RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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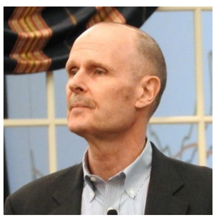
ISSN 2377-8016 : Volume 2020/Issue 18 May 5, 2020

PJM Monitor Defends FRR Analyses in MOPR Debate

By Michael Yoder and Rich Heidorn Jr.

PJM's Independent Market Monitor last week defended its conclusion that ratepayers are likely to see cost increases in jurisdictions that exit the RTO's capacity market and adopt the fixed resource requirement (FRR) option.

Regulators in Illinois, New Jersey and Maryland have said they are considering the FRR option in response to FERC's December order requiring PJM to expand the minimum offer price rule (MOPR) to new state-subsidized resources. (See *PJM's MOPR Quandary: Should States Stay or Should they Go?*)



PJM IMM Joe Bowring | *© RTO Insider*

"Based on conversations I've have had — both public and private — with those who are pursuing FRRs, they're increasingly recognizing ... that the costs are likely to be higher under an FRR than under the competitive market," Monitor Joe Bowring said during Raab Associates' Energy Policy Roundtable in the PJM Footprint webinar April 28.

States can require their utilities to make the FRR election. The FRR entity must provide adequate capacity for all load-serving entities in its territory regardless of the existence of retail choice, Bowring said. LSEs are required to pay the FRR entity based on either a state-mandated compensation mechanism or — in the absence of a mechanism — on the Rest of RTO capacity price, he said.

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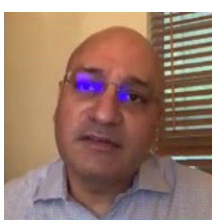
PJM Outlines Revised MOPR Compliance Filing (p.21)

PJM CEO Introduces Himself

Ex-Energy Trader, Raised in Middle East, Returned to Philadelphia After 25 Years

By Rich Heidorn Jr.



New PJM CEO Manu Asthana introduced himself via teleconference at the Energy Policy Roundtable in the PJM Footprint.

Manu Asthana was 17 when he arrived in Philadelphia as an undergraduate at the University of Pennsylvania's Wharton School in 1991. Born in India, he had grown up in the Middle East, where his parents moved for work. The U.S., he said, was "quite a culture shock."

Nearly 25 years after his graduation, Asthana returned to the Philadelphia area as CEO of PJM.

"It was quite an interesting completion of the circle for me," Asthana, who joined the RTO in January, told the Raab Associates Energy Policy Roundtable in the PJM Footprint via webinar April 28.

He returned, no longer a wide-eyed teenager, but an experienced energy executive looking for a new challenge.

After only four months on the job, he's already had several: Responding to FERC's controversial expansion of PJM's minimum offer price rule (MOPR), winning stakeholder approval of tougher credit requirements in its markets and — unexpectedly — figuring out how to prevent the coronavirus pandemic from disrupting PJM's 24/7 operations.

"It has been humbling to be reminded that we don't get to write the script," he smiled.

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Judge Orders PG&E to Improve Line Inspections

Says Utility 'Cheated on Maintenance' for Years to Boost Profits

By Hudson Sangree

The judge in charge of Pacific Gas and Electric's criminal probation, stemming from the 2010 San Bruno pipeline explosion, found the utility was failing in its inspection and maintenance of power lines and ordered it to improve its performance to avoid starting wildfires.

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COVID-19 RESPONSE

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MISO Preps for Balmy Summer with Pandemic Effects (p.12)

DTE to Cut Spending in Response to Pandemic (p.13)

CMS Energy Stays Course Despite Virus Havoc (p.14)

Pandemic to Sting C&I-dependent Utilities, Researchers Say (p.19)

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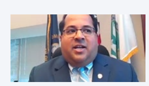

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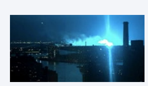

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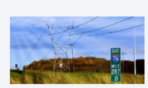

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FERC/Federal News

Adjusting to New Normal, Chatterjee Looks Ahead

By Tom Kleckner

Like many Americans, FERC Chairman Neil Chatterjee has seen his life upended by the COVID-19 pandemic.

