RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

ISSN 2377-8016 : Volume 2019/Issue 29 July 23, 2019

FERC Heaps Praise on Departing LaFleur

The meeting room was nearly full as many former LaFleur staff attended in her honor. | © *RTO Insider*

By Michael Brooks

WASHINGTON — Current and former colleagues gathered at FERC headquarters Thursday to praise departing Commissioner Cheryl LaFleur.

As the commission does not hold open meetings in August, Thursday marked LaFleur's last as a sitting commissioner before her term ends Aug. 31. When it does, she will have served 3,336 days, according to Chairman Neil Chatterjee, making her the second-longest serving commissioner in the agency's history (519 days short of William L. Massey, who served from 1993 to 2003).

"Rare are those who ... through grace, logic and verve make a genuine difference," said former

Continued on page 5

FERC Reduces MBRA Data Requirements (p.6)

FERC Clears MISO 2015/16 Auction Results

By Amanda Durish Cook and Rich Heidorn Jr.

In a decision marked by minor controversy, FERC on Thursday capped a three-year-old investigation into MISO's 2015/16 Planning Resource Auction by finding no market manipulation on Dynegy's part.

The commission also found the $150/MW-day clearing price in Southern Illinois' Zone 4 was just and reasonable, despite ordering MISO to change capacity auction rules following the auction. Thursday's order also declined to set up an evidentiary hearing to possibly recalibrate the auction results (*EL15-70*).

The investigation centered on an auction in which Zone 4 *cleared* at $150/MW-day, a ninefold price increase compared with just $16.75/MW-day a year earlier. MISO's other nine local resource zones cleared below $3.50/MW-day that year.

Complaints followed swiftly, questioning the justness of Zone 4 prices, and included then-Illinois Attorney General Lisa Madigan, Southwestern Electric Cooperative, Illinois industrial energy consumers and the public interest group Public Citizen. All questioned Dynegy's market behavior because the company controlled a significant portion of the capacity available in Zone 4. (See *FERC Launches Probe into MISO Capacity Auction*.)

Two years before the auction, Dynegy acquired from Ameren four coal-fired generators in Zone 4 with a total installed capacity of more than 3 GW. At the time of the transaction, Dynegy's market share in MISO's capacity market was analyzed on a systemwide basis — rather than at the zonal level — because the 2013/14

Continued on page 19

Also in this issue:

ERO Insider

ERO Insider's website is now live! And for a limited time, access is free. Here are just a few of the stories we published this week:

Con Ed: Failed Relay Protections Caused NYC Blackout

NARUC Offers Tools for Measuring Cybersecurity

U.S. House Takes on Grid Security

ERO Budget Nears OK Despite Canada's Concerns

SPP Western Reliability Briefs: July 16-17, 2019

Check it out at *www.ero-insider.com*

10837 Deborah Drive ▪ Potomac, MD 20854 ▪ (301) 299-0375 ▪ info@rtoinsider.com ▪ www.rtoinsider.com

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
Christen Smith 717-439-1939

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions

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

Sales Director
Marge Gold 240-750-9423

Account Manager
Martha Patterson

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

2019 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,450
Newsletter PDF Plus Web	$2,000

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

In this week's issue

Stakeholder Soapbox

PJM's Market Design is Hurting Clean Energy

By Miles Farmer and Amanda Levin

PJM is lagging other regions in addressing carbon emissions and has added significantly more fossil generation than any other grid operator in the U.S. In a *recent analysis*, we argued that PJM's market design plays an important role in the build-out of fossil-fueled power plants, and market reform is needed for the cleaner energy future that states and customers in the RTO demand.

Steve Huntoon's response (See *Counterflow: Scary Wrong*.) is a collection of distractions from our central concern: PJM's gas boom will break the "carbon budget" for the region, making it impossible to reach emissions goals. Market structures are a significant factor in determining the energy mix and investments made in a region. PJM's capacity market, in particular, is built around the characteristics of fossil-fired plants, procures too much capacity and blunts market signals that could drive the expansion of clean energy resources such as wind and solar.

Gas Won't Save Us

Huntoon suggests that coal-to-gas switching must continue. This is not a climate solution for the region: Retiring coal must be replaced with zero-emission energy sources. Simply replacing remaining coal with gas will not extend the emission reductions PJM has achieved in the past decade. Even as coal-fired power continued to decline last year, carbon pollution in the region (and nationwide) increased year over year in 2018 as natural gas consumption and generation reached new highs. This is projected to continue in the U.S. government's own most recent energy outlooks. (See the Energy Information Administration's *2019 Annual Energy Outlook*). Even as coal retires across PJM, emissions in the region will plateau in the coming years under a business-as-usual, high-natural-gas scenario.

This is not a climate-safe future. While the reductions PJM has achieved so far from coal-to-gas switching are roughly consistent with a 1.5 or 2-degree Celsius warming trajectory, they will not continue without focused efforts to deploy zero-carbon resources.

PJM's market has worked well for gas but poorly for other technologies. A new formula is needed to push the region past gas and achieve reductions in line with a net-zero future.

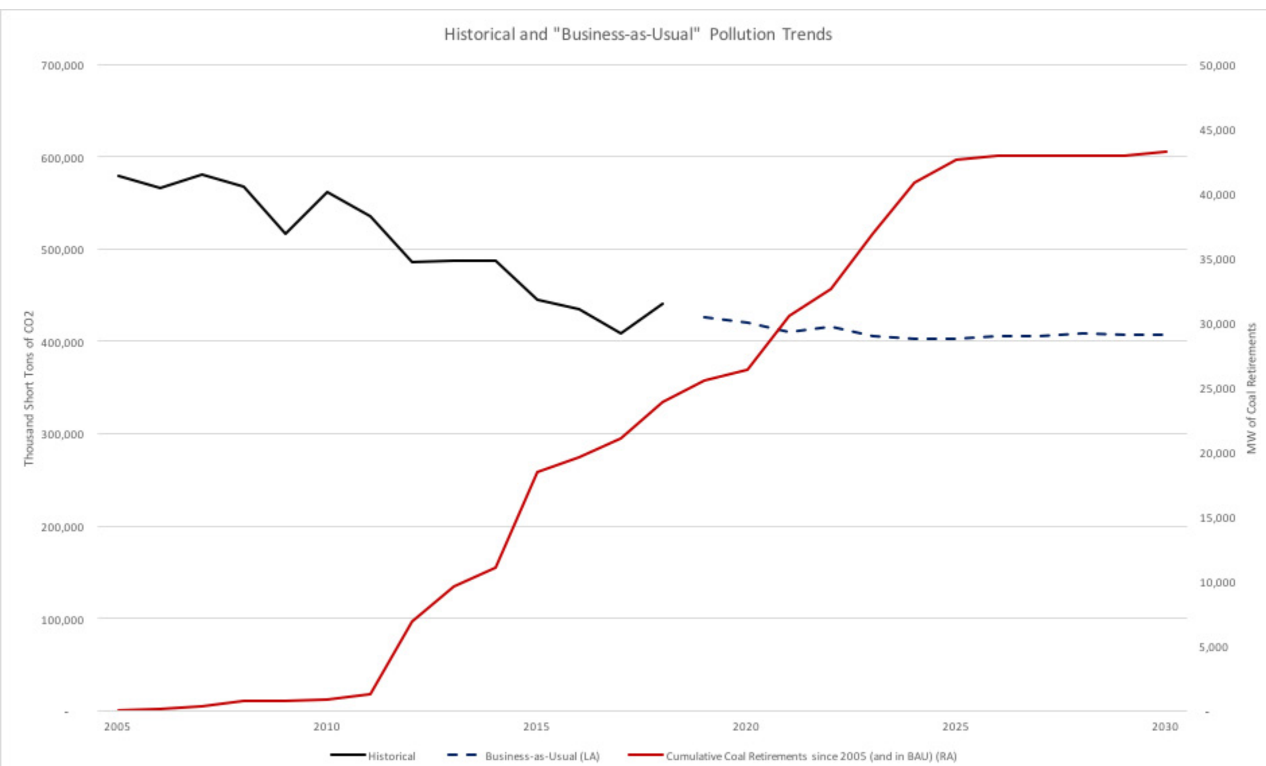
PJM's Capacity Market is Flawed

Many factors influence a region's energy mix, including market rules, as well as state policies and renewable resource potential (i.e. how strong the winds are or how often and powerful the sun shines). We agree with Huntoon that other RTOs, like ERCOT in Texas, were dealt a better hand to play than PJM when it comes to renewable resource quality. Even so, it is clear that PJM's capacity market design over-procures fossil capacity and blunts clean energy investment.

As we explained in our article, PJM is procuring vastly more capacity than reliability regulators have deemed necessary to keep the lights on.

One reason for this is that PJM has failed to implement a seasonal market and thereby fails to fully leverage resources like demand response, solar and wind. Aggregation fails to address the real issue that the region has different needs in summer and winter.

Huntoon contends that prices would be the same in any case, as "there is no free lunch." But PJM's current construct essentially forces all customers to buy a heaping dinner portion even at breakfast time, when they aren't very



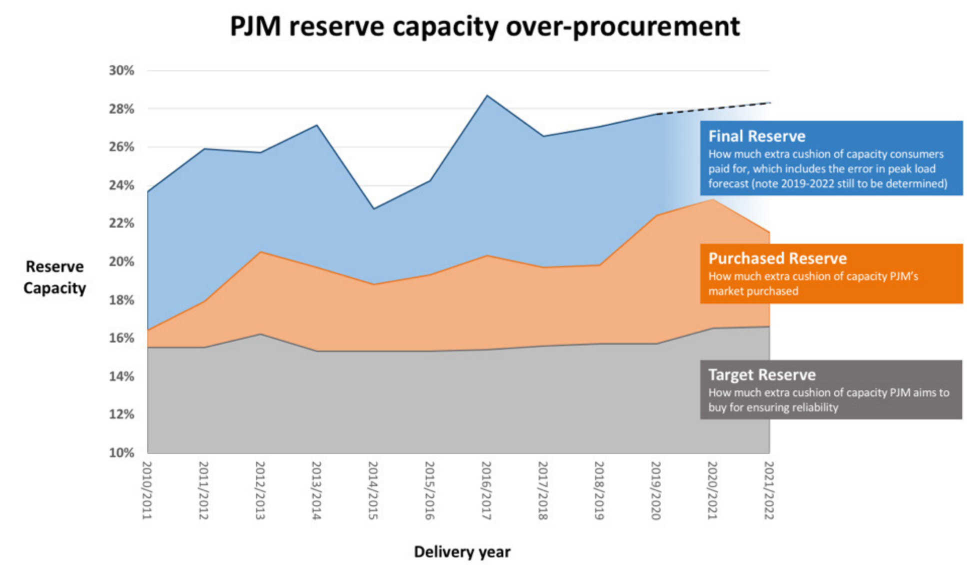
| Historical data from S&P Global Market Intelligence; Projections derived from U.S. EIA's Annual Energy Outlook 2019

Stakeholder Soapbox

hungry, and makes it very costly for chefs to include any menu options other than foods that can be served for both meals. The Brattle Group *estimated* that separate procurement periods would push costs down by roughly $100 million to $600 million per year.

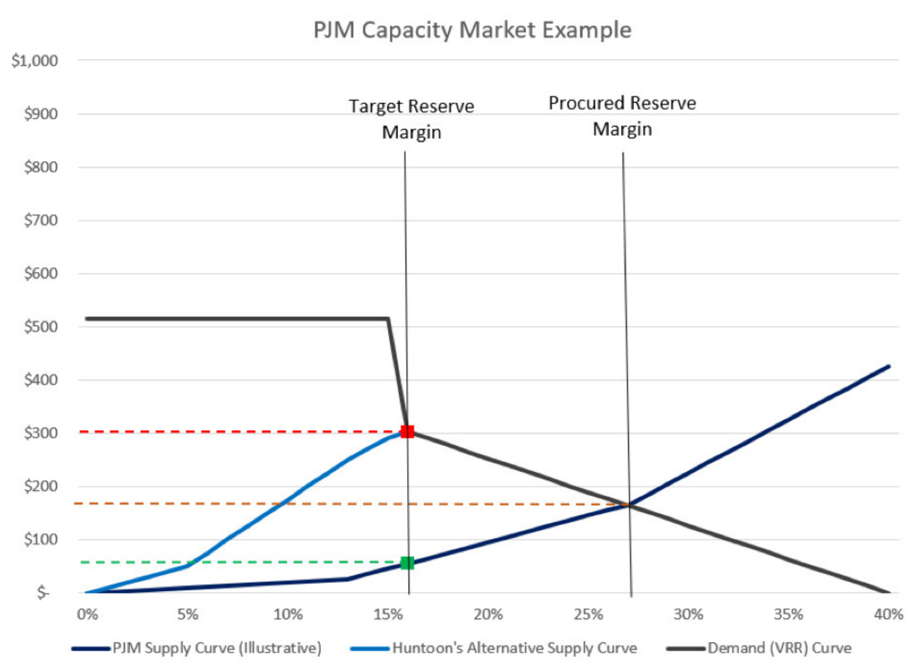
In addressing our point that PJM's over-procurement has been costly to customers, Huntoon proposes his own free lunch, contending that our simple intuition that buying more stuff costs more money "profoundly misunderstands" the capacity market. His logic on this point is circular. Huntoon explains that if capacity suppliers had offered higher prices (high enough that PJM wouldn't want to over-procure supply), costs would have been higher.

This is a faulty counterfactual. If PJM were to just procure the capacity necessary to serve a lower reserve margin (and then stop procuring additional "low-cost" capacity that has bid in), the market would actually see lower clearing prices. Our point is not that PJM should switch to a vertical demand curve (which has other downsides), but rather that after procuring significantly more than its target year after year after year, it is clear that PJM has based its demand curve on erroneous inputs and the overall market construct needs to be reassessed.



| *PJM Base Residual Auction & Reserve Requirement Study Reports*

PJM's unwillingness to leverage seasonal resources and persistent over-procurement mean more money is gained from the region's capacity markets, distorting energy and ancillary markets. Unlike in the rest of the country, renewable resources are largely excluded from resource adequacy planning and are left to compete against heavily subsidized fossil fuel plants in energy markets. In contrast to PJM's capacity market, wind and solar resources compete in the energy and ancillary services markets on equal footing, as those markets are not defined by administrative criteria.



In Steve Huntoon's calculation, he assumed supply bid prices were high enough that PJM would not procure beyond the target reserve (red dot). However, if PJM were to just procure the capacity necessary to serve the target reserve margin (and not procure additional "low-cost" capacity), the market would actually see lower clearing prices (green dot).

PJM Can Change Course

Fighting climate change will not be easy. Large, integrated, efficient markets are an essential tool in this fight. But those markets must not create barriers to clean resources or climate policy. Critically, those markets must not be dominated by administrative constructs where incumbent market participants fight over hidden subsidies and create barriers to competition.

Highlighting the consequences of overbuilding gas does not ignore that the region has not been blessed with the same renewable resources as other areas of the country. PJM's rules play an important role in determining the future resource mix. The recent leadership change at PJM provides the grid operator with an ideal opportunity to shift course, allowing them to better respond to the demands of customers and states, reverse its trend of capacity over-procurement, and better integrating state clean energy policies into a reliable and clean energy future for the region. ■

Miles Farmer is a senior attorney and Amanda Levin is a policy analyst in the Climate & Clean Energy Program of the Natural Resources Defense Council.

FERC Heaps Praise on Departing LaFleur

Continued from page 1

Commissioner Marc Spitzer, one of 12 she served with during her tenure. "That's Cheryl LaFleur."

She was also the longest serving chairman, with 704 days at the helm, Chatterjee said, including two stints as acting chair. During the meeting, LaFleur stacked her three nameplates — chairman, acting chairman and commissioner — in front of her.

LaFleur arrived first among her colleagues to the hearing room, where a packed audience with few open seats awaited her. The meeting began slightly late; it was only until Chatterjee walked in with Commissioners Richard Glick and Bernard McNamee right behind him that it became apparent why. Each wore a Boston sports jersey in imitation of LaFleur's tradition of supporting her teams during playoff runs: Patriots for Chatterjee, Red Sox for Glick and Celtics for McNamee.

After the meeting's official proceedings, Chatterjee brought forward Spitzer; former Montana Public Service Commission Chairman Travis Kavulla; Jamie Simler, former director of the commission's Office of Energy Market Regulation; and LaFleur legal adviser Steven Wellner. Along with her current colleagues, they all praised LaFleur as wise, gracious and having a good sense of humor.

"She's one of the funniest people I've ever met and always has a story or analogy for pretty much any occasion," Wellner said.

Simler choked up as she spoke about how supportive LaFleur is of her staff, especially during the quorum-less period in the early days of the Trump administration, in which she was eventually the only commissioner at the agency. (See *LaFleur Recounts Turbulent Tenure at FERC*.) "No matter what your title was, we had the security of knowing that you cared ... about the agency, the staff, the decisions and getting things right, or as close to right as possible."

Chatterjee also praised her for leadership during the period. After serving as chair, "I now have a greater appreciation for how difficult a period that must have been, not just because of the stress of the backlog that was accruing, but just maintaining morale among our wonderful staff," he said.

"You're the embodiment of what it means to be not only a good regulator, but a good person," McNamee said. "Washington will be something less because you're not a part of it."

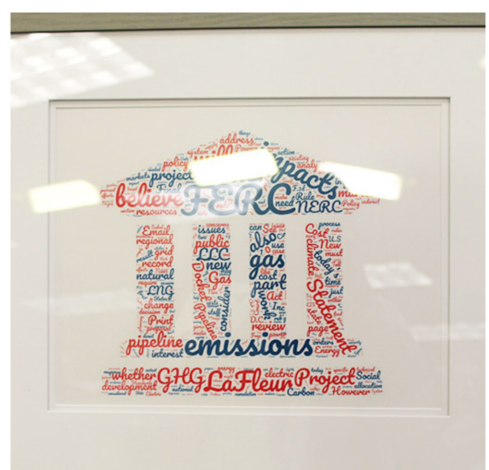
LaFleur thanked all her current and former staff members, many of whom were in the audience, and called her time at FERC "the most rewarding professional experience of my life."

Chatterjee handed her the gavel to close out the meeting one last time. ■

Chairman Chatterjee presents LaFleur with a farewell gift. | *Federal Energy Regulatory Commission*

Commissioners Bernard McNamee, Cheryl LaFleur, Neil Chatterjee and Richard Glick | *Federal Energy Regulatory Commission*

Chairman Neil Chatterjee invited (from left to right) former Montana Public Service Commission Chairman Travis Kavulla; former FERC Commissioner Marc Spitzer; and Jamie Simler, former director of the commission's Office of Energy Market Regulation, to speak. | © *RTO Insider*



Commissioner Richard Glick's farewell present to LaFleur was a word cloud representing the more than 50,000 words she has spoken and written, as documented on the FERC website. | © *RTO Insider*

FERC Reduces MBRA Data Requirements

Glick Balks on Connected Entities

By Michael Brooks

FERC Commissioner Richard Glick (right) differed with Chairman Neil Chatterjee over proposed rules regarding connected entities. | © *RTO Insider*

WASHINGTON — FERC on Thursday adopted two new rules intended to reduce paperwork for electricity sellers with market-based rate authority (MBRA), acting on a proposal issued more than three years ago (Order 860, *RM16-17*).

Currently, sellers are required to describe the activities of all their upstream owners, often requiring them to submit multiple amendments to their filings. Once the new rule goes into effect on Oct. 1, 2020, sellers will only need to identify their "ultimate" upstream affiliate — the furthest upstream owner.

Sellers will also no longer be required to report assets — such as generators and long-term power purchase agreements — owned by its affiliates with MBRA. They will also no longer have to submit corporate organizational charts. They will, however, be required to report assets owned by affiliates without MBRA, as these are relevant to the seller's market power analysis, the commission said.

FERC will collect all seller information through a relational database to be created by the order.

"The relational database construct modernizes the commission's data collection processes, eliminates duplications and renders information collected through its market-based rate program usable and accessible for the commission," FERC said.

Connected Entity Info Tossed

Under the proposal, sellers would have had to identify all affiliate owners with franchised service areas or MBRA, or that directly own or control generation; transmission; intrastate natural gas transportation, storage or distribution facilities; coal supply sources; or access to transportation of coal supplies.

Collectively known as connected entity information (CEI), this new class of information was panned by market participants in late 2015 and again in response to FERC's proposed 2016 revision. (See *FERC Issues Revised Connected Entity, Data Collection Proposal*.)

