an accident of fate," or more accurately, a series of them, starting with how he got into the power business in the first place. While he went to college to become an electrical engineer, he spent his summers laboring at a local steel mill near his home in Wallingford, Conn. However, the job was threatened each year by union unrest or overproduction at the mill. He took the suggestion of a college friend from Philadelphia to join him in seeking summer employment with the Philadelphia Electric Co. (now PECO Energy) and found himself working on substations.

Upon graduation, he attempted to land a full-time position at the utility, only to have the offer rescinded at the last moment. Scrambling, he found work near San Francisco as a field engineer for nuclear submarines. On a trip back East to propose to his fiancée, Gail, and pick up a car, he happened to swing back through Philadelphia and stop in PECO's offices.

"You got my letter!" a former supervisor said upon greeting the bewildered Pratzon.

"I'm just driving through," he responded.

The boss said they were trying to contact him about a job opening and asked if he had time to interview.

"Sure," Pratzon said, "as long as it's today."

The company's response traveled faster to his West Coast home than he did.

"By the time I got there, there was the letter with my official offer," Pratzon said.

He quit the submarine job, partially to move back closer to home but also because part of

Dave Pratzon

his job would have involved "sea trials" of the ships, and he realized he's claustrophobic.

"I could never survive out there for a week or two under water in steel containers," Pratzon said. "I was happy to come back. ... It was kind of a step back to the East Coast that I figured would be another temporary position on my way back to New England."

It would be his last major move.

"My wife and I, being New Englanders, thought this would be a temporary job before moving [back] up there, but 45 years later, we haven't left yet," Pratzon said.

Gail became a librarian and helped found the public library in their town, Lower Providence Township.

"Opportunities have come for both of us," he said.

### PJM Work

From his first day at PECO, Pratzon was heavily involved with PJM. PECO supplied PJM's staff for the first several decades after its founding, and Pratzon worked for the grid operator from 1973 to 1991, before being transferred to PECO as a "broadening" assignment. He was the first secretary of PJM's cost-development subcommittee in the mid-1970s and helped develop the initial market rules that he jokes Independent Market Monitor "Joe Bowring may or may not like right now."

Pratzon's career was a period of change for both the industry and PJM, which began transitioning to an independent organization in 1993. In 1997, it opened its membership to non-utilities and elected an independent Board of Managers.

"The market was very different when it was

## PJM News

just the eight companies dealing with each other," he said, referring to PECO, Public Service Electric and Gas, Pennsylvania Power & Light, General Public Utilities (GPU), Baltimore Gas and Electric, Potomac Electric, Atlantic City Electric, and Delmarva Power and Light.

The first major transition occurred during the Three Mile Island crisis, when plant owner GPU began searching for power supplies outside of the other seven utilities in PJM at the time. Up until then, the companies had bought and sold among each other, with PJM determining which plants would run to provide all of the power necessary at the cheapest overall cost.

Each day, the companies would submit their projected costs to run each plant the following day. If one company's plant would cost more to run the next day than those of other companies, PJM would dispatch the cheaper plant to cover the demand and charge the company with the more expensive plant half of the difference between the plants' costs in an accounting method known as "split savings."

But GPU's alternative during the TMI crisis was combustion turbine plants, which were experiencing a crisis of their own during the oil shortages of the 1970s. Using the expensive CTs as the baseline cost under the split savings method would have cost GPU a fortune, so the company sought alternatives outside of the PJM ring. It was controversial and "unheard of at the time," Pratzon said, at least partially because the other companies anticipated the profits they might make from GPU's problems.

GPU, however, saw external tie lines that weren't being used. "They were the first PJM utility to go out on their own," he said.

Another blow to split savings occurred when merchant generators entered the market thanks to open-access transmission lines and subsequently refused to share their cost information.

By the time PJM began working on its locational marginal pricing proposal, Pratzon had left the grid operator and was working at PECO.

From 1992 through 2002, he advocated for PECO's interests, including testifying at FERC in opposition to LMP. PECO at the time thought a bilateral-contracting approach would be more profitable. Pratzon was also involved developing the wholesale market participation rules for competitive suppliers in Pennsylvania, the first state in PJM to adopt retail customer choice.