While the commission and its staff have been "going about our business" — conducting its April open meeting and all other meetings virtually — Chatterjee has assumed additional responsibilities at home. With his three children now sequestered at the family's Virginia home, he has taken on the role of middle school and elementary school teacher. This weekend, he added barber to his duties.

"Seventh-grade math is probably more challenging than the oversight of wholesale markets," Chatterjee said during a virtual fireside chat conducted by the nonpartisan Atlantic Council think tank April 28.

Chatterjee appeared to be speaking from the FERC offices. That is, unless he collects and stores governmental flags at his home.

"We really are making a conscious effort to keep the commission running as normal as possible," he said. "Seven weeks in, we have transitioned all our employees, here in D.C. and across the country, to full telework."

Chatterjee said the commission has faced the pandemic's regional stay-at-home orders with a three-phased approach.

First, he said, FERC made clear to its stakeholders that, given the lack of face-to-face meetings, it recognized that not all compliance obligations could be met. "We tried to provide transparency and clarity and let them focus on their No. 1 priority: keeping the lights on," Chatterjee said.

The second phase is keeping the commission running and letting stakeholders know FERC is still open for business. Check.

The third phase, and probably most important, is preparing the electric grid and industry for what happens "when we come out of this," he said.

Chatterjee cited the load shift from industrial and commercial demand to residential demand, the moratorium on customer cutoffs and the suspension of infrastructure work as examples of changes in the industry.

He also noted an increase in the dispatch of gas-fired plants as natural gas prices plummeted along with that of oil.

"Gas being dispatched at a higher rate is putting [financial] pressure on renewables, nuclear and coal. We could see shutoffs and shutdowns occur as a result of economic pressure, then see a surge in demand when we reopen," he said. "I want to start talking about these things now ... and getting people at the commission, federal and state levels to start thinking through some of the challenges we'll face when we reopen."

Noting social distancing and stay-at-home orders have reduced demand as much as 9% in some regions and affected intraday load shapes, Chatterjee warned of their impacts over the long term.

"You could have RTOs and ISOs and utilities cancel projects. Developers might cancel projects because of lower loads," he said. "These are really thorny issues. This goes back to the balance we have to continually strike between consumer concerns and utility concerns. It's a reason why we not only need to be focused on how to get out of this pandemic, but we have to be ready when we come out."

FERC Chair Neil Chatterjee during last Tuesday's webinar.

Until then, Chatterjee's concerns will rest with the electric industry and its workers. He said utility workers have been "real heroes" during the pandemic, along with other front-line workers and first responders.

"Most people are working from home. Power plant operators have moved from home to work," he said, alluding to those who have set up camp at their plants to protect their health. "It's really, really patriotic and heroic. When this is all over, I hope utility workers get their due for the sacrifices they have made." ■

Atlantic Council's David Goldwyn and FERC Chair Neil Chatterjee open last Tuesday's webinar.

CAISO/West News

PG&E Says Most Board Members Will Leave

Former FERC Commissioner Brownell Among Planned Departures

By Hudson Sangree

PG&E Corp. said Friday that 11 of its 14 directors would be leaving its board, mostly complying with a demand from California Gov. Gavin Newsom and the president of the California Public Utilities Commission for a complete replacement of the board.

Former FERC Commissioner and PG&E Corp. Chair Nora Mead Brownell is among those who will leave the board. | *PG&E*

Among those exiting will be PG&E Chair Nora Mead Brownell, a former FERC commissioner and Pennsylvania utility regulator. Kristine Schmidt, a former member of CAISO's Western Energy Imbalance Market Governing Body who was an adviser to Brownell at FERC, will also be leaving.

The announcement was part of PG&E's first-quarter earnings report.