Speakers at a 2015 technical conference and commenters on the proposal said it would create significant reporting burdens.

On Thursday, FERC declined to adopt the CEI provision, instead opening a new docket (AD19-17) "should the commission wish to consider this again in the future," staff said.

This move was strongly criticized by Commissioner Richard Glick, who issued a partial dissent. "I'm really having a hard time figuring out how that's any different from killing the proposal altogether, and that's what I'm very much troubled by," he said at the commission's open meeting Thursday.

"In my opinion, through its actions today, the commission is dropping the ball to the detriment of consumers across the country," he continued. He called CEI "critical" to preventing market manipulation and the exercise of market power. "What I want to know is, why was this information no longer considered to be necessary, or [do] we simply no longer care about how we're addressing market manipulation?"

FERC also dropped the proposed requirement that traders of financial transmission rights and virtual products also submit affiliate information, which Glick also criticized.

"Virtual/FTR participants are very active in RTO/ISO markets, and surveilling their activity for potentially manipulative acts consumes a significant share of the Office of Enforcement's time and resources," Glick said in his dissent. "It may, therefore, be surprising that the commission collects only limited information about virtual/FTR participants and often cannot paint a complete picture of their relationships with other market participants."

He pointed to the Order to Show Cause issued this month to Federico Corteggiano, whom Enforcement alleged manipulated CAISO's market to limit losses on Vitol's congestion revenue rights. Enforcement said Corteggiano engaged in similar behavior while employed by Deutsche Bank. (See *FERC Proposes $6.8M Fine for CAISO Market Manipulation*.)

"Without the connected entity reporting requirements contemplated in the [proposal], the commission lacks any effective means of tracking individuals who perpetrate a manipulative scheme at one entity and then move locations and engage in similar conduct elsewhere, as Corteggiano is alleged to have done," Glick said. "That makes no sense. We should not be leaving the Office of Enforcement to play 'whack-a-mole,' addressing recidivist fraudsters only when evidence of their latest fraud comes to light."

"I know that there are some who will construe our decision not to move forward with the connected entities proposal as a lack of commitment to our Enforcement program," Chairman Neil Chatterjee said before Glick spoke at the meeting. "To anyone with that misconception, let me be clear: Robust enforcement of our orders and regulations is and will remain one of the commission's most critical objectives."

Speaking to reporters after the meeting, Chatterjee said, "I respect Commissioner Glick, but I disagree with the point that he made. I think it's a matter of good governance. We were ready to move forward with a piece of it; we

FERC/Federal News

weren't ready on the connected entities part, so rather than hold up the MBR piece, which has been out there for three years, we moved forward with it." He also said he didn't think "it was a fair characterization" to say that opening the new docket ends the process.

The order is "a critical step in our ongoing efforts to modernize and, where possible, streamline the MBR program to ensure that we have the information we need to evaluate market power while not unduly burdening market participants," Commissioner Cheryl LaFleur said. "I recognize that these reforms do not address all the issues the connected entities proposal would have covered, particularly with respect to financial market participants and traders. I made the pragmatic decision that it was important to move forward on the MBR improvements that have been held up for three years due to being placed in the same [proposal] as the connected entities."

Commissioner Bernard McNamee did not participate in the ruling.

Screens Eliminated for 4 RTOs

FERC also approved eliminating the requirement for power sellers with MBRA to submit pivotal supplier and wholesale market share screens in PJM, ISO-NE, MISO and NYISO (Order 861, *RM19-2*). FERC will now presume that the grid operators' commission-approved monitoring and mitigation rules provide adequate protection against market power abuse.

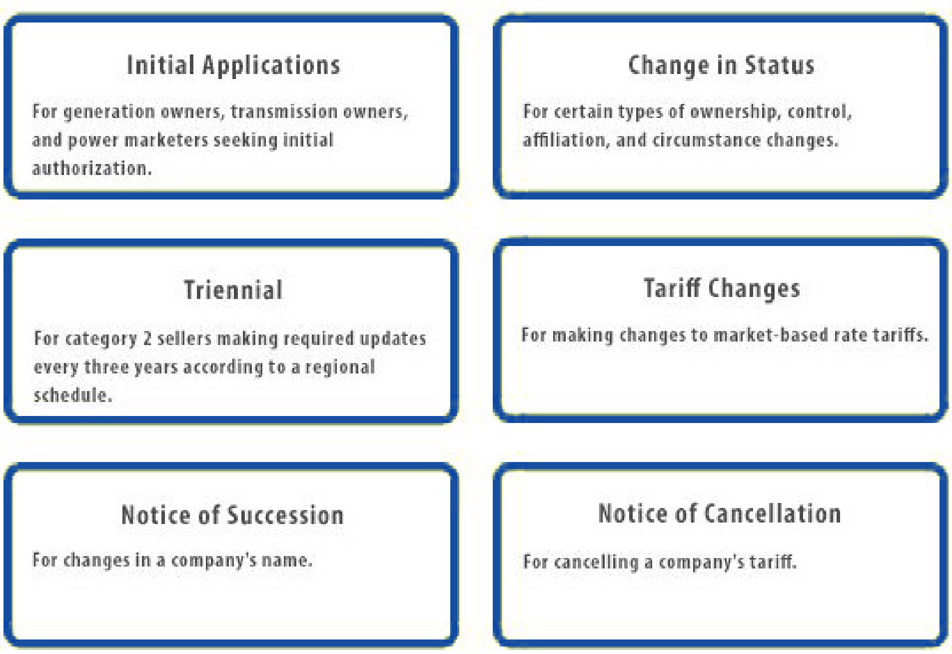
"Robust enforcement of our orders and regulations is and will remain one of the commission's most critical objectives."

— Chairman Neil Chatterjee

MBR sellers of capacity in SPP and CAISO, which do not have capacity markets, will still need to submit the screens. The order's relief also does not apply to any participants in CAISO's Energy Imbalance Market.

Effective 60 days after its publication in the Federal Register, the order's relief would begin with MBR sellers scheduled to file their triennial updates for the Northeast region in December 2019 and June 2020, commission staff said.

Sellers filed almost 600 indicative screens over the last three years, according to staff. Once the rule goes into effect, sellers would be relieved of submitting more than half of those screens, they said.



Types of market-based rate authority filings. | *FERC*

FERC clarified certain details about its initial proposal, issued last December, but it did not decline to adopt or alter any of its provisions. (See *FERC Proposes Market Screen Exemptions*.) Though paired with RM16-17 for discussion at Thursday's open meeting, it received little mention in comparison.

Rehearing Denied on Interlocking Directors

In a third ruling, the commission denied rehearing but made one clarification on its February order updating its regulations on commission authorization of interlocking positions between public utilities and financial companies. (Order 856-A, *RM18-15-001*). The revised rule provides an exemption for some applicants for interlocking positions between utilities and companies that underwrite public utility securities. (See "Other Rules," *'Boring Good' Rulemaking Seeks to Clean up Order 845*.)

The commission denied El Paso Electric's rehearing request that FERC grant equal treatment to all interlocks authorized under section 45 of its regulations.

"The commission has recognized a difference between holding interlocks among two or more commonly owned or controlled public utilities, and holding an interlock between, for example, a public utility and an electrical equipment supplier," FERC said. "Interlocks that fall under section 45.2 and are not between two or more commonly owned or controlled public utilities (and therefore are outside the scope of section 45.9a) are reviewed by the commission so that the commission can be sure that the 'evils to be eliminated by the enactment of [Federal Power Act] Section 305b' are not present. By contrast, for interlocks that fall under section 45.9a's automatic authorization, the commission has found that the evils to be eliminated by the enactment of Federal Power Act Section 305b are not present because the potential for abuse would be unlikely to result from such interlocks."

The commission did grant a clarification on another question raised by EPE, saying that "if, as a result of the change in FPA Section 305b(2) in 1999 and the corresponding changes to section 45.2 of the commission's regulations made by Order No. 856, an individual no longer holds an interlock that requires commission authorization, that individual no longer needs to adhere to the requirements of [sections] 45 and 46 of the commission's regulations governing commission approval of such interlocks." ■

FERC/Federal News

States, Public Power Challenge FERC Storage Rule

By Christen Smith

State regulators, utilities and public power groups have asked the D.C. Circuit Court of Appeals to overturn part of FERC's landmark rulemaking on energy storage participation, challenging the commission's refusal to allow states to opt out.

The National Association of Regulatory Utility Commissioners petitioned to find that portions of Order 841 and its rehearing order (841-A) "are arbitrary and capricious" and "not in accordance with law." The Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association and American Municipal Power filed a separate petition July 15 also challenging the orders.

In a press release July 16, NARUC *said* it hopes states and relevant electric retail regulatory authorities (RERRAs) will be permitted to manage electric storage resources (ESRs) in the same way they oversee demand response aggregation. NRECA *told* the House Energy and Commerce Committee in June that FERC had overstepped its authority and local regulating authorities should be able to determine when and how ESRs join the marketplace.

In May, FERC ruled 3-1 to reject requests to allow RERRAs the ability to opt out of its storage provisions, as the commission did for DR under Order 719. Commissioner Bernard McNamee was the lone dissent. (See *FERC Upholds Electric Storage Order*.)

NARUC's criticism echoes comments from RTOs, utilities and states that said FERC's order exceeded the commission's authority. (See *States, Utilities, RTOs Push Back on Storage Order*.) Association spokeswoman Regina Davis said the group's petition won't impact implementation of new rules because no stay was requested. There is no official timeline for court action either, she said.

Energy storage in Minnesota | *Connexus Energy*

All six jurisdictional RTOs and ISOs are facing a December deadline for compliance with Order 841, which requires them to revise their market participation models to allow storage resources 100 kW and larger to provide capacity, energy and ancillary services within their technical ability. In April, the commission sought more information on the grid operators' plans that were submitted five months prior. (See *FERC Asks RTOs for more Details on Storage Rules*.)

Supporters of Order 841 said some of the submitted plans currently under review are impractical and burdensome.

Astrape Consulting released a *study* July 15 — funded by the Energy Storage Association and the National Resources Defense Council — that concluded PJM's proposal requiring a storage asset to run for 10 continuous hours in order to qualify its full output for the capacity market "is unnecessary and unduly restrictive."

"Energy storage is being installed on electric grids across the country at a rapid pace, helping transform our electric system to a more resilient, efficient, sustainable and affordable one," ESA CEO Kelly Speakes-Backman said. "We stand behind the leadership at FERC to modernize energy rules to enable this transition. This study clearly affirms FERC's judgment to include a broader set of technologies to participate, saving consumers money and supporting a diverse supply of clean energy generation."

PJM spokesman Jeff Shields on July 16 said the RTO is awaiting FERC's order on its Order 841 compliance filing. "Subject to FERC's order, we are planning to implement in December 2019 as Order No. 841 proposed," Shields said. "We will monitor any court developments in the meantime." ■

CAISO/West News

California Energy Summit Focuses on Wildfires

By Hudson Sangree

Marty Niles, Cantega Technologies | © *RTO Insider*

LOS ANGELES — To open his presentation at Infocast's California Energy Summit last week, Marty Niles, a veteran lineman and founder of Cantega Technologies, played a clip from the quiz show "Jeopardy!"

The deputy director of the National Security Agency said the No. 1 threat to the U.S. electrical grid came from these climbing rodents, host Alex Trebek said.

"What are squirrels?" a contestant answered correctly.

Niles, whose company makes Greenjacket covers for electrical equipment, then showed a series photos and videos in which birds and animals had become trapped in substations, transformers and conductors, sparking fires and explosions. Greenjacket's covers could help prevent fires caused by animal damage, Niles said.

"We're just another tool in the toolbox with regard to the fire suppression effort," he said.

Niles' presentation was one of several talks at this year's summit that focused on the utility-sparked wildfires that have ravaged California in recent years. (See *Calif. Wildfire Relief Bill Signed After Quick Passage*.)

The California Energy Summit in Los Angeles drew representatives from industry, academia and nonprofits July 16-18. | © *RTO Insider*

Microgrids and Wildfires

In a panel on wildfire prevention, panelists discussed the need for microgrids to maintain essential services — such as emergency shelters at schools — during incidents in which the main power supply was switched off or damaged.

Craig Lewis, executive director of the nonprofit Clean Coalition, said smaller-scale grids powered by renewable energy are essential, with California facing greater threats from massive fires fueled by climate change.

In the fire-prone Santa Barbara area, he said, electric infrastructure is crucial for pumping water uphill from coastal areas to battle mountain blazes.

"That water is absolutely critical for fighting fires," he said.

Tim Hade, co-founder and COO of Scale Microgrid Solutions, said California is "on the path to having the most expensive and least reliable electricity in the United States" because of the wildfire threat.

Utilities have been using public safety power shutoffs to prevent their equipment from sparking fires during periods of low humidity and high winds.

With power shut off to entire communities, having microgrids as backup is crucial, Hade and others said. Those who depend on medical devices, for instance, can't go without electricity.

"We need to reinvent electricity," Hade said. "That's the challenge."

Inspecting Poles and Undergrounding Lines

On the same panel, Sumeet Singh, vice president of Pacific Gas and Electric's community wildfire safety program, said the bankrupt company has been making strides to head off wildfires before they start.

The company is widely blamed for causing the Camp Fire, which burned much of the town of Paradise in November, killing 85 people. PG&E equipment also sparked devastating wildfires in Northern California's wine country in 2017 and in the Sierra Nevada foothills in 2015, the California Department of Forestry and Fire Protection has said.

PG&E declared bankruptcy in January, citing billions of dollars in fire liability. (See *PG&E's Bondholders Push $30 Billion Investment Plan*.)

The company recently issued a *press release* outlining the accomplishments of the program Singh heads. They included visual inspections of 96% of about 50,000 transmission structures in high fire-risk areas, the utility said. The company also said it had inspected 222 substations and nearly all its 700,000 distribution poles in high-risk fire areas.

PG&E has installed 430 weather stations since 2018, including 231 so far this year, it said.

In Paradise, PG&E is undergrounding new power lines where it makes most sense, Singh said. It's also replacing wooden poles with composite structures. During the fast-moving Camp Fire, wooden poles toppled, blocking escape routes for some who died.

"I wish we could say undergrounding is a panacea," Singh said. But it's costly and time consuming, and while 1 mile of conductor is being undergrounded, many other miles of line remain at risk.

Another panelist, Diane Moss, founder and director of the Renewables 100 Policy Institute, said her friends from Germany were amazed to see overhead power lines in California that "reminded them of Africa." Germany undergrounded most of its lines after World War II, she said.

"Are we going to have to wait to do that?" Moss asked.

Abe Powell, chairman of the Montecito Fire Protection District Board, said he understood undergrounding 200 miles of line in Paradise would cost about $1 billion. Montecito, near Santa Barbara, was ravaged by the Thomas Fire in late 2017 and ensuing mudslides in early 2018. The death toll was 23. Southern California Edison has admitted at least partial responsibility. (See *Edison Takes Partial Blame for Wildfire in Earnings Call*.)

Powell, however, questioned whether undergrounding lines for one community is the best use of $1 billion.

"We haven't thought this through all the way," he said. ■

(Left to right) Tim Hade, Scale Microgrid Solutions; Craig Lewis, Clean Coalition; and Diane Moss, Renewables 100 Policy Institute, examined wildfire prevention and mitigation. | © *RTO Insider*

CAISO/West News

PG&E Deserves $30M ISO Adder, FERC Says

FERC Rejects CPUC Argument that CAISO Participation is Mandatory

By Hudson Sangree

Despite a rebuke from a federal appeals court, FERC last week reaffirmed its earlier decision that Pacific Gas and Electric participates voluntarily in CAISO and qualifies for hefty financial incentives to remain in the ISO (*ER14-2529-005*).

The decision came after the 9th U.S. Circuit Court of Appeals instructed FERC in January 2018 to reassess its longstanding practice of granting an annual 50-basis-point return on equity adder to encourage PG&E to be part of CAISO. The incentive earns the currently bankrupt utility about $30 million a year.

In response to the court's ruling, FERC instructed PG&E, the California Public Utilities Commission and other interested parties to brief it on the issue of whether PG&E could leave CAISO if it chose. (See *Can PG&E Quit CAISO? FERC Wants to Know*.)

FERC had concluded in late 2017 that participation in the ISO was voluntary. The commission decided Thursday it had been right all along.

We "find that California law does not mandate PG&E's participation in CAISO, and that the RTO participation incentive induces PG&E to continue its membership," FERC wrote. "We therefore reaffirm the commission's prior grant of PG&E's request for the RTO participation incentive."

FERC said PG&E can get an incentive adder for remaining in CAISO, headquartered in Folsom, Calif. | *© RTO Insider*

Mandatory or Voluntary?

The controversy over whether PG&E and other utilities are entitled to the incentive payments has been going on for years.

In the Energy Policy Act of 2005, Congress amended the Federal Power Act to require FERC to provide financial incentives to induce utilities to join RTOs.

FERC responded in 2006 with Order 679, which provided ROE adders for utilities that participate in transmission organizations. The bonuses were meant to give utilities an extra reason to join or remain members of RTOs, which are generally voluntary.

For staying in CAISO, PG&E has requested and received adders under Order 679 since 2007.

The CPUC, however, argued that membership in CAISO is mandatory for the state's three big investor-owned utilities: PG&E, Southern California Edison and San Diego Gas & Electric. It protested in years past and again in November 2017, saying the adder for PG&E was an "unjustified windfall" at the expense of California ratepayers. The Sacramento Municipal Utility District joined the protest.

FERC dismissed the objections, but on appeal, a three-judge panel of the 9th Circuit ruled FERC commissioners had abused their authority. The commission, the court said, did not reasonably interpret Order 679 as justifying adders for remaining in a transmission organization. Instead, the commission created a generic adder in violation of the order, the judges ruled.

"Order 679 says FERC 'will approve, when justified, requests for ROE-based incentives for public utilities that join and/or continue to be a member of' transmission organizations," the court noted.

"If all utilities that continued to be members of transmission organizations automatically qualified for incentive adders, the 'when justified' language would be surplusage," it said.

FERC Erred, CPUC Argues

On remand from the appeals court, FERC asked the parties to brief it on four issues, including whether California law requires PG&E to participate in CAISO and whether FERC must defer to the CPUC's interpretation of state law.

CAISO/West News

PG&E, SCE and SDG&E responded in September and October 2018, supporting PG&E's contention that participation in CAISO is voluntary and that the incentive adder is justified to encourage them to remain CAISO members.

In addition, PG&E's participation in CAISO is governed by the Transmission Control Agreement (TCA) between the ISO and transmission owners, whose assets the ISO controls, SCE and SDG&E said in their *joint brief*. Only FERC has authority over the TCA, they argued.

"The TCA is a filed rate subject to the exclusive jurisdiction of [FERC] and explicitly allows PG&E to withdraw from the CAISO. California lacks jurisdiction to alter the terms of the TCA," the utilities argued.

The CPUC, the Sacramento Municipal Utility District and the Transmission Agency of Northern California (the "California parties") filed joint briefs. They *argued* FERC had misinterpreted the 9th Circuit's decision, which they said directed FERC to correct its own errors, not to undertake further inquiries.

Moreover, state law governs the dispute, and FERC is obligated to show deference to the CPUC, they contended.

"The California parties respectfully request that the commission conclude that PG&E does not qualify for the transmission organization membership incentive ... because the CPUC has demonstrated that PG&E's continued CAISO membership is not voluntary because it is required by state law," they wrote.

FERC Decides It Was Right

FERC disagreed that the 9th Circuit had only wanted the commission to correct itself.

The "California parties erroneously assume that the 9th Circuit found that California law mandates PG&E's ongoing participation in CAISO," it said.

The commission also rejected contentions that state law alone governed the matter.

"As a creature of federal statute created by Congress, this commission's subject matter jurisdiction over proceedings before it arises solely under the acts that the commission is required to administer," it said. "Specifically, the issue here involves the transmission and sale at wholesale of electric energy in interstate commerce, over which the FPA provides exclusive jurisdiction to this commission."

Finally, FERC said PG&E and was free to leave CAISO. No California law prevented it from doing so, FERC concluded, and PG&E could reclaim control of its transmission grid from the ISO without CPUC approval.

"As the commission explained in Order No. 679, the basis for the RTO participation incentive is a recognition of the benefits that flow from RTO/ISO membership and the fact continuing membership is generally voluntary," FERC wrote.

