RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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Why 4 Colo. Utilities Joined CAISO EIM, not SPP WEIS

Benefits Would be Far Greater if All Mountain West Utilities Joined EIM Together, Study Found

By Hudson Sangree

Xcel Energy and three other Colorado utilities decided to join CAISO's Western Energy Imbalance Market instead of SPP's Western Energy Imbalance Service in December because of projected economic benefits.

Those benefits could have been far greater, however, if the other former members of the Mountain West Transmission Group also had selected the EIM instead of the WEIS, a Brattle Group study found.

Mountain West was a coalition of seven utilities whose effort to join SPP's RTO fell apart when Xcel withdrew in 2018. (See *Still 'Committed,' SPP Halts Mountain West Integration Effort*.)

If all seven had joined the EIM, the benefits for Xcel and the three other utilities in its balancing authority area would be $17.34 million instead of $1.98 million per year, the study found.

"The benefits jump eight to nine times as high,"

Jason Smith, Xcel Energy | *© RTO Insider*

Jason Smith, senior manager of market operations for Xcel, told the EIM's Regional Issues Forum on Wednesday. "There's just a ton of transmission to optimize within that footprint."

Smith gave the most detailed public *explanation* yet of the decision by Xcel's Public Service Company of Colorado — together with Black Hills Colorado Electric, Colorado Springs Utilities and Platte River Power Authority — to join the EIM as soon as 2021. (See *EIM Lands Xcel, 3 Other Colo. Utilities*.)

Xcel's BAA covers the greater Denver area and most of eastern Colorado. The utility alone serves about half the state's load.

The three other one-time members of Mountain West — the Western Area Power Adminis-

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PJM Proposes Auction 6 Months After FERC Ruling

Seeks Flexibility to Accommodate States

By Rich Heidorn Jr.

PJM officials plan to hold the next Base Residual Auction about six months after they receive FERC approval of its compliance filing implementing the expanded minimum offer price rule (MOPR).

The *proposed timeline* will be included in the RTO's compliance filing to expand the MOPR tto new state-subsidized resources, due Wednesday.

Stu Bresler, PJM | *© RTO Insider*

"We have worked very hard at PJM to achieve a balance between the disparate stakeholder positions on this subject," Stu Bresler, senior vice president of market services, told a *special meeting* of the Market Implementation Committee. "We need to get back on that three-year forward mechanism."

FERC ordered PJM on Dec. 19 to expand the MOPR to new state-subsidized resources, including self-supply assets of cooperatives and vertically integrated utilities (*EL16-49*, *EL18-178*). (See *FERC Extends PJM MOPR to State Subsidies*.)

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Senate Confirms Danly to FERC

By Michael Brooks

FERC General Counsel James Danly at his confirmation hearing in November | *© RTO Insider*

The U.S. Senate on Thursday voted 52-40 to confirm FERC General Counsel James Danly as a commissioner.

Three Democrats joined the Republican majority: Doug Jones (Ala.), Kyrsten Sinema (Ariz.) and Joe Manchin (W.Va.). Majority Leader Mitch McConnell (R-Ky.) on Wednesday filed a motion to invoke cloture on Danly's nomination, which the Senate approved 54-40 Thursday morning.

Danly fills a seat left open by the death of Commissioner Kevin McIntyre in January 2019; his term will conclude June 30, 2023. His confirmation has been a matter of when, not if, since the Energy and Natural Resources Committee advanced his nomination, along with that of Dan Brouillette as energy secretary, to the floor in November. The

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Senate Confirms Danly to FERC

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Senate quickly confirmed Brouillette but did not get to Danly before it adjourned for the year. The ENR Committee re-advanced Danly on March 3. (See *Danly Re-advances, but not Without Drama*.)

Manchin, the ranking member of the committee, said prior to the confirmation vote that he was supporting Danly "because I believe he is well qualified for the job" and "he understands the complex legal issues that come before the commission." But he lambasted President Trump for not nominating the Democrats' choice — Allison Clements, clean energy markets program director for the Energy Foundation — to fill the seat left open by the departure of Cheryl LaFleur in August. Danly's confirmation gives Republicans a 3-1 majority on the commission.

"The politics involved in this town is outrageous, truly outrageous, that even proper decorum, simple civility, just a little bit of procedure is not even considered anymore," Manchin said, adding that the administration was undermining "the bipartisan structure of the commission."

He repeated a promise he made March 3 to oppose any Republican nominee to replace Commissioner Bernard McNamee, who has said he would not seek another term, unless they are paired with Clements. "I will not support another nominee unless we get both. This has got to stop. ... Let's make sure that we have a complete, working commission, and not just a partial commission that's over-weighted."

Senate Minority Leader Chuck Schumer (D-N.Y.) said on the floor that the White House has "given no reason or explanation why" Clements has not been nominated.

After the vote, FERC Chairman Neil Chatterjee *said*, "This is great news for FERC and for the country. I have appreciated getting to know and work with James as my general counsel, where he's already proven to be an invaluable asset to the commission. James has an exceptional ability to carefully and thoughtfully consider the legal and regulatory questions raised by matters before us, and I look forward to working alongside him as a fellow commissioner."

FERC Chairman Neil Chatterjee photographed General Counsel James Danly (right) as he watched the Senate confirm him to be a commissioner March 12. | *FERC Chairman Neil Chatterjee*

American Council on Renewable Energy CEO Gregory Wetstone also congratulated Danly but asked "the president to nominate, and the Senate to confirm, two more commissioners on a bipartisan basis to fill the remaining commission vacancies."

McNamee's term ends June 30, but he has said that if no replacement has been confirmed, he will stay on past that date until he is replaced or the end of the year, whichever comes first. ■

CAISO/West News

Why 4 Colo. Utilities Joined CAISO EIM, not SPP WEIS

Benefits Would be Far Greater if All Mountain West Utilities Joined EIM Together, Study Found

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tration, Basin Electric Power Cooperative, and Tri-State Generation and Transmission Association — announced in September they would join SPP's nascent WEIS, saying they thought it would be more cost-effective and collegial. (See *WAPA, Basin, Tri-State Sign up with SPP EIS*.)

SPP said in June it would start the WEIS to compete with CAISO's fast-growing EIM. SPP's move, and a new Colorado law requiring the Public Utilities Commission to examine market options, prompted Xcel to examine the costs and benefits of joining the imbalance markets, Smith said.

They hired Brattle, which found that even if all seven Colorado utilities joined the WEIS and not the EIM, the benefits to the four entities in Xcel's BAA would add up to just $1.62 million per year — about one-tenth as much as if all seven joined CAISO's imbalance market.

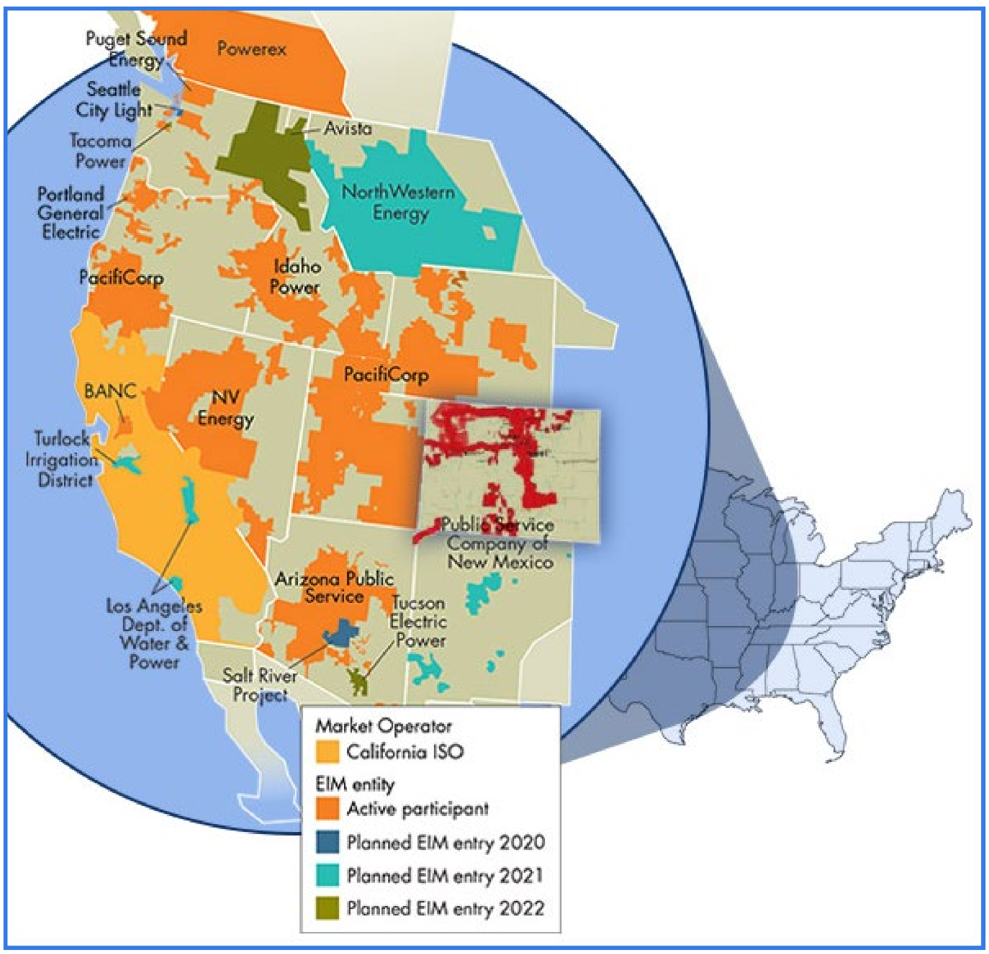
The EIM has provided nearly $862 million in benefits to participants since it began operating in 2014, mainly through cost savings and the use of surplus renewable energy, according to CAISO.

Asked if he thought the Brattle study might encourage the utilities that signed on with SPP to change their minds, Smith said he couldn't speak for them but wouldn't rule it out.

"In the future, things may change, but that's just a guess on my part," he said.

'A Close Call'

Brattle projected the four Xcel BA entities would spend roughly $1.6 million in start-up costs to join the market and $450,000 in annual administrative charges, Smith said.



Xcel's Jason Smith showed a slide with the four Colorado entities planning to join the EIM overlaid on the current EIM map.| *CAISO/Xcel*

The WEIS wouldn't require any start-up costs, but administrative fees would run about $3.5 million per year because of the relatively small number of participating entities to share the market's expenses over time, he said.

Only the three other former Mountain West participants have decided to join the WEIS so far. The EIM has nine active participants and 11 more scheduled to join by 2022, not including Xcel and the three other Colorado utilities.

Imbalance markets allow utilities to trade excess energy across BAs, often maximizing use of renewable energy such as wind and solar, and Xcel was the first large investor-owned utility to commit to becoming carbon-free by midcentury, a pledge it made in December 2018 partly in reaction to customer demands. The city of Boulder, served by Xcel, has been trying to buy its assets there to create a municipal utility. (See *Xcel Pledges to Go 100% Carbon Free*.)

Smith said the time zone difference between Colorado and California and the states' different resources would complement each other well. Colorado's solar power comes online an hour before California's morning peak, and eastern Colorado's ample wind energy continues after the sun sets on the West Coast during the evening peak.

The same synergy wasn't there if Colorado sent electricity east and south into SPP's footprint, he said.

"The geographic distance gave us an advantage quite a bit," Smith said. "That just wasn't there when you look at a north-to-south diversity overall."

Colorado has more transmission connections to SPP. Connection rights to CAISO and the other EIM entities are limited but should be adequate, he said.

"It was a close call, but we've got just enough transmission to make it viable," Smith said.

Buying or building more transfer capability should increase benefits, he told the Regional Issues Forum during its teleconference. (The planned in-person meeting in Phoenix was *called off* because of the COVID-19 coronavirus.)

The four utilities are working toward signing an implementation agreement with CAISO and don't anticipate any roadblocks, he said.

"We're ready to kick off," he said. ■

CAISO/West News

PG&E Ends $4 Billion Dispute between Fire Victims, FEMA

Removes Major Obstacle to Utility's Bankruptcy Exit

By Hudson Sangree

The Federal Emergency Management Agency last week dropped its claim to a large chunk of the $13.5 billion trust that Pacific Gas and Electric plans to fund for wildfire victims as part of its Chapter 11 reorganization.

Judge Dennis Montali | *Commercial Law League of America*

Lawyers for FEMA and PG&E told U.S. Bankruptcy Judge Dennis Montali in San Francisco that the agency had settled for $1 billion of its original $3.9 billion claim for wildfire expenses and can only recoup its money from the trust once all the individual wildfire victims have been paid.

Residents and business owners harmed by PG&E-sparked fires in 2015, 2017 and 2018 have filed more than 77,000 claims in the utility's bankruptcy case. Montali pointed out the deal could mean FEMA winds up getting nothing from the trust, which is what wildfire victims have wanted.

Stephen Karotkin | *Weil, Gotshal & Manges*

"I'm sure the fire victims will be happy to see the outcome, and so am I. Congratulations," Montali told attorneys Stephen Karotkin, who represents PG&E, and Matthew Troy, with the U.S. Department of Justice.

The dispute over whether FEMA could share in the victims' trust was one of the biggest threats to PG&E exiting bankruptcy by June 30, which it must do to take part in a wildfire insurance fund established by the state last year.

FEMA, along with a number of California state agencies, argued it was entitled to get back billions of dollars it spent responding to disasters started by poorly maintained PG&E equipment, including the November 2018 Camp Fire that killed 86 people and destroyed the town of Paradise.

Fire victims were angered by the claims and rallied against the agencies. (See *FEMA Wants $4 Billion from PG&E in Bankruptcy*.)

The U.S. Bankruptcy Court for the Northern District of California in San Francisco | *© RTO Insider*

PG&E and the government agencies reached the agreement during a mediation session March 9 intended to resolve disputes over the utility's disclosure statement, a simplified explanation of its reorganization plan for fire victims and others. The statement will soon be sent to more than 300,000 interested parties who can vote on PG&E's bankruptcy plan, the judge said. (See *PG&E Tries to Put Bankruptcy Plan in Layman's Terms*.)

Montali ordered the mediation before retired U.S. Bankruptcy Judge Randall J. Newsome last October to try to bring a timely end to one of the largest bankruptcies in U.S. history. PG&E and its adversaries, including lawyers for the fire victims' Tort Claimants Committee (TCC), said they had worked out several disputes involving the disclosure statement in last week's mediation session.

"We're pleased to report that objections raised by the TCC, the United States government and state agencies … have all been resolved," Karotkin told the judge. The agreements will be filed with the court in next few days.

"Thanks to the involvement of former Bankruptcy Judge Newsome, who's been working very hard over the last few days … we were able to reach these agreements," Karotkin said.

Montali responded: "He's my secret weapon. I'm going to turn him loose on the coronavirus next."

The bankruptcy, now estimated by PG&E to cost close to $60 billion, relies heavily on new stock and debt offerings. Fire victims and Gov. Gavin Newsom have expressed concern that a heavily leveraged PG&E may be unable to upgrade its aging infrastructure or to fully compensate those who lost homes and family members. ■

CAISO/West News

Judge OKs PG&E's $23B Plan to Exit Bankruptcy

Governor Drops Objection to Billions in New Debt amid Pandemic

By Hudson Sangree

Pacific Gas and Electric won approval Monday for its plan to issue $12 billion in new stock and to take on $11 billion in new debt to get out of bankruptcy, after California Gov. Gavin Newsom dropped his objection to the exit financing strategy in the face of the COVID-19 coronavirus pandemic-caused stock market meltdown.

The approval by U.S. Bankruptcy Judge Dennis Montali was another major hurdle PG&E had to clear in its effort to leave bankruptcy. It came during an unusual hearing held by telephone because Montali's court in San Francisco, like many other institutions and businesses, was closed to slow the spread of COVID-19.

After hearing briefly from lawyers for PG&E, Newsom's office and others, Montali said he was ready to declare PG&E's financial plan sound enough.

"The exigencies of the circumstances today do not lend themselves to try to be more detailed. The record speaks for itself," Montali said. "And therefore I'm going to compliment the moving parties and also the governor's office and his advisers for working with the debtor to come to the point we are. There are numerous things that have to continue to get resolved, but this is one of the many milestones that I think is important."

Wildfire victims and other parties to the bankruptcy must vote to approve PG&E's Chapter 11 reorganization *plan*, and the California Public Utilities Commission still must approve the proposal. (See *CPUC President Wants More Control over PG&E*.)

Gov. Gavin Newsom | *Cal OES*

PG&E's bankruptcy exit is being litigated in federal court in San Francisco. | © *RTO Insider*

PG&E filed for bankruptcy in January 2019 after a series of devastating wildfires sparked by its equipment in 2015, 2017 and 2018 put it in the position of having to pay more than $30 billion to thousands of residents who lost family members, homes and businesses in the fires.

The utility is trying to leave bankruptcy by June 30 to participate in a $21 billion wildfire insurance fund established by the state under last year's Assembly Bill 1054. The bill lists requirements PG&E must meet to take part in the fund, including the exit deadline.

As it met a series of milestones in its bankruptcy case, PG&E's stock rose from a low of $5/share on Oct. 25 to a recent high of $17.92/share on Feb. 21. (See *PG&E Resolves Dispute with Fire Victims, FEMA*.) But its stock price tumbled to $8.95/share Monday as investors sought safer investments amid the pandemic.

Lawyers for PG&E and the governor agreed Monday that it was crucial for PG&E to secure its exit financing plan before financial circumstances undermine it.

The governor withdrew his objection to the new debt PG&E plans to take on, which was based on his concern that a heavily indebted utility would be unable to make the estimated $40 billion to $50 billion in upgrades to its aging grid needed to ensure safe and reliable delivery of electricity. (See *What Spring Could Bring for PG&E*.)

Montali admitted he had trouble grasping details of the highly complex financing scheme, but he said he understood it from a "35,000-foot level." The judge said he was relying on assurances from Kenneth Ziman, managing director of the restructuring group at investment bank Lazard, a longtime financial adviser to PG&E.

Ziman *said* the equity and debt commitments PG&E had obtained from large financial institutions and investors represented the largest injection of capital in the history of corporate bankruptcies and "outside of bankruptcy would also rank among the largest capital raises in the last 20 years across all industries."

"These financial institutions and investors have committed significant capital to ensure the viability of the debtors' plan of reorganization, and I believe therefore have an interest in seeing it through to completion," Ziman wrote. "I believe these commitments also enhance the confidence of claimants, financial creditors, equity holders, ratepayers and other stakeholders that the debtors will timely emerge from Chapter 11 as a financially sound utility." ■

ERCOT News

Technology Offers Cheaper Alternatives to Tx Construction

By Tom Kleckner

AUSTIN, Texas — Some utilities are taking a hard look at non-wires alternatives (NWAs) given the difficulty and expense of getting transmission projects approved, gaining regulatory sign-off, and siting and building lines.


Hudson Gilmer, LineVision | © *RTO Insider*

Speaking last month at Infocast's ERCOT Market Summit, Hudson Gilmer, founder and CEO of line-monitoring firm LineVision, said his company and others like it offer options in the likely absence of a second competitive transmission build in Texas.

The first such effort — kicked off in the mid-2000s — resulted in 3,600 miles of transmission facilities able to carry 18.5 GW of capacity. The Competitive Renewable Energy Zone buildout, which ended in 2014 and cost $6.8 billion, connected barren and windy West Texas with the state's eastern and southern urban centers and set the stage for the massive development of renewable energy that was to follow.

Those lines are now full. ERCOT, which operates 90% of the state's grid, had 23.9 GW of wind capacity at the end of 2019. Another 12.2 GW of wind energy could be added by the end of 2022, while solar capacity could quadruple to nearly 10 GW during that same time.

"What we heard from the wind and solar developers is that transmission is the single-largest obstacle to continue integrated new renewables on the grid," Gilmer said. "What we're seeing with new, large transmission projects is that they tend to be fully subscribed. It's a chicken-or-egg thing. We believe there is an opportunity … to take a fresh look at transmission. Not in the way we've built it during the last 75 years, but as a way to unlock additional capacity on the grid."

Gilmer said he recently learned that typical usage on the average ERCOT transmission line is under 20%.

"That makes me pretty mad," he said. "If we can use technology to unlock additional capacity on those lines, that makes a difference and can make a project more viable when it suddenly didn't pencil out."

LineVision offers continuous monitoring of transmission line conductors to confirm they are performing within their acceptable operating limits. By taking advantage of low-cost sensors, Gilmer said, his company can watch for sagging lines and push out additional capacity when the line cools.