PG&E gave no date for its changes at the top. The holding company and its main utility subsidiary Pacific Gas and Electric Care trying to emerge from Chapter 11 bankruptcy by June 30, the deadline to participate in a state fund to insure investor-owned utilities from future wildfires.

CEO Bill Johnson, who recently announced he will be retiring at the end of June, said in a *news release* accompanying the first-quarter earnings report that PG&E is on track to meet the June deadline. (See *PG&E CEO Johnson Says He'll Step Down*.)

"We have developed a plan of reorganization that has the support of a broad coalition of stakeholders, including the governor's office," Johnson said. "Our plan compensates wildfire victims fairly, resolves our liabilities, assumes the collective bargaining agreements with our labor unions and is energy-bill-neutral for our customers."

PG&E filed for bankruptcy in January 2019, after devastating wildfires left it owing an estimated $30 billion to fire victims and insurers. The company has agreed to pay $13.5 billion to victims of fires in 2015, 2017 and 2018 and $11 billion to insurance companies and hedge funds that hold third-party subrogation (insurance) claims. It will also pay $1 billion to local governments affected by wildfires.

The next round of leadership changes will be the second in about 14 months. PG&E hired Johnson as CEO on May 1, 2019, its third chief executive in two years. Ten directors were also replaced, with Brownell and Schmidt among those joining what PG&E called its refreshed board.

In the impending turnover, Andrew Vesey, CEO of Pacific Gas and Electric, will stay in his position, PG&E said.

Bill Smith will remain on the board and serve as interim CEO after Bill Johnson's departure on June 30. | *PG&E*

PG&E said the three board members who will remain are Bill Smith, a retired AT&T executive who will become interim CEO when Johnson leaves; Cheryl Campbell, previously with Xcel Energy; and John Woolard, CEO of Meridian Energy. All were named to the board last year.

"Smith is the retired president of AT&T Technology Operations … and brings more than 35 years of experience in the telecommunications industry including overseeing operations, planning, engineering, construction, maintenance and a field workforce of more than 100,000 employees," PG&E said.

Campbell brings safety experience, a qualification that Newsom and PUC President Marybel Batjer have insisted must be a major part of a revamped PG&E board. Newsom and Batjer called for a replacement of PG&E's entire board with new directors, at least half of them Californians. (See *CPUC President Wants More Control Over PG&E*.)

Newsom and Batjer have yet to say whether PG&E's plan to leave three current directors in place will meet their expectations. The CPUC must still approve PG&E's Chapter 11 reorganization plan.

The company noted it received a proposed decision from the CPUC on April 20 that found its reorganization plan generally complies with Assembly Bill 1054, which created the wildfire insurance fund.

PG&E reported first-quarter GAAP income of $371 million ($0.57/share), compared with income of $136 million ($0.25/share) in 2019. The company said its GAAP results were impacted by $205 million in after-tax costs related to the bankruptcy.

Its non-GAAP earnings, which exclude non-core items, were $576 million ($0.89/share), compared with $546 million ($1.04/share), in the first quarter of 2019. ■

PG&E is headquartered in San Francisco's downtown financial district.

CAISO/West News

Judge Orders PG&E to Improve Line Inspections

Says Utility 'Cheated on Maintenance' for Years to Boost Profits

Continued from page 1

U.S. District Judge William Alsup imposed new probation conditions Wednesday, saying PG&E must hire its own cadre of inspectors to make sure vegetation clearance meets state standards after outside contractors failed to identify or fix urgent problems last year.

He also required the utility to adopt a new regimen of inspection and reporting of transmission towers after it failed to spot worn equipment, including the "ancient C-hook" that broke, dropping a line and starting the November 2018 Camp Fire, the deadliest and most destructive wildfire in California history. (See *PG&E to Plead Guilty to Killing 84 in Camp Fire*.)