While "in the beginning, a lot of [his work at

GT Power Goup's Dave Pratzon (left) and Tom Hyzinski | © *RTO Insider*

PECO] was reactionary" to what was happening in the industry, the company soon started to notice opportunities, such as selling the excess generation from its Limerick 2 nuclear plant into PJM's markets after its failed effort to get Pennsylvania Public Utility Commission approval to include it in ratepayers' bills.

Those experiences precipitated PECO forming a Power Team to market the excess power. "If you can't beat them, join them," said Pratzon, who was on the team from 2002 to 2012.

Exelon's merger with Constellation in 2012 moved the Power Team to Baltimore. Instead of moving further from his New England roots, Pratzon lit out on his own and eventually joined with former Pennsylvania PUC Chair Glen Thomas' GT Power Group, which already represented the PJM Power Providers group known as P3.

While Pratzon did testify at the PUC during Thomas' tenure as the commission's chair, they had never met.

"I don't remember him being there; he doesn't remember me testifying," Pratzon said. "He heard about me through mutual acquaintances."

### Enjoying Every Minute of It

Even as his time has been wrapping up, Pratzon has remained active and vocal in stakeholder meetings.

"I've loved every minute of it," he said. "It's never the same thing twice. ... I've invested so much of my work career into PJM and trying to help and resolve [issues]."

He hopes to have brought an attitude to the process of "trying to understand and respect the views and positions and needs of the many stakeholder groups and trying to find solutions that will help the market thrive."

"I think ... there is maybe now less of the collaborative spirit than there has been [at] times in the past. I'm not sure I can put my finger on why," he said. "I'll miss being part of the hopeful solution."

PJM is a "good atmosphere to try to resolve the new issues as they come up" because while the RTO "has the hammer" to implement rules as it sees fit, it "respects and listens to stakeholder input."

"It happens in PJM more than perhaps in any other RTO," Pratzon said.

So why leave now?

"I feel like I have to be all-in" to do this work, he said, and to do less "would feel like dabbling."

Instead, he's becoming a "full-time project manager" for three months to renovate his kitchen and plans to spend more time with his 3- and 6-year-old grandchildren.

Traveling is in the works "to get around and see more of the world than we have in the past," and he'll be volunteering with an elder support group in town to meet more people and aid those who might otherwise be lonely.

Still, the stakeholder process and what it means won't ever be far from his mind. In breaking the news of his retirement to industry colleagues, Pratzon has become fond of making a final request:

"Just remember: Keep the lights on for me now that I'm just a retail customer!" ■

## SPP

# SPP FERC Briefs

### FERC Approves SPP's Streamlined FCA Process

FERC last week approved SPP's plan to streamline the process by which it designates frequently constrained areas (FCAs), effective Dec. 22 (*ER19-166*).

The commission had directed SPP to seek approval of any new, removed or modified FCAs when the RTO submitted Tariff revisions in 2012 to implement its Integrated Marketplace. SPP and its Market Monitoring Unit worked with stakeholders to develop the designation process for areas with high levels of congestion and a dominant or pivotal supplier.

The commission agreed with SPP's argument that the designation process may result in a significant lag between the MMU's annual evaluation of FCAs and when they are updated in the Tariff. It said SPP's proposal allows the RTO and MMU to address market power concerns in a timely fashion.

"We find that this delay could result in the inappropriate application of mitigation measures during the lag period or, conversely, the lack of application of mitigation measures when appropriate, potentially allowing market participants to exercise market power," FERC said.

SPP's Tariff requires the MMU to re-evaluate FCAs at least annually.

The MMU said it strongly supported SPP's proposed revisions, noting that under the previous process, it could take up to six months to update the FCA list following its report. With the change, the Monitor's updates and associated analysis will be publicly available at least 14 days before any updates take effect. Affected market participants can raise any concerns with the MMU.

SPP stakeholders approved the Tariff *revision* during July's Board of Directors and Markets and Operations Policy Committee meetings.

The MMU's 2017 *analysis* reduced the FCA list to one, effective April 2018. (See *SPP's FCA List Pared to One Area*.)