"Not every line is monitored in ERCOT," he said. "The transmission operator has to make very conservative assumptions about the line."

Gilmer said topology control, which uses a software-based solution to identify grid reconfiguration opportunities on open relays and alleviate congestion, can offer a similarly less capital-intensive solution to building new high-voltage transmission lines.

Noting that close to half of all congestion in ERCOT is outage-related, he said LineVision advocates a shift in transmission construction.

"Traditionally, we build through towers and wires. Here's an opportunity to invest in Texas using software and analytics at a fraction of the cost, making the grid much more flexible and reliable and less expensive," Gilmer said.

Making the Case

David Townley, director of public policy for CTC Global, plugged his company's advanced conductors. CTC's conductors use high-strength, lightweight carbon and glass fibers that helps them withstand extreme peak-load conditions and reduce thermal sag.

"By replacing steel with carbon fiber, you're changing the performance of [the wire's] steel core, so it doesn't sag that much," Townley said. "Less sag allows you to put more current through the line."

Townley said the conductors have resulted in about a 20 to 60% increase in operating capacity on an existing system, and "up to 100% in emergency situations."

"Freeing up that capacity gets more out of the existing system," he said.

"I sleep better at night when I don't have to worry about how close a conductor is sagging to the ground," said Jonathan Greene, senior vice president of transmission operations for Lower Colorado River Authority. "Not having to upgrade or replace wire to get 15 to 20 additional feet is a benefit."

Greene said LCRA has installed advanced conductors in four locations, three of them in river or lake crossings, using 30-year-old exist-

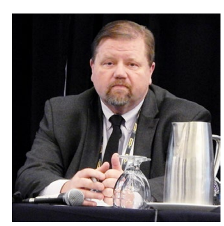

Jonathan Greene, Lower Colorado River Authority, listens to David Townley, CTC Global. | © *RTO Insider*

ing towers. He said the cooperative has seen increased line ratings but noted that LCRA hasn't seen that advanced conductors are cost effective for a full line upgrade.

"Advanced conductors are fantastic, but they're still fairly expensive," Greene said.

Gilmer, who advocates a shared-cost model, empathized with Greene.

"Regulated utilities need incentives to adopt these technologies. If you alleviate congestion with one of these technologies, you should get to share a percentage of those savings," Gilmer said. "We've been very encouraged by the response we've gotten at the federal level and at some state commissions. We're seeing, especially in the wake of California and the wildfires, an increased awareness of the safety risk for unmonitored lines. We feel like there's a very compelling return on investment in deploying sensors for situational awareness and anomaly detection."


Kip Fox, Electric Transmission Texas | © *RTO Insider*

Electric Transmission Texas President Kip Fox, whose joint venture between American Electric Power and Berkshire Hathaway Energy was involved in CREZ, posited that NWAs could actually increase returns on transmission lines.

"There's a lot of downward [regulatory] pressure on returns," Fox said, voicing an imaginary argument in favor of NWA upgrades. "'Hey, I've made this line more valuable [through NWA]. Why can't I have a higher return on this line?'" ■

ERCOT News

PUCT Responds to COVID-19 with Online Filings, Meetings

By Tom Kleckner

The Texas Public Utility Commission agreed during a short emergency open meeting Monday to take steps to minimize physical contact during the COVID-19 coronavirus pandemic.

Following social distancing best practices, the commissioners voted unanimously to suspend commission rules that require physical interactions, such as filing document hard copies, and said they may to loosen some deadlines related to the traditional filing approach. They also encouraged attendees to follow the PUC's open meetings *online* when possible.

"Each and every Texan has an obligation to help 'flatten the curve' of COVID-19 infections through the adoption of social distancing, and this agency is no exception," PUC Chair DeAnn Walker said. "There will certainly be challenges as we transition to a remote approach, but diligent utilization of communications technology can keep us connected as we do what is best for Texans."

The commission opened a docket in response to Gov. Greg Abbott's request for guidance on any laws that need to be suspended and other coronavirus-related matters (50664). Abbott declared a state of emergency Friday.

Texas' Public Utility Commission meets to discuss its response to the COVID-19 coronavirus.

The PUC said it will continue conducting commission business. As a precautionary measure, it has instituted an agency-wide teleworking policy for the "foreseeable future," with only certain "essential" personnel required to be on-site. The Customer Protection Division will continue fielding complaints.

Meanwhile, ERCOT on Monday extended its ban on in-person meetings and nonessential business travel and visitation restrictions to its facilities to May 3. The first among the first grid operators to issue such restrictions on March 3, ERCOT initially set the new protocols through March 15. That was quickly extended to March 31. (See *NYISO, MISO Join Operators in Suspending In-person Meetings*.)

The Board of Directors will convene its April 14 meeting by webinar to consider any matters that cannot be deferred until the its next regularly scheduled meeting in June. ■

ISO-NE News

Overheard at 165th NE Electricity Restructuring Roundtable

Meeting Goes Online as Covid-19 Precaution

Some 375 people registered for Friday's virtual version of Raab Associates' 165th New England Electricity Restructuring Roundtable, held exclusively online in response to the COVID-19 coronavirus pandemic.

Three of seven panelists appeared in person at the Boston law offices of Foley Hoag with moderator Jonathan Raab, while the others joined via video link.

Robert Ethier, ISO-NE | *ISO-NE*

Robert Ethier, ISO-NE vice president for system planning, stayed away from the venue under a new policy from the RTO, effective the previous day, for staff not to appear in person at any conference or stakeholder meeting through the end of April.

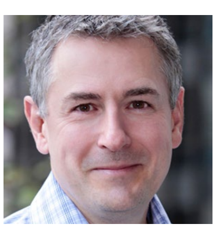
Later that day, Massachusetts Gov. Charlie Baker prohibited gatherings of more than 250 people in the state, which was already operating under a state of emergency.

The webinar focused on the evolution of the transmission system in a decarbonizing New England. Electrification of the transportation and building sectors will increase power consumption, and transmission will serve as the linchpin to the region's transition to a low-carbon and carbon-free future, Raab said.

"As New England states are pursuing their economy-wide greenhouse gas-reduction goals and mandates, our transmission grid will need to grow substantially to facilitate the development of renewable energy resources as we decarbonize our electricity supply," Raab said.

Following is some of what we heard.

Choice of Focus



Jürgen Weiss, The Brattle Group | *The Brattle Group*

Higher load, lower clean energy capacity factors and renewable curtailments mean New England will need more than 200 GW of capacity by midcentury, said Jürgen Weiss, a principal with The Brattle Group.

Left to right: Peter Shattuck, Anbaric; Jonathan Raab, Raab Associates; Jürgen Weiss, The Brattle Group; and Robert Kump, Avangrid.

"We concluded that if you decarbonize the energy economy in the New England states, you can count on roughly doubling electric load by 2050," Weiss said during his *presentation*.

Brattle's analysis found that growth in electricity demand by midcentury will range from about 77% when policy is focused on energy efficiency, to 103% when it's focused on electrification, to 136% when it's focused on electrification and renewable fuels.

"If we use electricity to make renewable fuels, to make some carbon-neutral substitute for natural gas, those processes are actually more energy-intensive; they use more electricity per unit of energy delivered to the end use than direct electrification, so in that case, you might actually see significantly more than a doubling of electricity demand," Weiss said.

Any resource scenario has important implications for the transmission and distribution system, he said. Brattle estimated a rough doubling of incremental annual national transmission investment, largely related to connecting renewable energy resources to the grid.

"Relative to the annual transmission investments that have been occurring over the last few years, which are somewhere between $10 billion and $15 billion a year [in the U.S.], we probably need to add about twice that amount over the coming decades. So $25 billion of incremental transmission investments to do several things," Weiss said.

"First, the new transmission will interconnect a lot of resources that are not going to be sitting next to load like the current generation is," he said. "Here in New England, that's obviously a lot of offshore wind."

New distribution infrastructure also will address "very different load profiles, and ultimately much higher peaks," Weiss said.

Big Wind Overflow

Ethier agreed with Weiss's analysis and said that changing use patterns are "probably going to require an entirely new way of looking at the transmission system."

"The integration of renewables and storage may significantly change the transmission flows, and we're already seeing that with lots of resources added to the distribution system, which will cause some of our distribution feeders to actually flow in the opposite direction," Ethier said.

He *outlined* ISO-NE's transmission planning process and noted its first-ever solicitation in December for competitive transmission solutions for reliability needs in the Boston area, which drew 36 proposals — both AC and HVDC — ranging from $49 million to $745 million. The RTO is evaluating proposals and will review results with the Planning Advisory Committee. (See *ISO-NE Issues First Competitive Tx RFP*.)

"There are two issues with the transmission system: There's paying for it, and then there's getting it built," Ethier said. "Both of those are time-consuming, and both of those are things that, if the past is any guide, we're going to have a hard time keeping up with the states' goals [and] meeting their carbon-

ISO-NE News

reduction targets."

In addition, developers are proposing about 15 elective transmission upgrades (ETUs) to help deliver about 11,000 MW of clean energy to load centers in New England, he said.

"We're seeing lines that are seeking to connect northern Maine; we see lines seeking to connect offshore wind to load centers in New England, and also lines for hydropower from Canada," Ethier said. "In most cases, we see multiple versions of these things that would accomplish the same goals."

The ETU proposals "are queued up now and waiting for an opportunity to sell their services and sell their project as part of some sort of clean energy procurement at the state level, and until then, they'll just bide their time in our queue," he said.

The largest public policy effect in the region these days is offshore wind, and studies have shown that the rate of spillage increases as the buildout increases, Ethier said.

The RTO last month presented its latest study results on integrating up to 8,000 MW of offshore wind into the regional grid, analysis requested by the New England States Committee on Electricity (NESCOE). (See "OSW Study: More the Better," *ISO-NE Planning Advisory Committee Briefs: Feb. 20, 2020*.)

"Spillage is where we have excess generation in New England and we actually have to back down renewable resources," he said. "At 8,000 MW we hit spillage in every month of the year, so we have to back down various economic resources to accommodate these renewables. To avoid that you either need to increase load in the region, shift load around, or add significant amounts of storage."

(Clockwise) Abigail Krich, Boreas Renewables; Paul Joskow, MIT; and William Hogan, Harvard.

Offshore Planning

Robert Kump, Avangrid | *Avangrid*

Robert Kump, deputy CEO and president of Avangrid, said his company is working on both the Canadian hydropower side and offshore.

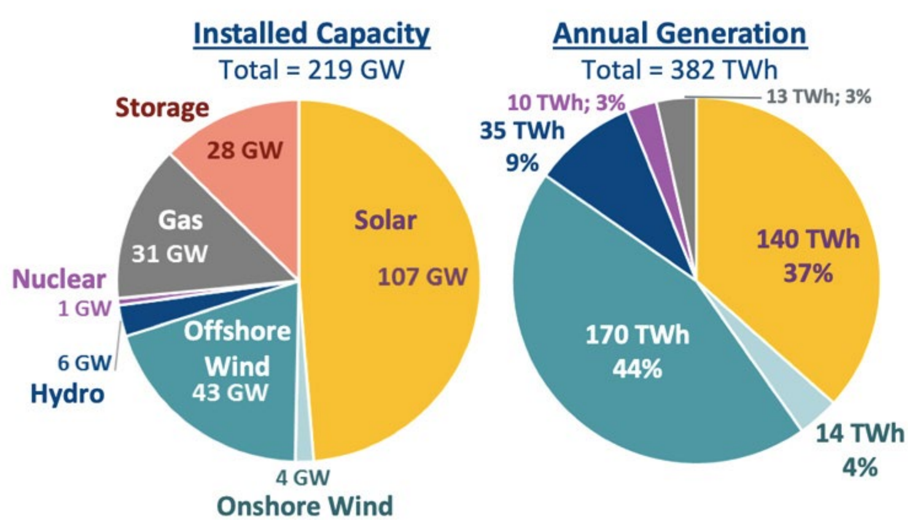
Avangrid subsidiary Central Maine Power is nearing completion of permitting for its $950 million New England Clean Energy Connect (NECEC) project to carry 1,200 MW of power from Hydro-Québec to Massachusetts, he said.

Changing use patterns are "probably going to require an entirely new way of looking at the transmission system."

—Robert Ethier, ISO-NE

"The latest approval was from the Maine Land Use Planning Commission, received in January," Kump said. "We expect any day now to get a draft approval from the Maine [Department of Environmental Protection]," which in fact *came* later that day.

"The goal would be to have all of our permits completed by the summer, and to start construction in the third quarter with a year-end 2022 completion date," Kump said. Four gigawatts of additional transmission is needed to balance variable resources, he said, citing a Massachusetts Institute of Technology *study* this year on the role of Canadian hydropower in decarbonizing the Northeast.



New England 2050 resource scenario | *The Brattle Group*

ISO-NE News

Kump also presented data from Vineyard Wind, his company's offshore wind joint venture with Copenhagen Infrastructure Partners, and called for increased state and federal coordination to reduce permitting and siting risks.

"The starting point for thinking about how we connect this brand new and significant resource to the grid is looking at where we can bring it ashore," said Peter Shattuck, chief information officer of Anbaric Development Partners. "Overall, independent transmission can minimize interconnection costs, reduce marine cabling and enable offshore wind to scale."


Peter Shattuck, Anbaric | *Anbaric*

Shattuck presented an argument for networked HVDC offshore transmission that compared scenarios of planned and unplanned development, with the latter seeing energy losses of 8%, while a planned network had only 3% losses, with comparable reductions in environmental and fisheries impacts because of 49% fewer miles of cables needed.

Wholesale Market Design

The second panel focused on what wholesale market design should look like in a fully decarbonized regional grid.

MIT economist Paul Joskow discussed how wholesale markets will support the investment costs of new generation and storage technologies.


Paul Joskow, MIT| *MIT*

"The systems in place have worked least well in stressed conditions in terms of providing efficient price formation," Joskow said. "There's been a lot of discussion about resource adequacy and capacity compensation focused on adapting capacity markets in various ways to provide additional net revenues. I don't think that the conventional capacity markets framework used in most RTOs is well-adapted to a system dominated by intermittent generation."

Joskow's observation that New England "is way behind the other states and regions in the smart meter or smart grid technology" prompted a question from Manuel Esquivel of the Boston Planning and Development Agency as to what municipalities could do to encourage the adoption of smart meters.

"Mandating real-time meters and other smart equipment, controllable sensing equipment, inverters that can do more; these are state public utility commission decisions," Joskow said. "This is not some way-out thing. Philadelphia has 100% penetration of smart meters; Baltimore has 100% penetration."

The most important thing is to get the real-time design correct, said professor William Hogan, of Harvard University's John F. Kennedy School of Government.

"If not, you'll create many new problems," Hogan said.

He highlighted that under scarcity pricing in ERCOT, high prices of $9,000/MWh last summer occurred at the right time and were not socialized through capacity market charges spread over all load. (See "Scarcity Pricing Likely Again in 2020," *Overheard at Infocast's ERCOT Market Summit*.)

Sue Coakley, executive director of Northeast Energy Efficiency Partnerships, asked what the market design would need in order to include carbon-free demand-side resources, especially energy efficiency.

"I have a long record of not being a big fan of capacity markets, so if you're worried about this problem, the worst place to start would be the capacity markets," Hogan said. "I would go much more towards the retail rate design side."


Abigail Krich, Boreas Renewables | *Boreas Renewables*

Boreas Renewables President Abigail Krich agreed with Hogan, saying that ISO-NE's current capacity market design "absolutely would not be sufficient" to decarbonize New England's grid.

"Some other mechanism is needed to secure a new way of financing, whether it's in the centrally run market by ISO-NE, or whether it's some mechanism by the states, or hedging," Krich said. "I think this is going to be an iterative process ... and there is a lot of investment needed."

Robert Stoddard of Berkeley Research Group asked if the states' roles needed to fundamentally change: For example, does New England need to adopt mandatory retail choice, as in Texas?

"I actually think the Massachusetts attorney general has it right in pushing to eliminate retail choice at the residential customer level," Krich said. "I think that experiment has not worked in Massachusetts so far. At a larger scale, there are customers who are able to make informed decisions." ■

— Michael Kuser

ISO-NE News

NEPOOL Markets Committee Briefs

ESI Virtually Rolls to April Deadline

ISO-NE is wrapping up its Energy Security Improvements (ESI) initiative ahead of an April 15 filing deadline with FERC, stakeholders learned last week during a two-day meeting of the New England Power Pool Markets Committee (*EL18-182*).

The committee plans to vote on ESI at its March 24 meeting, and the NEPOOL Participants Committee plans to vote on the market design at its April 2 meeting.

The start of the second day's proceedings was delayed by a brief discussion of teleconference protocol after ISO-NE *announced* that, in response to the spreading COVID-19 coronavirus, its staff will not participate in person at stakeholder meetings from March 12 to April 30.

ISO-NE staff members chair NEPOOL stakeholder meetings, and the RTO now joins CAISO, ERCOT, MISO, NYISO and SPP in taking all stakeholder meetings online for the time being. (See *RTOs Take Steps to Address COVID-19's Spread*.)

Later on Wednesday, NEPOOL announced that "future NEPOOL meetings in March and April will be conducted via teleconference with webinar capabilities."

Focus on Winter Benefits

Todd Schatzki of Analysis Group presented a *draft* impact analysis that shows that — in addition to expected reliability benefits — ESI can also improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory reduces energy production from less efficient and higher-cost fuels.

The study of winter months demonstrates that changes in net revenues vary across resource types, although the direction of these impacts (i.e., whether net revenues increase or decrease) is generally the same across resource types within each case, given the nature of the stressed market conditions, Schatzki said.

Much of the quantitative analysis focuses on impacts in winter months, partly because the ESI proposal aims to improve market efficiency by better aligning individual participant incentives with the region's need for energy supplies during tight market conditions, according to the full draft *report*.

ESI would be expected to increase total payments by load to suppliers on a rising scale, with the increase being lowest during periods when stressed market conditions are uncommon or infrequent and highest when they are frequent, while the extended case shows a 2.5% decrease in such payments.

Multiple factors influence the impact, such as

	Millions of Dollars		
Winter Months	No RER (savings)	RER Plus (Proxy for Load Forecast Error extra cost)*	$10 Strike Price Adder (Savings)
High Case / Severe Winter / Frequent Stressed	$ 73	$ 99	$ 2
Medium / Moderate Winter / Extended Stressed	$ 55	$ 42	$ 22
Low / Mild Winter / Infrequent Stressed	$ 9	$ 16	$ 13
Non-Winter Months	Millions of Dollars per non-Winter (nine months)		
Moderate Summer Conditions	$ 43	n/a	$ 21
Severe Summer Conditions	$ 71	n/a	$ 19

** The RER plus scenario added 600MWs of RER – ISO-NE initial indication of LFE = ~360MW*

Consumer costs scenarios under ESI | *NESCOE*

Table 7. Summary of Change in Total Payments, Winter Central Case

Product / Payment		Frequent Case CMR	Frequent Case ESI	Frequent Case Difference		Extended Case CMR	Extended Case ESI	Extended Case Difference		Infrequent Case CMR	Infrequent Case ESI	Infrequent Case Difference	
Energy & RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary Services	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

Summary of change in total payments, Winter Central Case | *Analysis Group*

ISO-NE News

the frequency and duration of the stressed conditions, and the amount of incremental energy inventory incented by ESI, as the inventory can lower market prices, particularly during stressed market conditions, the presentation showed.

Stakeholder Amendments

Massachusetts Assistant Attorney General Christina Belew presented an *amendment* to remove replacement energy reserves (RER) from the ESI proposal. (See "ESI Methodology in Question," *NEPOOL Markets Committee Briefs: Jan. 14-15, 2020*.)

"On a high level, we think that RER is both unnecessary to successfully implement FERC's fuel security requirements, and we think it is not required to be priced for compliance with NERC or [Northeast Power Coordinating Council] standards," said Belew's colleague in the Massachusetts attorney general's office, Ben Griffiths, an energy analyst for regional and federal affairs.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

The RTO's impact analysis has not demonstrated that RER would actually improve system reliability, he said.

RER has a much weaker link to fuel security, the reason for the market initiative, than either generation contingency reserves (GCR) or energy imbalance reserves (EIR) products, Griffiths said.

"While removing RER reduces some of the ISO's desired incentives, it seems that removing [RER] will save $50 [million] to $142 million per year, depending on how you combine the different winter and summer seasons," Griffiths said. "And in doing so it doesn't disrupt the rest of the core ESI design — the GCR and EIR components, and the self-disciplining that they offer one another."