"A fundamental concern in this criminal probation remains the fact that Pacific Gas and Electric Co., though the single largest privately owned utility in America, cannot safely deliver power to California," Alsup said. "This failure is upon us because for years, in order to enlarge dividends, bonuses and political contributions, PG&E cheated on maintenance of its grid — to the point that the grid became unsafe to operate during our annual high winds, so unsafe that the grid itself failed and ignited many catastrophic wildfires.

"In the past three years alone, PG&E wildfires killed at least 108 and burned 22,049 structures," the judge said. "It will take years, now, for PG&E to catch up on maintenance so that the grid can safely supply power at all times. The conditions of probation herein have been aimed at requiring PG&E to do so."

A public safety power shutoff last fall may have prevented a downed tree on a PG&E distribution line from starting a fire. | *PG&E*

Distribution Line Shortcomings

PG&E's vegetation clearance around power lines has been stepped up but still lags years behind, the judge said. The company contracts out its line inspections and tree-trimming work, which has proven problematic, he said.

"PG&E is fond of handing up records indicating completed work," Alsup said, but spot-checks performed by a court-appointed monitor showed the records were untrustworthy.

In 2019, the monitor "checked the work, putting boots to the ground and independently inspecting over 550 miles of lines in high fire-threat districts," the judge said. The monitor found 3,280 "risk" trees that PG&E's contractors hadn't identified, including 15 instances of urgent conditions that could have resulted in harm to people or property if left unfixed, the judge said.

"In one instance, PG&E contractors had recently marked an urgent condition — where a tree was 1 foot away from a primary conductor — as 'tree work complete,'" Alsup said. "Similarly, a tree touched a primary conductor right outside the driveway of a home.

"In another case, the monitor identified a tree within inches of a primary conductor. The leaves of the tree bore burn marks from the ongoing intermittent contact," the judge said. "That tree had been identified for routine compliance work in November 2018, and tree-trimming contractors reported they had completed the work in February 2019, although clearly they had not."

To remedy the deficiencies, Alsup ordered PG&E to hire, on its own payroll, inspectors to examine power lines before and after vegetation-clearance work.

"PG&E shall employ a sufficient number of inspectors to manage the outsourced tree-trimming work," Alsup wrote as a new term of the company's San Bruno probation. "The pre-inspectors must identify trees and limbs in violation of California clearance laws that require trimming. Post-inspectors must spot-check the work of the contracted tree-trimmers to ensure that no hazard trees or limbs were missed."

He instructed the utility to prepare a detailed plan by May 28.

Transmission Line Problems

The judge set the same date for PG&E to offer

CAISO/West News

a new transmission inspection plan.

"For transmission towers, the problem is defective and worn-out hardware on the towers themselves," Alsup wrote.

"The Butte County [Camp] Fire, for example, started because an old C-hook had become so deeply gouged from decades of swaying against the plate on which it hung that the C-hook simply broke and fell, causing the attached power line to fall onto the metal tower, spewing sparks onto the wind-blown dry grass below."

The transmission tower, part of PG&E's century-old Caribou-Palermo line, had "supposedly been assessed just days before the fire … [the subject of an unusual] nonroutine enhanced inspection," Alsup said.

"PG&E refused to say why it sent contractors to inspect the line but conceded that the line's age was a factor," he said. "Inspectors climbed the 100-foot-tall towers, presumably searching for equipment deficiencies, yet reported zero instances of cold-end hardware issues such as worn-out C-hooks."

In last November's Kincade Fire in Sonoma County, state investigators are focused on a broken jumper cable found hanging from a transmission tower where the fire started, the judge said. Yet months earlier, "three separate inspections — via tower climbers in February, high-resolution drone imaging in May and ground inspectors with binoculars in July — had all failed to identify the problematic jumper cable," he said.

"Like a broken record, PG&E routinely excuses itself by insisting that all towers had been inspected and any noted faults were addressed, at least according to its paperwork," Alsup said. "But these transmission tower inspections failed to spot dangerous conditions.