"In light of the voluntary nature of RTO/ISO membership from the commission's perspective and the lack of any relevant mandate under California law, we find that PG&E could unilaterally leave CAISO without obtaining CPUC authorization," FERC said. "Consequently, we find that the RTO participation incentive induces PG&E to remain a participating member of CAISO ... [and] we reaffirm the continuation of PG&E's 50-basis-point ROE adder."

The transmission trade group WIRES praised the ruling, saying it "clearly complies with the congressional mandate for FERC to provide incentives for public utilities for their participation in RTOs and ISOs." ■

ERCOT News

Texas PUC Briefs

PUC Defers Day-ahead Actions for RTC Implementation

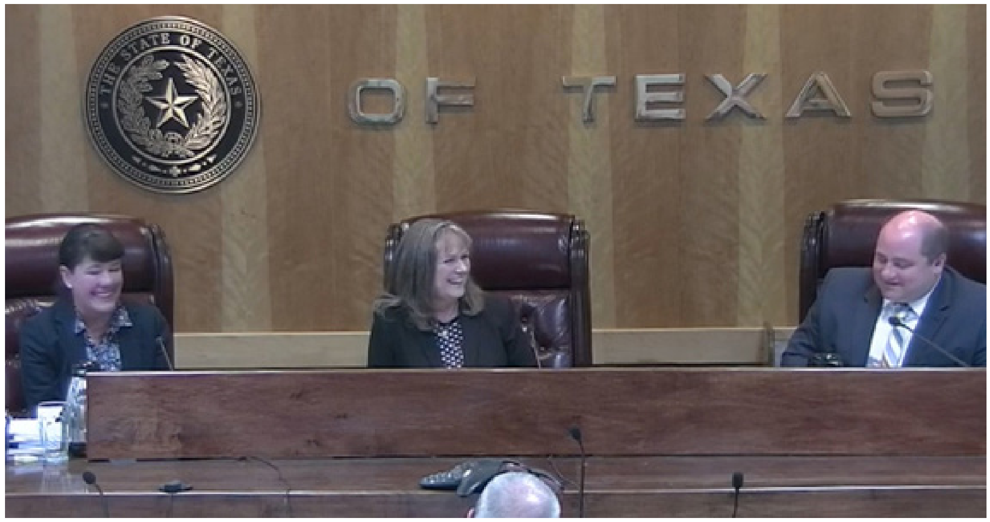
Texas regulators last week postponed action on improvements to ERCOT's day-ahead market (DAM), citing potential delays to implementing the real-time co-optimization (RTC) of energy and ancillary services (*48540*).

During the Texas Public Utility Commission's open meeting Thursday, PUC Chair DeAnn Walker said she had met with ERCOT staff earlier in the week. Walker said she was told that incorporating DAM improvements along with RTC would cause a two-year delay in the latter's implementation.

"ERCOT told me there would be a delay in opening the hood," Walker said. "Fixing [the DAM] at the same time doesn't fit in there. I'd rather have them focusing on real-time co-optimization than coming up with a solution on this."

ERCOT *says* it could deploy RTC by mid-2024, keeping it on the same timeline with upgrades to the grid operator's core energy management system. (See *ERCOT Real-time Co-optimization Falls into Place*.)

Walker said delaying day-ahead improvements would give ERCOT's market participants and the Independent Market Monitor time to determine how they want to move forward.



From left, Commissioner Shelly Botkin, Chairman DeAnn Walker and Commissioner Arthur D'Andrea

"This is not anywhere close to being thought through," she said. "I think they can do this in the regular stakeholder process."

Rate Case Recovery Remanded Back

The commission *remanded* back to docket management Southwestern Electric Power Co.'s request to recover $3.9 million in rate case expenses, asking the parties involved to seek a settlement (*47141*).

Walker told fellow Commissioners Arthur D'Andrea and Shelly Botkin she has long been concerned with the methods used by utilities to recover rate case expenses.

"We would be approving ratepayer expenses that have nothing to do [with the case]. To me, they seem to be the cost of doing business," Walker said. "The goal by utilities is to recover every single penny over a period of time. If that's the goal, then we have to start seriously looking at the risks involved when setting their [returns on equity]."

Commission staff, SWEPCO, the municipal group Cities Advocating Reasonable Deregulation (CARD), the Office of Public Utility Counsel and Texas Industrial Energy Consumers had reached a settlement over rate case expenses incurred through June 30, 2018, in dockets 46449 and 48233.

The commission's remand asked the parties to reach an agreement that will "fully and finally resolve all issues concerning SWEPCO and CARD's rate case expenses." If they are unable to do so, they will request that the case be sent to the State Office of Administrative Hearings for a hearing.

SWEPCO, Entergy Get TCRF Approvals

The PUC approved transmission-cost recovery factor (TCRF) modifications for SWEPCO (*49042*) and Entergy Texas (*49057*). The changes will result in TCRF annual revenue requirements of $11.5 million for SWEPCO and $2.7 million for Entergy. ■

— Tom Kleckner

PUC adviser Stephen Journeay

NEPOOL RC/TC Briefs

Regional Network Service Rates Update

STOWE, Vt. — Mary Bimonte of Eversource Energy on July 16 presented a joint meeting of the New England Power Pool Reliability and Transmission committees with an *overview* of the regional network service (RNS) rates that became effective June 1.

Bimonte, a member of the Participating Transmission Owners Administrative Committee, showed the RNS rate increased $1.51/kW-year from last year to $111.94/kW-year, with the region's aggregate annual transmission revenue requirement (ATRR) rising $41.3 million to nearly $2.19 billion.

Eversource subsidiaries Public Service Company of New Hampshire, NSTAR West and NSTAR East accounted for much of the ATRR increase, along with Vermont Transco and Maine Electric Power.

During a presentation of the five-year RNS rate *forecast*, Bimonte noted this year's increase was 67 cents/kW-year short of projections made last year for 2019.

Modifying Interconnection Procedures

ISO-NE Director of Transmission Strategy and Services Al McBride led a discussion of *proposed* modifications to interconnection procedures — specifically, Planning Procedure No. 10 sections 7.7 and 7.8 — to clarify adjustments to interconnection capability following partial market exits.

According to the RTO's market *procedures*, "permanent and retirement delist bids can be submitted for all or just a portion of a resource's capacity. A partial delist bid allows a resource to remove the portion of its megawatts it cannot deliver from all ISO-NE markets or only the capacity market, depending on the type of delist bid submitted."

"When a partial retirement delist bid clears in the Forward Capacity Auction, the resource remains active and its interconnection rights are reduced to the appropriate megawatt level," according to the RTO. "When a partial permanent delist bid clears in the FCA, the qualified capacity value for the resource is reduced."

In February, the NEPOOL Participants Committee approved the general changes, which include methodologies to update the levels of interconnection service available for generators (and external elective transmission upgrades) after the clearing of a retirement delist bid, permanent delist bid or substitution auction demand bid in the Forward Capacity Market.

The RC and TC will alternately discuss the specific proposed revisions ahead of a planned vote by the PC in November, with a tentative effective date of January 2020.

During the previous discussions, stakeholders identified circumstances where the winter capability of their generating facilities after a partial market exit may not be correctly calculated by the formulas currently contained in PP10, McBride said.

The RTO will propose a new section of the Tariff to capture the rules associated with the establishment and relinquishment of interconnection service amounts and plans to present the proposed revisions at the Aug. 21 TC meeting.

Eversource crews work to restore power following a Jan. 20 ice storm in Connecticut. | *Eversource Energy*

Operating Procedure Revisions

The RC voted to recommend that the PC support revisions to a handful of ISO-NE operating procedures slated to become effective Aug. 2, including:

- Altering OP-24 to describe the confidential Appendix C as a list of transmission facilities for which transmission owners are required to report protection settings, characteristics, failures or degradation. RTO staffer Jerry Elliott presented proposed revisions reflecting that Appendix C previously included a diagram, but now includes a list. The proposed changes to OP-24 are conforming changes.
- Revising *OP-12* (Voltage and Reactive Control) and *OP-12D* (Voltage Schedule Annual Transmittal Form) to clarify local control center actions for providing voltage schedules to generators.
- Revising *OP-5* (Resource Maintenance and Outage Scheduling) to indicate that outage requests for import capacity resources are for notification purposes only. The motion passed with six opposed (two from the Generation Sector, two from the Supplier Sector and two from the Alternative Resource Sector) and three abstentions (one Generation Sector, one Supplier Sector and one Alternative Resource Sector).

Future Vote on OP-14E Revision

Elliott presented proposed *revisions* to *OP-14E* to incorporate energy storage as a type of asset-related demand that can be selected on ISO-NE's form NX-12E.

The RC is scheduled to vote on the revisions at its Aug. 20 meeting, and the RTO is seeking a vote by the PC at its Sept. 13 meeting.

The changes include correcting terms defined in section I.2.2 of the Tariff or ISO-NE manuals, in addition to replacing the term "nominated consumption level" with the defined term "nominated consumption limit."

The RTO also notified the RC of revisions to OP-10 Appendix A to update the contact information for the U.S. Department of Energy in cases of reporting major system disturbance, outage or incident. The revisions took effect immediately upon the notification.

ISO-NE News

(A)		(B) 2020	(C) 2021	(D) 2022	(E) 2023
(1)	Estimated Additions In-Service and CWIP ($ in Millions)	$ 1,076	$ 930	$ 1,036	$ 704
(2)	Forecasted Revenue Requirement ($ in Millions)	$ 148	$ 125	$ 145	$ 94
(3)	Estimated RNS Rate Impact ($/kW-Yr)	$ 8	$ 6	$ 7	$ 5
(4)	Estimated RNS Rate Forecast ($/kW-Yr)	$ 120	$ 126	$ 133	$ 138
(5)	Estimated RNS Rate Forecast ($/kWh) Assumes a 54.1%[1] Load Factor	$ 0.019	$ 0.020	$ 0.021	$ 0.022

A summary of the RNS five-year forecast from 2020 to 2023 | *ISO-NE*

Reactive Capability Auditing Tariff Changes

The RC voted to recommend PC support for proposed revisions to section I.2.2 of the Tariff to incorporate definitions for interconnection reliability operating limit (IROL) and system operating limit (SOL).

ISO-NE lead operations analyst Kory Haag said the revisions incorporate four new defined terms in the Tariff: reactive capability audit, reactive resource, IROL and SOL.

The meeting focused on IROL and SOL, which will now be defined as the meaning specified in the *glossary* of terms used in NERC reliability standards.

NERC defines IROL as "a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system."

It defines SOL as "the value ... that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria."

The RC requested an Oct. 1 effective date for the definitions, following a vote by the PC in August.

Eversource Substation Upgrades

The RC voted to recommend that ISO-NE determine that three proposed substation upgrades by Eversource would not adversely affect the stability, reliability or operating characteristics of nearby transmission facilities.

Upgrades to the Andrew Square and Dewar Street substations in South Boston would entail the installation of two independent current differential high-speed protection groups on the K Street-to-Andrew Square 115-kV cables and the Dewar 115-kV cables to provide the selectivity to differentiate between a line fault and a transformer fault. The work will provide protection system fault clearing selectivity and design in compliance with Northeast Power Coordinating Council protection system design criteria (*NPCC Directory 4 BPS*). The proposed in-service date for both projects is in November 2019.

An upgrade to the Portsmouth substation in New Hampshire would entail the replacement of an existing 115/34-kV, 44.8-MVA transformer with a 62.5-MVA rated unit, the addition of a second 115/34-kV, 62.5-MVA transformer, installation of one new 115-kV bus tie circuit breaker, and installation of two new 115-kV circuit breaker disconnect switches. Eversource will also install one new 11-kV circuit switcher for high-side transformer protection and add two 7.2-MVAR capacitor banks, one on each 34-kV bus. The upgrade also will add a 34.5-kV bus tie circuit breaker, which will normally be open, with an automatic close function upon loss of a transformer. The proposed in-service date is June 1, 2020.

4 20-MW Solar Projects by FPS Approved

The RC voted to recommend that ISO-NE determine that implementation of four separate 20-MW solar projects proposed by Freepoint Commodities (FPS) would not adversely affect the grid.

None of the projects include energy storage, and each comprises 10 2-MW arrays.

SGC Engineering's Jeff Fenn presented the separate project overviews, showing the solar farm in Plainfield, Conn., interconnecting to the 23-kV bus at the Fry Brook substation and with a proposed in-service date of December 2022.

The firm's project in Fair Haven, Vt., will interconnect to the 46-kV line between the Green Mountain Power Fair Haven and Carver Falls substations, while the project in Shaftsbury, Vt., will interconnect to the 46-kV line between the GMP South Shaftsbury tap and East Arlington substation, both with a proposed in-service date of July 1, 2022. The project in Claremont, N.H., has the same in-service date.

Enhancing Competitive Tx RFP

ISO-NE Transmission Planning Director Brent Oberlin led a discussion of competitive transmission solicitation enhancements that included proposed clarifications to Attachment K of section II of the Tariff, the draft selected qualified transmission project sponsor (SQTPS) agreement, and to sections I.2.2 and I.3.9 of the Tariff associated with preparing for competitive transmission solicitations under FERC Order 1000.

Based on the results of the 2028 Boston Needs Assessment, which were presented to the ISO-NE Planning Advisory Committee in April, the RTO plans to issue its first request for proposals for a competitively developed transmission solution in December 2019. (See *ISO-NE Planning Advisory Committee Briefs: April 25, 2019*.)

Tx Cost Allocation Revisions

The RC voted to recommend that ISO-NE approve pool-supported costs for two projects by Avangrid's United Illuminating subsidiary in Connecticut, including $11.24 million for work associated with the East Shore 345-kV circuit switcher replacement and $8.17 million to replace line optical ground wire and related fiber optic equipment on the 115-kV 1130 Line between the Pequonnock and Sasco Creek substations.

UIL determined that none of the costs associated with either upgrade can be considered localized.

Capacity Cost Compensation

The RC voted to recommend that ISO-NE designate PSEG Power's Bridgeport Harbor gas-fired plant and the Wheelabrator North Andover waste-to-energy plant as dynamic

ISO-NE News

reactive resources meeting the RTO's capacity cost compensation program eligibility requirements.

The committee recommended the facilities be eligible for compensation associated with a qualified reactive resource designation effective Aug. 1.

RC Consent Agenda

The RC approved a consent *agenda* that included seven proposed plan application (PPA) notifications for Massachusetts solar generation totaling nearly 27.5 MW.

The list includes five projects being interconnected through Eversource:

- Borrego Solar's 3.75-MW project in Plymouth, interconnecting to the Valley substation, with a proposed in-service date of Dec. 31.
- Borrego's 4.999-MW project in Freetown, interconnecting to the Bell Rock substation, with a proposed in-service date of May 1, 2020.
- CVE North America's 2.5-MW/1.262-MW Wing Lane solar and battery project in Acushnet, interconnecting to the Wing Lane substation with a proposed in-service date of Oct. 31.
- SunRaise Development's 2.5-MW Cranberry Highway project in Wareham, interconnecting to the Tremont substation with a proposed in-service date of Dec. 1.
- Syncarpha's 4.99-MW Chester Road solar and battery project in Blandford, interconnecting to the Blandford substation with a proposed in-service date of Nov. 18.

Solar panels in Vermont like the 20-MW projects approved by the NEPOOL RC on July 16 | *Green Mountain Power*

Two projects will interconnect through New England Power:

- Ameresco's 2.5-MW Otter River Road project in Gardner, interconnecting to the Crystal Lake Substation with a proposed in-service date of Sept. 1, 2020.
- NSTAR Electric's 4.99-MW Denslow Road project in East Longmeadow, interconnecting to the East Longmeadow substation with a proposed in-service date of Nov. 15, 2020.

The consent agenda also included one PPA non-solar notification, the 1.5-MW Madison Business Park battery energy storage facility in Madison, Maine, which New England Battery Storage will interconnect to the Jones Street substation with a proposed in-service date of Jan. 1, 2020.

The agenda also included three Level I (for information only) transmission PPA notifications:

- New England Power is updating the summer normal and revised winter line ratings to reflect current cable design on a new 345-kV underground line from the Wakefield Junction substation to the company's border with Eversource at the Wakefield/Stoneham, Mass., town line; two new circuit breakers at the Wakefield Junction substation; and a new 345-kV variable shunt reactor. The proposed in-service date is in May 2021.
- Eversource is updating the summer normal and revised winter line ratings to reflect current cable design on the installation of a new 8-mile, 345-kV underground cable circuit from the Woburn substation in Massachusetts to National Grid's Wakefield Junction substation, in Wakefield, including 160-MVAR variable shunt reactors at each terminal. The work will expand the 345-kV switchyard at Woburn to be a breaker-and-a-half substation with four bays. The proposed in-service date is in May 2021.
- Eversource is also rebuilding the existing 69-kV 667 Line from the Salisbury substation in Salisbury, Conn., to the Falls Village substation because of asset conditions. The proposed in-service date is Dec. 31.

— Michael Kuser

ISO-NE Refines Competitive Tx RFP Template

By Michael Kuser

ISO-NE Director of Transmission Planning Brent Oberlin *presented* a revised draft of the competitive transmission request for proposals template at a teleconference *meeting* of the Planning Advisory Committee on Thursday.

The RTO plans to issue its first RFP for a competitively developed transmission solution under FERC Order 1000 in December to address the results of the Boston 2028 Needs Assessment. (See "RTO Seeks Comments on RFP Template," *ISO-NE Planning Advisory Committee Briefs: June 19, 2019*.)

The materials provided — including general instructions and related workbooks — focus on a solicitation for a reliability transmission upgrade or a market efficiency transmission upgrade.

To submit proposals, respondents will use RFP360, a web-based application the RTO uses to communicate with the respondents and to collect responses.

"'Make sure there's a controlled environment.' That's one of the lessons we've learned from other areas," Oberlin said.

The RTO has drafted similar documentation for an RFP for a public policy transmission need, but it has not yet published it, he said.

Oberlin described the lifecycle cost workbook as "a monster," saying "it takes a while to open, so don't touch anything while it's opening or you'll regret it."

The RTO has posted an *unlocked* version of the lifecycle cost workbook for review.

Comments on this latest draft of the RFP materials should be submitted to *pacmatters@iso-ne.com* by Aug. 5.

Refined Accuracy

Responding to a question from Eversource Energy, Oberlin said ISO-NE is "going to be pushing the bounds" on cost estimate accuracy and hopes that "everyone is in at least the plus 50%, minus 25% range."

"Our desire would be to actually be a lot tighter than that; plus/minus 10% would really be the goal, because we don't to revisit this in the future," Oberlin said.

Between phases 1 and 2 of the application process, the RTO asks for additional information to better understand the project and "really dig in on the nuts and bolts," he said.

"It is not a time for the respondent to be changing the design of the project," Oberlin said. "We shouldn't see night-and-day changes in the estimate between those two stages, so we are looking for a fairly refined accuracy right up front."

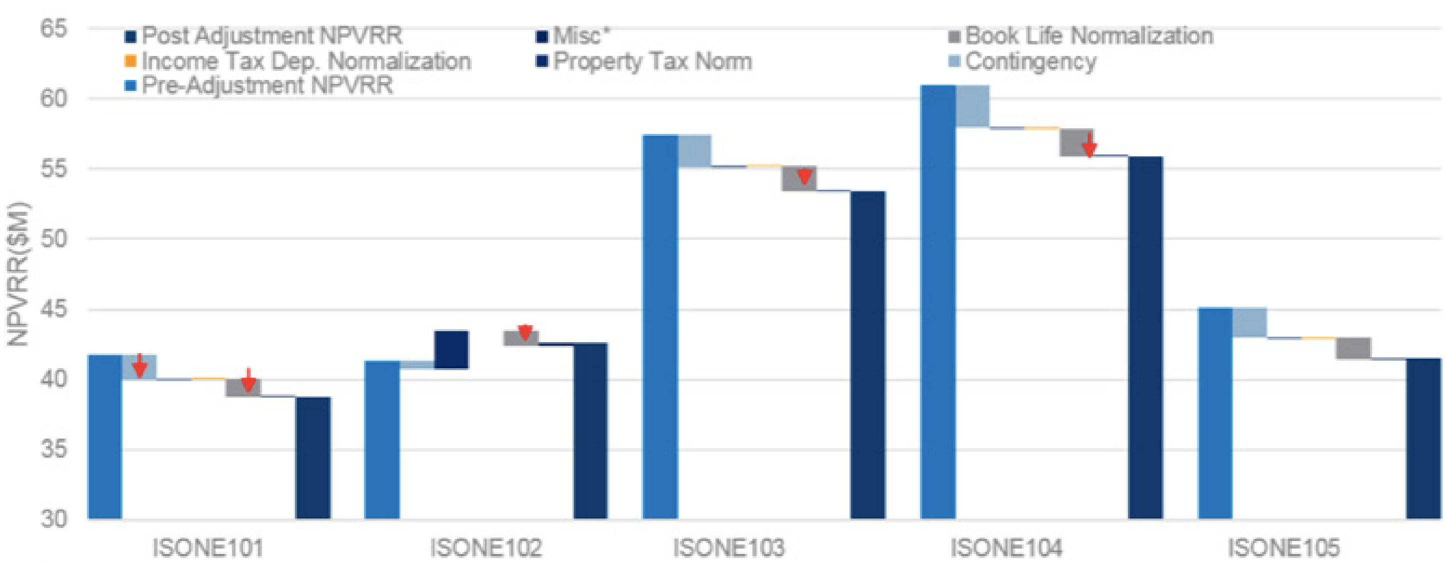
Respondents can also provide their own workbook with an explanation of why they do things differently, he said.