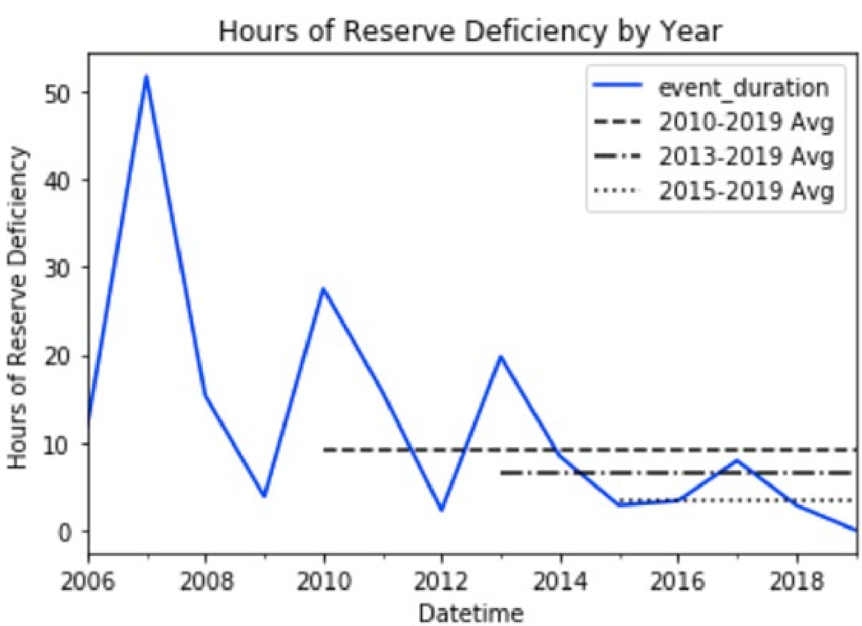
Griffiths noted that much of the material in their presentation was not new, but that they updated data looking at the historical role of reserve deficiencies: their durations, magnitudes and season.

Based upon exogenous fuel assumptions, ESI tends to increase fuel availability, which might be helpful, "but the impact analysis does not show — when the rubber hits the road, when the system gets really tight and we start approaching reserve deficiencies — that ESI actually improves reliability," Griffiths said.

"RER offers poor value for money," he concluded.

Look Back, Carefully

The Massachusetts attorney general's office and the New England States Committee on Electricity (NESCOE) are jointly sponsoring an *amendment* to add a look-back provision to the ESI program to enable evaluation of its efficacy.



The Massachusetts attorney general's office argues that reserve deficiencies are uncommon, so the need for reserve restoration production is low. | *ISO-NE*

Under the amendment, the Internal Market Monitor would assess the competitiveness of the energy call option offers and day-ahead reserve prices, determine if any uncompetitive prices are the result of market power and estimate any excess consumer payments resulting from market power.

"We are conscious of and want to respect the Market Monitor's independence; so while we felt comfortable saying what one of the purposes of the evaluation would be, we leave it exclusively to the discretion of the IMM to determine what evaluation criteria it's going to use," Belew said.

The amendment proposes that the Monitor file a quarterly report of its findings with FERC, while ISO-NE will file a quarterly certification of the competitiveness of the energy call options and resulting prices.

Jeff Bentz, NESCOE director of analysis, said his organization had open discussions of the various amendments with IMM staff, who were helpful.

"This ESI thing is in such flux, there's only small pieces being proposed now," Bentz said. "There's a lot of work to do afterwards, so we thought it would not be fruitful to define the criteria here in this room between now and March 24" — the date of the MC vote.

NESCOE also put forward several ESI *amendments* to include a $10 strike price adder; set the RER quantity to zero for non-winter months; and remove accounting for load forecast error in RER.

"We really have worked hard starting back in July and August, and came to this committee in September, made changes and continued to work towards what we thought were amendments that would decrease consumer costs while still not harming the incentives for the objectives that ISO New England was trying to achieve," Bentz said.

"This isn't an attempt to just whittle down money and to be cheap," he said. "It really comes back to what are the costs and what are the benefits. If we can get the same benefits at a lesser cost, that's the right approach."

The Markets Committee also voted to recommend that the Participants Committee support NESCOE-sponsored Tariff *revisions* relating to energy efficiency resource capacity supply obligations during scarcity conditions. (See "NESCOE Intent on EER Revisions," *NEPOOL Markets Committee Briefs: Nov. 12-13, 2019*.) ■

— Michael Kuser

ISO-NE News

FERC Reverses Ruling on ISO-NE 'Economic Life' Rules

FCA 15 Delist Deadline Delayed for ESI Filing

By Rich Heidorn Jr.

FERC Chair Neil Chatterjee and Commissioner Bernard McNamee last week reversed the commission's November 2018 order correcting a key calculation in evaluating ISO-NE's capacity delist bids (*ER18-1770-002*).

At issue is how ISO-NE's Internal Market Monitor calculates the economic life of resources that want to retire or permanently leave the capacity market. Such a resource must provide at least five years of cash flow estimates to justify their delist bids, which specify the price at or below which it would retire. The rule change was intended to correct calculations that ISO-NE said overstated the true economics of some resources and could result in improperly high delist bids.

"We find that the benefits of ISO-NE's economic life revisions do not outweigh the disruption to market participants' settled expectations associated with changing an FCM [Forward Capacity Market] rule regarding delist bids after the [Forward Capacity Auction] 13 qualification process for those delist bids had commenced," the commissioners said March 10. "Thus, we reject the economic life revisions in their entirety, effective Aug. 10, 2018."

The 2-1 vote granted a rehearing request by the New England Power Generators Association (NEPGA), which asked that the commission make the economic life revisions effective, "if at all, beginning in FCA 14." That auction was held last month. (See *ISO-NE Capacity Prices Hit Record Low*.)

In the 2018 ruling approving the calculation changes, Commissioner Richard Glick joined with then-Commissioner Cheryl LaFleur in the majority. Chatterjee filed a dissent saying that making the change effective for FCA 13 violated the commission's rule against retroactive ratemaking because market participants had made commercial decisions based on Tariff rules in place before the ruling. (See *Split FERC OKs New 'Economic Life' Rules for ISO-NE*.)

This time around it was Glick dissenting, insisting that the original ruling "correctly balanced the harms and benefits of ISO New England's proposal."

"I note that nothing in today's order precludes ISO New England from refiling substantially the same provisions tomorrow," he added. "Today's order, as I understand it, is concerned only with the timing of ISO New England's previous filing and not its merits."

ISO-NE spokesman Matt Kakley said Wednesday the RTO will determine its next steps after reviewing the order.

Chatterjee and McNamee agreed with NEPGA's contention that a market participant that chose not to submit a retirement delist bid in FCA 13 based on the then-existing economic life calculation might have submitted such a bid under the revisions based on expectations of future FCA clearing prices.

But they declined to order FCAs 13 and 14 be rerun without the economic life revisions, saying that would create more harm than benefit.

"We acknowledge the harm to market participant confidence resulting from changing the economic life calculation for delist bids midway through the FCA 13 process," they said. "However, we find that, because rerunning FCA 13 and FCA 14 would further decrease market participant confidence, such action is ill-suited to providing market participants relief in these circumstances."

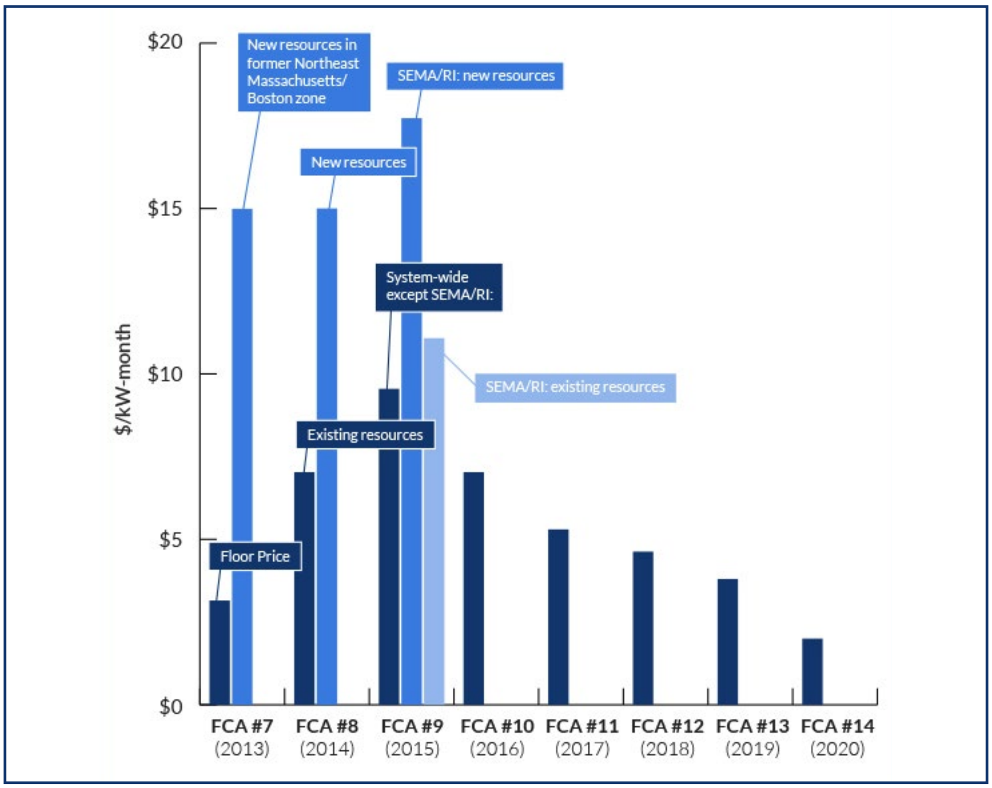
Deadline Waiver Granted

The commission also granted a waiver allowing market participants to adjust or withdraw their retirement or permanent delist bids for FCA 15 based on potential changes to ISO-NE's Energy Security Improvements proposal (*ER20-759*).

ISO-NE is expected to file the ESI proposal on April 15, following a vote by the New England Power Pool Participants Committee on April 2 — after the FCA 15 delist deadline of March 13.

The RTO requested the waiver, saying that market participants' retirement bid decisions may be affected by revenues they will earn or costs they incur under the ESI proposal.

The commission said it will extend the March 13 deadline through seven calendar days after the PC vote. If ISO-NE makes "a non-clerical change" to the ESI proposal after March 13, market participants will have seven calendar days following the vote to either withdraw their bid or update their retirement bids to reflect the changes. ■



ISO-NE Forward Capacity Auction prices (2013-2020) | *ISO-NE*

MISO News

MISO SATOA Proposal Set for Technical Conference

By Amanda Durish Cook


Invenergy's Grand Ridge Battery Storage Facility in Illinois | *BYD*

MISO's contentious first storage-as-transmission-assets (SATA) proposal will become the subject of a future technical conference to allow FERC to weigh the merits of the plan, the commission ruled last week.

FERC formally accepted MISO's bid to include storage options in its annual transmission planning while also suspending the new Tariff provisions until Aug. 11 after determining they might be "unjust, unreasonable, unduly discriminatory or preferential." Details of the upcoming technical conference will be included in a later notice (*ER20-588*).

The commission said the conference will most likely tackle MISO's plans for evaluating and selecting storage as a transmission-only asset (SATOA), the existing formula rate providing a cost recovery process for SATOA projects and the operating guides applying to the projects. FERC will also discuss SATOA's "market activities and any potential wholesale market impacts of those activities" and how the projects could potentially impact the RTO's generator interconnection queue.

MISO's plan — which stipulates that SATA be limited for now to transmission-only functions and thus operated solely by transmission owners — drew several protests from stakeholders criticizing the RTO's filing as giving its TOs an unfair advantage. Multiple entities said MISO's ruleset is primed to allow incumbent TOs to effectively have a monopoly on storage assets functioning as transmission, harming competition. Several urged FERC to reject the filing. (See *MISO SATOA Proposal Faces Opposition*.)

The commission said it will collect comments after the technical conference and will consider them in further action on the filing.

MISO has said its ruleset would avoid introducing complexities around cost recovery, particularly related to how non-transmission owners would be compensated for providing transmission services.

RTO staff have also repeated assurances that they will soon begin designing new rules that will allow SATA to function as transmission while simultaneously participating in MISO's energy markets.

MISO officials have also said storage developers and owners who are not classified as transmission owners could still propose projects under the RTO's existing rules for selecting non-transmission alternatives (NTAs) in the place of transmission projects. MISO last year placed several mentions of electric storage resources into *BPM 20*, the Business Practices Manual managing NTAs.

But MISO storage owners and developers said the treatment remains unequal because NTAs must first clear the RTO's approximately three-year generation interconnection queue. The queue is not a requirement for TOs proposing SATOA, who instead submit their projects for study through the annual MTEP process.

MISO's 2019 Transmission Expansion Plan (MTEP 19) includes American Transmission Co.'s Waupaca-area energy storage project, which is meant to ease transmission reliability issues in central Wisconsin. The first-ever SATOA project in the RTO's footprint was withheld from final MTEP 19 approval as MISO waited on the SATOA rules for its cost recovery method. The RTO had planned for its Board of Directors to hold a special March vote on approval of the project once it had FERC's go-ahead on its rules and cost recovery method. (See *MTEP 19 Could Yield First MISO SATA Project*.) ■

MISO News

MISO Eyes Sleeker Interconnection Queue

By Amanda Durish Cook

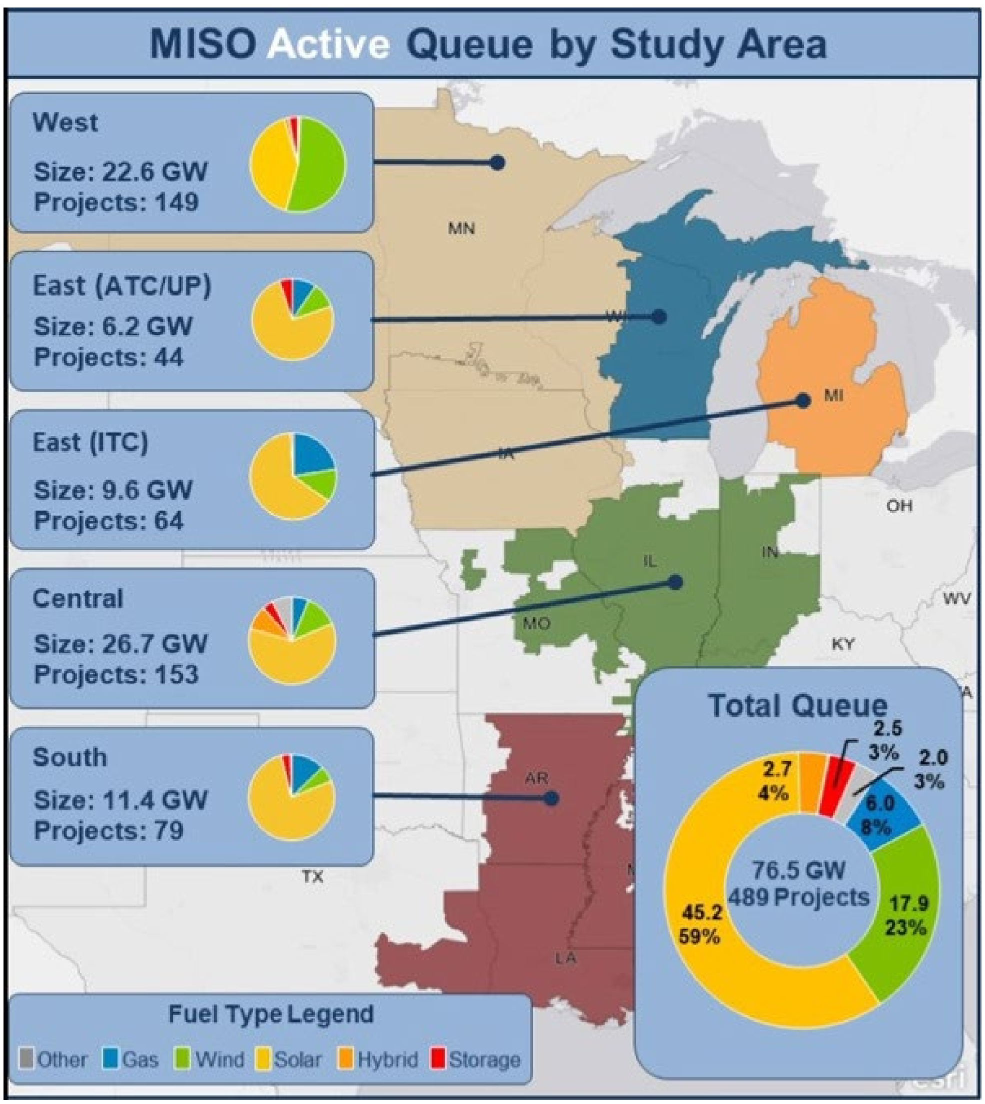
Fresh off approval for one change to its interconnection process, MISO is still looking for more ways to advance generation projects more quickly through its queue, stakeholders learned last week.

The RTO put out the renewed call for ideas during an Interconnection Process Working Group (IPWG) meeting that was converted to a conference call as MISO responds to the COVID-19 coronavirus outbreak. (See related story, *MISO Steps Up COVID-19 Response*.)

MISO is seeking ideas to allow it to simultaneously perform analyses under the definitive planning phase (DPP) and the annual Transmission Expansion Plan, possibly identifying projects that can meet multiple needs. (See *MISO Committees Tackle Queue, Tx Planning Disparities*.)

"We're going to strive to improve the process for our customers," MISO engineer Cody Doll said. "If we're on the same timeline, we could have common models and joint solution development. … It won't be a bifurcated effort. It'll be a coordinated effort between the two functions."

Doll said he would return to the IPWG in May with more discussion and early proposals. MISO doesn't yet have a specific target date for when it would file changes to its queue.



MISO queue | *MISO*

It takes just under a year for a proposed generation project to clear the interconnection queue. MISO's current queue contains 489 projects representing 76.5 GW. Nearly 60% of the projects are proposed solar generation.

"Keep in mind we were over 100 GW after last April's application deadline," MISO Manager of Resource Utilization Project Management Jesse Phillips told stakeholders. MISO's next project application window for the interconnection queue closes June 25. The deadline was extended because of the late April rollout of a new online application tool. (See *MISO to Debut Online Queue Requests*.)

MISO is also drafting Business Practices Manual language for its new, firmer requirement that project sponsors prove exclusive land use for generation projects entering the queue.

The RTO in December won approval to require interconnection customers to demonstrate 100% site control 90 days before proposed projects enter the first phase of the three-phase DPP of the interconnection queue for study. It also scrapped the previous practice of accepting a $100,000 cash deposit in lieu of demonstrating site control. (See *MISO OK'd to Require Site Control in Queue*.)

The RTO's site control land requirements are now 50 acres/MW for wind generation, 5 acres/MW for solar generation, 0.1 acres/MW for battery storage facilities and a standard 10 acres for conventional generating facilities.

MISO has said it will use contractors to help review site control documentation. The cost for project reviews will be charged to customer's study deposit, similar to other queue study costs. Paul Muncy, of MISO's transmission access planning division, said the RTO uses contractors for "numerous other project-related studies."

Muncy said MISO "intends to review site control documentation for each project in order to ensure that no projects are able to take an unfair advantage in proving that they have met all requirements."

After stakeholder inquiries, Muncy said MISO had more work to do to outline in the BPM what official documentation it will accept as proof of land use. Multiple stakeholders said the style of documentation varies on a county-to-county level and that the RTO's documentation requirements could be overly burdensome by not accounting for those differences. ■

MISO News

MISO Steps Up COVID-19 Response

By Amanda Durish Cook

MISO last week introduced temporary measures to contain the COVID-19 coronavirus outbreak, converting all in-person meetings to conference calls and barring visitors from its three offices until further notice.

The prohibition on visitors covers RTO offices in Carmel, Ind.; Eagan, Minn.; and Little Rock, Ark. Indiana and Minnesota both recently recorded their first cases of COVID-19, while Arkansas so far has no confirmed cases.

MISO's measures come about a week after other RTOs announced they were suspending in-person meetings. (See *NYISO, MISO Join Grid Operators in Suspending In-person Meetings* and *RTOs Take Steps to Address COVID-19's Spread*.)

MISO has tightened access to its control room and put a hold on all control room tours. It has also suspended all nonessential business travel for its employees.