A worn C-hook, like the one pictured here, broke on Nov. 8, 2018, dropping a high-voltage line and sparking California's deadliest wildfire. | *PG&E*

"Was this because the inspections were poorly designed, or was it because they were poorly executed? Had someone falsified inspection reports? It is hard to get a straight answer from PG&E," the judge said. "The offender is masterful at falling back on the inspection reports and saying, 'See, judge, we had that very line inspected and all was well,' or, 'We fixed whatever they found wrong. We did our part.' The reports, however, are a mere courtroom prop."

The judge said that under its current protocol, PG&E contractors don't "accurately assess the degree of corrosion on the type of hardware that broke and caused the Butte County fire. For example, contracted inspectors could not agree on the amount of wear of a deeply gouged C-hook on a line parallel to Butte County's Caribou-Palermo line."

Three inspectors said it was 5 to 30% worn, but an expert witness rated the wear at 30 to 50%, which would require immediate replacement, he said. "And, because PG&E's inspection forms only ask inspectors to check 'yes' or 'no' to the prompt 'cold-end hardware in poor condition,' any degree of wear simply went unmarked," he said.

Alsup ordered the company to start keeping records identifying the age of all transmission equipment, including every piece of hardware, and its recorded date of installation.

"In consultation with the monitor, PG&E shall design a new inspection system for assessing every item of equipment on all transmission towers," the new probation conditions say. "Forms shall be precise enough to track what inspectors actually do, such as whether they touch or tug on equipment. Videos must be taken of every inspection."

'PG&E Struck Again'

Since August 2017, Alsup has overseen PG&E's probation resulting from its conviction of six felonies related to the San Bruno explosion, in which "eight people burned to death or died from wounds. Fifty-eight survived with injuries, and over 100 homes burned," the judge recounted in his latest order.

The catastrophe occurred when a 30-inch gas pipeline ruptured and exploded under a suburban San Francisco neighborhood, sending up flames hundreds of feet high and shaking the ground to the point that residents and emergency crews thought it was an earthquake.

A federal jury in August 2016 convicted PG&E of five felony counts of "knowingly and willfully" violating federal pipeline safety standards and one felony count of obstructing a government investigator.

Then, "one year into its probation, PG&E struck again," Alsup wrote. The company was deemed responsible for at least 17 of the 21 major Northern California wine country fires of October 2017, in which 22 people died and more than 3,256 structures were destroyed.

The California Department of Forestry and Fire Protection found at least three of the fires were caused by PG&E's failure to maintain specified clearances required by state law between its power lines and nearby trees or limbs.

In November 2018, the Camp Fire tore through the rugged foothills of Butte County, Calif., and leveled much of the town of Paradise, killing 85 people and destroying nearly 19,000 structures in a single morning. It was the deadliest and most destructive wildfire in state history, and PG&E acknowledged its equipment was likely responsible.

Fire investigators eventually determined that the worn C-hook on a 100-year-old transmission tower had failed.

PG&E recently said it would plead guilty to 84 counts of involuntary manslaughter in the Camp Fire and pay $4 million in fines and costs. (One death was deemed a suicide as the flames approached.) The corporation is scheduled to be sentenced May 26 in Butte County Superior Court.

After the Camp Fire, Alsup undertook determining what new safety measures were needed to prevent PG&E from starting additional conflagrations.

The judge said in Wednesday's order that PG&E's probation for the San Bruno convictions ends in early 2022 and cannot be extended. He urged the California Public Utilities Commission to penalize utilities for failing to meet vegetation-clearance regulations and to tie executive bonuses to safety management.

He also said that until PG&E can assure the state its grid can be operated safely, the controversial public safety power shutoffs (PSPSs) that plagued the state last year should be continued. There were no major fires in 2019, when close to a million customers were blacked out purposefully, he noted. (See *California Officials Hammer PG&E over Power Shutoffs*.)