### NPPD Complaint Against Tri-State Denied

The commission denied Nebraska Public Power District's complaint against fellow SPP member Tri-State Generation and Transmission Association that certain costs in the latter's annual transmission revenue requirement (ATRR) and its failure to credit certain revenues are unjust and unreasonable (*EL18-194*).

Tri-State G&T transmission upgrade project in Colorado | *Tri-State G&T*

NPPD alleged that Tri-State unfairly included in its ATRR the costs of two grandfathered agreements (GFAs) and its facilities not physically connected to SPP's system. It also said Tri-State excluded point-to-point revenue from the credits applicable to revenue requirements for network service. The utility asked the commission to remove all costs related to the two GFAs and the facilities from Tri-State's ATRR and SPP's rates for NPPD's transmission zone, and to include point-to-point revenue as a credit to the cooperative's revenue requirement.

The complaint stems from Tri-State's placement in NPPD's transmission zone when the cooperative wholesale power supplier joined SPP in 2015 as part of the Integrated System. NPPD protested at the time but reached a settlement with Tri-State and SPP in 2017.

FERC ruled the disputed cost components were covered in the settlement agreement, saying that NPPD had failed to demonstrate that without its proposed modifications, the settlement "seriously harms the public interest."

### SPS Gets Partial Approval to Issue Refunds

FERC granted one of Southwestern Public Service's three waiver requests related to the issuance of customer refunds, but it rejected a second and dismissed a third as unnecessary (*ER18-2377*).

The Xcel Energy subsidiary requested the waivers in September, saying it had received a $12 million refund from El Paso Natural Gas (EPNG), which provides fuel to SPS and third-party-owned gas-fired plants on its system. The utility said each wholesale requirements customer has a power supply agreement that contains a fuel cost adjustment clause, through which SPS recovers fuel transportation costs.

The commission accepted SPS' request for a waiver of section 35.14 of FERC's regulations, which limits the fuel cost adjustment clause to the recovery of current fuel costs. That clears the way for the utility to issue about $3 million in refunds to eight of its current and former wholesale customers.

FERC rejected the utility's request for a waiver of section 35.19a of its regulations and its methodology for computing interest on refunds. SPS requested the waiver to avoid paying interest for the period between its receipt of the refunds from EPNG and the distribution of refunds to SPS' wholesale customers.

The commission said the utility's arguments were insufficient to explain why it should be exempt from paying interest.

Finally, FERC dismissed SPS' request for a waiver from the utility's fuel cost adjustment protocols as unnecessary, saying they don't conflict with providing EPNG refunds to wholesale requirements customers. ■

*— Tom Kleckner*

El Paso Natural Gas' iconic "Blue Flame" headquarters in El Paso | *Texas Historical Commission*

## SPP

# MOPC Gets New Leadership for 2019

SPP's Markets and Operations Policy Committee will begin 2019 with new faces in all its leadership positions following the Board of Directors' approval of NextEra Energy Resources' Holly Carias as chair and Evergy's Denise Buffington as vice chair.


Holly Carias listens to a discussion during a 2018 MOPC meeting. | © *RTO Insider*

SPP Vice President of Engineering Lanny Nickell, who will become the committee's staff secretary, made the announcement late Friday in an email to stakeholders.

"I'm confident they will do a fabulous job leading the group," said Nickell, who is replacing SPP COO Carl Monroe on the committee. Monroe served as secretary for 18 years.

Carias, a senior director with NextEra who became heavily involved with the MOPC during 2018, has been a vocal proponent for renewable resources.

Buffington, director of federal regulatory affairs for Evergy companies Kansas City Power & Light and Westar, has focused on SPP's budget and transmission zonal placement issues. The board and MOPC in 2017 both rejected her attempts to address cost shifts caused by the RTO's zonal placement decisions. (See *SPP Board Rejects Changes to Tx Zonal-Placement Rules*.)

Carias and Buffington replace Nebraska Public Power District's Paul Malone and independent consultant Jason Atwood. Malone cycled off the committee in December, while Atwood left the Northeast Texas Electric Cooperative in November to start his own business. ■


Denise Buffington | © *RTO Insider*

*— Tom Kleckner*

# SPP, ERCOT Set New Wind Generation Marks

For the last two years, SPP and ERCOT have been saying, "Anything you can do, I can do better" in their friendly competition to see which can produce more wind energy or a greater share of its production.