The conference call policy applied to last week's March 10 Interconnection Process Working Group meeting and March 11 Planning Advisory Committee meeting and Integrated Roadmap workshop. MISO doesn't have any in-person meetings scheduled March 16-20. It said decisions about future meetings will be "communicated as they are made."

The RTO is conducting a reassessment of attendance at its *Board Week* in New Orleans for March 24-26, having asked all registered attendees to change their registration status by March 12 if they no longer planned on traveling to the meetings.

MISO said its "top priorities are the health and well-being of our employees and stakeholders and the reliability of the bulk electric system."

In a March 9 message to stakeholders, CEO John Bear *said*, "MISO's Incident Management Team continues to track the situation closely and is consulting with experts on appropriate safety steps that help protect employees and ensure grid reliability." The RTO has initiated more cleaning practices, and employees and contractors are similarly limiting large, in-person gatherings. He also said MISO is prepared to have employees work from remote locations.

MISO Little Rock headquarters | *Google Maps*

"All areas within MISO have business continuity plans that enable work to continue from alternative locations if necessary. We will continue to monitor developments and implement additional protocols as necessary to minimize risk to the MISO community," MISO said, adding that new developments will be posted on its Twitter account and *misoenergy.org*. ■

FERC Seeks Info on MISO Dispatchable Solar Push

MISO's proposal to bring solar resources under its umbrella of dispatchable intermittent resources (DIRs) prompted a deficiency letter from FERC on Wednesday.

The commission directed MISO to be more specific about its defined categories of solar generation and exactly when the RTO intends for them to come under dispatch (*ER20-595*).

FERC said according to MISO's transmittal letter accompanying the proposal, solar resources already in commercial operation "can, but are not required to" register under its DIR category, while solar resources with a generator interconnection agreement as of March 15, 2020, "are subject to the DIR registration requirement and will have until March 15, 2022, to register as a DIR." Solar resources without a GIA as of March 15 "must register as a DIR in order to operate," FERC summarized.

However, the commission noted that MISO's proposal didn't similarly mention the three solar categories based on GIA date, only stating that "any generation resource fueled by solar energy not in commercial operation prior to March 15, 2020, may qualify as an intermittent resource but must register as a dispatchable intermittent resource by March 15, 2022."

| *Consumers Energy*

The commission asked MISO to clarify what solar resources are meant to adhere to the 2022 deadline. It also asked when solar resources must register as DIRs if they are without GIAs as of March 15, 2020, or if their commercial operation dates are later than March 15, 2022.

In preparing the plan, MISO said it was handling the dispatch expansion much like it did with wind generation in 2011. (See *Anticipating Boom, MISO Extending Dispatch to Solar*.) RTO staff have said they wouldn't grandfather certain solar resources as DIRs. ■

— Amanda Durish Cook

MISO News

MISO PAC Briefs

MISO Invites More Stakeholder Suggestions on New Tx Planning Futures

MISO will allow stakeholders an additional month to file their opinions on the RTO's draft 2021 transmission planning futures scenarios.

The three *futures* have undergone three sets of alterations as MISO evaluates and responds to stakeholder requests. (See *MISO Outlines Electrifying Tx Planning Futures*.) The RTO had hoped to finalize new scenarios in April.

Speaking during a Planning Advisory Committee conference call Wednesday, Planning Manager Tony Hunziker said MISO will now collect stakeholders' written feedback through March 27 and hold more discussion at the PAC's April meeting.

Future I — formerly Announced Plans — assumes an 85% probability that companies' renewable growth and carbon-cutting goals will materialize and full certainty that states' clean energy plans will come to pass. It also includes a 40% reduction in carbon emissions from 2005 levels by 2040.

Future II — previously Accelerated Fleet Change — assumes MISO members meet or exceed decarbonization plans while carbon emissions drop 60% from 2005 levels. Electric vehicle adoption stimulates demand, while residential and commercial electrification reaches 39% of its technical potential, representing a 30% energy growth footprint-wide by 2040.


The MISO PAC meeting in January | © *RTO Insider*

Future III — Advanced Electrification — also assumes members fulfill their renewable plans and consumers adopt EVs. It foresees a sharp increase in demand because of residential and commercial electrification hitting 77% of its technical potential, representing a 60% energy growth. MISO also experiences a minimum 50% renewable penetration level as carbon emissions dip 80% below 2005 levels.

From its last futures draft, MISO has eliminated the nearly 35% renewable generation minimum penetration by 2040 prediction in Future I. The RTO's most aggressive renewable prediction in the MTEP 19 futures estimated that renewables would take a 36% share of the resource mix by 2035.

Consultant Kavita Maini said it didn't appear MISO was preparing for the possibility of an economic slowdown and a subsequent postponement of the retirement of certain plants in an effort to keep investments and customer rates low. She said some utilities might not achieve the emissions reductions for which MISO is planning.

"I don't think we want to plan for doomsday," Minnesota Public Utilities Commission staff member Hwikwom Ham responded, noting that MISO plans for an average growth, not the troughs and booms of the economy.

"Regardless of your political leanings, I can guarantee there's going to be at least one administration", that changes party, MISO Planning Manager Tony Hunziker said.

The futures are set to guide the 2021 MISO Transmission Expansion Plan (MTEP 21). MISO will begin planning for MTEP 2022 in June.

The RTO has also scheduled an April 16 workshop to discuss resource siting for the MTEP 2021 futures.

PAC to Begin MTEP, Queue Synchronization

MISO members will soon decide whether to retire the Coordinated Planning Process Task Team (CPPTT), charged with compiling ideas for synchronizing the annual transmission expansion plan with interconnection project planning.

The CPPTT's sole purpose was to review the MTEP and generation interconnection planning processes and identify ways the RTO could increase consistency and coordination across the two. The team forwarded its findings to the PAC and Planning Subcommittee. (See *MISO Committees Tackle Queue, Tx Planning Disparities*.)

MISO Senior Manager of Economic Planning Neil Shah said having created the list of issues, stakeholders could decide to retire the CPPTT if there are no additional assignments for the group.

Shah said once reliability, economic and interconnection queue planning processes are synched up, MISO could identify fewer and more cost-effective transmission projects.

"We can evaluate a single solution instead of three separate solutions using three different processes," Shah said. "If the timing is not aligned, there isn't much opportunity to share information and evaluate."

Some stakeholders asked that MISO either draft a white paper or hold workshops before drafting solution ideas in the PAC.

Stakeholders will again discuss the issue at the April PAC meeting.

Retiring Coal Plants Prompt Expedited MTEP 20 Projects

MISO is recommending that two substation bypass projects begin earlier than the MTEP 20 cycle allows, stakeholders heard.

The RTO received two expedited project review *requests* from Ameren in December to bypass the 345-kV Coffeen and Duck Creek substations in western Illinois. Ameren said the projects are necessary because Vistra Energy has retired the corresponding Coffeen and Duck Creek power plants, which used to be pseudo-tied into PJM.

MISO said the bypass projects will "eliminate the need for AC/DC station service at these stations since these services became inefficient due to the retirements." The RTO also said it didn't discover any reliability issues as a result of the projects.

Ameren said it will save about $1.5 million if it no longer has to provide AC/DC station service or oversee the operations and maintenance costs of the substations.

MISO said it will move both projects into Appendix A of MTEP 20 and authorized Ameren to begin construction. ■

— Amanda Durish Cook

PJM News

Monitor: PJM Saw Record-low Energy Prices in 2019

By Michael Yoder and Michael Brooks

The average load-weighted, real-time LMP in PJM was $27.32/MWh last year, a 28.6% decrease from 2018 and the lowest in the RTO's 21-year history, the Independent Market Monitor said Thursday.

According to the Monitor's annual State of the Market *report*, energy prices made up only 54.3% of the average total price of PJM's markets ($50.33/MWh), also the lowest of any year. Capacity and transmission made up 22.4% and 20.6%, respectively, of the total price.

"The most significant single source of the reduction was natural gas and coal prices," Monitor Joe Bowring said in an online press conference presenting the report. "The rest was the lower markups as people add less to their costs. That's a way for saying the market was more competitive. In addition, load was down annually 2.4%, so it was a combination of three of those things."

Of the $10.92/MWh decrease, 41.5% was a result of lower fuel costs, the dispatch of lower-cost units, decreased load and lower markups, Bowring said.

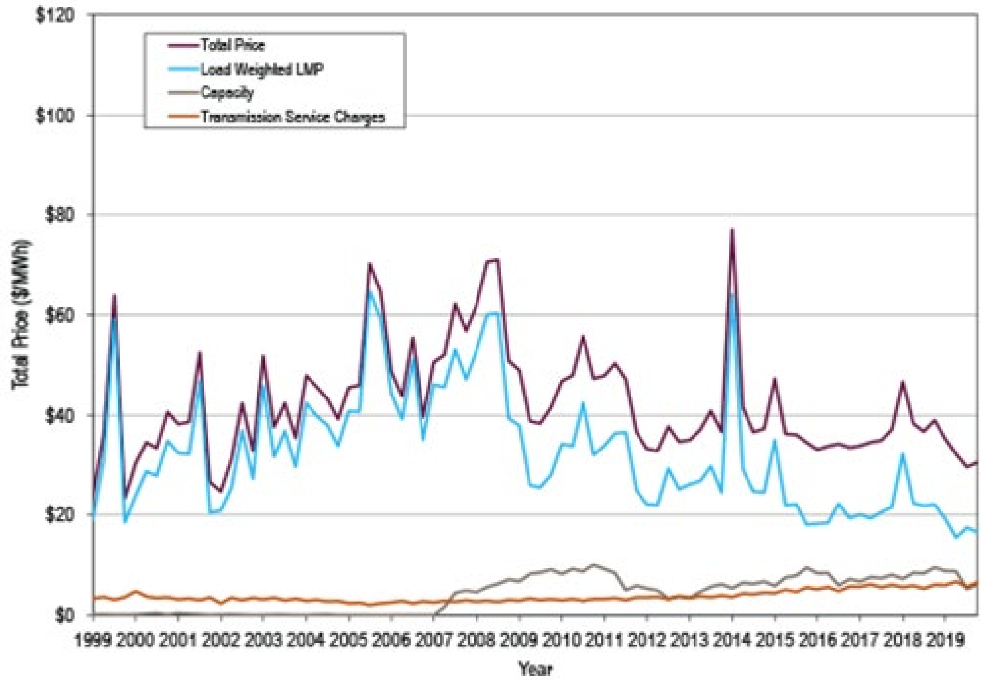
2019's average LMP beat the prior record low, set in 2016 at $29.23/MWh.

Load was down 2.4% from 2018 to 88.1 GWh. Bowring said the early months of the year were mild compared to the brutal cold of January 2018.

Natural gas continued to increase its dominance in the RTO's resource mix last year, with gas-fired output exceeding that of both coal and nuclear for the first time. Gas provided 36.2% of energy, followed by nuclear (33.6%) and coal (23.8%). Gas-fired output exceeded coal-fired in 2018 but not that of nuclear. (See *Monitor Says PJM's Capacity Market not Competitive*.)

Although the Monitor found the energy markets competitive overall, Bowring pointed out a recommendation to correct flaws in the implementation of market power mitigation rules. Bowring said the rules depend on having accurate cost-based offers equal to the short-run marginal cost and clear definitions for cost-based offers highlighted in Manual 15.

He also noted a recommendation, made in the third quarter of last year, that "PJM always enforce parameter-limited values by committing units only on parameter-limited schedules



Inflation-adjusted top three components of quarterly total price ($/MWh): January 1999 through December 2019. | *Monitoring Analytics*

when the [three-pivotal-supplier] test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies."

"Unfortunately, some generation participants in PJM are trying to undermine the entire role of market mitigation and are attacking the very idea of fuel-cost policies," Bowring said.

Oct. 1 Event

Bowring highlighted PJM's handling of an emergency event on Oct. 1, which he said the RTO mishandled. (See *PJM, Stakeholders Baffled by DR Event*.)

PJM issued a hot-weather alert on Sept. 30 for Oct. 2, expecting an unusually hot day. But the RTO declared a synchronized reserve event around 3 p.m. ET on Oct. 1, leading to a spike in LMPs close to $700/MWh.

In the report, the Monitor said several factors led to the spike. PJM drastically underestimated load for 2 to 6 p.m. in most of its forecasts; the Monitor noted that for the 2 to 3 p.m. hour, the actual load was 2,706 MWh above the day-ahead forecast and 1,202 MWh above the one-hour-ahead forecast. For the 5 to 6 p.m. hour, the actual load was 4,014 MWh above the day-ahead forecast.

It also faulted inadequate generator response to the event. Between 2:25 and 2:55 p.m., at least 79 units failed to achieve the output level requested by PJM, for a total of 872 MW.

But in his presentation, Bowring focused on a 25-minute gap on Oct. 1 in which PJM's real-time security-constrained economic dispatch (RT SCED) solutions were not approved, meaning the RTO's Locational Price Calculator (LPC) continued to use the last approved solution, produced at 4:48 p.m.

"Without an updated approved RT SCED solution, PJM does not send an updated dispatch signal to generators," according to the report. "The dispatch signal from the case that was approved at [4:48 p.m.] continued to be the target until a new case was approved at [5:14 p.m.] that solved for a target time of [5:25 p.m.]. ... For three five-minute intervals, the prices for the solved RT SCED cases differed from actual average RTO price by hundreds of dollars per megawatt-hour."

Bowring said this could be prevented by fixing a mismatch between RT SCED, which is automatically executed every three minutes, and the LPC, which runs every five minutes. The Monitor recommended that PJM approve one RT SCED case for each five-minute interval to dispatch resources during that interval, and

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that the RTO calculate prices using the LPC for that five-minute interval using the same approved RT SCED case.

MOPR 'Hysteria'

PJM held no capacity auctions last year because of the wait on FERC to act on proposals to change the minimum offer price rule (MOPR), which it eventually did in December, expanding it to all new state-subsidized resources.

"Contrary to the hysteria, there is no evidence that the expanded MOPR will lead to increased prices," Bowring said. He said that renewable developers have told him they expect to continue to be competitive in the capacity market and qualify for unit-specific exemptions.

The Monitor's report was critical of state consideration of exiting the capacity market via the fixed resource requirement (FRR) alternative.

"The rationale for leaving the PJM capacity market via the FRR option is based on the incorrect premise that the MOPR order will increase capacity market prices. The FRR option is more likely to increase the cost of capacity to customers than to decrease it," according to the report. "If new renewables are not competitive in the longer run, the least-cost option for customers in states that wish to pursue renewable targets is more likely to be competitive markets plus separate state subsidies for desired technologies than ending participation in the capacity market through the FRR option."

Other Recommendations

The Monitor made 23 new recommendations in 2019, including 12 in the annual report:

- Capacity Performance resources should be required to perform without excuses. "Resources that do not perform should not be paid regardless of the reason for nonperformance." (Priority: High.)
- Remove all maintenance costs from the cost development guidelines. (Priority: Medium.)
- Review the FRR rules, including obligations and performance requirements. (Priority: Medium.)
- Modify the market data posting rules to allow the disclosure of expected performance, actual performance, shortfall and bonus megawatts during a performance assessment interval (PAI) by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low.)
- Base the net revenue calculation used by PJM to calculate the net cost of new entry and net avoidable-cost rate on a forward-looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium.)
- Prohibit emergency stationary reciprocating internal combustion engines (RICE) from participation as demand response when registered individually or as part of a portfolio if it does not meet emissions standards because the environmental run hour limitations mean that emergency RICE cannot meet the capacity market requirements to be DR. (Priority: Medium.)
- Eliminate the total regulation signal sent on a fleet-wide basis and replace it with individual regulation signals for each unit. (Priority: Low.)
- Remove the ability to make dual offers (as both a RegA and a RegD resource in the same market hour) from the regulation market. (Priority: High.)
- Replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High.)
- Eliminate the variable operating and maintenance cost from the definition of the cost of tier 2 synchronized reserve and remove the calculation of synchronized reserve variable operations and maintenance costs from Manual 15. (Priority: Medium.)
- Define the components of the cost-based offers for providing regulation and synchronous condensing in Schedule 2 of the Operating Agreement. (Priority: Low.)
- Require all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. (Priority: Medium.) ■

PJM Proposes Auction 6 Months After FERC Ruling

Seeks Flexibility to Accommodate States

Continued from page 1

The Organization of PJM States Inc. (OPSI) voted last month to ask for at least 12 months between the FERC compliance order and the BRA, with a cap limiting the delay to no later than May 31, 2021. Regulators from Ohio and Pennsylvania abstained. Other market participants have urged PJM to conduct the next auction before the end of 2020.

Starting the Clock

Bresler said the RTO will need six months to plan the auction after the ruling, calling the expanded MOPR the biggest change to the capacity market since the beginning of Capacity Performance rules, which took effect with the 2015 BRA. "We can't start that clock the day the compliance order comes out," he said, adding the RTO will need about two weeks to review the ruling before beginning pre-auction activity.

Bresler said PJM officials will propose compressing the pre-auction activity timeline to six months from the normal nine months for the 2022/23 auction, which has been delayed since last year because of uncertainty over the rules.

PJM will ask FERC for flexibility to delay the 2022/23 auction until as late as mid-March 2021 if a member state passes legislation responding to the expanded MOPR before June 1 and the state requests the additional time.

Bresler said PJM didn't want a blanket delay if no state legislation is passed but also didn't want to lack the flexibility to respond to the states, which could seek to leave the capacity market by having their utilities adopt the fixed resource requirement. (See *PJM's MOPR Quandary: Should States Stay or Should they Go?*)

Pre-auction activities would be compressed further to 4.5 months after the 2022/23 BRA. PJM said it would conduct BRAs for 2023/24 through 2025/26 at six-month intervals, with a six-week span between the posting of auction results and the beginning of pre-auction activities.

Incremental Auctions

PJM typically holds three Incremental Auctions for each delivery year, with the first 16 months after the BRA, the second 10 months later and the third in the February before the delivery year begins.

But officials said they may cancel the first or second IAs if required by the schedule. An IA will be canceled if: its normally scheduled date has already passed; if it would fall within the same calendar year as the BRA for that delivery year; or if it falls within 10 months from the BRA for that delivery year.

Asset Life Ban

PJM officials also outlined their proposals for implementing the asset-life ban provisions of the Dec. 19 order along with their definition of "asset life" and the treatment of generation-backed demand response.

FERC said a resource would be barred from the capacity market if it clears the market under the competitive exemption by initially forswearing state subsidies but "subsequently" accepts a subsidy.

PJM's Pat Bruno said there is disagreement about what FERC meant by "subsequently," with some stakeholders saying the ban is triggered if the resource ever accepts a subsidy after winning a capacity obligation.

But Bruno said PJM will propose that the ban apply only if a subsidy is accepted for the delivery year in which the resource was treated as new entry and won a capacity obligation.

Asset Life

FERC's order said default cost of new entry (CONE) calculations should assume a 20-year asset life for all generation resources. But PJM said it will propose to allow asset lives of up to 35 years for resources seeking a unit-specific

PJM would seek to eliminate the first and second Incremental Auctions for delivery year 2022/23 if the Base Residual Auction is not held until December 2020. | *PJM*

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Adam Keech, PJM | © RTO Insider

MOPR floor price.

"We want it to be reasonably close to commercial reality," explained Adam Keech, vice president of market services.

Keech said PJM settled on the 35-year maximum based on Footnote 301 of the order, in which the commission responded to a proposal by the American Wind Energy Association, the Solar RTO Coalition and the Solar Energy Industries Association, which filed comments as "Clean Energy Industries."

"Rapid changes in market conditions and generation technology could make resources uneconomic in less than Clean Energy Industries' proposed 35 years," FERC said.

PJM said it and the Independent Market Monitor will review claims of longer asset lives based on evidence including audited financial statements; project financing documents; independent project engineer opinions; manufacturer's performance guarantees; and federal filings such as FERC Form No. 1 or SEC Form 10-K.