Lawrence Willick of New England Energy Connection asked about the period for lifecycle costs, and how the RTO would reconcile project components of varying lifetimes.

Oberlin said it is assuming 15 years for the base lifecycle and that it would be up to the RTO to understand the varying lifecycles of installed components. ■

"We shouldn't see night-and-day changes in the estimate between those two stages, so we are looking for a fairly refined accuracy right up front."

— ISO-NE Director of Transmission Planning Brent Oberlin



In evaluating competitive transmission proposals, ISO-NE says it will use a normalized base case analysis (illustrated) along with a risk analysis to consider market and project-level risks. | *ISO-NE*

MISO News

MISO Looks to Prune Competitive Tx Process

By Amanda Durish Cook

MISO is wagering that proposed rule changes will cut down on the time and expenses spent evaluating transmission proposals and position it to assess multiple competitive projects in a single Transmission Expansion Plan (MTEP) cycle.

The RTO said Thursday that it will soon file with FERC to outline increased data requirements, page limits and tighter deadlines in its competitive developer selection process.

Stakeholders have repeatedly asked MISO to make the improvements.

MISO Senior Manager of Competitive Transmission Administration Brian Pedersen said the length of proposals grew sharply between the solicitation for the Duff-Coleman project — the RTO's first competitive project — and the currently embattled Hartburg-Sabine project. (See *Uncertainty Deepens for Hartburg-Sabine Project*.) Developers vying for Duff-Coleman in 2016 on average attached about 85 files to their proposals, but the file attachments had grown to about 150 per proposal by the 2018 Hartburg-Sabine solicitation.

"We have good developers and they submit full proposals," MISO design engineer Alex Monn said during a Thursday *workshop* on the competitive transmission process.

But the proposals might have been a bit too fleshed-out for planners, prompting MISO to propose setting a 125- to 300-page limit, depending on the size and complexity of the transmission project being bid on.

The RTO also wants to "right size" its evaluation time based on size and complexity and is proposing to spend no more than 240, 375 or 480 days on one developer selection. It said the three proposal windows will "match the right level of proposal preparation and evaluation resources to each project." Pedersen said the idea is to trim timelines and evaluation efforts on smaller, more straightforward projects.

MISO's Tariff currently allows a maximum 480 days to execute the developer selection process from MTEP approval to an executed selected developer agreement. The Duff-Coleman selection took nearly all that time, while Hartburg-Sabine took less than a year.

The RTO also said it will change rules so it can accept a smaller project evaluation deposit for simpler projects that won't require as much review. The current deposit requirement is $100,000 per proposal. Accordingly, MISO is proposing to scale down its proposal submission windows to either 60, 120 or 165 days, also depending on project intricacy.

Multiple stakeholders said a 60-day window would not be enough time to put together project proposals.

"Sixty days is just not enough time. … I feel like 90 days would be the minimum," Entergy's Yarrow Etheredge said.

Pedersen said he would re-examine the smallest proposal window with his staff to make sure it's a sufficient amount of time.

"Matching our level of effort with your level of effort is a good thing," Pedersen said. "Just like you're on the clock, we're on the clock when the proposals come in."

Brian Pedersen, MISO | © *RTO Insider*

MISO is also adding requirements to ensure the information received from developers is more valuable in aiding selection. It would specifically ask for recent project success stories, more project cost breakdowns and calculations to support design decisions along with three years of financial data and company credit ratings.

Pedersen said MISO will still move ahead with improving the competitive bidding process despite FERC's rejection of its proposed cost allocation for competitive projects last month. (See *MISO Allocation Plan Fails on Local Project Treatment*.)

"There is a future out there and we still need to plan. It's better to be ready when it happens," he said.

MISO plans to file the competitive process changes with FERC in mid-September, with a goal to enact the rules by December. The RTO will not have a competitive project process in 2019. ■

MISO News

FERC Clears MISO 2015/16 Auction Results

Continued from page 1

auction cleared at a single price of $1.05/MW-day. Dynegy has since been acquired by Vistra Energy.

In early 2016, FERC determined that MISO's $155.79/MW-day maximum bid was too high, needing to be set closer to $25/MW-day, and that the RTO didn't accurately gauge power exports. As a result, MISO revised capacity import limits, set the initial reference level for capacity at $0/MW-day and developed default technology-specific avoidable costs. (See *FERC Orders MISO to Change Auction Rules*.)

In the auction, Dynegy offered 1,709 MW of capacity at $0/MW-day, 270 MW at $108/MW-day, 651 MW at $150/MW-day and 2,775 MW at $167/MW-day.

In Thursday's order, FERC said that although Dynegy had pivotal supplier status and that substantial price separation occurred, MISO had conducted the auction in accordance with its Tariff and market power mitigation rules.

The commission noted that all Dynegy's offers were made below Zone 4's $247.40/MW-day cost of new entry and said it agreed with MISO and Dynegy that a clearing price isn't unjust simply because it's higher than expected.

"We find no evidence in the record to support a finding that Dynegy's offers violated MISO's Tariff, and we conclude … that the resulting auction clearing price was just and reasonable," FERC determined.

MISO Independent Market Monitor David Patton had argued the RTO's previous auctions, not the 2015/16 auction, were the problem, saying that previous "near-zero" clearing prices "undervalued the reliability provided by that capacity."

"The price increase in Zone 4 merely reflects that prices were unreasonably low in previous planning years," the Monitor said.

'Full and Thorough'

The commission also said that contrary to complainants' arguments, its Office of Enforcement conducted "a full and thorough investigation" into the matter, spanning more than three years, with review of about 500,000 pages of documents and 17 days of testimony from 11 witnesses.

"We reject any implication that the investigation was not sufficiently complete to consider the conduct at issue," FERC said, adding it would take no further action to investigate allegations of market manipulation in the auction.

Southwestern Electric Cooperative's complaint went a step further, arguing that all sellers in Zone 4 stood to be enriched by the high clearing price. Madigan also argued that all Zone 4 sellers should refund excess charges to customers.

But FERC dismissed that complaint, saying Southwestern Electric failed to specify any alleged violations of statutory or regulatory standards on the part of Zone 4 sellers.

Glick Miffed at Chair's Action

During Thursday's open meeting, Commissioners Cheryl LaFleur and Richard Glick noted pointedly that — although the investigation had been authorized by the entire commission — they were not consulted before Chairman Neil Chatterjee unilaterally ended the probe.

While LaFleur said she concluded that there was no evidence of market manipulation, Glick said Chatterjee "cut short" the probe prematurely.

Glick, who dissented on the order, noted that Congress gave the commission expanded authority to police market manipulation as part of the Energy Policy Act of 2005.

"I really don't believe that when Congress enacted the law, they intended for there to be one commissioner to be able to make the decision about whether to conclude an investigation or not," Glick said. "I think that Congress intended for all commissioners to … take a vote on those decisions."

He echoed LaFleur in saying "reasonable minds very much could disagree" on whether the investigation should have continued. But because the evidence is not public, he said, "we can't really have a discussion on the record. There's not really any transparency about it. So, one of the things we should do is release as much of the information as we can. People need to have a lot of confidence in what we do and confidence in the markets."

Glick said the commission's ruling in the MISO case, and a separate rulemaking that reduced the amount of data the commission will require in market power reviews, "don't really instill the kind of confidence we need to have in our markets."

Dynegy's Baldwin Energy Complex | *Christopher Martin*

In his dissent, Glick called Thursday's order a "wholly unsatisfactory response to the allegations of market manipulation" and derided the commission's explanation behind terminating the investigation as "a series of statements, none of which adequately support the commission's finding that those results were just and reasonable."

"Today's order does not provide even the scantest reasoning to support its finding that the nearly 1,000% year-over-year increase in the MISO Zone 4 capacity price had nothing to do with market manipulation," Glick wrote. "Instead, all we have is the commission's unsubstantiated assurance that no one violated the commission's regulations regarding market manipulation."

Asked by reporters after the meeting why he decided to close the investigation without consulting his colleagues, Chatterjee said, "It has always been the chairman's prerogative to close an investigation. I'm not getting into the particulars of exactly when and how the investigation was closed, because that's nonpublic. But the results of the investigation were made available to my colleagues, and as you can see, a majority of us agreed that market manipulation did not occur." ■

Michael Brooks contributed to this article reporting from Washington.

MISO News

MISO Makes 2nd Attempt at More Rigorous Queue

By Amanda Durish Cook

CARMEL, Ind. — MISO will this month take a second shot at a FERC filing that would change its generator interconnection fee structure and require customers to secure locations for projects earlier in the queue.

The commission in March rejected a plan to impose more stringent site control requirements and increase milestone payments for interconnection customers, ruling that the RTO didn't adequately demonstrate its proposals were reasonable and not unduly discriminatory. But it did agree that more stringent site control requirements and higher milestones could help reduce speculative and duplicative projects. (See *MISO Promises Refile on Stricter Queue Requirements*.)

This time around, MISO will not make changes to its first milestone payment, which would remain $4,000/MW instead of becoming a variable cost representing 10% of the average network upgrade cost from the last three definitive planning phase (DPP) cycles. FERC said the RTO's percentage proposal would have resulted in inconsistent payment amounts.

However, the new plan will add a refund mechanism to the total milestone fees imposed on a customer. The "true down" feature will cap total milestones at 20% of a project's network upgrade cost, with any excess payment refunded back to interconnection customers after a project clears the second decision point, roughly 250 days into the queue.

Like MISO's first filing, 50% of milestone fees are considered at risk of not being refunded if they're needed to help defray network upgrade costs should a project withdraw at the first decision point, about 180 days into the queue. At the second decision point, the percentage of at-risk fees drops to 25%. The RTO currently considers all milestone fees at risk of acquisition to help pay for promised system upgrades at both decision points.

MISO will request an Oct. 1 effective date in its new filing, Manager of Resource Interconnection Arash Ghodsian said during a meeting of the Interconnection Process Working Group on July 16.

"We understand that the process is working as is ... but we're looking to fine-tune. The goal is to provide the highest amount of certainty for projects coming through the queue," Ghodsian said.

Arash Ghodsian, MISO | © *RTO Insider*

He said the new filing will occur within the month. "Exact date TBD. But we're shooting for the near future. Soon."

Multi-project Sites

MISO is also proposing to amend the Tariff to allow different fuel types and multiple generation projects to share the same site. The RTO said its new proposal will allow "multiple proposal submissions provided they are concurrently viable."

FERC had said MISO's earlier requirement that project owners demonstrate "exclusive use" site control conflicted with a Tariff section that allows interconnection customers to submit "multiple interconnection requests for a single site" and a policy that requires customers to submit separate requests for generating units that use multiple fuel sources.

MISO will propose to require all projects sharing a location to identify each other in their respective interconnection requests and provide a common diagram of land usage. It would then analyze whether all the projects can be developed on the same parcel of land.

Site Maps vs. Secured Acreage

Stakeholders argued that interconnection customers' responsibility to demonstrate an acreage-per-megawatt minimum can be done without providing a site plan map. MISO would require customers provide a location map as part of site control 90 days prior to the start of planning studies.

Some stakeholders still contended that an acre-per-megawatt demonstration and a project site map are two different requirements. Coming up with a site map is an administrative burden, they said.

"I just don't see how you demonstrate site control without providing a map," responded Paul Muncy, of MISO's transmission access planning division.

Mike Blackwell, with MISO's legal staff, said he didn't see how a site plan map amounted to an administrative burden because any prospective project applying to the queue should at least already have a location map or parcels for lease options.

Ghodsian said interconnection customers should be prepared to submit an approximate project layout, even if the location changes from the final site control demonstration due at the time of signing the generator intercon-

MISO News

nection agreement.

"Initially what we're asking is, 'Do you have enough land for your project?' … I don't think this is that burdensome. If your project is ready, you should be able to put land on a site map for us," Ghodsian said.

Other stakeholders pointed out that the queue takes three years to complete, and providing a facility site map so early in the process all but guarantees location changes.

Ghodsian said early site maps will help MISO determine whether multiple projects are proposing to develop on the same property. Maps help weed out site overlap instances later in the queue, he said.

Stakeholders also questioned MISO's proposal that interconnection customers provide a full demonstration of site control prior to entering the DPP, pointing out that two years ago, FERC deemed sufficient a 75% *demonstration* of site control at the time of interconnection application.

Ghodsian said the 100% site control requirement was not up for renegotiation in the refiling. He said the new proposal will stick to the same principles as the original but take FERC guidance into account.

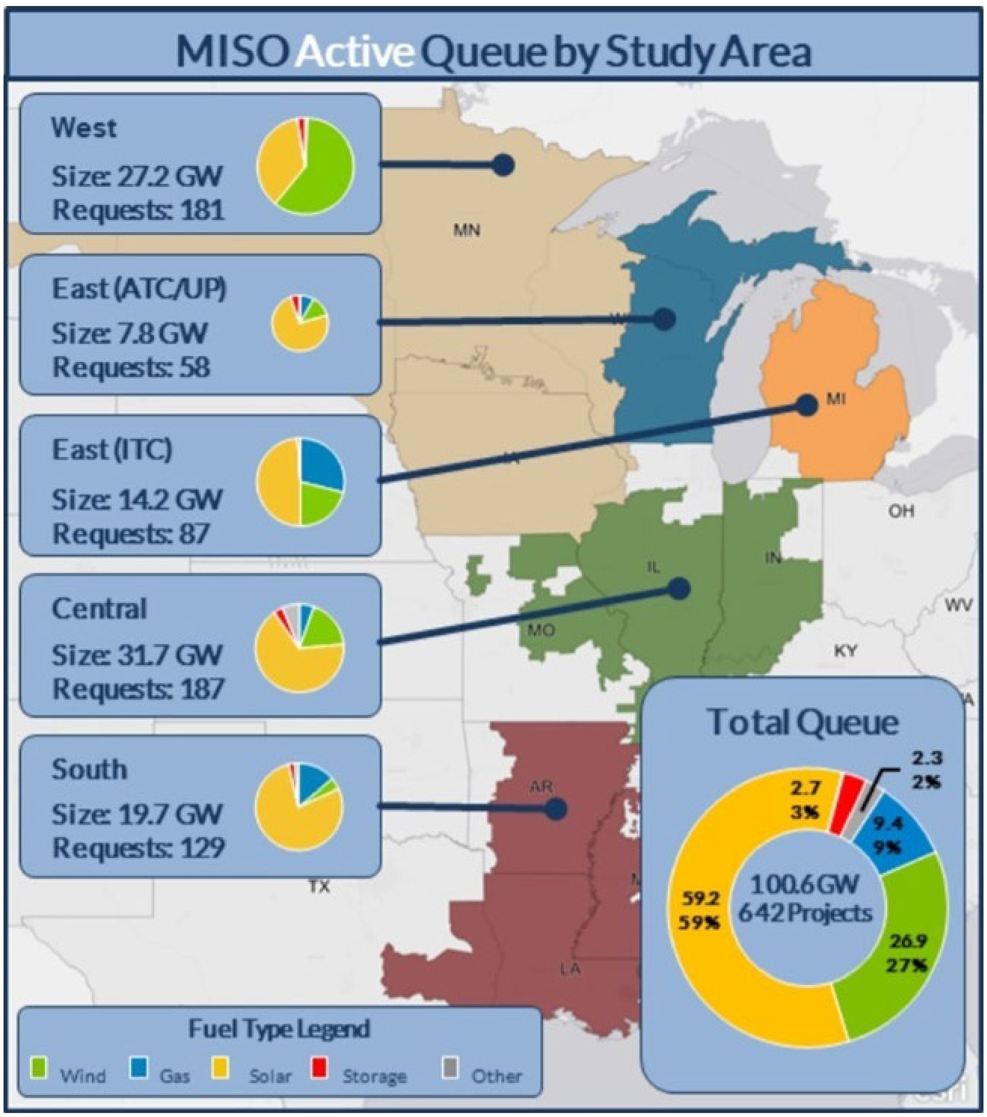
MISO Resource Interconnection Planning Manager Neil Shah said the changes are as important as ever, given that the RTO received 45 GW of new project requests this spring, bringing the queue to more than 100 GW.

"Everybody involved in that process knows that not all are going to go through," Shah told Planning Advisory Committee members in June. "In short, the urgency is about processing the projects in the queue as quickly as possible."

MISO's current generator interconnection queue includes 642 prospective projects totaling 100.6 GW.

Except for its western region, MISO will begin processing the slate of projects received in April in October or November. Because of the large number of interconnection requests in the west, the RTO will begin work on those projects in August.

MISO has negotiated more than 30 interconnection and construction agreements so far in 2019; the RTO *projects* it will negotiate upward of 130 agreements by year-end.



| MISO

Other Time Savers

The RTO is also pursuing other avenues to reduce the amount of time projects spend in the interconnection process.

Queue engineer Will Buchanan *said* MISO will continue building DPP system models in-house after a successful trial run.

"MISO was able to save a considerable amount of time in the 2018 cycle versus past years," Buchanan said.

Buchanan said the RTO's handling of queue modeling will maintain a consistency it couldn't achieve when it outsourced modeling work to third parties. The move also cut out the "months of delay" that it experienced with modeling vendors, Buchanan said.

MISO will also create an instant, online application for interconnection requests, replacing its previous print-and-return PDF form.

Finally, MISO is betting it can shave an additional 10 days off the queue by requiring the bulk of stakeholder model reviews take place prior to the kickoff of DPP cycles. It will allow 10 business days from model posting for stakeholder review and another five business days for any final review after the official start of the DPP.

Stakeholders said shortening the timeline on model review may increase the margin for error, especially in MISO's western states, which currently account for 69 project requests alone in the DPP. But RTO staff countered that no review time would be lost, with the idea being that MISO releases models sooner so stakeholders can begin sizing them up earlier.

"If we can get the models out earlier, it gives people more time to review. … We're trying to give you an extended period. It just doesn't look the same as it does now," Buchanan said. ■

MISO News

MISO: Grid Can be Stable at 40% Renewables

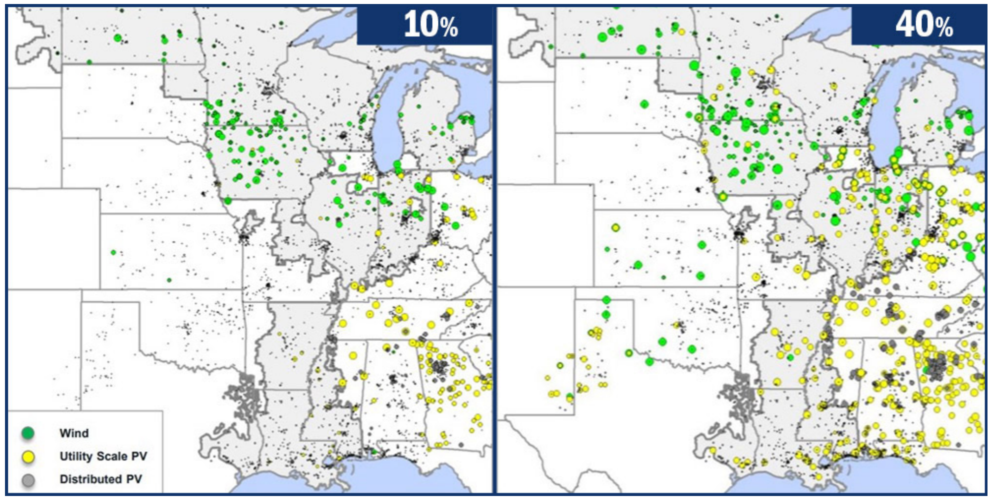
By Amanda Durish Cook

CARMEL, Ind. — MISO's grid can withstand major reliability risks even when renewables reach 40% of the generation mix, RTO staff said last week.