Both grid operators set new records for wind generation this month, with SPP producing a new wind peak of 16.4 GW at 7:40 a.m. on Dec. 20, six days after ERCOT topped out at a record 19.2 GW on Dec. 14.

SPP's previous record of 15.7 GW was set in December 2017. ERCOT, which established its latest record just seven minutes into the new day, eclipsed the old mark of 17.9 GW, set Nov. 12, by almost 7%.

ERCOT may produce more wind energy — it has 22 GW of installed wind capacity, while SPP recently passed the 20 GW level — but SPP relies on wind for more of its capacity. On April 30, it served 63.96% of its load with wind energy, and it is making plans for wind-penetration levels of 70%.

SPP became the *first* North American grid operator to top the 50% wind penetration level in February 2017.

Texas wind farm | *Target*

ERCOT's high for wind penetration is 54.22%, set in October 2017. Wind penetration was only 51.53% at the time of its latest wind peak. ■

*— Tom Kleckner*

# Company Briefs

### FERC OKs PG&E Tariff Settlement

FERC on Thursday approved Pacific Gas and Electric's tariff settlement that ended two cases in which the California Public Utilities Commission and other complainants challenged the utility's calculation of its transmission revenue requirements (TRR) and rates under its 19th transmission owner tariff (TO19).

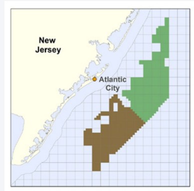
The complaint stemmed from PG&E's request to increase its wholesale base TRR from $1.319 billion to $1.705 billion and boost its retail base TRR from $1.331 billion to $1.718 billion. (See *PG&E Transmission Revenue Complaint Rejected Again*.) The complainants argued that PG&E actually required less revenue than it was already approved to collect, that FERC should allow for refunds below the current wholesale TRR and that their complaint should be consolidated with a rate increase proceeding.

FERC said the settlement "appears to be fair and reasonable and in the public interest."

More: *ER17-2154, EL17-95*

### US Wind Sells NJ Offshore Lease to EDF

US Wind last week announced it has agreed to sell its 750-square-km offshore wind lease area 7 miles off the New Jersey coast to EDF Renewables North America for $215 million.




EDF already owns the northern portion of the New Jersey Wind Energy Area. The agreement came after the New Jersey Board of Public Utilities unanimously rejected the Nautilus Offshore Wind project, a joint venture between EDF and Fishermen's Energy, citing high costs. EDF made the US Wind purchase through a newly formed joint venture with Shell Energy, Atlantic Shores Offshore Wind.

US Wind said it plans to focus on its 32-turbines, 268-MW project off the Maryland coast.

More: *Baltimore Business Journal*; *North American Windpower*; *NJBIZ*

### 2018 Record Year for Corporate Renewable Procurement

U.S. corporations set a new single-year record for new wind and solar capacity procurement, at 6.43 GW, the Rocky Mountain Institute's Business Renewables Center announced last week.

Facebook, AT&T, Walmart, ExxonMobil and Microsoft were the top five corporations in renewable procurement, according to the center, with Facebook signing deals for 1,849.5 MW of renewables. In its first year of market participation, AT&T procured 820 MW.

The center said corporations have procured 15 GW of renewables in total since 2013, when it first began tracking deals.

More: *Rocky Mountain Institute*

### ExxonMobil Asks EPA to Regulate Methane Emissions

ExxonMobil wrote EPA last week to express support for federal standards to mitigate methane emissions for both new and existing source oil and gas facilities, urging the agency "to continue to pursue cost-effective regulations," according to a letter obtained by Axios.

The letter is in response to rollbacks of Obama-era methane regulations that EPA has undertaken this year.

In the face of investor pressure and legal challenges, Exxon has recently taken a pro-environment stance. But as one of the largest producers of natural gas in the U.S., it can also afford to install costly pollution-control equipment, giving it an edge over smaller competitors.