Generator-backed Demand Response

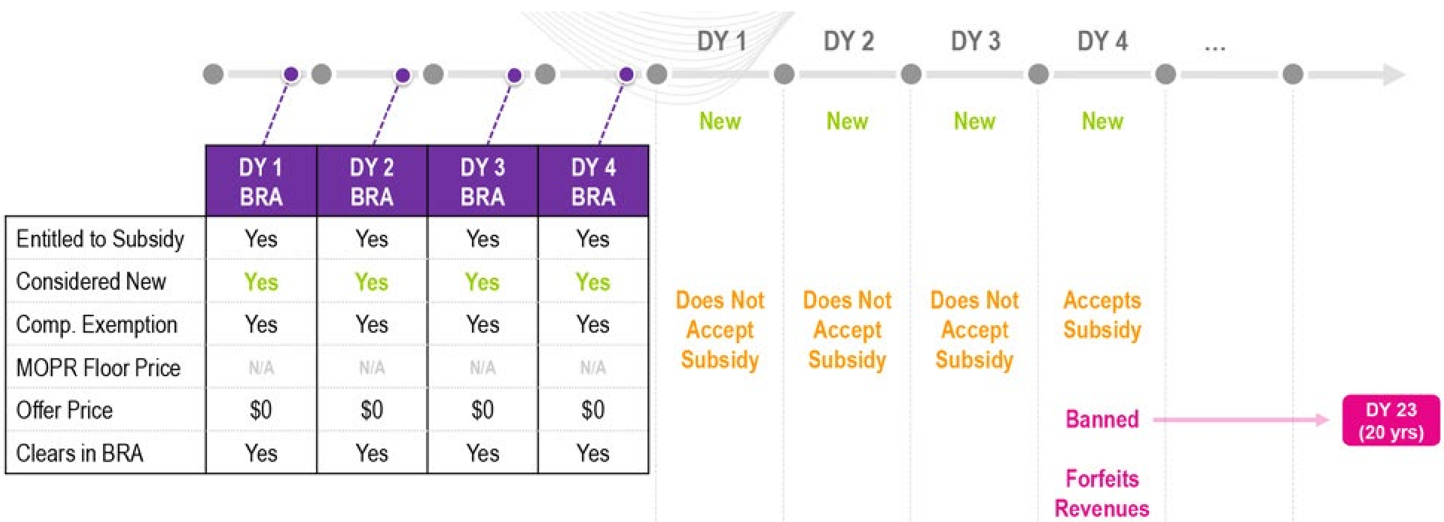
PJM also plans to propose generator-backed DR providers be allowed to provide evidence showing that the cost of a backup generator is not reflective of their cost to implement planned DR or their avoidable costs. DR providers have said that many backup generators are installed for resilience, not for provision of DR.

The RTO also will propose that DR providers be permitted to provide evidence showing reduced demand charges to offset the costs of a backup generator if the generator's cost is included in the CONE or avoided-cost rate (ACR) for the DR.

PJM acknowledged that the demand charge savings could be difficult to quantify and will require subjectivity in resource-specific reviews. But the RTO said ignoring the savings would artificially inflate the net cost of providing DR.

Filing Due Wednesday

MIC Chair Lisa Morelli ended Thursday's meeting by saying it was unlikely PJM staff will have time to share a draft of the compliance filing prior to Wednesday's deadline. "I don't have huge expectations that we will have time to do so," she said. ■



Under PJM's proposal, a resource would be barred from the capacity market if it clears the market under the competitive exemption by initially forswearing state subsidies but later accepts a subsidy for the delivery year in which it wins a capacity obligation. | *PJM*

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PJM MOPR Floor Prices Reduced for Gas, Nuclear, Solar Units

By Rich Heidorn Jr.

PJM officials told stakeholders last week that revised calculations show lower floor prices for gas, nuclear and solar generating units under the expanded minimum offer price rule (MOPR).

Last month, PJM and The Brattle Group received feedback from stakeholders on their initial calculations of net cost of new entry (CONE) and avoidable-cost rate (ACR) values, the default minimum price for existing units. (See *PJM Stakeholders Get First Look at MOPR Floor Costs*.)

At Wednesday's Market Implementation Committee meeting, PJM and Brattle shared revised numbers. PJM's *calculations* showed a 39% reduction in onshore wind's net CONE, to $1,023/MW-day, because of an increase in the capacity value (to 17.6% of nameplate) and an increase in its energy and ancillary services (E&AS) revenue offset.

Net CONE for combined cycle plants was reduced to $152/MW-day, a 35% reduction from the price PJM shared last month, because of a near-doubling of its E&AS offset to $152/MW-day.

Solar PV (fixed) came in at $367/MW-day, an 18% reduction from the earlier calculation, because of a reduction in gross CONE and an increase in E&AS revenue.

FERC's Dec. 19 order requiring an expansion of the MOPR required that net E&AS offset revenues be determined for each transmission zone. PJM plans to propose using zonal LMPs from the last three years.

Brattle's ACR *results* also showed reductions for nuclear and coal plants largely attributed to PJM's guidance that shifted costs from the gross ACRs to variable costs.

Resource Type	Gross CONE ($/MW-Day) (*Nameplate*)	Average Zonal E&AS Revenue Offset ($/MW-Day) (*Nameplate*)	Net CONE ($/MW-Day) (*Nameplate*)	Capacity Value (Percent of *Nameplate*)	Net CONE ($/ICAP MW-Day)
Nuclear	2,000	517	1,483		**1,483**
Coal	1,068	43	1,025		**1,025**
Combined Cycle	320	168	152		**152**
Combustion Turbine	294	48	246		**246**
Solar PV (Tracking)	290	185	105	60%	**175**
Solar PV (Fixed)	271	117	154	42%	**367**
Onshore Wind	420	240	180	17.6%	**1,023**
Offshore Wind	1,155	337	818	26%	**3,146**
Battery Storage	532	116	416	40%	**1,040**

Average zonal net cost of new entry (CONE), capacity value basis | *PJM*

Under the new analysis, the combination of gross ACR and variable costs include all avoidable costs to operate the resource for another year but not infrequent costs to extend the asset's life or enhance its long-term performance. Maintenance costs for systems used for electric production are included in the operating costs maintenance adder for cost-based energy offers and excluded from the ACRs.

The ACR for "representative" multiple unit nuclear plants was reduced 27% to $444/MW-day, and 22% to $692/MW-day for single-unit nuclear plants, primarily because of shifts of fuel costs, sustaining capital costs, and materials and services operating costs to variable costs.

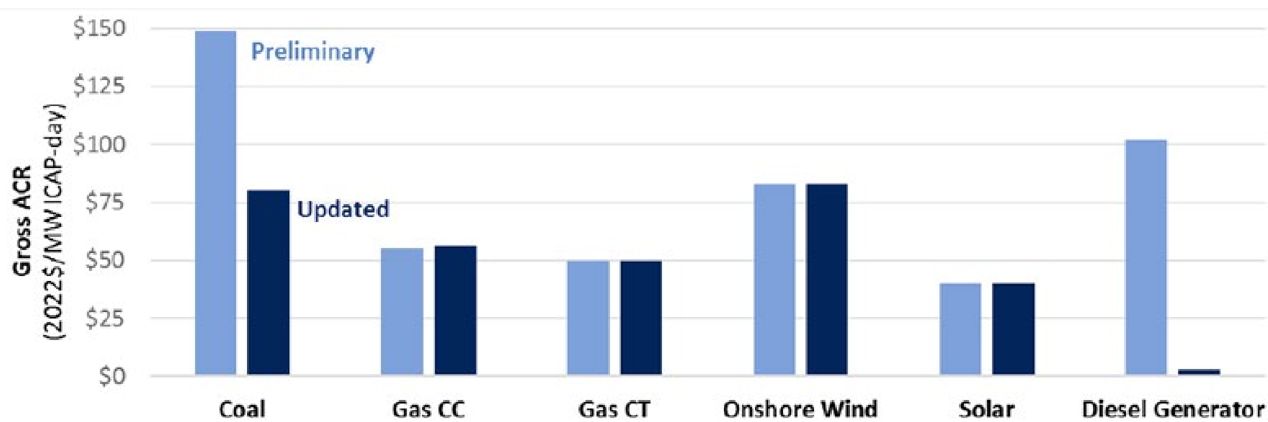
Coal's ACR was cut to $80/MW-day for the representative plant, a 46% reduction, after Brattle shifted necessary and routine expenditures to maintain performance from gross ACR to variable costs.

The diesel generator ACR was slashed to $3/MW-day from $102/MW-day based on a changed cost basis from a 12-MW wholesale resource to a 1-MW behind-the-meter resource at a commercial facility. The gross ACR was revised to include only an annual maintenance contract.

The energy efficiency net CONE value was cut 19% to $1,761/kW from $2,179/kW to correct an overcount of incentive costs. Brattle is now using the total resource cost of each program.

PJM must file a compliance filing in response to the order by Wednesday

On Monday, the Sierra Club and the Natural Resources Defense Council released a report by economist James F. Wilson criticizing the RTO's capacity market, particularly its net CONE estimates. (See related story, *Report Slams PJM Forecasting, CONE Estimates*.) ■



Existing Generation Gross ACRs, preliminary and updated ($/MW ICAP-day) | *The Brattle Group*

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Report Slams PJM Forecasting, CONE Estimates

Estimates $4B in Excess Capacity Costs

By Michael Yoder

PJM's Reliability Pricing Model is acquiring more capacity than needed, leading to dirtier, less efficient generation and billions annually in excessive costs for consumers, according to a report released Monday.

Economist James F. Wilson said PJM is purchasing unnecessary capacity because of auction design features and inaccurate peak load forecasts, leading to a retention of "older, inefficient and often environmentally damaging" power plants that should be retired and the entry of new power plants that are not yet needed.

The report, prepared for the Sierra Club and the Natural Resources Defense Council, reiterates longstanding complaints about PJM's capacity market while also attempting to quantify the impact of them.

Wilson said the total cost of the most recent Base Residual Auction, held in 2018, would have been $4.4 billion lower if its demand curve was corrected (by reducing the net cost of new entry (CONE) from $321.57/MW-day to $160.79/MW-day) and the reliability requirement was reduced by 8,000 MW.

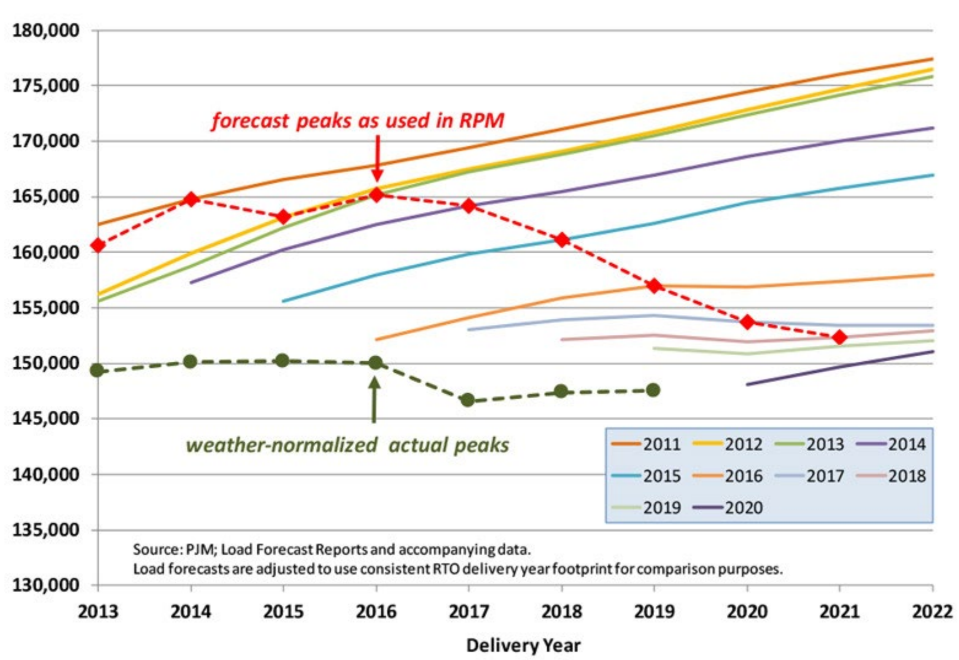
Wilson also found that the excess capacity depresses spot prices for electricity and ancillary services, dampening price signals that could attract flexible resources that are increasingly needed to supplement renewables.

Although PJM's target installed reserve margin is generally around 16% of the forecast peak load, Wilson found the RPM auctions regularly clear significantly more, accounting for an equivalent to reserve margins of 20% or more.

When the reserve margins were recalculated based on the final peak load forecast for each delivery year, the reserve margins have been 24% or more for all but one of the delivery years between 2012/13 and 2020/21. Wilson said RPM typically results in commitments that are roughly 10% or more in excess of the target, resulting in more than 15,000 MW of excess capacity in recent years.

Wilson said excess capacity is likely to increase in the future because FERC's order expanding the minimum offer price rule (MOPR) will prevent additional resources that receive state subsidies from clearing the RPM. The removal of nuclear plants and renewable sources from the RPM through the MOPR will set a higher clearing price through duplicative capacity that falsely signal a need for additional resources, Wilson said, worsening the over-procurement issue.

"RTOs such as PJM are responsible for reliability and resource adequacy, not its cost, and they generally prefer more capacity, committed sooner, and under the most stringent performance requirements," Wilson said in the report. "Capacity sellers also prefer market rules that raise capacity procurement quantities and, as a result, increase the capacity auction clearing prices they receive. Thus, the current planning procedures and market rules lead to over-procurement and higher capacity prices and have not been designed to achieve a reasonable balance in the interests of consumers between the value of more capacity and its cost and other market impacts."



PJM's RTO peak load forecasts (red) have regularly overshot its weather-normalized actual peaks (green). | *Wilson Energy Economics*

PJM Responds

Asked to respond Monday to the report, PJM said that its capacity market has helped to maintain a reliable system that has kept market-driven electricity costs flat for two decades, while at the same time incentivizing new technologies that have helped reduce emissions rates by 34% since 2005.

"PJM is constantly refining and enhancing its forecasting and capacity procurement models," Jeff Shields, PJM's media relations manager, said in a statement. "Changes made to the forecasting models starting 2016 — to account for energy efficiency, distributed solar generation and other factors — have greatly improved forecasting accuracy. In addition, the factors we used to determine the capacity needs for 13 states and the District of Columbia are developed through an independent consultant, thoroughly vetted in a stakeholder process, then submitted to FERC, which considered similar arguments raised in the report before it approved the best course to maintain resource adequacy."

Although Wilson acknowledged PJM has made improvements, he said its peak load forecasting model "has failed to fully capture this trend toward increasing efficiency, and its three-year-forward forecasts have generally been 10,000 MW or more too high." ■

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PJM PC/TEAC Briefs

Effective Load Carrying Capability for Storage

PJM will present a problem statement and issue charge to the Markets and Reliability Committee later this month on its *proposal* to apply its effective load carrying capability (ELCC) calculation to include storage resources.

PJM's Andrew Levitt told the Planning Committee that RTO officials identified ELCC, which was already under consideration for solar resources, as "an effective alternative" to the 10-hour minimum run time requirement that was rejected by FERC in October.

ELCC evaluates reliability in each hour of a simulated year and compares a resource mix with limited resources against one with unlimited resources. A resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value than a resource that delivers the same capacity only during low-risk hours.

On Oct. 17, FERC partially approved PJM's Order 841 compliance filing but set a paper hearing to determine whether its 10-hour minimum run-time requirement for storage seeking capacity obligations is unjust and unreasonable. ISO-NE sought only a two-hour minimum in its Order 841 compliance filing, while NYISO proposed four hours. (See *FERC Partially OKs PJM, SPP Order 841 Filings*.)

In November, PJM requested a 90-day extension on the initial brief deadline for the hearing and asked that the proceeding (EL19-100, ER20-584) be held in abeyance until Jan. 29, 2021, when it hopes to file Tariff changes applying ELCC to storage for all intermittent and limited-duration resources. It has proposed a new senior task force to discuss the issue.

FERC set a new deadline for initial briefs for April 27. Responses to PJM's motion for abeyance were due March 11.

Order 845 Update

PJM's Susan McGill reviewed the changes proposed by PJM in its Feb. 21 compliance filing on FERC Order 845.

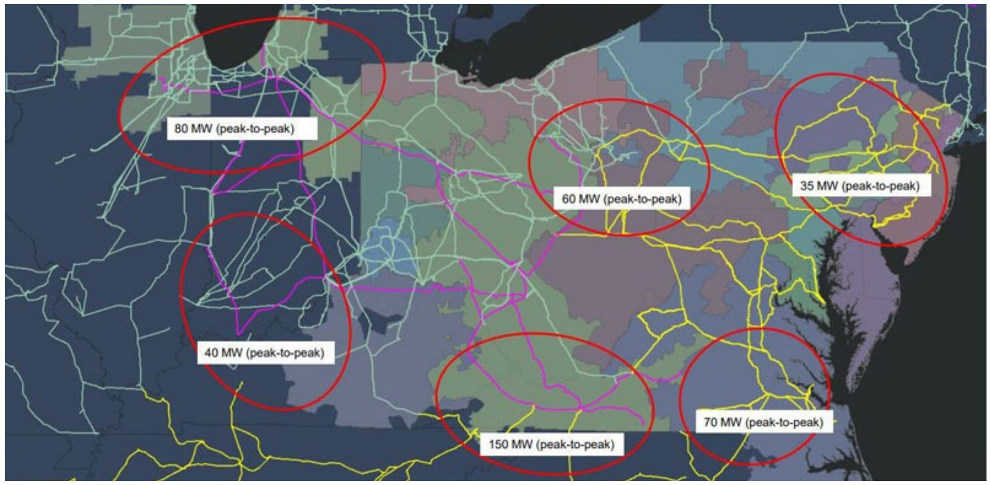
In December, FERC approved six of PJM's 10 Order 845 proposals but required changes on four issues regarding contingent facilities (unbuilt interconnection facilities and network upgrades upon which the interconnection request's costs and timing are dependent); provisional interconnection service that allows limited operation of a generating facility prior to completion of the full interconnection process; surplus interconnection service (any unused portion of interconnection service established in a large generator interconnection agreement); and the rules governing technology changes that can be considered without affecting the interconnection customer's queue position (*ER19-1958*).

PJM's Feb. 21 *filing* seeks to address FERC's concern over a lack of transparency regarding contingent facilities by clarifying the scope of the study and the criteria used. It also clarified that studies for provisional interconnection service will be conducted annually.

FERC required PJM to conduct the surplus interconnection service process outside of the interconnection queue. PJM's revisions also require that surplus service be only from in-service generators and that use of the service cannot impact the existing system or other queue projects as determined by load flow, short circuit and stability analyses. Applicants will be required to make a study deposit of $10,000 plus $100/MW.

PJM revised its process to allow technology changes as long as they do not increase the size of the project or change a generator's fuel type. Technology changes must be submitted before the return of a facilities study agreement without a material modification review.

The RTO asked that the changes take place 60 days following the commission's acceptance except for surplus interconnection service, for which it requested 180 days.



PJM is looking to expand the use of synchrophasors, in part, to help diagnose future oscillation events, like the one in January 2019, when a malfunctioning steam unit in Florida sent the Eastern Interconnection rocking like an unbalanced washing machine for 18 minutes. | *PJM*

Critical Infrastructure Ruling Expected

PJM's Christina Stotesbury told the PC that the RTO expects a ruling within days on the Transmission Owners sector's proposed confidential process to mitigate critical infrastructure on NERC's critical infrastructure protection (CIP-014-2) list.

In January, stakeholders endorsed a resolution objecting to the TOs' proposed revisions to Manual 4, saying it lacked transparency. (See *PJM Members Resist TO Critical Infrastructure Filing*.)

The PC has held three special Critical Infrastructure Stakeholder Oversight sessions, at which stakeholders separated issues into two categories: mitigation of existing CIP critical facilities, and avoiding creating new critical facilities, Stotesbury said.

A fourth meeting is set for 1-4 p.m. on April 3. Regardless of how FERC rules on the TOs' proposal, "we are still planning to move forward working the avoidance issue and defining a more transparent process to prevent those facilities from becoming CIP-critical," she said.

PJM to Expand PMU Deployment

PJM's Shaun Murphy said the RTO plans to expand the use of synchrophasors and formalize their placements — currently voluntary — into the Regional Transmission Expansion Plan.

Murphy said the RTO will begin discussions in the PC to require synchrophasors — also known as phasor measurement units (PMUs) — in all new substations and major construction projects to monitor bus voltage and line

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flows. He said the communication equipment needed at each substation costs $50,000 to $100,000. Each substation would have two or three PMUs — provided by already installed equipment such as relays or digital fault recorders.

PJM also plans to install 14 additional PMUs and retrofit four PMUs to support interconnection reliability operating limit (IROL) monitoring.

PJM last month completed a PMU data exchange with the Tennessee Valley Authority and expects to exchange data with Southern Co. and SPP later this year. The exchanges are intended to support reliability coordinator situational awareness and the Department of Energy's oscillation detection pilot, an effort prompted by the Jan. 11, 2019, *oscillation event*. (See *Oscillation Event Points to Need for Better Diagnostics*.)