That finding represents a turnabout from a study last year that found the RTO would need to take significant steps to reinforce its grid to handle a jump from 30% to 40% renewable penetration. (See *Study: MISO Grid Needs Work at 40% Renewables*.) But it is now more confident about its ability to maintain reliability as renewable development intensifies.

"The challenge is a non-linear thing. There are certain points where it becomes more complex as you eat up some of the flexibility and capacity on the system. … There's more megawatts of capacity needed on the system over time," MISO Manager of Policy Studies Jordan Bakke said during a special workshop on the topic Wednesday.

MISO foresees continued wind growth in the northern part of its footprint, with most renewable generation in the South coming from solar. As more solar comes online, the daily peak risk hour shifts to later in the day as the sun sets, Bakke said.



MISO renewable growth projection | *MISO*

"The characterization of renewable generation deployment is wind in the north and solar basically everywhere," he said.

In a scenario in which renewables account for 40% the resource mix, MISO found they could serve 42% of peak load, 67% of shoulder or light load, and up to 81% of load when weather conditions for renewables are optimal. When renewable conditions are ideal, wind and solar generation drastically cut into the share of load served by natural gas and coal generation.

"Renewables try to replace other generation because of the economics," MISO Senior Transmission Expansion Planning Engineer Nihal Mohan said.

Although MISO found frequency response degrades as more renewables are added, the system would remain stable at 40%, even when a hypothetical large generator of about 4,500 MW trips offline. When that happens, the system stays above the 59.5-Hz underfrequency load shedding threshold.

Bakke said MISO staff now think declining frequency response is not as serious as first suspected.

While frequency response seems to remain acceptable up to 40% renewables, staff say they're still concerned about scenarios with combinations of high renewable output, low load and large generator disturbances.

And MISO is still concerned that reliability will suffer in other ways.

Under a 40% renewables scenario, the RTO may need to remedy low short-circuit issues with transmission lines equipped with dynamic support capabilities. It said members may be better off building HVDC lines rather than installing several synchronous condensers, then mitigating the small signal stability issues that such equipment produces.

"You can add small lines, you can add condensers, but they would probably add more stability issues," Mohan said. "It's probably better to think about this in advance and come up with an [all-encompassing] solution."

"We're able to get to a renewable energy penetration and deliver energy in a stable way" if MISO members are willing to move to new technologies, Bakke said.

MISO also found that at a higher penetration of renewables, the system would in most cases have more time to clear line faults.

Keeping with previous discussions on the renewable integration assessment, stakeholders asked how MISO envisions that electric storage resources will mitigate reliability issues.

"At this phase of study, we're not considering storage," Mohan said. Storage devices will make an appearance in the third phase of the ongoing study, he said.

MISO will host another workshop Sept. 13 to discuss its study results on a 50% renewable future. The final phase of the study will examine how the grid operates when locally sited renewables serve load. ■

| © RTO Insider

MISO News

MISO Mulling Next Steps on Cost Allocation Overhaul

By Amanda Durish Cook

MISO last week said it will still pursue major aspects of a cost allocation proposal that FERC rejected last month after it found that the RTO's treatment of a new category of local economic transmission projects would have violated the principle of cost causation.

The extensive cost allocation plan would have lowered the voltage threshold for market efficiency projects (MEPs) from 345 kV to 230 kV, created two new project benefit metrics and eliminated a 20% footprint-wide postage-stamp cost allocation method for projects. It would have also provided limited exceptions to the competitive bidding process if a transmission project were needed immediately for the sake of reliability. (See *MISO Allocation Plan Fails on Local Project Treatment*.)

MISO says it will still seek most of those changes, staff revealed during a Wednesday conference call of the Regional Expansion Criteria and Benefits Working Group. Director of Economic and Policy Planning Jesse Moser said the RTO is still hopeful it can apply the cost allocation changes before the 2019 Transmission Expansion Plan is approved in late December.

Keep Local Economic Project?

But MISO's proposal also sought to create a new project type — the local economic project — meant for smaller, economically driven transmission projects between 100 and 230 kV, where 100% of costs would be allocated to the local transmission pricing zone containing the line. The projects would not only have to meet a local benefit-to-cost ratio of 1.25 to 1 or greater within their pricing zones, they would also be required to show the same minimum regional 1.25-to-1 ratio required of MEPs.

FERC ultimately rejected MISO's entire cost allocation proposal on the basis of the local economic project design. The commission said the requirement to show regional benefits only to charge project costs to local pricing zones would have violated its cost-causation principle.

MISO is currently undecided on whether to alter the local economic project criteria or abandon the proposal altogether.

The revised plan could include a "Local Economic Project 2.0," Moser said, adding that MISO could remove the 1.25-to-1 regional benefit-to-cost ratio requirement and preserve the proposed project criteria.

"I have some reservations on even using the [local economic project] terminology because it was rejected," Moser said.

But Clean Grid Alliance's Natalie McIntire argued that MISO should commit to assigning costs commensurate with any regional beneficiaries, even for small transmission projects.

"We're trying to get some direction. I don't think we even have enough detail to call them options just yet," Moser said. "We're not proposing anything today."

However, MISO is clear that it will not lower its proposed regional MEP voltage threshold from 230 kV to 100 kV, although some stakeholders on the call said the RTO should consider lowering the threshold across the board.

At any rate, staff said, FERC will address the 100-kV issue shortly in response to LS Power's June complaint seeking to compel MISO to lower the threshold for competitively bid transmission projects to 100 kV. (See *Complaint Seeks Bigger Role for Smaller MISO Projects*.)

Interregional Aspect

While MISO will still seek to lower its internal MEP voltage threshold to 230 kV, it still must address a six-year-old FERC compliance directive to lower its interregional MEP voltage threshold to 100 kV.

FERC in 2013 ordered MISO and PJM to lower interregional project thresholds after Northern Indiana Public Service Co. complained about shortfalls in the RTOs' interregional planning process.

Like the local economic project proposal, MISO had proposed that its share of interregional economic projects with voltages below 230 kV but 100 kV and above be fully allocated to the transmission pricing zones where the project is located. FERC similarly ruled out the proposal based on deviation from the cost-causation principle.

"MISO is not at a place where we have a preferred option or solution to address the interregional. We're at the place where we have to do something for PJM lower-voltage projects, but maybe we leave SPP alone?" Moser said.

Moser said MISO could either file to lower the interregional project threshold to 100 kV on both seams or make a standalone filing to extend MEP cost allocation to lower-voltage interregional projects with PJM. He added those were merely options at this point. MISO is on a 90-day timeline to address the NIPSCO complaint order.

MISO asked stakeholders to weigh in over the next three weeks on which interregional filing path it should take. ■

Jesse Moser, MISO | © *RTO Insider*

MISO News

FERC Rebuffs ITC Call to Restore Full ROE Adders

By Amanda Durish Cook

FERC last week affirmed a previous ruling that a 2016 merger left three ITC Holdings subsidiaries no longer fully independent, disqualifying them from a full return on equity incentive intended for standalone transmission providers (*EL18-140*).

The commission last year halved the ROE adders previously granted to ITC subsidiaries for being independent providers, saying a merger with Canada-based Fortis and Singapore government-owned investment company GIC Private Limited compromised the parent company's autonomy. (See *FERC Reduces ITC Adders over Independence Issues*.)

Under FERC rules, a fully independent transmission company is eligible to receive a 50-basis-point transco adder. The commission last October determined that a reduced incentive of 25 basis points was appropriate for International Transmission Co., ITC Midwest and Michigan Electric Transmission Co.

"We continue to find that to be the appropriate incentive in this case," the commission said in its order Thursday, noting again that the merger reduced, but did not eliminate, the ITC companies' independence.

In seeking rehearing on the issue, the ITC companies argued that their relatively new upstream owners have no impact on their investment planning or capital formation. They also repeated a contention that their affiliates aren't MISO market participants and said the commission failed to justify its decision to reduce the adder.

"ITC Holdings' governance is fully independent from market participant influence, as ITC Holdings is governed, managed, operated and financed on a standalone basis," the companies argued.

But FERC said ITC misunderstood the yardstick the commission uses to gauge independence.

The commission said that while it considered ITC's structure and arrangement with subsidiaries, it also found that both Fortis and GIC own other market participants that exercise control over the companies. Fortis, the commission pointed out, evaluates capital expenses for its "entire corporate family."

"On capital formation, the ITC companies necessarily rely on Fortis for financing, as they cannot issue their own common stock, and Fortis indicated that cash for subsidiary capital expenditure programs will also come from debt issuances from Fortis," FERC explained.

The commission also noted that both Fortis and GIC representatives sit on ITC's board of directors and that "all executives of Fortis' regulated utility subsidies meet regularly to discuss business operations."

ITC had argued that a "majority" of its board members are independent.

"We remain disappointed with FERC's departure from precedent and failure to fully recognize ITC's independence related to awarding incentives for the independent transmission model," the company said in a statement. "ITC's operating companies remain fully independent of affiliate market participants in all RTO/ISOs in which they operate, and therefore continue to fully meet the conditions under which FERC originally granted independence adders."

In a separate, partial dissent, Commissioner Richard Glick repeated his previous assertion that the companies are not independent enough to justify any ROE adder.

"I do not believe that a 25-basis-point adder is just and reasonable here, and [I] would instead eliminate the ITC companies' ROE adder altogether," Glick said.

ITC said it was "disappointed" in the ruling.

"ITC's operating companies remain fully independent of affiliate market participants in all RTO/ISOs in which they operate, and therefore continue to fully meet the conditions under which FERC originally granted independence adders," said Nina Plaushin, vice president of regulatory and federal affairs, in a statement. "To the extent the commission chooses to make changes to this specific incentive adder, any change should be consistently applied across the industry and warrants full discussion in the general proceeding currently before FERC."

In March, FERC issued a Notice of Inquiry seeking feedback on whether it should change the "scope and implementation" of its incentives policy (*PL19-3*). Dozens of entities submitted comments last month. (See *Tx Incentives NOI Brings Calls for Broader Reforms*.) ■

ITC Midwest builds a transmission line in Iowa in 2013. | *ITC Midwest*

MISO News

FERC Calls for Cold Weather Reliability Standard

By Rich Heidorn Jr.

FERC on Thursday called for reliability rules requiring generator owners and operators to winterize their units and provide their reliability coordinators (RCs) and balancing authorities (BAs) with information about their preparations.

The commission issued the directive as a result of a joint FERC-NERC investigation into the abnormal cold and higher-than-forecast demand that caused MISO and SPP to seek voluntary load reductions and nearly forced load shedding in MISO South on Jan. 17, 2018. (See *FERC, NERC to Probe January Outages in MISO South*.)

"Today's report finds that, despite prior guidance from FERC and NERC, cold weather events continue to result in unplanned outages that imperil reliable system operations," the regulators said in a press release. Although the system remained stable, "continued reliable operation would have required shedding firm load if MISO had experienced its largest single generation contingency in MISO South."

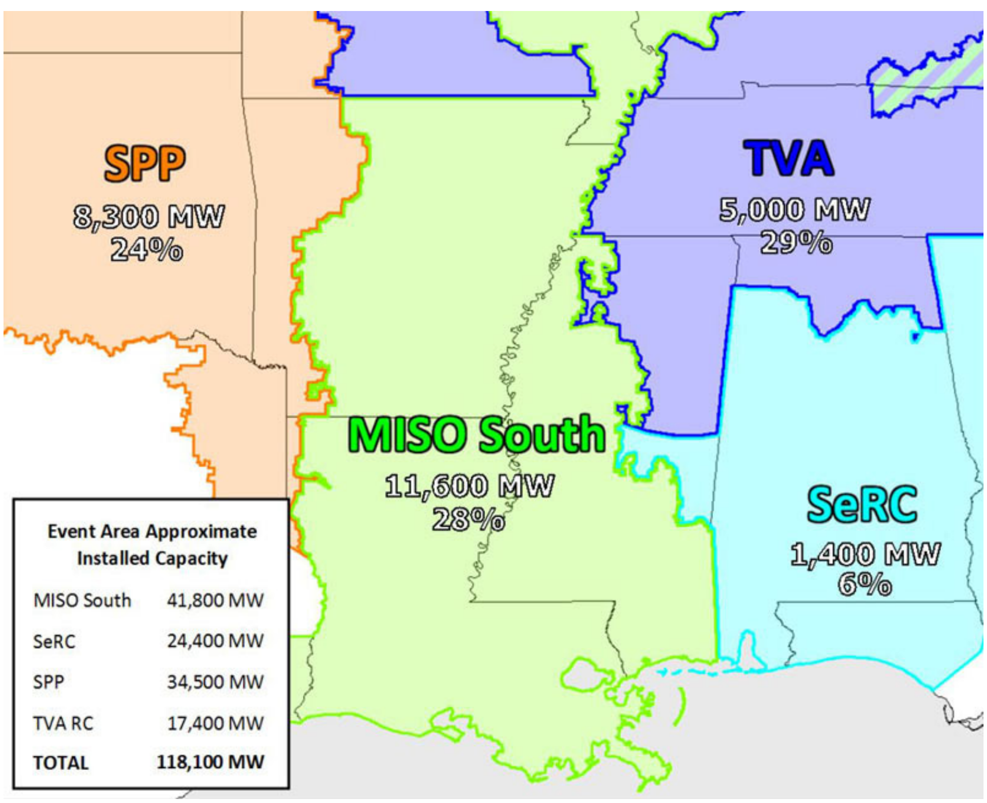
They said the need for a new reliability standard to improve generator performance was demonstrated by the 2018 incident as well as the large-scale unplanned outages during the 2014 polar vortex and the 2011 Southwest cold weather event.

"Learning from near-miss events is extremely important," Chairman Neil Chatterjee said in announcing the report at Thursday's open meeting.

The *report* said the 2018 incident resulted from both gas supply shortages and a failure to properly winterize generation facilities. It made 13 recommendations, calling for improvements in generator performance, load forecasts, communication and planning

9 States Affected

The event affected all or parts of nine states, including MISO South (Arkansas, eastern Texas, Louisiana and Mississippi); southeastern SPP (lower Kansas-Missouri border, the eastern half of Oklahoma, Arkansas, eastern Texas and Louisiana); the western portion of the Tennessee Valley Authority (western Tennessee, lower Missouri, northeastern Oklahoma, northern Mississippi and Alabama) and the western portion of the Southeastern Reliability Coordinator (SeRC)/Southern Co. footprint (southern Mississippi and Alabama).



Generation outages and derates by RC footprint beginning Jan. 17, 2018 | *FERC*

MISO did not expect to have a problem meeting its South load on Jan. 17, based on anticipated generator availability and precautionary measures it took to increase projected reserves. But conditions worsened because of the "extraordinary" level of generation outages and derates.

The report found 183 generating units in the RC footprints of SPP, MISO, TVA and SeRC suffered an outage, derate or failure to start between Monday, Jan. 15, and Thursday, Jan. 19.

Including generation already derated or on planned or unplanned outages before Jan. 15, the four RCs had more than 30,000 MW of generation unavailable in the South-Central portions of their footprints by the Jan. 17 morning peak.

MISO South had as much as 17,000 MW of generation unavailable — all but 4,000 MW unplanned — including 57% of generation in Louisiana and 23.5% of that in Arkansas.

"Had MISO's next single contingency generation outage in MISO South of 1,163 MW occurred, continued reliable [bulk electric system] operations would have depended on system operators shedding firm load promptly to prevent further degradation of BES conditions," the report said.

Weather Impact

Generator owners and operators (GOs and GOPs) directly blamed 14% of the generator failures between Jan. 15 and 19 on the cold weather, citing frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing and low-temperature cutoff limits.

An additional 30% were indirectly linked to the weather, including fuel curtailments to gas-fired generators (16%) and mechanical causes related to cold weather (14%), such as freezing of gas purge valve and steam turbine intercept valves, drops in oil pressure, wet or frozen coal and the loss of feedwater.

The report recommended GOs and GOPs implement freeze protection measures, such as installing wind breaks on generating units and conducting regular maintenance, and inspection of other protections, such as heat tracing equipment and thermal insulation.

MISO News

The investigators noted about 70% of the unplanned outages occurred in gas-fired units. They recommended requiring gas generators to inform their RCs and BAs whether they have firm gas supplies.

Ambient Temperature Ratings

The report also recommended better information sharing on the impact of ambient temperatures on generators and transmission lines.

It said GOs and GOPs should ensure the accuracy of generating units' ambient temperature design specifications and share them with RCs and BAs.

All four of the RCs experienced transmission constraints, and MISO declared an energy emergency because it lacked enough reserves to balance generation and load in South. But the researchers said some system operating limits that became constraints were based on summer temperatures or static, year-round ratings, which understated the lines' winter capabilities.

The report said SOLs and their associated equipment ratings should be based on "at a minimum, ambient temperature conditions that would be expected during high summer load and high winter load conditions, respectively."

Power Transfers

The report also noted that increased electricity demand resulted in large power transfers, with MISO and SPP dispatching remote wind generation and SPP importing power over its HVDC ties with ERCOT. In addition, MISO's regional directional transfer (RDT) from Midwest to South exceeded its contractual firm and non-firm limit of 3,000 MW, peaking at 4,331 MW about 6:30 a.m. CT.

"Although MISO exceeded the RDTL, and did not reduce the RDT below the 3,000-MW limit within 30 minutes as contemplated by the settlement agreement [with SPP and neighboring RCs], MISO operators communicated with adjacent RCs ... that MISO would be exceeding the limit, and that if MISO's RDT flows caused a system emergency for the adjacent RCs, MISO would take appropriate actions," the report said.

The report also called for improvements to the joint Regional Transfer Operations Procedure that governs MISO's use of the RDT. The recommendations included changes to clarify roles and timing and a requirement that affected entities declare an emergency before MISO sheds firm load to reduce the RDT.

The report also recommended that RCs consider the deliverability of reserves, noting that the constraints "caused reserves to be stranded from MISO South."

It also said MISO should notify the other RCs when it is counting on the as-available, non-firm portion of the RDT to deliver reserves for MISO South.

Inaccurate Load Forecasts

The investigators gave good marks to the RCs' system operators, saying their actions were "effective and timely." But they said they were hampered by inaccurate load forecasts for MISO South. MISO's five-day forecast for Jan. 17 underestimated load by about 6,000 MW (18.9%), and its three-day forecast was 1,900 MW low (6.1%). The report said MISO should work with its local BAs and adjacent RCs to improve its accuracy.

"While MISO and its neighbors worked together to maintain system reliability during the event, we recognize the opportunity to collaborate on changes that improve coordination during extreme events," MISO spokeswoman Julie Munsell said Thursday. "We look forward to reviewing the findings and recommendations in the final report."

Studies and Drills

Several of the recommendations concerned additional studies.

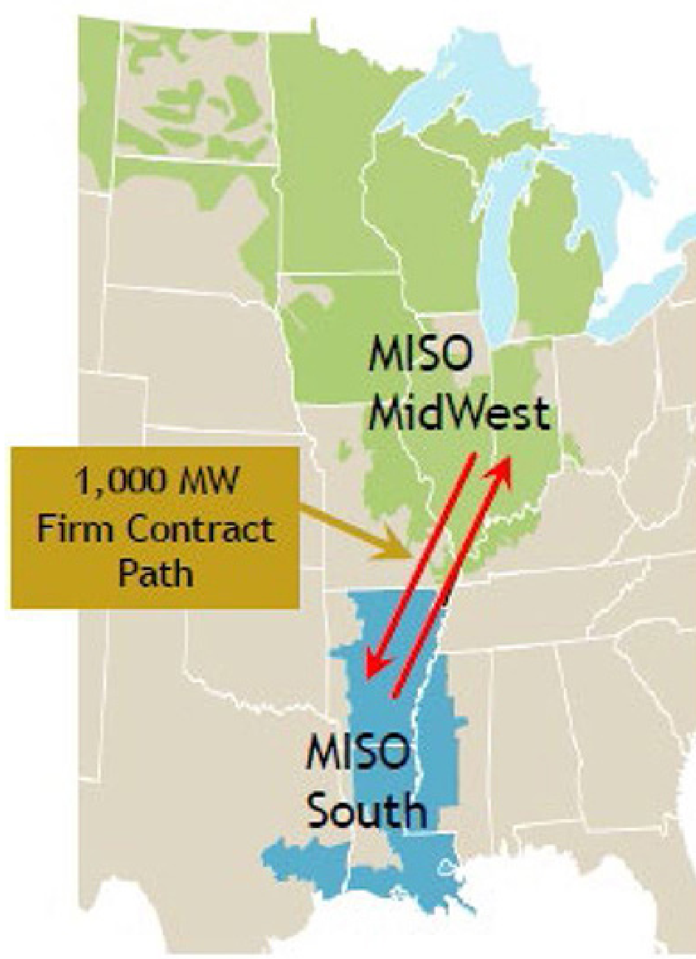
The report recommends studies that consider "stressed but realistic conditions," noting that none of the RCs had anticipated the widespread transmission constraints on Jan. 17.