More: *Axios*

# Federal Briefs

### FERC Spared from Government Shutdown

FERC, the Nuclear Regulatory Commission and the Energy Department will continue to operate as normal during the partial government shutdown that began at midnight Saturday, thanks to a 2019 "minibus" budget bill signed by **President Trump** on Sept. 21. EPA was not included in the bill, nor in a second mini package signed on Sept. 28, but the agency "has sufficient carryover funds to operate for a limited period of time," according to acting Administrator Andrew Wheeler.

The Senate passed a continuing resolution last Wednesday that would have kept the rest of the government funded until Feb. 8. Trump, however, insisted on a bill that included $5 billion in funding for his proposed wall along the Mexican border, which the House of Representatives passed Thursday. Negotiations to reconcile the bills failed before the midnight deadline.

The shutdown affects about 800,000 federal workers. The full effects, however, will not be felt until tomorrow because of the weekend, the Christmas holiday and the fact that Trump *ordered* all executive agencies closed for Christmas Eve. FERC said any filings due Dec. 24 will be accepted Dec. 26 because of the order.

More: *Roll Call*; *Politico*

### Congress OKs Nuclear Licensing, Budgeting Changes

The House of Representatives on Friday approved legislation to simplify the licensing process for commercial advanced nuclear reactors. The 361-10 vote followed the Senate's passage of the Nuclear Energy Innovation and Modernization Act by voice vote on Thursday.

Co-sponsored by 10 Republican and eight Democratic Senators, the bill orders the Nuclear Regulatory Commission (NRC) to modify the licensing and budgeting process for commercial advanced nuclear reactors.

In *announcing* the bill in 2017, the sponsors said it would promote innovation in the nuclear sector, increase the transparency and accountability of NRC's budget and fee programs and the Department of Energy's process for disposing of excess uranium. "This legislation will create more certainty for nuclear plant operations, without compromising safety or government oversight, and encourage greater investment for the next generation of nuclear power," House Energy and Commerce Committee Chairman Greg Walden (R-Ore.) and Subcommittee on Energy Chairman Fred Upton (R-Mich.) said in a statement Friday.

Maria Korsnick, CEO of the Nuclear Energy Institute, said the bill "establishes a more equitable and transparent funding structure which will benefit all operating reactors and future licensees. The bill also reaffirms Congress' support for nuclear innovation by working to establish an efficient and stable regulatory structure that is prepared to license the advanced reactors of the future."

More: *S.512*

### FERC Eliminates Hydro Facility Recreation Form

FERC on Thursday approved the elimination of Form 80, a 52-year-old document that solicits information on the use and development of recreation facilities at hydropower projects.

The Federal Power Act requires that hydro developers include recreational use in their projects. FERC created Form 80 in 1966 to formalize enforcement of that provision. The form required developers to provide an inventory of the use and development of recreational facilities at their projects.

"The commission concludes that the benefits and the reduced burden for licensees and staff that result from eliminating the Form 80 outweigh the potential minor obstacles that may arise during the transition from the Form 80 data to specific recreation data gained through licensee compliance with project-specific license conditions," FERC said.

More: *RM18-14*

### House Democrats Pick Castor to Chair Climate Committee

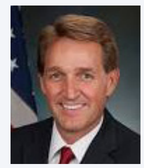
House Democrats last week chose Rep. **Kathy Castor** (Fla.) to chair a special committee on climate change.

The choice of Castor, along with the structure and mandates of the committee, will not be official after Jan. 3, when the new Congress is sworn in. But it had previously been unclear whether the new Democratic majority would even recreate the panel.

Progressive Democrats, however, are upset that the committee will not have subpoena power nor the ability to advance legislation to the House floor. It will also not be tasked with forming a "Green New Deal" legislative package, including a national 100% renewable portfolio standard, and members who have received donations from fossil fuel companies will not be banned, two major demands by the progressive wing.

More: *The Hill*

### Senate Version of Carbon Tax Bill Introduced



Sens. **Jeff Flake** (R-Ariz.) and Chris Coons (D-Del.) last week introduced a version of a bill in the House of Representatives in late November that would impose a carbon tax on major industrial carbon emitters throughout the U.S.