In addition to current roles in post-event analysis and oscillation detection, PJM plans to expand PMUs' use to include detection of system islanding and other events and as backup monitors for area control error (ACE).

2020 RTEP Proposal Window Eyed

PJM posted the summer peak case for the 2020 RTEP on Feb. 28 and is asking transmission providers to begin their Form 715 analyses. The RTO plans to post preliminary violations between April 15 and May 1. It will open a competitive proposal window on potential solutions June 1.

Landfill Retirements Cleared

PJM's reliability analyses found no reliability violations from the retirement of three landfill gas generators: Sussex County landfill (2 MW) in the JCPL zone and the Salem County landfill (1.7 MW) in the AEC zone, both retiring April 26, 2020; and the BC landfill (6 MW) in the PSEG zone, retiring May 31, 2023.

Analyses are underway on the retirement of the coal-fired Chesterfield Units 5 and 6 (1,015 MW) in the Dominion zone, retiring May 31, 2023, and Keystone NUG (4.9 MW) in the PPL zone, retiring May 31, 2020.

Questions on PPL Supplemental Project

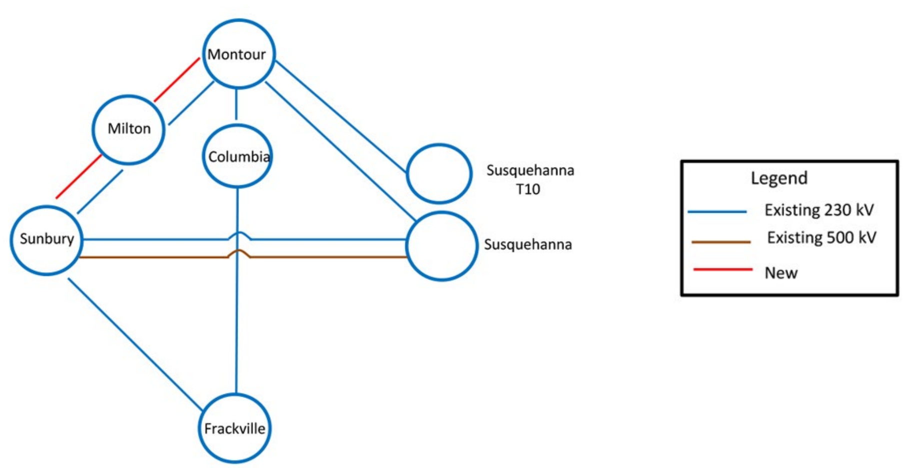
TOs presented summaries of $173 million in supplemental projects, led by American Electric Power ($105.9 million) and PPL ($63 million).

Baltimore Gas and Electric presented two projects totaling $3.2 million, and Dominion Energy presented two projects totaling $1.25 million.

AEP's biggest project is in response to the termination of the Department of Energy's plan to retire its X 530 substation, which is connected to the Ohio Valley Electric Corp. (OVEC), and its request for a new delivery point at AEP's Don Marquis substation. The total cost to AEP is estimated at $30.4 million, with OVEC spending an additional $4.4 million.

OVEC was created in 1952 to service a DOE uranium enrichment plant near Piketon, Ohio, that ceased operations in 2001. DOE ended the 2,000-MW contract in 2003 but maintains a load estimated to peak at 38 MW. (See *FERC OKs OVEC Move to PJM*.)

PPL said scope changes have reduced the cost of a supplemental project in northern Pennsylvania from $95 million to $63 million (S1106).



A representative of the PJM Industrial Customer Coalition questioned why a $63 million supplemental project is being built by PPL as a stability project rather than being considered within the Regional Transmission Expansion Plan. | *PJM*

The project was originally presented before the M-3 process in January 2016 and called for building a new 230/500-kV substation and tapping the Sunbury-Susquehanna 500-kV and 230-kV lines and the Columbia-Frackville 230-kV line to address a stability issue in the Montour area. PPL said a three-phase fault with normal clearing on the double circuit Montour-Susquehanna 230-kV line will cause generator instability and tripping of several power plants totaling 2,400 MW.

PPL's Shadab Ali said the new design involves 22 miles of second circuits on existing 230-kV lines between the Montour, Milton and Sunbury substations and rebuilding 12 miles of the Montour-Milton 230-kV line to double circuit. The project would also change the operating voltage of about 10 miles of 69-kV line between the Milton and Sunbury 230-kV substations and line terminal work at the Montour, Milton and Sunbury substations. The project is expected to be online by the summer of 2023.

David Mabry of the PJM Industrial Customer Coalition said he recognized the region as a "generation pocket" for PPL but questioned why stability issue concerns weren't identified in the RTEP process or through the generation interconnection studies rather than being a supplemental project.

"It seems like we might be transferring cost allocation onto PPL's end-use customers [for what is] a network-type upgrade," Mabry said.

Ali said the project was originally proposed based on an actual event that identified it as a weak area in the system. With as much as 45% of PPL's generation coming from that region, Ali said the utility wanted to address the issue even though it did not violate PJM or PPL criteria.

"It's a little bit more than what is required in terms of criteria," Ali said. "That's why it's not part of the RTEP process."

Mabry asked if paying for the risk was being misallocated and said new generating facilities that affect stability should have some responsibility for the upgrade costs.

"Obviously new generation is going to make the situation worse, but there's no way that new generation coming online making the situation worse has any cost responsibility in fixing the problem," Mabry said.

Ali said Mabry's feedback would be considered in potential changes to PPL planning criteria. ■

— Rich Heidorn Jr. and Michael Yoder

LS Power Challenges PJM on MEP, SATA

By Rich Heidorn Jr.

PJM's Planning Committee delayed a vote last week on a new regional targeted market efficiency project (RTMEP) process to consider whether it can be approved without first considering related cost allocation rules.

The RTO *said* cost allocation is the responsibility of transmission owners under the Consolidated Transmission Owners Agreement (CTOA) and should not be considered until FERC approves the planning change. It cited the timeline for the recent change to the market efficiency benefit/cost ratio, which was approved by FERC in February 2019 (ER19-80) and followed by a cost allocation filing in January 2020 (ER20-776).

Sharon Segner, LS Power | © *RTO Insider*

LS Power's Sharon Segner acknowledged that cost allocation is the TOs' responsibility. But she said FERC Order 1000 requires any regional planning process to be accompanied by a "cost allocation methodology."

"We believe this is a different situation than in the past … What's being proposed here is an entirely new type of regional planning project with … new parameters; new conditions; new modeling," she said. "We don't think it's possible to separate the cost allocation from the planning protocol under Order 1000, and stakeholders deserve to understand both at the same time."

PJM attorney Pauline Foley disagreed with Segner's conclusion, saying FERC has historically reviewed planning processes separately from cost allocation. "We believe, based on historical practices, that should not forestall us moving forward," she said.

The committee ultimately approved a motion by Alex Stern of Public Service Electric and Gas to defer the vote for two months and allow LS Power to share a legal memo with the PC outlining its arguments. The issue of cost allocation had been ruled out of scope in the proceedings of the Market Efficiency Process Enhancement Task Force, which developed the three sets of *packages* on which the PC had been scheduled to vote.

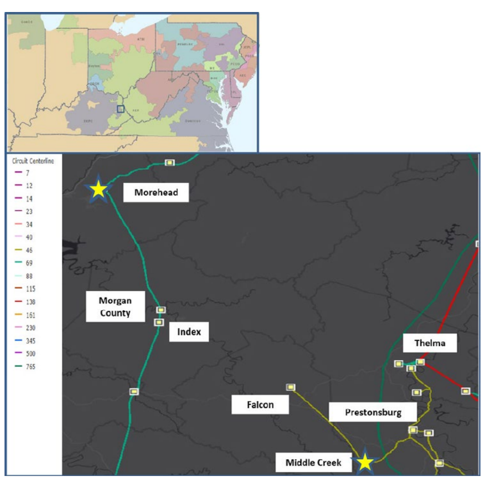
Stern made his motion after Segner said she would raise a point of order via a legal memo on the issue at the Markets and Reliability Committee meeting if the package advanced beyond the PC before considering the cost allocation. "I'd rather discuss it in a collaborative fashion rather than a contentious one," he said. "We worked hard to get consensus. While I don't necessarily agree with LS Power's legal conclusions, I would like to see them before I'm having to see them at the MRC."

The packages address changes to the benefit calculation, the window for capacity drivers and the RTMEP process, and included proposals from PJM, the Independent Market Monitor, American Electric Power and FirstEnergy. (See "Market Efficiency Process Enhancement Packages," *PJM PC/TEAC Briefs: Feb. 4, 2020*.)

Storage as Transmission

LS Power also challenged PJM during a discussion on the RTO's efforts to develop rules for treating energy *storage as a transmission asset*.

PJM hopes to develop rules by the end of the year for treating storage that would be dispatched by the RTO to address thermal, voltage or stability violations or to relieve transmission constraints. Other potential drivers are operational performance (mitigating real-time violations not identified in planning studies) or public policy (grid enhancements requested by a state to further its policies). The PC is scheduled to review a draft issue charge at its April meeting.



AEP has proposed a $41.3 million project to use storage to help correct repeated outages on its Falcon-Prestonsburg 46-kV circuit, which dates to the 1940s and 1950s and is plagued by rotted wood poles and damaged guy wires and cross arms. | *AEP*

Segner has raised questions about a proposal by AEP to use storage to correct repeated outages on its Falcon-Prestonsburg 46-kV circuit (*AEP-2018-AP010*). AEP said the 23-mile line, which dates to the 1940s and 1950s, is plagued by rotted wood poles and damaged guy wires and cross arms.

The company proposed a supplemental project to install a 2-MW battery at its Middle Creek substation at a cost of $9.7 million; rebuild 8.5 miles of 46-kV line between Prestonsburg and Middle Creek station ($25.5 million); and retire 14.5 miles of 46-kV line between Falcon and Middle Creek ($6.1 million).

AEP said the total cost of $41.3 million would save almost $30 million over the $70 million cost of rebuilding the entire 23-mile line.

Segner said PJM cannot include non-transmission alternatives such as storage in the Regional Transmission Expansion Plan until it has been designated as transmission by FERC. Allowing AEP to win approval of the project under the M-3 process — which is limited to TOs — discriminates against non-TOs, she said.

PJM's Aaron Berner said the RTO disagrees with LS Power's position. "We don't believe there are any issues about how the M-3 process is being followed," he said. "The asset is being proposed in accord with that process."

Segner said her company might seek to use the dispute resolution process under M-3.

"We would like to avert dispute resolution," Berner said. "But if you wish to continue that … we can start discussions on how to move that forward."

A similar dispute has arisen in MISO, where LS Power and other intervenors have challenged a proposal to allow the selection of storage-as-a-transmission-only asset in the MISO Transmission Expansion Plan. (See *MISO SATOA Proposal Faces Opposition*.)

"Hopefully FERC will rule on the MISO issue sooner rather than later," Segner said. A few hours later, FERC did rule, ordering its staff to schedule a technical conference on the issue. The commission said MISO's Tariff changes "may be unjust, unreasonable, unduly discriminatory or otherwise unlawful" (*ER20-588*). (See related story, *MISO SATOA Proposal Set for Technical Conference*.) ■

PJM News

PJM Operating Committee Briefs

SOS to Meet Weekly on COVID-19 Impacts

Paul McGlynn, PJM | © RTO Insider

PJM's Paul McGlynn told the Operating Committee on Thursday that the *System Operations Subcommittee* (SOS) will begin holding weekly conference calls later this month to discuss how the COVID-19 coronavirus is impacting generation and transmission operators locally "and the steps that we're all taking to deal with the situation."

"I think it will help us to share best practices," McGlynn said.

PJM has canceled all business travel, restricted access to its buildings and limited stakeholder meetings to Webex through at least March 27. The RTO is encouraging staff to stay home if feeling ill and planned to hold a telecommuting exercise March 13 to test its remote capabilities.

Scott Heffentrager, PJM's chief security officer, said there have been nine presumptive cases of COVID-19 in Montgomery County, Pa., where the RTO's two control rooms are located. PJM is conducting regular sanitizing operations of the control rooms.

The RTO will announce a decision by April 3 on the status of its Annual Meeting, scheduled for May 4-5 in Chicago.

PJM canceled the first three weeks of its Operator Seminar, scheduled to begin in Baltimore on March 10, and will decide by the end of today if training set for Columbus, Ohio, will be held.

Senior Vice President of Operations Mike Bryson said companies should contact PJM's training department if they are concerned about staffers unable to complete required training because of the cancellation.

Mike Bryson, PJM | © RTO Insider

Heffentrager said PJM has experienced an increase in "phishing attempts and other scams" related to the virus. NERC warned of the risk of virus-related phishing attempts in a *Level 2 Alert* it issued March 10.

The alert advised registered entities to maintain situational awareness, reinforce good personal hygiene practices, and review and update business continuity plans. It also advised of possible supply chain disruptions that could affect the availability of electronics, personal protective equipment and sanitation supplies.

| Lawrenceburg Municipal Utilities

Station Power Complaint Challenges FERC Jurisdiction

PJM Associate General Counsel Steve Pincus briefed members on a FERC complaint filed March 6 by Lawrenceburg, Ind., and the Indiana Municipal Power Agency against the RTO, American Electric Power Service Corp. and Lawrenceburg Power alleging that the commission does not have jurisdiction over station power and seeking to void the power self-supply monthly netting provisions of the RTO's Tariff (*EL20-30*).

The city's Lawrenceburg Municipal Utilities has an exclusive franchise for supplying electricity within city limits and says Lawrenceburg Power's 1,096-MW combined cycle plant in the city must take station power service from the city because Indiana law does not allow it a choice of retail supplier. Lawrenceburg Power is owned by a joint venture of The Blackstone Group and ArcLight Capital Partners. The plant is interconnected with AEP transmission facilities under PJM's operational control.

The complaint asks FERC to declare that supply station power is a retail sale over which the commission lacks jurisdiction and that PJM Tariff provisions providing a merchant seller the right to self-supply station power through monthly netting are void and unenforceable. The complainants say Lawrenceburg Power must take station power service under the retail rates and terms of state and local law.

"The reason we're bringing this to your

PJM News

attention is the complaint may implicate other members," Pincus said.

Comments and PJM's answer are due March 30.

FERC approved the netting rules in 2001, saying station power can be supplied to a generating plant in three ways: on-site self-supply (from behind-the-meter generation); remote self-supply (from another generator owned by the same company); or third-party supply.

The city is relying on federal court rulings in 2010 and 2012 that electricity purchased from a third party for use at a generating plant is a retail sale subject to state jurisdiction.

Manual 3 Update Prompts Questions

Stakeholders voiced surprise and concern in response to a proposal to create a confidential appendix to *Manual 3* (Transmission Operations), which details requirements for transmission outages and includes guidelines on thermal, voltage and stability limits.

PJM's Lagy Mathew said the RTO plans to move section 5 of the manual — which contains operating procedures for specific areas of the system and is amended frequently to reflect topology changes — to a new Manual 3B (Transmission Operating Procedures). Because of its sensitivity, section 5 is only accessible to stakeholders with Critical Energy/Electric Infrastructure Information (CEII) clearance.

Mathew said the published version is not always current and that even members with CEII clearance don't see changes until the semiannual update. PJM maintains a separate, internal-only version for system operators, he said.

PJM proposed that the new Manual 3B not go through the committee endorsement process when it is revised, although the RTO would review changes monthly at SOS meetings.

That would ensure that the operational procedures are current for PJM dispatchers and eliminate the need for the separate internal version, Mathew said.

Several stakeholders questioned the value of the proposed change. "Why do you need to do it?" one stakeholder asked. "You already have two versions."

Adrien Ford of Old Dominion Electric Cooperative recalled "very contentious" discussions in the OC regarding "the whole gas contingency situation, and much of that was in the CEII version of Manual 3."

Darlene Phillips, PJM | © *RTO Insider*

"I'd urge PJM not to make a change until we've had a more fulsome discussion," she added.

PJM's Darlene Phillips said staff "underestimated the level of conversation and confusion that this might cause. We thought we were doing something that would simplify the process."

She said staff will create a question-and-answer document to address stakeholders' questions in time for the OC's April meeting.

Generation Cold Weather Survey Due April 1

PJM's Vince Stefanowicz reminded generation operators that the RTO's survey on minimum operating temperatures, which opened on *eDART* on Dec. 1, will close April 1. The survey was prompted by the joint NERC/FERC *report* on the MISO cold-weather event in January 2018. ■

— Rich Heidorn Jr.

PJM MIC Briefs

PJM 'Confident' on Fast-start Filing

Tim Horger, PJM | © RTO Insider

PJM is "confident" it will meet FERC's deadline for resolving pricing and dispatch misalignment issues in its fast-start pricing proposal, the RTO's Tim Horger told the Market Implementation Committee on Wednesday.

In January, FERC held PJM's fast-start compliance filing in abeyance until July 31, after the Independent Market Monitor and others told the commission the RTO currently computes dispatch instructions using a different market interval than it uses to calculate prices. "PJM appears to dispatch resources for a target interval that is roughly 10 minutes in the future but immediately assign the prices associated with that future dispatch interval to the current interval," the commission said. (See *FERC Stalls PJM Fast-start Compliance Filing*.)

In April 2019, the commission ordered PJM and NYISO to revise their tariffs to allow fast-start resources to set clearing prices, saying their current rules are not just and reasonable.

Horger said PJM staff conducted a site visit to SPP and scheduled a conference call with MISO to learn how those RTOs implemented fast-start pricing. PJM's plan to visit MISO was canceled because of new travel restrictions implemented in response to the COVID-19 coronavirus pandemic.

"They're not going to be able to sit in with the [MISO] operators, but we think that the conference call … should be beneficial. All the questions that we're looking at should still be answered. We don't think that's going to get in the way of any decision moving forward," Horger said.

He said PJM is working with the Monitor to solve the alignment issues to meet FERC's directive and hopes to develop a "comprehensive package" that could include additional changes to the RTO's real-time security-constrained economic dispatch application.

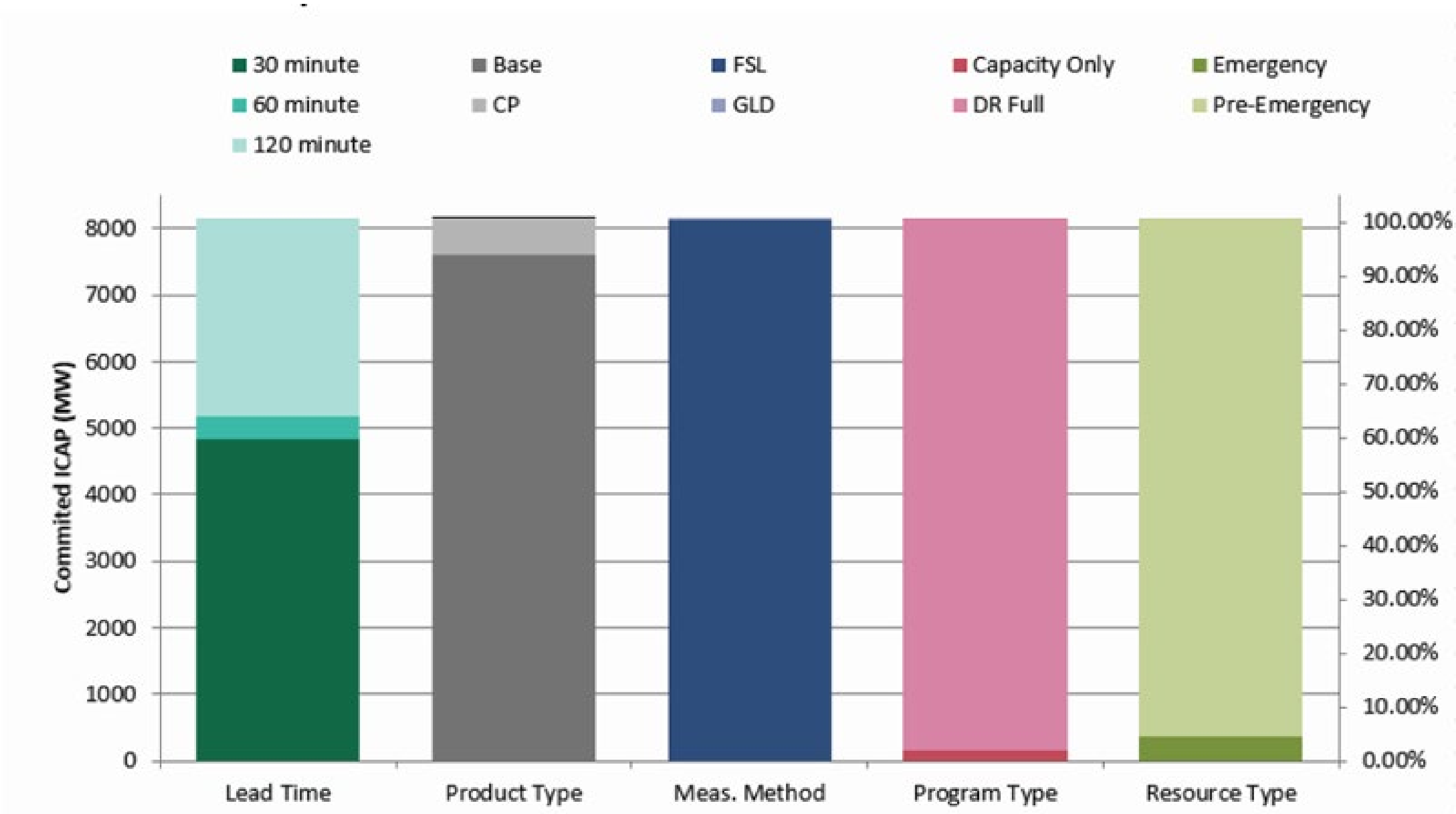
"If we can't move forward with the comprehensive package, PJM still wants to move forward with the narrow approach that PJM feels is in compliance with the fast-start order," Horger said. He said the RTO will return to the MIC in April with the "path forward."