MISO and SPP should "jointly perform seasonal transfer studies and sensitivity analyses in which MISO and SPP model same-direction simultaneous transfers (e.g. north to south, south to north, west to east) to determine constrained facilities so that they can develop mitigation plans or other procedures for the operators," it said.

It also said planning coordinators and transmission planners should jointly develop and study scenarios to prepare them for extreme weather. It said the studies should include removing generation units entirely to represent actual generation outages as opposed to scaling generating unit outputs.

The study team also recommended that MISO and other RCs perform:

- Voltage stability analyses in future constrained conditions and benchmark planning and operations models against actual events that stressed the system;
- Periodic impact studies to identify which elements in the adjacent RCs' systems have the most impact on their own systems; and
- Drills to "execute load-shedding for maintaining reserves while at the same time alleviating severe transmission conditions." ■



1,000-MW contract path between MISO Midwest and MISO South | *FERC*

NYISO Business Issues Committee Briefs

TE&I Manual Revisions

NYISO's Business Issues Committee on Wednesday voted to approve updates that align the Transmission Expansion & Interconnection (TE&I) manual with Tariff changes made since the last comprehensive manual update, provide additional detail regarding interconnection study methodology, and clarify existing practices and procedures.

The Operations Committee reviewed and approved the revisions on Thursday.

The ISO's senior manager for interconnection projects, Thinh Nguyen, *detailed* the TE&I Manual revisions and the Tariff revisions accepted by FERC over the past two years to alter the transmission expansion and interconnection procedures. Updates include:

- Revisions made as part of the 2017 comprehensive queue revision, such as reducing the number of study agreements.
- Creating deadlines for study reports.
- Clarifying roles and responsibilities of parties in the interconnection process.
- Making feasibility studies under Attachments X and Z options at the developer's election, with two alternative levels of analyses.
- Revising interconnection request data forms and requirements.
- Providing parties the option to narrow the scope of studies required or uprate projects.
- Allowing certain projects with multiple voltage levels to submit a single interconnection request.

The manual changes also reflect queue reforms aimed at improving the class year study process by revising start dates; creating the "bifurcated class year" process; affording additional opportunities for projects to withdraw from the class year study; and specifying how a project can finalize an interconnection agreement prior to completion of a class year study and/or request limited operations prior to execution of an interconnection agreement.

Other changes to the interconnection process reflected in the manual updates include clarification of interconnection study base case inclusion rules; updated small generating facility deposits and application fee requirements; clarification of the clustering process for small generating facilities; clarification of the process for evaluating alternative points of interconnection for small generators; and the requirement that certain large generating facilities install phasor measurement units.

The manual changes, consistent with the 2017 revision, also explain the process for calculating capacity resource interconnection service values applicable to the winter capability period and require stakeholder review of changes in transmission owner planning criteria, while also increasing the frequency of required updates to proposed in-service, initial synchronization and commercial operation dates.

External Capacity Resource Eligibility

Director of Market Design and Product Management Robert Pike presented the monthly Broader Regional Markets *report* and highlighted item 26, regarding an effort to clarify the minimum deliverability requirements for external capacity into the NYISO Installed Capacity (ICAP) market.

The ISO reviewed eligibility and deliverability requirements for external capacity from ISO-NE with stakeholders at the June 27 ICAP/Market Issues Working Group meeting and will return to future working group meetings to continue the discussions, he said.

NYISO will continue to evaluate what, if any, additional performance requirements and obligations are needed for deliverability to the New York Control Area border for purposes of external resource eligibility to sell capacity into New York.

LBMPs down 25% YoY in June

NYISO locational-based marginal prices averaged $24.43/MWh in June, up slightly from $23.10/MWh in May, but down about 25% from the same month a year ago, Pike said in delivering the monthly operations *report*. Year-to-date monthly energy prices averaged $35.76/MWh, a 25% decrease from a year ago.

Day-ahead and real-time load-weighted LBMPs came in higher compared to May. Average daily sendout was 429 GWh/day in June, compared with 373 GWh/day in May and 445 GWh/day in the same month a year ago.

Transco Z6 hub natural gas prices averaged $2.10/MMBtu for the month, off slightly from May and down 14.1% from a year ago.

Distillate prices were down 13.2% year over year and lower from the previous month, with Jet Kerosene Gulf Coast averaging $13.50/MMBtu, down from $14.64/MMBtu in May, while Ultra-low Sulfur No. 2 Diesel NY Harbor dropped to $13.23/MMBtu from $14.54/MMBtu in May.

June uplift dropped to 7 cents/MWh from 13 cents/MWh in May, while total uplift costs, including the ISO's cost of operations, came in higher than the previous month.

The ISO's 19 cents/MWh local reliability share in June was down from 23 cents the previous month, while the statewide share dropped a penny from the previous month to -12 cents/MWh.

The Thunderstorm Alert cost for New York City was 77 cents/MWh, up from 19 cents in May. ■

– Michael Kuser

St. Lawrence-Franklin D. Roosevelt Power Project on the St. Lawrence River | *NYPA*

Ohio Senate Clears Nuke Subsidies

By Christen Smith

A bill to subsidize Ohio's nuclear plants cleared the state Senate on Wednesday. | *FirstEnergy*

The Ohio Senate on Wednesday cleared a controversial plan to curb state renewable energy mandates and create subsidies for nuclear and coal plants, but the House of Representatives' stamp of approval is still likely a week away.

Nineteen senators — 17 Republicans and two Democrats — approved House Bill 6 after months of hearings that debated the merits of saving FirstEnergy Solutions' nuclear reactors at the Davis-Besse and Perry facilities near Lake Erie. The bankrupt company said it will begin shutting down the plants over the next few years without ratepayer subsidies to offset the flood of cheap natural gas that makes it difficult to compete in the wholesale energy market. (See *FirstEnergy Extends the Clock on Ohio Nuke Plan*.)

Two Ohio Valley Electric Corp. coal plants would also receive funding, which some critics have described as a sweetener to attract support from the state's other electric distribution utilities (EDUs). (See *Ohio Nuke Bill: A Worthwhile Trade-off?*)

The latest iteration that moved out of the Senate Energy and Public Utilities Committee last week would collect $150 million for the plants starting in 2021 via ratepayer fees that range from 85 cents for residential customers up to $2,400 for large industrial plants. The charge would sunset in 2027 and the Public Utilities Commission would audit the nuclear facilities each year between 2022 and 2026 to determine if the subsidies are still needed — an attempt to placate critics who insist the plants aren't losing money at all.

Another $20 million would support six solar power projects being built throughout the state. The OVEC fees would range from $1.50 for residential customers to $1,500 for commercial and industrial customers, and would be subject to OVEC revocation.

The bill also preserves a scaled-back renewable portfolio standard, dropping from 12.5% by 2027 to 8.5% until 2025, with no continuation of the mandate thereafter.

The House didn't vote on the plan but returns to session Aug. 1. Speaker Larry Householder (R) has reportedly worked behind the scenes to secure bipartisan support in his chamber by pushing the fees for OVEC and slashing RPS mandates long unpopular among state Republicans.

"This will give Ohio an energy plan that puts Ohioans first," he said when the plan cleared the House Energy and Natural Resources Committee in May. "We're keeping good-paying jobs here in Ohio and maintaining a diverse energy portfolio."

Although the current version of HB 6 — Ohio's Clean Air Act — walks back some of the House-approved components, critics insist the bill remains deeply flawed and misguided. The Sierra Club said it would wreck the state's potential to become a leader in wind and solar development all for the sake of a "regressive" and burdensome surcharge that would disproportionately hurt small businesses.

"Cleverly, the word 'nuclear' is not even in the bill," said Pat Marida, chair of Ohio Sierra Club Nuclear Free Committee, in a blog *post* July 14. "But it is written in a way that only gives a bailout to FirstEnergy for their two nukes and two coal plants, one of which is in Indiana!"

The Ohio Consumers Council and the Ohio Manufacturers' Association sent a joint resolution to Gov. Mike DeWine on Wednesday urging him to veto the bill, saying it will thwart the benefits customers receive from competitive energy markets. A spokesperson for the governor did not return request for comment, but DeWine has signaled support for the bill in the past few months.

FirstEnergy did not respond to requests for comment from *RTO Insider* on Thursday. The company extended the June 30 deadline for legislative action, remaining "optimistic" that lawmakers would approve the bill in the coming weeks. ■

PJM Markets and Reliability Committee Preview

Below is a summary of the issues scheduled to be brought to a vote at the PJM Markets and Reliability Committee on Thursday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

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

Consent Agenda (9:20-9:25)

PJM stakeholders will be asked to endorse the following manual revisions:

B. *Manual 13: Emergency Operations*, to provide a single location for reporting operational restrictions that impact multiday operations planning, replacing multiple forms of reporting currently employed by members. The changes, which incorporate lessons learned from 2018/19 winter operations, are intended to improve operators' situational awareness and communication regarding cross-sector interdependencies. The changes align with new Markets Gateway functionality for resource limitation reporting to be implemented on Aug. 1 and adds clarifications on which units may be placed in max emergency during emergency operations.

C. *Manual 18: PJM Capacity Market*, adding administrative updates, deleting outdated provisions and adding revisions to conform with FERC orders resulting from a periodic review.

D. *Manual 21: Rules & Procedures for Determination of Generating Capability* to clarify capacity injection rights (CIR) evaluations and conform with Tariff changes. Adds more explicit explanations and some omitted testing criteria regarding CIR evaluations for combined cycle units. Re-classifies run-of-river hydro units with storage and dispatch capability.

E. *Manual 28: Operating Agreement Accounting* resulting from the periodic review. Adds documentation of the process to be used if state estimator loss data are unavailable for calculating transmission loss deration factors. Deletes obsolete section on calculation of credits for quick-start reserves. Updates credit calculation for resources providing reactive services. Update formula terms for consistency.

F. *Manual 39: Nuclear Plant Interface Coordination* resulting from the periodic review with the Nuclear Generators Owners User Group (NGOUG). Adds language on coordination around remedial action and load shedding schemes. Adds language regarding the regulatory requirements of the deactivation and retirement process. Adds language to address the coordination between reliability coordinators.

Endorsements/Approvals (9:25-10:35)

1. PJM Manual 14B Amendments (9:25-10:25)

After seven months and three deferrals, the MRC is scheduled to vote on *language* that alters the way PJM manages supplemental projects in the Regional Transmission Expansion Plan.

Both RTO staff and LS Power's Sharon Segner pushed for the 30-day deferral at the June MRC meeting, saying that stakeholders at the special Planning Committee sessions had four issues to resolve before seeking a vote. (See "RTEP Poll," *PJM MRC/MC Briefs: June 27, 2019*.)

Segner gave a brief description of the four outstanding issues: conversion and how supplementals become baseline projects without undergoing the Order 1000 planning process; the displacement of supplemental projects through the regional planning process; ensuring that supplemental projects do not undermine the integrity of the Order 1000 process; and PJM's authority to remove supplementals from the RTEP once permits have been denied.

2. Stakeholder Process Task Force Sunset (10:25-10:35)

Stakeholders will be asked to endorse sunset of both the Energy Price Formation Senior Task Force and the Energy Market Senior Uplift Senior Task Force.

The uplift group formed in 2013 and *completed* its work in 2017 with changes to the Operating Agreement to restrict the locations for up-to-congestion trades, increment offers and decrement bids. (See "Stakeholders Endorse Third Phase of PJM's Uplift Solution Despite Opposition," *PJM MRC/MC Briefs: June 22, 2017*.)

PJM filed its price formation plan with FERC in March and awaits a ruling. (See *PJM Files Energy Price Formation Plan*.)

— Christen Smith

Nuclear, Gas Seen as Crucial to PJM's Renewables Growth

By Christen Smith

PHILADELPHIA — PJM's anticipated increase in renewables over the next decade won't succeed without the support of more reliable fossil fuels and nuclear reactors, industry analysts said last week.

The predictions came during presentations at the Mid-Atlantic Renewable Energy Summit hosted at The Bellevue Hotel on Thursday, where experts from all corners of the energy sector gathered to discuss the future of PJM's resource mix and the anticipated shift from policy-based investment to more economic drivers.

Stu Bresler, PJM | © RTO Insider

"The increase we've seen so far is nothing compared to the increase that looks like it's coming at us in the future," said Stu Bresler, PJM's senior vice president of markets and planning. "We ain't seen nothing yet."

Data from the National Renewable Energy Laboratory and U.S. Energy Information Administration show PJM's installed wind and solar capacity currently exceeds 11,000 MW — the majority of which joined the grid during the last 10 years. ICF Resources said 70% of the renewables scheduled for connection through 2030 will come online in New Jersey, Maryland and D.C., where elected officials have set aggressive clean energy targets and other policies to reduce the effects of climate change.

The Garden State alone will install 3,500 MW of offshore wind power over the next decade. It announced last month that Denmark-based Ørsted will construct the first 1,100 MW 15 miles off the coast of Atlantic City beginning in the early 2020s. (See *Ørsted Wins Record Offshore Wind Bid in NJ*.)

"We are living amidst a revolution right now, a revolution in terms of technology change, a revolution of climate change … and finally a revolution of electricity decarbonization," said Stuart Caplan, partner at Troutman Sanders. "Beware of what you ask for … treat fossil fuels not as an enemy of renewables. The pendulums can swing quickly."

Caplan said that the intermittency of current renewable technologies means fossil fuels will continue to have a place in PJM in order to "preserve balance." In March, the Independent Market Monitor said natural gas-fired energy output exceeded coal in PJM's market last year for the first time ever. (See *Monitor Says PJM's Capacity Market not Competitive*.) Economists on Thursday said coal retirements in favor of more efficient combined cycle units will continue — but the cheap price will not, providing a valuable opening for nuclear energy in the market.

D.C. Public Service Commissioner Greer Gillis said reaching the district's goal of 100% renewable energy and 50% carbon emissions reduction by 2032 will be challenging, but possible. D.C. set the targets in December 2018, making it the most ambitious clean energy policy enacted nationwide, she said.

"We are very optimistic," she said. "But I think one thing we are all concerned about is the pricing."

Judah Rose, ICF Resources | © RTO Insider

Judah Rose, executive director of energy markets for ICF, said zero-emission credits and renewable energy credits will likely increase between 2022 and 2025, temporarily spiking energy costs. Post 2025, he said, the combination of carbon pricing and states meeting their renewable portfolio standard mandates will cause renewable energy prices to fall.

ICF's market forecast assumes the implementation of a national CO_2 program with a price of $4/ton, though Rose said the "real action" could happen through the Regional Greenhouse Gas Initiative, where policy in the participating states could create "big upward pressure" on the price of carbon. It wouldn't wipe out gas development entirely, however.

"We still see huge economics for combined cycle units … mostly located in western PJM," he said. "For coal and nuclear, we see unfavorable economics for both areas. In the long run, however, as gas prices increase and we have some kind of carbon price, we see nuclear becoming economic."

New Jersey and Illinois have already enacted ZEC programs for their own nuclear plants, despite criticism that the subsidies distort prices in the wholesale electricity market. Ohio legislators also appear close to consensus on a bill to rescue FirstEnergy Solutions' reactors at Davis-Besse and Perry nuclear plants near Lake Erie. (See *Ohio Senate Clears Nuke Rescue*.) Supporters of the programs argue PJM's existing market structure doesn't value the carbon-free reliability of nuclear energy and that allowing the units to retire would not only be irreversible, but foolish.

Jason Barker, Exelon | © RTO Insider

"Nuclear has to be part of the equation," said Jason Barker, director of wholesale market development for Exelon. "If you take just the carbon output in one year of those three [retiring nuclear] units, it's equal to all of the wind that's ever been installed in PJM. It's undeniable in the short run if we want to reach our societal targets."

Exelon manages the largest nuclear fleet in the country, including the remaining operating reactor at Three Mile Island near Harrisburg, Pa. The company said in June it will deactivate the unit in September after state legislators stalled on a plan to keep it running via ratepayer subsidies and changes to Pennsylvania's RPS. (See *Nuclear Subsidies Still on the Table in Pennsylvania*.)

"Because of the intermittency of current dominating renewables, we need something to pick up when the wind stops blowing and the sun stops shining," Barker said. "We need to value the flexibility attributes of those units, and that will be what drives LMP."

He also said PJM's minimum price offer rule (MOPR) — currently pending approval at FERC after initially being rejected last year because it didn't include the impact of renewable and nuclear subsidies — "doesn't matter" in terms of carbon pricing policy, noting the way Illinois designed its ZECs to decline as revenue for nuclear units increase (ER18-178). PJM stakeholders are currently reviewing ways to reduce economic and emissions leakage throughout the RTO if some states adopt carbon pricing and others don't. (See *Carbon Pricing Steers Discussion on PJM's Future*.)

"So, if there were border adjustments … it would increase the energy value and therefore decrease the cost of the ZEC, therefore making the MOPR less destructive," Barker said. "Depending on what this MOPR ruling looks like … the carbon pricing could be a substitute or a type of substitute in the absence of more global policy." ■

PJM Names Chief Risk Officer

By Christen Smith

PJM on Monday announced the selection of its first chief risk officer — the official who will oversee the RTO's credit policies in the wake of the GreenHat Energy default.

Nigeria Poole Bloczynski | *PJM*

Nigeria Poole Bloczynski will join PJM on July 29 after serving as director of commodity and corporate risk management for WGL Holdings, the parent company of Washington Gas, WGL Energy, WGL Midstream and Hampshire Gas. She brings more than two decades of experience in commodity and risk management from both the financial and energy markets and currently serves on the board of directors for the Committee of Chief Risk Officers.

Interim CEO Susan J. Riley said Bloczynski "brings a depth of knowledge and experience in this important area that I am confident will serve our organization and stakeholders well."

Bloczynski will supervise all aspects of PJM's risk function, including credit and collateral policies, market surveillance, monitoring of market-participant behavior, and both qualitative and quantitative analytics. The Board of Managers' Risk and Audit Committee will oversee Bloczynski in her new role, which the RTO said was a measure of its commitment to "further instill the importance of risk management throughout the organization."

The announcement comes four months after an independent review of the internal factors that led to the GreenHat debacle characterized PJM management as "naive" and recommended bringing a CRO on board to fill a gap in the RTO's management. (See *Naive PJM Underestimated GreenHat Risks*.)

In June 2018, GreenHat defaulted on 890 million MWh of financial transmission rights, leaving PJM members on the hook for at least $100 million in losses. FERC's recent order to unwind five months of FTR settlements and liquidate GreenHat's portfolio could cost stakeholders in excess of $430 million.

Currently, the RTO and members are negotiating the next steps in the liquidation process before FERC commences a paper hearing on its previous order. (See *FERC: PJM Settle Disputes Before GreenHat Hearing*.)

The report faulted PJM staff for putting too much faith in verbal and written agreements with GreenHat guaranteeing the company held $100 million in assets and would receive a $62.2 million payout from two bilateral contracts.

"If PJM knew its customer better, PJM may have recognized these instances as red flags indicating the GreenHat pledge agreement may have actually been a sham before signing," the report said. "These red flags may have helped PJM to conclude that GreenHat did not have an asset worth $62 million to pledge and assign."

Bloczynski will be the first of several new leaders coming to PJM. Longtime CFO Suzanne Daugherty and CEO Andy Ott both tendered their resignations earlier this year, though neither said their decisions were related to the default. (See *PJM CEO Andy Ott to Retire* and *PJM CFO Retiring in Wake of GreenHat Default*.) ■

SPP News

SPP Ends 8 Days of Conservative Operations

By Tom Kleckner

DES MOINES, Iowa — SPP ended eight days of conservative operations last week, just in time to meet near-record demand in its 14-state footprint.

The RTO declared the alert, a level down from an energy emergency, on July 10, when it projected an above-normal number of primarily forced outages and a drop in wind production. Normal operations resumed on Wednesday.

SPP was already without 13 GW of non-variable resources when it declared the alert. Those outages peaked at slightly more than 14 GW on July 13, before finally falling to less than 10 GW on Thursday.