Both bills are largely symbolic. They have a near-zero chance of passing amid a partial government shutdown over the holidays, in the last weeks of the current Congress. Some of the co-sponsors of the bills are either retiring from Congress, such as Flake, or defeated in their re-election bids, such as Rep. Carlos Curbelo (R-Fla.).

Both bills would charge companies $15/ton of carbon emitted and increase that fee by $10/year, with a goal of reducing emissions by 40% before 2028 and 91% by 2050. The Senate version of the bill would allow EPA to step in to ensure the U.S. is meeting that trajectory if it is found the tax is not resulting in fast-enough reductions.

More: *Ars Technica*

# State Briefs

## REGIONAL

### States, DC to Cap and Trade Vehicle Emissions

Nine Northeastern states and D.C. last week agreed to create a cap-and-trade system similar to the Regional Greenhouse Gas Initiative for vehicle emissions.

Connecticut, Delaware, D.C., Maryland, Massachusetts, New Jersey, Pennsylvania, Rhode Island, Vermont and Virginia agreed to join the system. Pennsylvania, New Jersey and Virginia are the only members not part of RGGI, though the latter two are seeking to join. RGGI members Maine, New Hampshire and New York are the only RGGI members that did not join the new program.

The states said they will spend a year designing the program before implementation.

More: *E&E News*

## DISTRICT OF COLUMBIA

### Council Confirms Phillips, Gillis to PSC Seats

The Council last week voted to confirm Public Service Commissioner **Willie Phillips** as the commission's new chair and Greer Gillis, director of the Department of General Services, as commissioner.

Gillis, a career engineering expert, was approved on an 8-5 vote, with some council

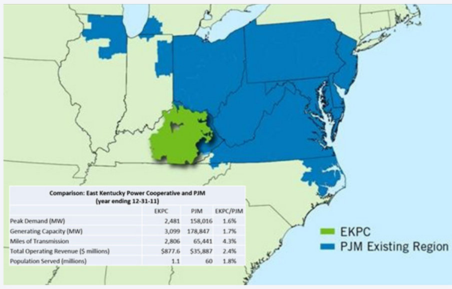
members opposing her over her lack of expertise in utility regulation or rates. Only one council member voted against Phillips, citing his vote to approve Exelon's acquisition of Pepco Holdings Inc. in 2016.

More: *Washington City Paper*

## KENTUCKY

### FERC Rejects Bid to Avoid PJM Tx Rates

FERC on Thursday rejected the city of Falmouth's request for a declaratory order




allowing it to obtain transmission service from East Kentucky Power Cooperative (EKPC) at the same rates and terms the city currently pays Kentucky Utilities. The transmission system of EKPC, which joined PJM in 2013, is intertwined with that of KU.

Falmouth's municipal electric system is terminating its contract with KU and will begin taking all its wholesale requirements power for its 4 MW of load on May 1, 2019, from the newly formed Kentucky Municipal Power Agency. Under the existing contract — in which Falmouth pays KU to deliver energy to its load on the EKPC system — the city was protected by a settlement that insulates KU's load from the effects of EKPC's integration into PJM.

The commission said that Falmouth will lose that protection once it changes suppliers because the settlement was intended to protect load served by KU and its sister company Louisville Gas & Electric. "Instead, Falmouth's load will become a network transmission customer load of PJM under a new [network integration transmission service agreement] with PJM, and PJM will provide network transmission service to Falmouth's load by utilizing EKPC's transmission system." The commission acknowledged that Falmouth's transmission rates will increase as a result of the switch. "However, even where the terms of the new transmission service are less favorable, the commission has not used that as a basis to order continuation of the prior and more favorable terms," FERC said.

More: *EL18-176*

# MAINE

## Audit Report Clears CMP System for High Winter Bills

A report released Thursday by Liberty Consulting Group said the high electricity bills last winter could not be blamed on Central Maine Power's new billing and metering system.

The consulting firm, hired in July by the Public Utilities Commission, said the spike in bills was caused by an intense cold snap and a recently approved rate increase for the utility. But the report also criticized CMP for its poor response to the flood of complaints.