Scope, Name Change for Credit Subcommittee?

Dave Anders, PJM | © RTO Insider

PJM's Dave Anders said the RTO will propose a revised charter for the *Credit Subcommittee* that could have it reporting directly to the Markets and Reliability Committee to raise its "visibility" and improve meeting attendance.

Anders said the subcommittee — which hasn't met since December 2018, as members have focused their efforts on the Financial Risk Mitigation Senior Task Force in the wake of the GreenHat Energy default — is the best venue



Demand response for the 2019/20 delivery year by lead time, product type, measurement method, program type and resource type | *PJM*

PJM News

for considering a planned problem statement over a credit risk issue the RTO identified last month.

PJM told members Feb. 12 that it had identified a potential credit risk for the third Incremental Auction for the 2020/21 delivery year. "The good news is the potential credit risk … did not materialize" in the auction, which began Feb. 24, Anders said Wednesday.

Although the risk was expected to apply to only a small number of bids, PJM said that if a capacity market participant submits buy bids in an IA that could result in a position that is in excess of the committed unforced capacity for the delivery year in the same account, the RTO would require the participant to post collateral to secure any uncovered position.

PJM said that it will introduce a problem statement and issue charge to provide "additional clarity and protections with respect to certain capacity market scenarios."

In addition to having the subcommittee report to the MRC rather than the MIC, Anders said PJM is considering broadening the subcommittee's charter to "look more at risk issues and risk mitigation." The revised charter of the "credit/risk" subcommittee will be brought to the MRC, perhaps as early as this month's meeting, he said.

PJM Developing Alternative on Stability-limited Generators

PJM officials outlined a potential change in how it curtails generating output when needed to maintain stability during nearby maintenance outages.

Units must sometimes be reduced below their normal economic max limit if a planned or unplanned outage presents stability problems that could result in damage to the units.

Current rules require the RTO to implement a thermal surrogate to reflect the stability constraint in the day-ahead and real-time markets and to bind the constraint, affecting the unit's dispatch.

Alternatively, a generation owner can voluntarily reduce its eco max limit and submit a notification ticket to PJM. In that case, the RTO will not bind that constraint and the unit will be paid the system LMP at the reduced output.

Units can also agree to reduce output in lieu of making system upgrades when stability limits are identified in the interconnection study process.

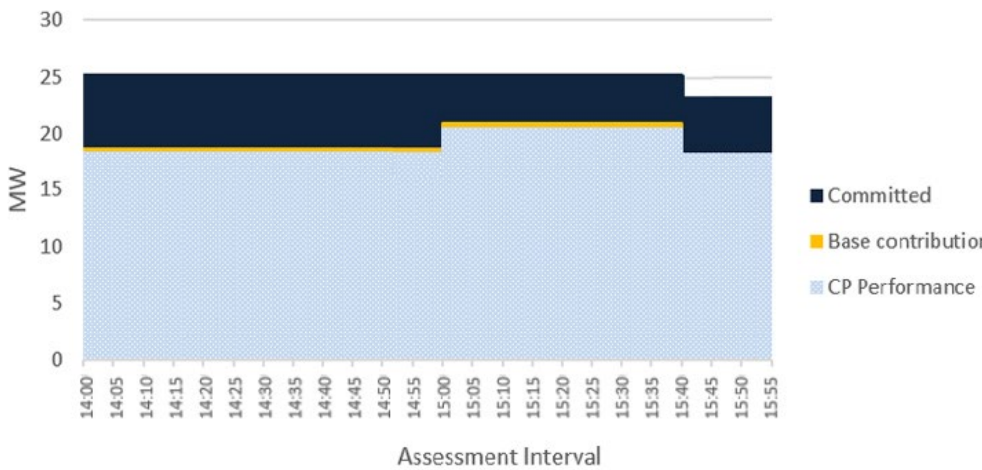
The MIC agreed in August to consider alternative approaches in response to a problem statement and issue charge by Panda Power Funds' Bob O'Connell, who said PJM's decision to remove supply from the market to address stability constraints will result in some units committing at price-based offers, rather than cost. Under the RTO's rules, only the affected generator would know of the constraint, O'Connell said, gaining a competitive advantage over other units and possibly incorporating greater mark-ups into their offers. (See "Modeling Units with Stability Limitations," *PJM MIC Briefs: Aug. 7, 2019*.)

PJM's Keyur Patel outlined a *proposal* to model stability limits on generating units as a "capacity constraint" that doesn't directly affect the LMP. The sum of megawatts from stability-restricted units would be capped at the stability limit regardless of virtual bidding. The sum of energy megawatts plus reserve megawatts from stability-restricted units would also be capped at the stability limit. The output of stability-restricted units would be based on their offer curve and LMPs.

Stakeholders questioned some of the examples in Patel's presentation, saying they did not respect merit order. None offered any additional suggestions to the solution *matrix*.

MIC Chair Lisa Morelli said the committee will begin considering complete packages at its next meeting.

Load Management Mid-Year Performance Report



Load management interval performance during Oct. 2, 2019, performance assessment interval event | *PJM*

PJM's Jack O'Neill gave a *presentation* on the Load Management Mid-Year Performance Report, highlighted by the performance assessment interval (PAI) event on Oct. 2, 2019, the first to occur since April 2015.

PJM dispatched both Capacity Performance demand response long lead resources and base DR from 2 to 3:45 p.m. ET in the Dominion, PEPCO and BGE zones and from 2 to 4 p.m. in the AEP zone during the event, which was caused by an underestimated load forecast, combined with typical maintenance schedules and unexpected line losses. (See *PJM, Stakeholders Baffled by DR Event*.)

CP resources, which were in their mandatory compliance period, produced 19.9 MW of reductions, 78% of the committed capacity of 25.4 MW. Base DR, which was not mandated to respond, produced only 373 MW of an expected 704 MW.

PJM uses the expected energy reductions reported by curtailment service providers as part of the dispatch decision-making process when DR resources are required to maintain system reliability, the report said.

The event resulted in $40,049 in penalties ($284/MW) on CP resources that failed to produce required reductions and bonuses totaling $447,666 ($34.73/MW), nearly all of it to base DR resources.

The RTO has 8,159 MW of load management resources for 2019/20. ■

— Rich Heidorn Jr. and Michael Yoder

SPP News

MISO, SPP Staff Recommend 2020 Joint Study

By Amanda Durish Cook and Tom Kleckner

MISO and SPP staff are both recommending that the RTOs take another stab this year at a coordinated system plan (CSP) in their elusive pursuit of an interregional project.

Staff have identified 10 congestion areas that merit further evaluation and shared them with stakeholders March 10 during the Interregional Planning Stakeholder Advisory Committee's annual issues review. The areas were selected based on their level of congestion and shadow prices, which both RTOs use to identify economic congestion issues.

MISO and SPP have conducted three joint studies since 2014 but have yet to come up with a project to which both could agree. The RTOs modified project criteria last year to improve their chances of reaching an agreement, although differences still remain. The changes included a mandated frequency of CSP studies, elimination of the $5 million cost threshold for the projects, addition of avoided costs and adjusted production cost benefits to project evaluation, and removal of the joint modeling requirement in favor of individual RTO regional analyses. (See *MISO, SPP to Ease Interregional Project Criteria*.)

The recommendation to undertake a CSP must still be approved by the Joint Planning Committee, which is composed of a representative from each RTO and meets later this month. Assuming its approval, the CSP process would begin shortly thereafter with the scope's development. Initial portfolios would be filed by each grid operator in August.

The Advanced Power Alliance (APA), American Wind Energy Association and Clean Grid Alliance (CGA) filed a joint letter with the IPSAC supporting the need for interregional planning. They said it is a need that "continues to increase as the use of the grid evolves" with renewable energy's replacement of fossil fuel generation.

"It should now be clear that forward-looking regional transmission planning is indispensable to ensure both reliability and cost-effective results for customers," the organizations wrote.

APA's Steve Gaw highlighted the need to address current restrictions on moving power between MISO North and South. Ben Stearney, MISO's interregional planning adviser, said the RTO has been evaluating the issue since last year but has found placing the solutions in the CSP to be a "gray area." (See *Interregional Projects May Become Reality for SPP, MISO*).

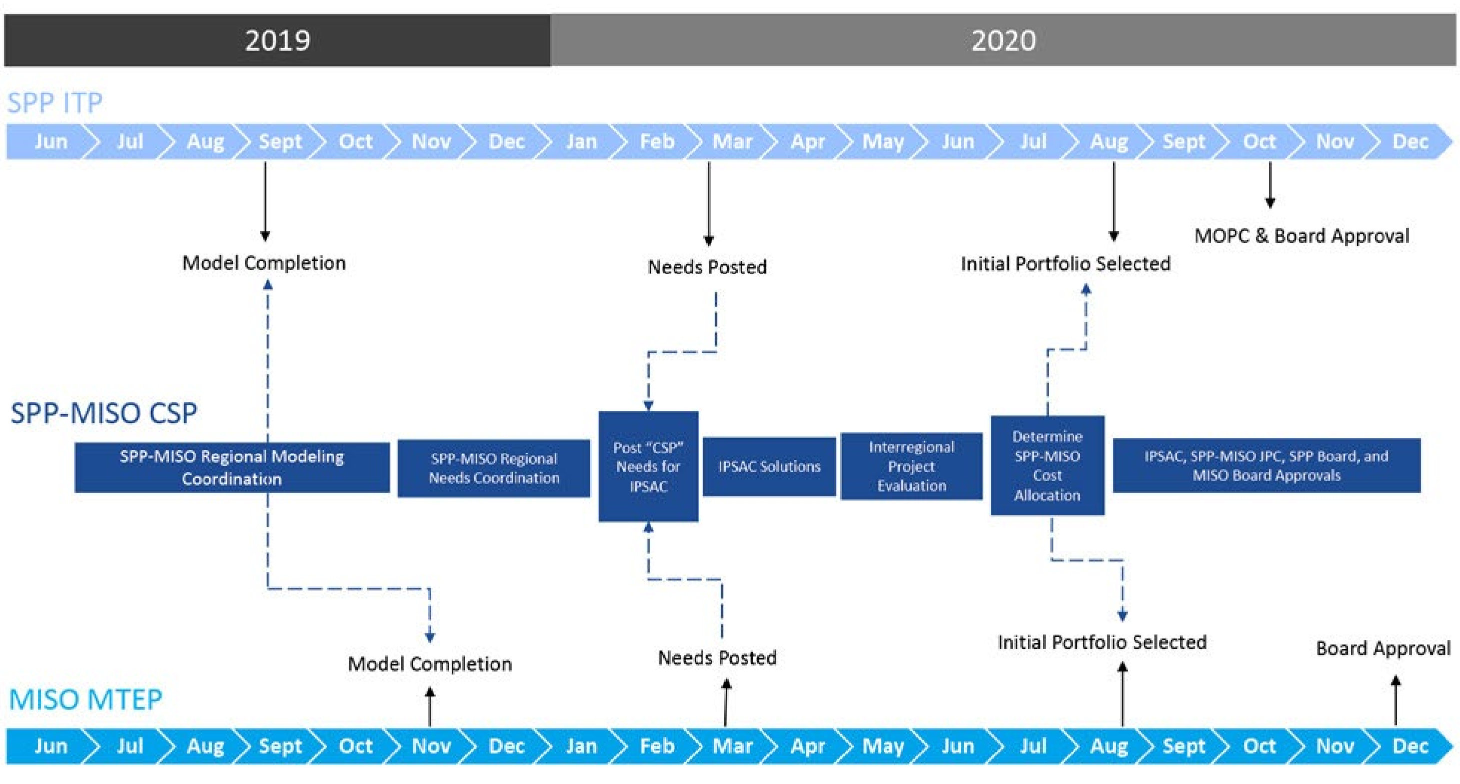
CGA's Natalie McIntire raised concerns about MISO's 2019 futures, which are also being used in its 2020 Transmission Expansion Plan models, saying they are "not very representative of what the future is likely to be like."

Stearney said his staff are working "diligently" on its 2021 futures. However, the futures are not likely to be ready for the 2020 study.

"Part of the advantage of the new process is that it allows us to refresh on an annual basis," Stearney said.

Regulators' Seams Committee Wants More Info

Meanwhile, the Organization of MISO States (OMS) and the SPP Regional State Committee's (RSC) Seams Liaison Committee (SLC) is seeking more information from the RTOs before it scopes its own interregional issues analysis.



| SPP, MISO

SPP News

The committee decided last week it wants an updated analysis on historical congestion across flowgates and more information on the process behind evaluating interregional reliability projects.

Adam McKinnie, chief economist with the Missouri Public Service Commission, said the SLC is seeking transparency into how individual transmission owners collaborate to propose potential reliability projects across the seams to the RTOs.

"We're looking for how that evaluation takes place," McKinnie said during a conference call March 9.

The committee said it has identified "a potential disconnect and general lack of coordination in the [CSP] interregional planning process."

"Although reliability projects can be proposed through the interregional planning process, this does not occur, and planning for reliability continues to happen predominately separately, or on an *ad hoc* basis through individual transmission owner collaboration," the SLC wrote.

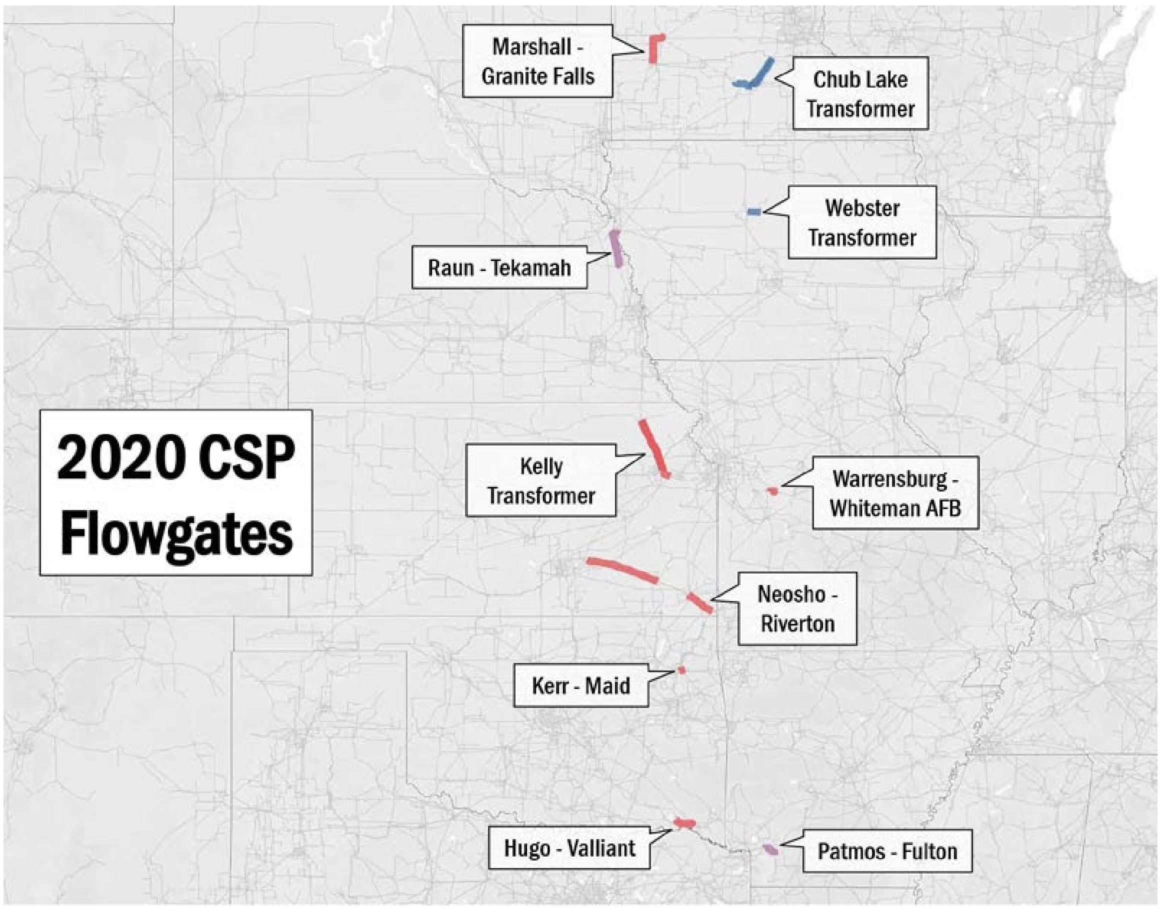
To date, MISO and SPP have not approved a seams reliability project, instead favoring regional projects. MISO officials have attributed that to low load growth in recent years, saying the RTOs haven't had the need for reliability projects along their seams. Staff from the RTOs have also maintained that their reliability planning processes are fundamentally different.

"I don't have the belief that the seams are so different that we couldn't benefit from a coordinated reliability process," McKinnie said.

The SLC will also ask MISO and SPP for a presentation on historical market-to-market congestion using 2018 and 2019 data that could be used in an upcoming CSP. Finally, the SLC is also asking that MISO and SPP detail how it plans to address flowgate congestion now that it has an improved CSP process in place.

The committee won't select a direction or draft a scope for their seams analysis until they have more information on the two topics.

The OMS and RSC in January laid out the option to either re-examine the RTOs' past analyses of proposed interregional projects or embark on a series of smaller studies on congested flowgates that could produce entirely new project proposals. (See *OMS, RSC Chart Course on Interregional Study*.) At this point, McKinnie said, regulators aren't sold on the idea of creating a similar interregional project design like MISO and PJM's targeted market efficiency project category. (See *MISO, PJM Weighing New Interregional Study*.) ■



2020 CSP Areas of Congestion

Info		10 Year Out Average Congestion	
Constraint	Footprint	MTEP 20 (Shadow Price (k$))	ITP 20 (Congestion Score (in Thousands))
Raun - Tekamah 161kV	Tie	175	137
Patmos - Fulton 115kV	Tie	21	54
Chub Lake 345/115kV Transformer	MISO	219	503
Webster 345/115kV Transformer	MISO	33	43
Hugo - Valliant 138 kV	SPP	30	243
Kelly 161/115kV Transformer	SPP	118	76
Kerr - Maid 161kV #2	SPP	33	136
Marshall - Granite Falls 115kV	SPP	28	34
Neosho - Riverton 161kV	SPP	120	260
Warrensburg - Whiteman AFB 161kV	SPP	95	20

| *SPP, MISO*

SPP News

SPP Strengthens Response to COVID-19

SPP on Thursday stiffened its response to the COVID-19 coronavirus with the strictest measures yet undertaken by an RTO or ISO.

The RTO *said* it is canceling all in-person stakeholder meetings through April and replacing them with virtual meetings. It is also prohibiting staff business travel and nonessential visitors from its facilities.

"Circumstances surrounding the spread of the COVID-19 coronavirus continue to evolve rapidly," the RTO said. "The continued spread of the COVID-19 virus has prompted us to take several steps to safeguard the health and safety of all SPP stakeholders and the people with whom we work."