Bruce Rew, SPP | © *RTO Insider*

"At one point, 45% of our generation was unavailable to us through outages or derates," Operations Vice President Bruce Rew told the Markets and Operations Policy Committee on July 16. He said outages were slightly less than 8 GW a year ago on July 13.

Rew said SPP was predicting a more normal wind production of 12 to 13 GW through the end of last week. Forecasters pretty much nailed their prediction.

"Less than 5 GW is a low wind day for us anymore," he said.

Fortunately, the alert ended just as SPP was expecting to set new records for peak demand. Demand fell short Wednesday to Friday, though on Friday it came within 30 MW of the all-time mark of 50.6 GW, set in July 2016.

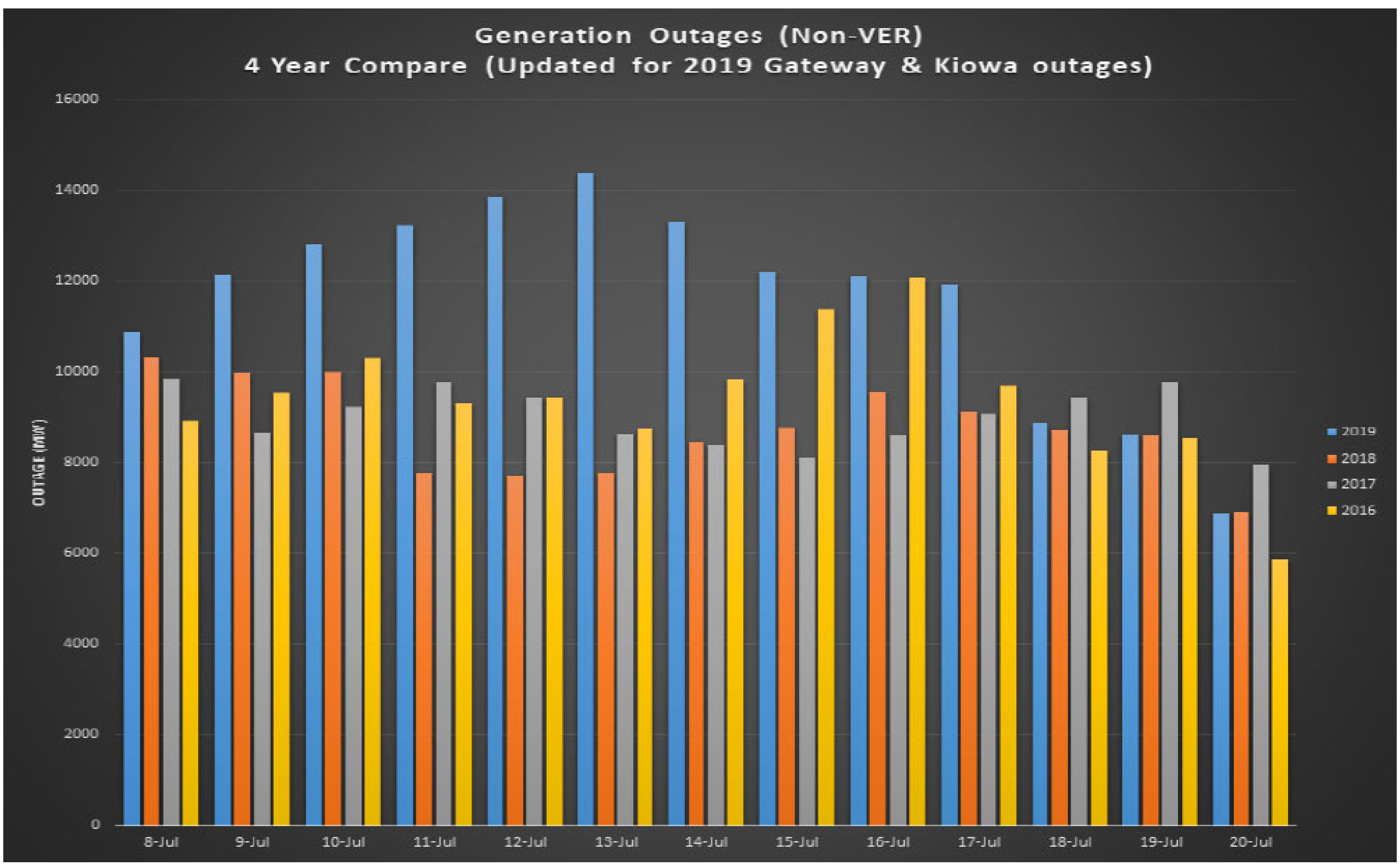
It was the sixth time the RTO has called for conservative operations this year, more than it did all last year. The first two alerts were called in February and March as a result of normal cold weather events. SPP has since issued alerts on May 29, June 4 and July 1 over what staff called "uncertainty factors."

"What's the weather forecast? Potential generation? Certainty of load?" Rew said. "We're seeing outages extending a little longer than normal."

Asked if SPP's criteria for declaring conservative operations have changed, C.J. Brown, director of system operations, said no.

"We have gotten better at what we're looking at from a certainty perspective," he said.

Given the number of conservation alerts called this year, which have totaled 25 days, the MOPC asked SPP to further evaluate this year's events and bring back a recommended policy and/or process improvement to October's regular meeting. Members asked for more detailed information on the outages and the discrepancies between real-time operating capacity and assumed planned capacity, and to clarify the RTO's current must-offer requirements. ■



A comparison of SPP's July outages | *SPP*

SPP News

FERC OKs Changes to MISO-SPP Joint Study Process

By Tom Kleckner

FERC on July 16 approved changes to the MISO-SPP joint operating agreement intended to improve an interregional planning process that has yet to produce joint projects.

The commission found the proposed Tariff revisions, effective Wednesday, to be just and reasonable and in compliance with Order 1000, which reformed FERC's transmission planning and cost allocation requirements for transmission service providers (*ER19-1895, ER19-1896*).

The RTOs filed the revisions after Coordinated System Plan (CSP) studies came up empty in 2014 and 2016. After gathering feedback and other input from stakeholders, they proposed three primary improvements to the CSP process:

- Eliminating the use of a joint model in favor of individual RTO regional analyses;
- Adding avoided costs and adjusted production cost benefits to project evaluation; and
- Removing the $5 million cost threshold to be eligible as an interregional transmission project.

The RTOs said the improvements would allow them to continue performing joint and coordinated planning annually, but also "to more efficiently evaluate regional and interregional transmission projects concurrently, potentially test more projects than the existing process, and evaluate potential interregional transmission projects under 'multiple regional futures' which may allow for a better business case than projects studied under a joint model with a 'single future.'"

Stakeholders, particularly those on SPP's side of the seam, had complained about the study process' "triple hurdle," which required the $5 million threshold, a 345-kV project or larger, and RTO benefits representing 5% or greater of the total benefits in the combined region. (See *MISO, SPP to Ease Interregional Project Criteria*.)

"It takes a herculean effort in what amounts to a simple screen" before going to the regional review, MISO's Eric Thoms, then manager of interregional planning and coordination, said during a 2018 meeting of the RTOs' Interregional Planning Stakeholder Advisory Committee.

"The changes resulted from extensive stakeholder discussions about the barriers to reviewing interregional transmission projects," SPP's David Kelley, director of seams and market design, said in a statement. "We believe the changes will lead to a more efficient, collaborative planning process as we continue to evaluate opportunities for addressing transmission needs along the extensive SPP-MISO seam. We're putting this new process into place immediately and will continue to evaluate its effectiveness over the next couple of planning cycles."

David Kelley, SPP | *© RTO Insider*

MISO spokesperson Julie Munsell agreed with Kelley, saying the changes "will allow both RTOs to better identify and build cost-effective, mutually beneficial interregional projects."

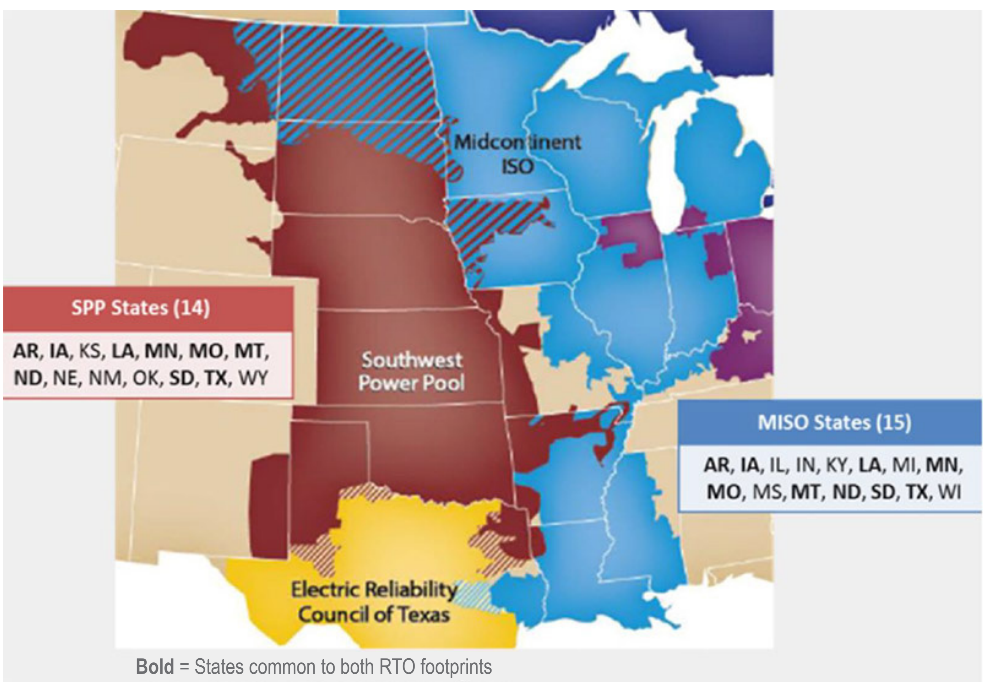
The RTOs are already well into a 2019 CSP study, although they have yet to identify a joint project. (See "Revised Seams Study with MISO yet to Bear Fruit," *SPP Seams Steering Committee Briefs: July 10, 2019*.)

The American Wind Energy Association, Clean Grid Alliance and Advanced Power Alliance protested the RTOs' filing, asking FERC to reject the elimination of the joint model, the most contentious issue among stakeholders. They argued that "negative consequences will outweigh any positive benefits" and that without the joint model, there would be no mechanisms for the RTOs "to work together or agree to study assumptions."

MISO and SPP would wind up with "a transmission planning mechanism that is not robust and a cost allocation in which stakeholders will lack confidence," the parties said.

FERC found that a joint model is not required to ensure interregional transmission coordination. It said that the JOA and CSP processes "support coordination between the two RTOs, including the proposed joint review of each region's models."

"We find that the [CSP] process adequately ensures that MISO and SPP are coordinating and sharing the information necessary to make transmission planning decisions and identify potential beneficial transmission projects," the commission said. "Since each RTO uses its respective regional model to calculate project benefits using the benefit metrics outlined in the JOA, stakeholders in each region should have the same level of confidence in the cost allocation method for an interregional transmission project as they would have for a regional transmission project." ■

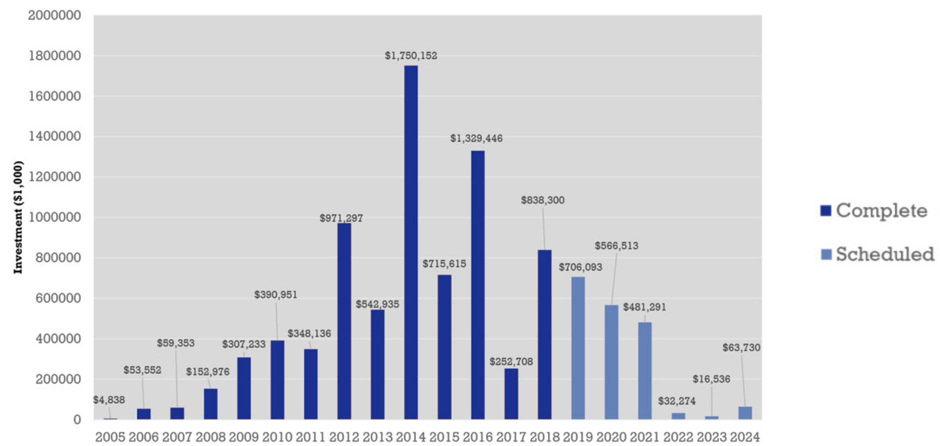


MISO, SPP footprints and seams | *FERC*

SPP News

SPP Strategic Planning Committee Briefs

Stakeholders Ponder Probabilistic Approach to Tx Planning



SPP-directed transmission investment | *SPP*

DES MOINES, Iowa — SPP's Strategic Planning Committee last week debated the merits of deterministic versus probabilistic planning approaches during a review of the RTO's transmission investments.

Lanny Nickell, SPP's vice president of engineering, told the SPC during its July 15 meeting that his staff use the industry's standard deterministic approach, which requires that a single component's outage does not cause system instability, thermal overloading, load curtailment or cascading outages. Critics say the approach does not adequately consider all the possibilities that arise during an event.

Probabilistic planning evaluates a range of possible outcomes but is more expensive than the deterministic approach. Nickell said a 2013 assessment of the approach estimated it would cost about $275,000 to develop probabilistic planning concepts, and another $2 million to develop and implement the software systems needed.

Nickell pointed out that SPP's Integrated Transmission Planning (ITP) studies have performed "selective sensitivities" on the portfolios' final assessments, including ranges for wind energy, gas prices and load growth. He also reminded the committee of the RTO's 2016 transmission-value study, which indicated that for every $1 of transmission investment made in 2012-2014, members could expect at least a $3.50 benefit to ratepayers. (See *SPP Begins Promotional Campaign to Tout Transmission Value*.)

SPP's transmission planning process has resulted in $7.7 billion in completed projects. Another $1.9 billion in projects have been approved.

If anything, Nickell said, SPP tends to be conservative when planning transmission buildouts.

"When building an ITP portfolio, our benefit-to-cost [studies] tend to be lower. We don't do a lot of what-if scenario analyses," he said, noting the 2019 scope's reference case and emerging-technologies case are fairly similar. "I don't think it's too far out of the realm from what we've seen in the past. If the world dramatically changes, what will that mean? We don't know until we study it."

Golden Spread Electric Cooperative's Mike Wise, the SPC's vice chair, praised SPP's work in creating an "uncongested, reliable system," but he said current practices may need to change.

"Going further than what we've done requires a real stretch of the imagination," he said. "I'm concerned we're going to look back and say, 'Did we make a quality decision to ensure we understand the probability of regret?'"

SPP CEO Nick Brown agreed with comments about future uncertainty, saying, "We're woefully inaccurate in terms of how we look at the future."

"We, as an industry, should be spending a lot more time than we do on transmission planning," he said. "I think it's time we move into a probabilistic approach to transmission planning."

To increase planning confidence, Nickell said SPP could increase the minimum benefit-cost threshold for approval from 1.05 to 1.25, reduce the financial analysis time frame and perform more frequent assessments with real-time data, as it did with its transmission-value study.

SPP Chairman Larry Altenbaumer said the RTO has built a strong foundation with its planning processes, "but we can't let that blind us moving forward."

Altenbaumer said the Value and Affordability Task Force (VATF), which he chairs, is also looking at the issue. The discussion will continue there, he said.

Expansion the Top Strategic Priority

The SPC also reviewed feedback from its May planning retreat, during which members were asked to determine which strategic initiatives should be actively pursued.

Committee members identified the top three priorities as:

- Expanding SPP's 14-state footprint, both east and west.
- Implementing the Holistic Integrated Tariff Team's recommendations shared with the Markets and Operations Policy Committee. (See related story, "*Stakeholders Get Last Chance at HITT Report," SPP MOPC Briefs: July 16-17, 2019*.)
- Implementing the VATF's recommendations. The task force was formed in January to review the cost recovery of transmission investments as well as the ongoing benefit from those investments and SPP's operation. (See "Altenbaumer Continues to Exert his Influence," *SPP Strategic Planning Committee Briefs: Jan. 16, 2019*.)

Staff said the SPC members' consensus was that continuing to seek opportunities to provide services and develop markets "would add tremendous value and benefit to SPP's current stakeholders." The feedback indicated expansion "must be considered strategically and proactively while minimizing the cost to existing members," staff said.

The SPC also identified other priorities as expanding services within SPP, a continued focus on cybersecurity, taking a lead role in applying battery storage, better integrating renewables and resolving issues that prevent the export of renewable or other low-cost generation.

The SPC will share its feedback with the Board of Directors and Members Committee during their July meeting. ■

— Tom Kleckner

SPP News

SPP MOPC Briefs

Stakeholders React to Proposed Working Group Consolidation

DES MOINES, Iowa — Saying "no feedback is bad feedback," SPP's Lanny Nickell last week asked Markets and Operations Policy Committee members to provide their input on a proposal to consolidate the 16 stakeholder groups that report to the committee. (See *SPP Seeks Slimmer Stakeholder Group Structure*.)

"Not just consolidation, but also how to improve the effectiveness and efficiency of the groups," the MOPC staff secretary said during the July 16-17 meeting. "Do they have the right structures? The right representatives? Do they coordinate when they coordinate? Should they coordinate? Are there opportunities to consolidate?"

Members pushed back against recommendations that would disband the Seams Steering Committee (SSC) and parcel out its responsibilities to other working groups.

July's MOPC meeting in Des Moines, Iowa | © *RTO Insider*

Jim Jacoby, AEP | © *RTO Insider*

American Electric Power's Jim Jacoby, who chairs the SSC, said he supports handing off planning functions and operational issues to other groups to retain a focus on the interregional transmission process. He also said much of the SSC's recent work has been related to markets and improving their coordination with MISO.

"To me, it comes down to policy issues," Jacoby said. "I want to keep the focus on the seams. If you push that into other groups, I think you will lose that focus."

Jacoby is supported by the Holistic Integrated Tariff Team (HITT), which recommends that SPP continue to make seams a high priority and address them as a part of the strategic plan. The HITT says the SSC "should continue to provide direction to SPP staff on seams issues."

NPPD's Tom Kent (left) and Dogwood Energy's Rob Janssen present the HITT's work. | © *RTO Insider*

"We need to collapse the groups for the sake of efficiency, but we need to maintain and increase the focus on seams questions," the Advanced Power Alliance's Steve Gaw said, adding that his main concern is that interregional planning with MISO is shifting into the regional planning process. "If it morphs into something different than today, we will really need closer coordination, particularly with the Economic Studies Work Group (ESWG), to make sure those two groups are linked."

Gaw credited Jacoby, who also participates on the ESWG, with ensuring coordination between the two groups. The ESWG develops and evaluates the planning processes' economic studies.

Reacting to the possibility of combining the Operating Reliability and Transmission working groups, Southwestern Public Service's Bill Grant drew laughs when he said, "I want to be in the room when you do that."

"I come from the operations side, and I've had my share of arguments with the planners," Grant said. "It's just different issues. I think we lose some expertise when you do this."

SPP News

Stakeholders Get Last Chance at HITT Report

The HITT celebrated the release of its *executive summary* with a tag-team education session for the MOPC and the Strategic Planning Committee. HITT Chair Tom Kent, of Nebraska Public Power District, and Rob Janssen, of Dogwood Energy, took turns reviewing the group's 21 recommendations and offering stakeholders one last chance to provide comments before the Board of Directors sees the final report July 30.

"When I walked out of that last meeting, I thought, 'I wish I had another three months of this process, because we have X, Y and Z issues that we can now pursue,'" Janssen said. "I'm glad we didn't extend the timeline. We're done, but this packet of recommendations moves SPP's operations to a different level. As a result, everyone involved will see new things to resolve and new opportunities to pursue that we haven't seen before."

The HITT separated its recommendations into four categories: reliability, marketplace, planning and cost allocation, and strategy. Thirteen of the recommendations, some of which are already in progress, are planned for implementation; the other eight require further study. (See *HITT Shares Draft Report with SPP Stakeholders*.)

Kent said the team spent much of its time improving SPP's congestion-hedging practices, before determining the RTO should continue with a market mechanism to hedge load against congestion charges. It suggested the existing market design include modifications to implement counter-flow optimization that is limited to excess auction revenues.

A suggestion to decouple the Schedule 9 and Schedule 11 transmission pricing zones and create larger Schedule 11 pricing zones and/or Schedule 9 sub-zones was also the subject of much conversation before the HITT. The team said that when creating the new pricing zones, "consideration should be given to new deliverability sub-regions, distribution factor calculations, and market and power flows."