"The extent and degree of performance degradation contributed strongly to a level of customer frustration, doubt and skepticism already high due to uncharacteristically large bills last winter," the report said.

More: *Portland Press Herald*

# MISSOURI

## PSC Holds Rehearings on Grain Belt Express After Remand

The Public Service Commission last week held two hearings on Clean Line Energy Partners' Grain Belt Express Clean Line, after its rejection of the HVDC transmission project was remanded to it by the state Supreme Court.

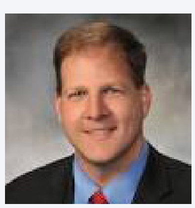
On hand to support the project this time was Invenergy, which has agreed to buy it from Clean Line, subject to PSC approval.

The PSC rejected the project because Clean Line had not obtained approval from every county through which the project would pass. The court said this was a misinterpretation of case law.

More: *KOMU*

# NEW HAMPSHIRE

## Sununu to Request Federal Offshore Wind Study



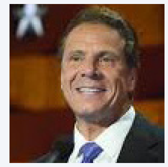
Gov. **Chris Sununu** last week said he would ask for a federal Bureau of Ocean Energy Management task force to study potential offshore wind development off the state's small coastline.

Sununu made the remarks almost casually on New Hampshire Public Radio: "Sure, if you want to set up a task force to look at wind, I don't have any problem with that at all." A spokesman later confirmed Sununu's comments meant he would make the task force request, but he did not give a timeline for doing so.

More: *New Hampshire Public Radio*

# NEW YORK

## Cuomo to Set New Emissions Goal for State



Gov. **Andrew Cuomo** announced in a speech last week that he would update the state's carbon-reduction target to being carbon-neutral by 2040.

Details of the change — including whether it would require legislative action, and how the state would achieve such a goal — are still sparse, which disappointed environmental groups. "A vague pledge of carbon neutrality by the year 2040 is not the bold action necessary to move New York off fossil fuels," Food and Water Watch's Alex Beauchamp said.

Cuomo's current goals are 50% renewables by 2030 and emissions to be cut 80% from 1990 levels by 2050.

More: *Politico*

# TEXAS

## Garland Plant to be Mothballed


ERCOT said last week that it has received a notification of suspension of operations (NSO) for the city of Garland's Gibbons Creek Generating Station.

According to the NSO filed on Dec. 21, the plant will be mothballed "indefinitely," effective June 1, 2019, "for a period not less than seven months and not greater than eight months." Garland Power & Light told ERCOT last year it wants to run the 35-year-old, 454-MW coal-fired unit only from June 1 to Sept. 30 each year. It resumed operational status for this summer in May and returned to mothball status on Oct 1.

ERCOT stakeholders have until Jan. 11 to file any comments on the NSO as part of the standard reliability-must-run review.

The plant, located northwest of Houston, is operated by the Texas Municipal Power Agency.

## VIRGINIA

### SCC Estimates $5.6B Cost of Dominion's Coal Ash Excavation

The cost of excavating and partly recycling 27 million cubic yards of coal ash stored underground across the state could end up costing the average household an additional $3.30/month over 20 years, the State Corporation Commission told lawmakers last week.

More than half of the ash remains buried inside two storage ponds near Dominion Energy's Chesterfield Power Station. The SCC's briefing came just days after Dominion filed to recover roughly $302.4 million from ratepayers to cover the cost of upgrading three coal-burning power plants to meet federal and state environmental regulations.

More: *Richmond Times-Dispatch*

## WISCONSIN

### PSC Approves WE Solar Proposals

The Public Service Commission last week approved two proposals by We Energies that will increase the state's solar capacity.

One program will allow commercial customers to contract with WE to build renewable generation facilities to offset their energy use and then receive a share of the proceeds from the electricity generated. The other proposal, Solar Now, will allow the utility to install up to 35 MW of solar panels on customers' properties. WE would own the panels, but it would pay customers monthly based on how much electricity the facilities produce.

Solar Now is "a reasonable way for them to assist their customers," Commissioner Mike Huebsch said. "I think this opportunity that the company is providing … is a unique way of finding out if we are going to be able to effectively provide solar arrays within cities."

More: *Wisconsin State Journal*