SPP's actions mean the regular quarterly stakeholder meetings, originally scheduled for April at its Corporate Center in Little Rock, Ark., will now be conducted by webinar. Those meetings include:

- Markets and Operations Policy Committee, April 14-15;
- Strategic Planning Committee, April 15-16;
- Regional State Committee, April 27; and
- Board of Directors/Members Committee, April 28.

The grid operator promised to keep its stakeholders updated in the weeks ahead.

The SPP Corporate Center | *WER Architects*

"Our incident coordination team continues to work closely with local, state and federal agencies and is meeting daily to assess whether additional safeguards are appropriate," SPP said. ■

— Tom Kleckner

SPP Seams Steering Committee Briefs

Congestion Study Inconclusive on MISO Contract Path

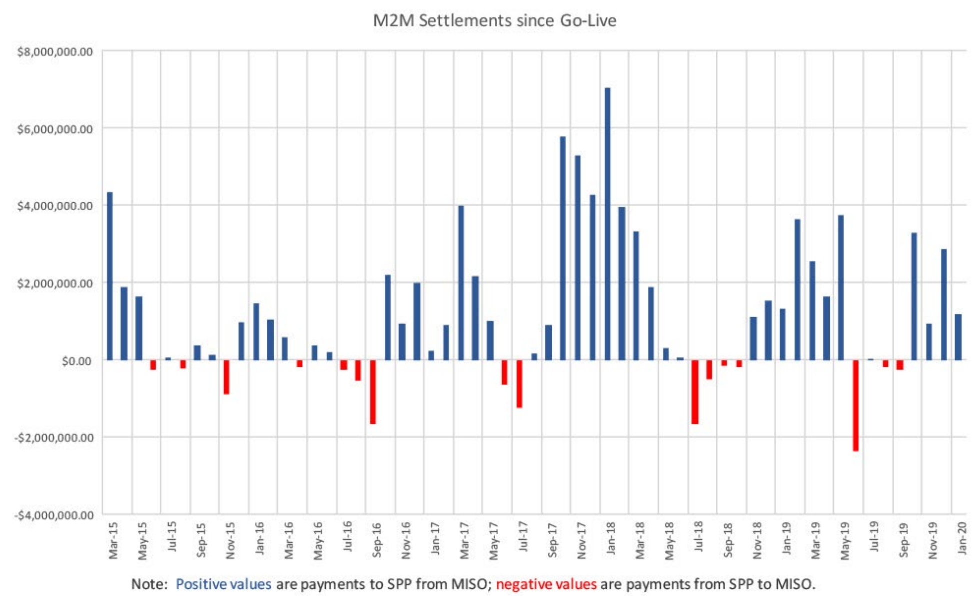
SPP staff last week shared a draft congestion study with the Seams Steering Committee on the effect of MISO's contract path to its southern footprint.

The study of the SPP day-ahead market's external flows and solution costs analyzed whether regional directional transfers (RDTs) above the contract path capacity between MISO's South and Midwest subregions created additional congestion or operating costs for SPP's market. MISO is limited to 1,000 MW of contracted, firm capacity over the contract path as a result of a 2015 settlement agreement. (See *SPP, MISO Reach Deal to End Transmission Dispute*.)

The committee had asked staff to provide more information on the differences in the hourly redispatch level, with a look at the generation footprint broken out by state and legacy balancing authority. Staff's limited study was inconclusive as to whether MISO's above-capacity RDTs created a "pattern of financial harm."

SSC Chair Jim Jacoby noted during the committee's meeting Thursday that high north-to-south days would "probably" overstate the study's results.

Staff will return to the committee for its April 2 conference call with a final version of the study. The SSC plans to endorse or accept the report at that time.



| *SPP*

M2M Settlements Up to $72M in SPP's Favor

SPP earned $1.81 million in market-to-market (M2M) settlements in January, the fourth straight month — and 43rd in 59 months — that the M2M process with MISO has settled in its favor.

SPP has now incurred $72.14 million in M2M settlements from MISO since the two began the process in March 2015. The process provides a compensation mechanism when SPP or MISO have to redispatch transmission around congested flowgates.

Temporary and permanent flowgates on the RTOs' seam were binding for 438 hours during January. Temporary flowgates accounted for 427 of the binding hours. ■

— Tom Kleckner

Company Briefs

BCSE Announces New Chairman, Members

The Business Council for Sustainable Energy last week announced the appointment of **Emily Duncan** as its board of directors' new chairman. Duncan is also the director of federal government relations for National Grid US.

The council also announced Jon Sohn, who is the U.S. director of government relations for Capital Power, as a new board member and the America Public Gas Association as a new associate member.

"As the politics of Washington, D.C., and beyond become more polarized, pragmatic coalitions like the council play a critical role in keeping discussions focused on viable solutions to America's energy needs," Duncan said. "States around the country are working to develop and integrate clean energy resources; we believe that energy efficiency, renewable energy and natural gas complement each other in our evolving energy system."

More: *Business Council for Sustainable Energy*

Utilities Suspend Shutoffs over Coronavirus

Many utilities across the U.S. have announced that they will suspend power shutoffs to those late on payments because of the ongoing COVID-19 coronavirus pandemic.

Consumers Energy (Michigan), Entergy New Orleans (Louisiana) and Xcel Energy (Minnesota) were among the utilities that have notified costumers about the delayed shutoffs. The time frames of suspensions range from two weeks to two months. The Illinois Commerce Commission also contacted utilities urging them to cease disconnections for nonpayment and suspend the imposition of late payment fees or penalties until May 1.

On Monday, Maryland Gov. Larry Hogan issued an *order* prohibiting electric and gas utilities from shutting off any residential customer's service or charging any residential late fees.

More: *CIProud.com*; *WDSU*; *WCCO*; *MiBiz*

Duke, Dominion and Southern Set to Miss Climate Targets

Duke Energy, Dominion Energy and Southern Co., which together produce 4.2% of all U.S. carbon dioxide emissions, will miss their decarbonization targets if the utilities move forward with planned investments in fossil fuel plants and other infrastructure, according to a report by Synapse Energy Economics.

The report said the companies, which together serve more than 15 million customers, own roughly 12.7% of national generation capacity and are responsible for 12.4% of power sector CO_2 emissions. Furthermore, roughly 75% of the companies' remaining coal capacity will still be online beyond 2030 while they plan to add more than 22 GW of natural gas capacity over the next 20 years, which will represent nearly a third more gas capacity coming online than coal capacity being retired over the next two decades.

More: *S&P Global Market Intelligence*

Foresight Energy Files for Chapter 11 Bankruptcy

Foresight Energy, a St. Louis-based coal producer that operates mines in the Illinois Basin, filed for Chapter 11 bankruptcy relief last week.

Foresight joins parent company Murray Energy, which entered bankruptcy last October. Documents released by Murray last month showed the company had plans to shut down a Foresight mine in the first quarter of 2020 "due to its inability to operate profitably and ongoing issues with coal quality."

More: *St. Louis Post-Dispatch*

Mystic Generating Station Strike Ends with Tentative Deal

The Utility Workers Union of America Local 369 last week said its striking workers from the Mystic Generating Station in Boston have reached a tentative deal and are ex-

pected to ratify a new agreement.

The agreement led to new protections and improved working conditions, union President Craig Pinkham said. Dozens of employees started a strike two weeks ago over what they called concerns about safety and working conditions. Exelon confirmed the agreement but said the dispute was not over safety.

More: *The Associated Press*

Security Violations Found at Entergy's St. Charles Nuclear Plant

According to a letter sent to Entergy from the U.S. Nuclear Regulatory Commission last week, the company's Waterford 3 Steam Electric Station was found to have violations during an inspection conducted from Sept. 30 to Nov. 22, 2019. Regulators were checking on whether the plant complied with safety protocols for "preparing radioactive material in quantities of concern for transport," and the violations are serious enough that federal regulators are considering "escalated enforcement action."

Company officials planned to meet with NRC regulators this week. Specifics on what actions are being considered, or what violations were discovered, will not be released to the public. The commission has a policy that forbids the release of details about nuclear security problems or what enforcement actions are taken to correct them.

More: *The New Orleans Advocate*

Textron Aviation Turns to Wind to Power Factories

Textron Aviation last week said it has signed a 20-year agreement with Evergy to receive 55 MW for its two Kansas plants in Independence and Wichita from a wind farm under construction in Manhattan. The Soldier Creek Wind Farm will generate 300 MW and is expected to be operational by the end of the year.

Thanks to a tariff passed in 2018 by the Kansas Corporation Commission, Textron's rate will decrease from 2.3 cents/kWh to 1.8 cents/kWh.

More: *AIN Online*

Vogtle Workers Being Tested as Facility Hits Major Milestone

Georgia Power last week ordered the first nuclear fuel load for its Vogtle Unit 4 nuclear plant near Waynesboro, Ga. Unit 4, along with its sister Unit 3 that had fuel ordered for it last year, are the first newly designed nuclear reactors built in the U.S. in 30 years.

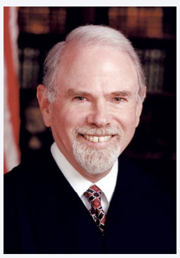
The project is approximately 84% complete.

The news came before Georgia Power confirmed two of its workers at the plant were being tested for the COVID-19 coronavirus. A memo sent to workers over the weekend, which the ***Aiken Standard*** subsequently obtained, states "immediate precautionary action" has been taken, including identifying those who worked closely with the workers being tested so "that they can stay home and self-isolate while we await the test results."

More: *Aiken Standard*; *Daily Energy Insider*

Federal Briefs

Judge Rules California-Québec Cap-and-Trade Agreement is Valid



California's agreement with Québec to share cap-and-trade markets to reduce greenhouse gases, which was challenged by the Trump administration, did not amount to a treaty or international compact in violation of the federal government's exclusive constitutional authority, U.S. District Judge **William Shubb** ruled last week.

While Shubb deferred consideration of other claims by the administration that the California-Québec program interfered with federal authority over international affairs and foreign commerce, he dismissed the administration's main argument to dash the agreement: that California had entered into a treaty or compact with a foreign state, powers the Constitution reserves to the federal government. If it decides to, the administration could appeal the ruling in the ongoing case.

The program was signed into law by Gov. Arnold Schwarzenegger in 2006, took effect in 2012 and was extended for another decade in 2017. It sets limits, which decrease over time, on California companies' emissions of carbon dioxide and other greenhouse gases. Companies that do not meet their emissions cap must trade by buying credits at an auction.

More: *San Francisco Chronicle*

Nuclear Waste Storage Facility Gets Federal Approval

The Nuclear Regulatory Commission last week issued a draft environmental impact statement for Holtec International's proposal to construct and operate a consolidated interim storage facility at a remote location between Eddy and Lea counties in Nevada. The facility would hold spent nuclear fuel rods temporarily from sites across the country while a permanent repository is developed.

The commission recommended Holtec be issued a license for the first phase of the project. The recommendation is pending an upcoming safety review and review of the project's compliance with federal law.

The EIS argued the waste would be stored well above the depth of most oil and gas operations, rating the impacts of construction, operations and decommissioning as "small." It did not consider potential expansions to operate longer or hold more waste than the 8,680 metric tons prescribed in the application, even though the U.S. has more than 80,000 metric tons, with 2,000 metric tons being generated per year, according to a report from Holtec.

More: *Carlsbad Current-Argus*

Research: Coal Investments Undercut by Cheap Renewables

Research released by think tank Carbon Tracker Initiative last week showed nearly $640 billion of investments in coal capacity worldwide is at risk because it is cheaper to generate electricity from new renewables. The report examined the economics of 95% of coal plants that are operating, under construction or planned worldwide.

Globally, 499 GW of new coal capacity is planned or under construction with an investment of $638 billion. The report said more than 60% of those plants are currently generating electricity at a higher cost than could be produced by building new renewables, and by 2030 at the latest, it will be cheaper to build new wind or solar capacity than continue operating coal in all markets. The U.S. currently has 254 GW of coal capacity, with 47% costing more than new renewables.

The capital recovery period for new investments in coal capacity is usually 15 to 20 years, making investments risky.

More: *Reuters*

US Storage Industry Achieved Largest-ever Quarter, Year in 2019

The U.S. energy storage industry capped off its biggest year and quarter of installations ever, with storage installation coming in at 522.7 MW for 2019 and 186.4 MW in the fourth quarter, according to Wood Mackenzie and the Energy Storage Association's Energy Storage Monitor 2019 Year in Review report.

One key driver was the decision by California to fund several hundred million dollars worth of batteries serving resilience in wildfire-threatened parts of the state. WoodMac estimated that one-in-four home solar installations in California this year will include storage.

Eight states contain utility-scale storage facilities adding up to more than 50 MW, while another 11 states operate more than 10 MW each. This year could also be the first in which the annual storage market surpasses $1 billion. In 2019, storage investments totaled $712 million. This year, Woodmac estimated they are poised to jump to just shy of $2 billion.

More: *GreenTech Media*

State Briefs

CALIFORNIA

LADWP Accused of Cybersecurity Coverup

Ardent Cyber Solutions has accused the Los Angeles Department of Water and Power (LADWP) of deliberately keeping widespread gaps in its cybersecurity a secret from regulators in a coverup involving Mayor **Eric Garcetti**.

Ardent was hired by the department in April 2019 to perform cybersecurity work and claims it uncovered an "extremely high number of unpatched vulnerabilities" in the company's "corporate IT network." Ardent said LADWP Board of Commissioners President Mel Levine, along with senior executives, were informed of the security issues by email on Aug. 12, 2019. Instead of addressing the issues, the department and city officials made "false statements and failed to disclose material facts" in a bid to cover them up.

Ardent further alleges Garcetti personally ordered the cancellation of Ardent's contract on Aug. 12 as a "retaliatory measure."

More: *Infosecurity Magazine*

INDIANA

Coal Bill Heads to Governor's Desk

House Bill 1414, legislation that would extend the life of the state's coal-fired power plants for another year, advanced out of conference committee last week and now heads to Gov. Eric Holcomb's desk for approval. The conference committee report passed the House of Representatives 55-38 before narrowly passing the Senate 28-21.

The bill barely made it out of the House last month with provisions that would make it harder for utilities to close coal-fired plants and created an incentive for utilities to buy more coal. The Senate made changes such as moving up the bill's expiration up by four months, as well as taking out the need of the Utility Regulatory Commission to analyze and issue a report on a utility's plan to retire a plant. Those changes were rejected by the House and sent the bill to conference committee.

Rep. Ed Soliday, the bill's author, returned the end date to May 1, 2021, and reinserted the role of the IURC to analyze and issue conclusions on proposed retirements.

More: *Indianapolis Star*

MAINE

Auburn Planning Board Approves Solar Project

The Auburn Planning Board last week unanimously approved a $17.6 million, 14.6-MW solar project that will consist of 36,072 PV panels over 142.7 acres. The project, which is two-thirds in Auburn and one-third in Poland, is pending approval from the Poland Planning Board, the state Department of Environmental Protection and the U.S. Army Corps of Engineers.

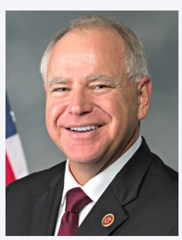
The project is estimated to start either in late fall or spring of 2021, with construction taking six to eight months.

The Poland Planning Board will take up the project on March 24.

More: *Sun Journal*

MINNESOTA

Walz Taps Energy Official for PUC Vacancy



Gov. **Tim Walz** last week announced the appointment of Commerce Department Deputy Commissioner of Energy Resources Joseph Sullivan to a Public Utilities Commission vacancy. Sullivan, whose seat was previously held by Dan Lipschultz until his term expired in January, will start his six-year term April 6. His appointment may still be reviewed by the Senate for confirmation.

Sullivan lobbied for regional environmental groups before joining the Commerce Department, including the Minnesota Center for Energy and Environment and Wind on the Wires. Before becoming a lobbyist, he worked as an attorney for a municipal power agency in Greater Minnesota.

More: *Post Bulletin*

NEBRASKA

NPPD Names New CEO

The Nebraska Public Power District's (NPPD) Board of Directors last week approved Thomas Kent as the company's new president and CEO. Kent currently is NPPD's executive vice president and COO.

Kent has been with the utility for 30 years, including the last nine years in his current position. He will replace Pat Pope, who will step down at the end of April.

More: *The North Platte Telegraph*

NEW MEXICO

PRC Approves Acquisition of El Paso Electric

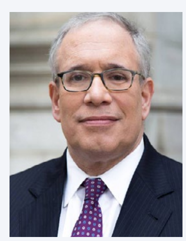
The Public Regulation Commission last week unanimously approved the sale of El Paso Electric to the Infrastructure Investments Fund. PRC staff told commissioners the purchase premium would exceed the book value of the utility by $1.63 billion.

Terms of the sale include a rate credit to state customers of $8.7 million distributed in 36 monthly installments. The terms had been previously approved by the Public Utility Commission of Texas and the city of El Paso.

More: *Las Cruces Sun-News*

NEW YORK

NYC Comptroller Slams National Grid's Plans



New York City Comptroller **Scott Stringer** slammed National Grid's long-term infrastructure and rate-hike plans in a letter to company President John Bruckner last week, saying the government should consider launching a publicly run energy utility if National Grid can't help the city and state meet their clean-energy goals.

Stringer said that "rather than raising rates to expand gas capacity and build out pipeline infrastructure … National Grid must instead do more to prioritize gas demand reduction and support beneficial electrification." He also dismissed National Grid's support of the proposed Williams Pipeline, an underwater pipeline structure that would run from New Jersey to the Rockaways.

National Grid, which cites infrastructure projects as its justification for a proposed $16.50 rate hike of customers' current bills, was scheduled to hold a hearing about its long-term plans last week.

More: *Daily News*

OREGON

Brown Orders State Action on Climate Change

Gov. **Kate Brown** issued a 14-page executive order last week that aims to curb greenhouse gas emissions. It comes less than a week after a Republican walkout killed Senate Bill 1530, a proposal for a cap-and-trade system.

The order, which will impact 18 state agencies and commissions, updates the state's carbon-reduction goals by setting targets of a 45% reduction below 1990 levels by 2035 and an 80% reduction by 2050. It also directs agencies to alter building codes to prioritize energy efficiency and further control the carbon intensity of gasoline, and has provisions for updated efficiency standards for appliances.

"This executive order is extensive and thorough, taking the boldest actions available to lower greenhouse gas emissions under current state laws," Brown said. "As a state, we will pursue every option available under existing law to combat the effects of climate change and put Oregon on a path we can be proud to leave behind for our children."

More: *Oregon Public Broadcasting*

WISCONSIN

Evers Appoints Clean Energy Advocate to PSC

Gov. Tony Evers last week appointed Tyler Huebner to fill the Public Service Commission seat vacated last month by Mike Huebsch. His appointment is effective today.

Huebner, who served as Renew Wisconsin's director for the last seven years, will be the first commissioner in more than 20 years to not be an attorney, lawmaker or legislative aide. He will have a salary of $126,000.

"I understand the importance of balancing the needs of utilities and customers, while accelerating Wisconsin's transition into the 21st century," Huebner said. "It is an honor to be appointed to the commission and to continue my career of public service in this new role."

More: *Wisconsin State Journal*

New EV Charging Stations Unveiled in Beaver Dam

Officials held a ribbon cutting last week to introduce new electric car charging stations — two level 2 chargers and two level 3 chargers — at 810 Park Ave.

Annemarie Newman, a senior communications partner for Alliant Energy, said the costs for the chargers fall in line with the general rule of a $1/gallon equivalent. Consumers have reported a cost of $2/hour to charge at level 2 and $13.20/hour to charge with a $1 connection fee at level 3.

Keller Real Estate Group, which owns the Park Village Shopping Center, donated the property for the charging stations.

More: *WiscNews*

WYOMING

New Law Requires Utilities to Attempt to Sell Coal Plants Before Retiring

Gov. Mark Gordon last week signed Senate File 21 into law, which will require public utilities to "first make a good faith effort" to sell their coal-fired generation facilities before retiring them. The law will go into effect July 1, 2021, and will allow non-utilities to purchase otherwise retiring coal plants and sell energy to industrial customers.

"According to the Public Service Commission, it is unlikely for a coal-fired plant to be offered for sale and sold to a non-utility before 2023. Under this bill, if a retiring coal fired power plant is sold, and the purchaser enters an agreement to provide one or more industrial customers energy that would otherwise have been provided by a public utility, the total gross intrastate revenue available for assessment to fund the PSC would be reduced by the amount of those sales," the Legislative Service Office said.

More: *Oil City News*