"The debate … could be part of a broader policy debate. There are a lot of things to sort out, such as how transmission planning, cost allocation and resource adequacy issues interact within new zones or sub-regions in SPP," Janssen said.

The recommendation is being handed to the Regional State Committee and its Cost Allocation Working Group for further evaluation.

"Finding common thought and commonality

SPS' Bill Grant (left) and Lincoln Electric's Dennis Florom | © *RTO Insider*

to deliver holistic recommendations is pretty exceptional," Kent said, thanking staff and stakeholders for their input. "There was a lot of response in bringing their issues and putting them on the table. We're ready to drop our mics."

Fortunately, no microphones were harmed during the presentation.

Western EIS Market Drawing Interest

While SPP works to complete NERC certification as a Western Interconnection reliability coordinator by September, it is holding "a lot of interesting" discussions with parties interested in its Western Energy Imbalance Service (WEIS) market.

Vice President of Operations Bruce Rew said there has been "significant interest" in SPP's proposal to stand up an EIS market in the West. An original Friday deadline for commitments has been pushed back to Sept. 3, extending the go-live date to February 2021. (See *SPP's Western EIS Market Poised to Challenge EIM*.)

Rew said market participants are expected to make a four-year commitment to the WEIS, with new entrants added every six months after go-live and allocated a portion of the start-up costs. Participants will be charged for implementation and ongoing costs based on a proportional share of annual net energy for load.

The WEIS is modeled on SPP's Energy Imbalance Market, which was replaced by the Integrated Marketplace in 2015.

MOPC Approves Early Market Close

The MOPC approved the Market Working Group's recommendation to shorten the window between submitting day-ahead offers and their posting by moving the award time from 2 p.m. to 1 p.m. CT. The MWG said the revision request (*RR365*) would result in a shorter day-ahead market time frame and move SPP closer to meeting FERC Order 809's requirement that the timely nomination cycle for scheduling gas transportation be from 9 a.m. to 1 p.m.

AEP's Jacoby offered an alternative motion that would have shifted the bid/offer submission deadline from 9:30 a.m. to 9 a.m. and the awards to 12:30 p.m. The motion was soundly defeated, receiving only 10 votes. (RR365 passed with five votes opposing and four abstaining.) Members in the northern states said they don't have price certainty on natural gas until 9:30 a.m.

"Even with price certainty, if you don't get to the timely nomination cycle, does it help you?" Jacoby said. "You can pick up a bid and hope the market solves for what you want, but that is not always the case."

"The extra 30 minutes goes a long way for us to have gas-price certainty," SPS' Grant said.

The vote was emblematic of the discussion held within the MWG, said Vice Chair Jim Flucke, of Evergy.

"Each had a different gas situation. Some members wanted an earlier time, others advocated for a later start time," he said, noting the one-hour shift was largely a consensus agreement.

Flucke said the MWG would withdraw *RR339*, which would set the submission deadline at 10 a.m., in favor of RR365.

The MOPC easily endorsed the MWG's *RR352*, which moves up the start of the day-ahead reliability unit commitment process to 1:45 p.m. from 2 p.m. The day-ahead market's

SPP News

posted results would then follow. ITC Holdings abstained from the vote.

Staff said the change will keep SPP in compliance with FERC's directive to eliminate "inflexible" operating limits and other rules that the commission said are preventing prices from reflecting the marginal cost of serving load. (See *FERC Orders Fast-start Rules for SPP*.)

"FERC's order was not without merit," Flucke said. "We remove the screening run, because that allows the correct resources to set the price."

LREs Meet Resource Adequacy Requirements

All of SPP's load-responsible entities (LREs) are in compliance with the resource adequacy (RA) requirement for the 2019 summer season, according to the Supply Adequacy Working Group's (SAWG) first RA report.

As a result of the Tariff's Attachment AA, which went into effect last July, LREs are required to maintain adequate capacity to cover their summer load and planning reserves. SPP's LREs met the 12% planning reserve margin (PRM) threshold with the exception of the Western Area Power Administration, which met its 9.89% PRM, carved out for LREs with at least 75% hydro-based generation.

SAWG Vice Chair Natasha Henderson, of Golden Spread Electric Cooperative, said generation retirements will drop SPP's reserve margin to 18.2% through 2024. The footprint will lose at least 1.8 GW in confirmed retirements this year, with confirmed and unconfirmed retirements totaling 3.5 GW in 2024, she said. With peak demand expected to grow at an annual rate of 0.6%, the 12% PRM is expected to be sufficient through 2024.

The MOPC approved an unbudgeted $80,400 for a battery storage study as part of a larger effective load carrying capability (ELCC) assessment. The ELCC study will determine the amount of incremental load a resource can dependably and reliably serve during peak hours by calculating the system's loss-of-load expectation with and without the resource.

CAISO, MISO and PJM already use the ELCC methodology. The SAWG wants to use ELCC as the guiding principle to accredit wind, solar and battery storage resources. An ELCC wind study will be posted annually in October.

"Companies retiring coal resources need to know what kind of accredited renewable resources they'll get," said SAWG Chair Brad Hans, of the Municipal Energy Agency of Nebraska.

2021 ITP Begins, Joining 2019, 2020 Studies

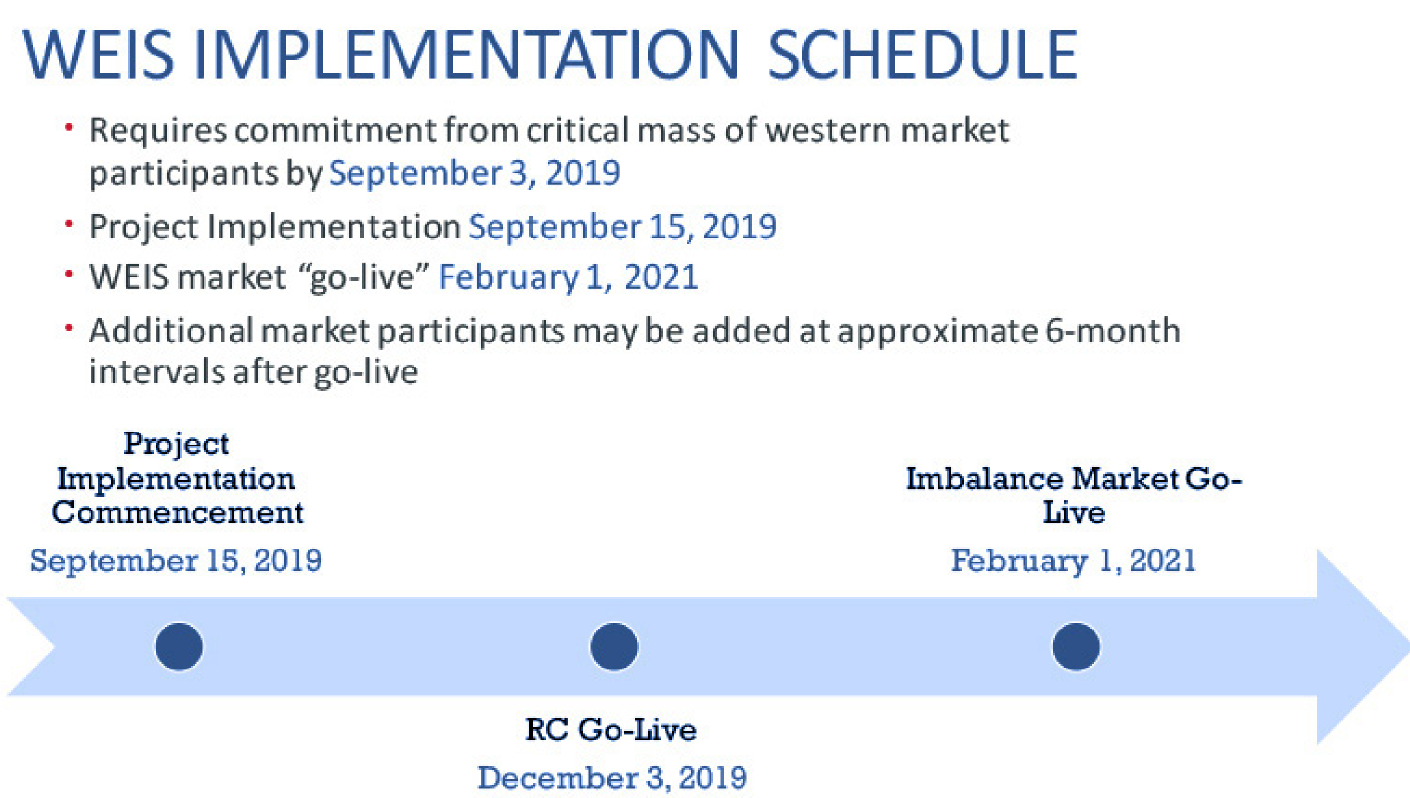
This was supposed to be the year SPP's transmission planning process was easy. Instead of separate 10-year, 20-year and near-term assessments, the RTO implemented an annual planning cycle with a standardized study scope and common reliability models.

Instead, SPP finds itself with three studies being conducted simultaneously.

The ESWG will present its final package of recommendations for the 2019 Integrated Transmission Planning study in October. Meanwhile, the 2020 assessment is establishing its economic model, while the 2021 study kicked off Thursday with a first discussion of its scope.

SPP Planning Director Antoine Lucas said the studies are hitting their deadlines but admitted the work "is very resource-intensive."

Questioned as to whether this was the intent of the revised planning process, Lucas said the



WEIS implementation schedule | *SPP*

SPP News

ITC Holdings' Alan Myers reviews the 2019 ITP. | © *RTO Insider*

studies are at very different stages.

"They require different sets of people. There's some overlap, but we're able to focus on different specific areas," he said. "We've learned a lot. We've been trying to do some refinements as we go along, but it's still too early in the process to determine whether or not we need to look at any significant changes to the process."

ESWG Chair Alan Myers, of ITC, said the group will work on "optimizing" the 2019 ITP's best portfolio for the October meetings, balancing reliability and market efficiency.

SPP Borrowing MISO's Generation Replacement Process

The MOPC directed staff to work with the Regional Tariff Working Group in developing language addressing the transfer of interconnection rights for existing generators that have been retired, demolished or replaced.

Steve Purdy, SPP's manager of generation interconnections, said the RTO could benefit from a similar process modeled on a recently approved MISO Tariff change. (See "Other Interconnection Filings," *MISO Promises Refile on Stricter Queue Requirements*.)

MISO can now accommodate the replacement of a generator with the same or lesser capacity at the same interconnection point. It will charge generation owners a flat study deposit of $60,000 — regardless of size — and conduct replacement impact studies and reliability assessments. The replacement must undergo the full interconnection study process if the new generator causes a material adverse impact.

Should the new capacity be greater than the existing capacity, only the incremental capacity must undergo the full study process. In any case, the new generator must be in service within three months of the existing facility.

Purdy said if SPP adopts a similar process, it will remove unnecessary barriers to beneficial replacements, facilitate reliable resource planning, and remove incentives for uneconomic retirement and interconnection queue behavior. The proposal would also be consistent with FERC guidance, he said.

"Yes, we should do this," SPS' Grant said. "Most of our generation is getting old. If everyone sticks to their plans, there are a lot of retirements coming our way."

Grant also recommended that SPP proceed with the Market Monitoring Unit's proposal to measure avoidable costs if a generator is retired or mothballed. (See "Best Practices," *Stakeholders Push Back Against SPP Retirement Changes*.)

"It's not directly related, but you need a process for generation retirement for this to be effective," he said.

Another BTM Load Survey in the Offing

Staff will once again survey its members and network customers as it attempts to validate billing efforts for behind-the-meter generation reporting network load for transmission service billing.

SPP staff and stakeholders have been wrestling with the issue since 2015. The MOPC rejected a revision request in 2017 that would have established a 1-MW threshold for reporting BTM load. (See "Stakeholders Unable to Reach Consensus on Network Load," *SPP Markets and Operations Policy Committee Briefs*.)

COO Carl Monroe said the survey, which will differentiate between wholesale and retail BTM loads, will be distributed to MOPC members, who would be responsible for providing their companies' positions. Staff would propose ways to address the issue in order to solicit responses, he said.

SPP will use the responses to bring a proposal clarifying network load calculations and reporting to the MOPC's October meeting.

Staff last surveyed members in 2018 when they assessed transmission customers' understanding of their responsibility to report network integration transmission service data.

Consent Agenda Lowers Project Estimate

The committee unanimously passed the consent agenda, which included seven revision requests and a Project Cost Working Group recommendation that a cost estimate for a previously approved project be reduced from $40.4 million to $31.6 million. Evergy's Kansas City Power & Light, KCP&L-Greater Missouri Operations and Westar Energy companies are responsible for the 345-kV voltage conversion project in Missouri.

The RRs were:

- *ESWG RR362*: Requires SPP and the ESWG to monitor changes to production tax credit values and federal corporate tax rates before each ITP study to help estimate the curtailment price applied to both internal and external projected wind units on a per-site basis.
- *MWG RR356*: Cleans up missing language, incorrect capitalized and lowercased terms, typos and other discrepancies between the Integrated Marketplace's production protocols and the forward-looking protocols.
- *MWG RR357*: Clarifies language to accurately describe the trading hub modifications process by removing the need for administrative changes.
- *MWG RR359*: Clarifies that non-dispatchable variable energy resources (NDVERs) registering and converting to dispatchable variable energy resources must do so even if they don't have generation-interconnection agreements. The change also includes a missed reference to run-of-river hydro in complying with FERC's conditional order (*ER19-356*) on *RR272*.
- *MWG RR360*: Ensures that settling credits through revenue neutrality uplift is accurately documented in the Tariff and Integrated Marketplace protocols and improves market settlements for emergency energy.
- *RTWG RR354*: Waives the requirement that a transmission project sponsor provide a letter of credit when funding an upgrade should the sponsor and the transmission owner building the project be the same entity.
- *RTWG RR358*: Revises the cost-recovery mechanism from market participants who use and benefit from SPP's services by subdividing Schedule 1-A into four rate schedules, including a mix of demand and energy charges. Current 1-A charges for transmission service will become Schedule 1-A1 charges and three market-related charges would be recovered through three energy charges. (See "Board Approves Modernized Cost-recovery Structure," *SPP Board of Directors/Members Committee Briefs: Jan. 29, 2019*.) ■

— Tom Kleckner

Company Briefs

NRG Returning Cogen Plant to Mothballs

NRG Energy notified ERCOT on Friday that it plans to return its Gregory Power Partners cogeneration plant to mothballs in October. The plant, which just returned to service in June, will be operated on a seasonal basis through Sept. 30.

Gregory, a three-unit, 365-MW combined cycle facility, is located just north of Corpus Christi, Texas, on the site of an aluminum plant. Built in 2002, it was mothballed in 2016 when Sherwin Alumina filed for bankruptcy and shut down.

NRG said it was returning the plant before summer to provide "additional reliability to our customers."

Vineyard Wind to Appeal Permit Denial

Vineyard Wind plans to appeal an Edgartown, Mass., Conservation Commission decision to deny a permit that would allow two underground cables to run through the Muskeget Channel.

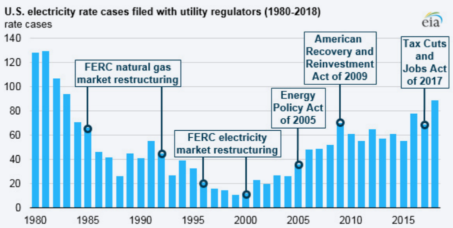
The company proposed to bury two 400-MW export cables 1 mile off Chappaquiddick from its proposed wind farm 15 miles south of Martha's Vineyard. The cables were approved by the Martha's Vineyard Commission, but at Conservation Commission hearings, fishermen pushed back, saying the cables might have detrimental marine effects.

Vineyard Wind will appeal the decision to the Massachusetts Department of Environmental Protection's Office of Appeals and Dispute Resolution.

More: *Martha's Vineyard Times*

Federal Briefs

EIA: Utility Rate Cases Increased in 2018



In 2018, 89 utilities, nearly half of all major U.S. electric utilities, tried to change electricity rates by filing rate cases with state regulatory commissions, according to the Energy Information Administration. It is the highest amount of utilities to file since 1983.

U.S. public electric utility companies must obtain permission from regulators before changing rates. Of the 89 utilities that filed cases in 2018, 10 proposed to decrease rates, one negotiated a rate freeze until 2020 and the other 78 utilities proposed increases.

The number of utility rate cases typically reflects changes in the costs of generating and delivering electricity. In 2018, increases in spending for transmission and delivery, rather than for generation, drove most of the approved increases.

More: *Energy Information Administration*

Nuclear Industry Push for Reduced Oversight Gaining Traction

The Nuclear Regulatory Commission last week released staff recommendations for rollbacks in safety inspections for the 90-plus U.S. nuclear power plants and for less flagging of plant problems for the public. The changes are part of money-saving rollbacks sought by the country's nuclear industry under President Trump.

Maria Korsnick, president of the Nuclear Energy Institute, said she welcomed changes in NRC plant oversight procedure "to ensure that it reflects a more robust understanding of the current performance of the U.S. nuclear fleet."

Opponents say the changes are bringing the administration's business-friendly, rule-cutting mission to an industry — nuclear reactors — where the stakes are too high to cut corners.

More: *The Associated Press*

State Briefs

MICHIGAN

PSC Approves DTE Purchase of 3 Wind Farms

DTE Energy has received Public Service Commission approval to purchase three wind farms to build what it says will be the largest clean energy operations in the state.

The company plans to buy Isabella I and Isabella II from Apex Clean Energy for a

383-MW operation — the largest renewable energy project for the company — and Fairbanks Wind in the Upper Peninsula from Heritage Sustainable Energy to create a 72-MW facility. Terms of the purchase were not disclosed, nor was DTE's planned investment in the farms.

The wind farms in Isabella County are scheduled to become operational by November 2020, while Fairbanks should be running by October 2020. The parks would increase DTE's renewable energy portfolio nearly 50%.

More: *Crain's Detroit Business*

NEW HAMPSHIRE

Supreme Court Denies Northern Pass Appeal

The state Supreme Court last week unanimously ruled to deny a request by project officials to order a state committee to reopen deliberations on the proposed Northern Pass $1.6 billion transmission power line.

The Site Evaluation Committee unanimously rejected the project in February 2018 and later turned aside a request to reconsider its decision and resume deliberations. Since then, Northern Pass officials "have not sustained their burden on appeal to show that the [SEC's] order was unreasonable or unlawful," the court said.

The 192-mile transmission route would have run from Pittsburg to Deerfield through more than 30 communities, bringing hydropower from Quebec into New England.

More: *New Hampshire Union Leader*

NEW YORK

State Awards Offshore Wind Contracts in Bid to Reduce Emissions

The state last week said it has reached an agreement for two large offshore wind projects.

The wind projects, to be built off the coast of Long Island, will start operation within the next five years and will have a capacity of 1,700 MW. They will account for about 20% of Gov. Andrew Cuomo's overall goal for offshore wind.

The projects, one of which will be 14 miles south of Jones Beach and the other 30 miles north of Montauk, are to be an important part of the state's plan to get 70% renewable sources by 2030. The projects will be built by a division of Equinor, and a joint venture between Ørsted and Eversource Energy.

More: *The New York Times*

OKLAHOMA

AEP Seeking Approval to Purchase 3 Wind Farms for $2B

American Electric Power is looking to buy three wind farms in Oklahoma that are currently under construction.

AEP said its Public Service Company of Oklahoma and Southwestern Electric Power Co. subsidiaries are seeking regulatory approval to purchase wind farms totaling 1,485 MW. They include a 999-MW project near Weatherford, a 287-MW project near Enid and a 199-MW facility near Alva. All are under construction by energy developer Invenergy.

AEP estimates it will invest $2 billion in the entire acquisition, but it also estimates the projects will save customers $3 billion over 30 years.

More: *Columbus Business First*

OREGON

Brown Signs Zero-emissions Vehicle Target Bill

Gov. **Kate Brown** last week signed a new zero-emissions vehicles target into law, in an effort toward reducing greenhouse gas emissions from the transportation sector.

The law requires 90% of all new vehicles sold and 50% of all registered vehicles in the state to be ZEVs by 2035.

"With the passage of Senate Bill 1044, Oregon is helping lead the nation on how to transition to a cleaner, modern transportation system," Brown said. "When zero-emission vehicles are widely used and charging stations are easily accessible to all, we can support economic development and the environment at the same time."

More: *Kate Brown*