"During the high-wind events, we must continue to tolerate PSPSs as the lesser evil until PG&E has come into compliance with state law and the grid is safe to operate in high winds," the judge said. ■

CAISO/West News

CPUC Proposal Would Boost Microgrids

Resilience During Wildfire Safety Shutoffs is Primary Goal

By Hudson Sangree

The California Public Utilities Commission issued a proposed decision last week that would speed the interconnection of microgrids to utility distribution systems in anticipation of the state's upcoming fire season and the public safety power shutoffs (PSPSs) that will likely accompany it.

The *proposal*, issued April 28, would order utilities to prioritize microgrids and resilience projects that could be put in place by Sept. 1. It is intended to "rapidly develop and deploy projects that could keep electricity on for critical facilities and other customers during power outages," the CPUC said.

"Wildfire season will begin soon and, if like last year, it will surge this fall, bringing public safety power shutoffs and other outages," Commissioner Genevieve Shiroma said in a statement. "Microgrids using independent energy supply can provide essential backup and resiliency for communities affected."

The proposed decision makes recommendations to reduce the time it takes to connect microgrids and distributed energy resources to the grid starting with this fall's fire season. Among its provisions, the proposal would require the state's big three investor-owned utilities to standardize application processes for project approvals, expedite utility sign-off on projects, and accelerate interconnection of projects for key locations, customers and facilities.

It would conditionally approve projects by Pacific Gas and Electric to upgrade substations that can be quickly energized with local power sources. It also would allow PG&E to procure temporary, portable generators to use at substations and "key locations of public benefit" for the 2020 wildfire season, which typically starts in summer and worsens in the fall.

Under the proposal, San Diego Gas & Electric would be authorized to move ahead with software and hardware upgrades to "enhance microgrid operations and to augment and interoperate with SDG&E's existing advanced distribution management system and microgrid projects."

Commissioner Genevieve Shrioma | *CPUC*

PG&E substation near Dixon, Calif. | *© RTO Insider*

The rulemaking falls under Senate Bill 1339, passed in 2018, that directed the CPUC to "facilitate the commercialization of microgrids for distribution customers of large electrical corporations" by Dec. 1.

It gained momentum after the decision by PG&E to cut power to hundreds of thousands of customers last fall angered public officials including Gov. Gavin Newsom and CPUC President Marybel Batjer, who called the utility's actions "unacceptable."

"This cannot be the new normal," Batjer said in a commission meeting in October. (See *Calif. Regulators Bash PG&E's Power Shutoffs*.)

The proposal is the latest in a series of actions taken by the CPUC to mitigate the effects of PSPSs. In January, the commission approved $830 million in new funding to subsidize self-generation in fire-prone areas, bringing its total funding for self-generation projects to $1.2 billion. (See *California PUC Devoting $1.2B to Self-generation*.) In February, it proposed new guidelines for PSPSs, including requiring utilities to restore power within 24 hours after the end of high-wind events in dry conditions, the usual cause of intentional blackouts. (See *CPUC Proposes New Power Shutoff Guidelines*.)

The CPUC is accepting public comment on the proposal and plans to vote on it June 11. ■

CAISO/West News

Renewable Prices Fall to Record Low in California

By Hudson Sangree

California renewable energy prices fell to record lows in 2019, driven by the proliferation and falling costs of wind and solar power, the Public Utilities Commission said Monday in its annual report to the State Legislature.

Renewable portfolio standard contract prices dropped to 2.82 cents/kWh in 2019, compared with 3.81 cents/kWh in 2018, for all RPS-eligible energy, the CPUC said in its 2020 *Padilla Report*. RPS contract prices dropped an average of 12.7% per year between 2007 and 2019, it said.

The state's three large investor-owned utilities continued to pay at a far higher rate because of renewable contracts signed last decade before prices fell dramatically. In 2019, the IOUs procured renewable power at an average cost of 10.23 cents/kWh, down from 10.57/kWh in 2018. The IOUs total procurement costs fell from $5.6 billion in 2018 to $5.4 billion in 2019, the report said.

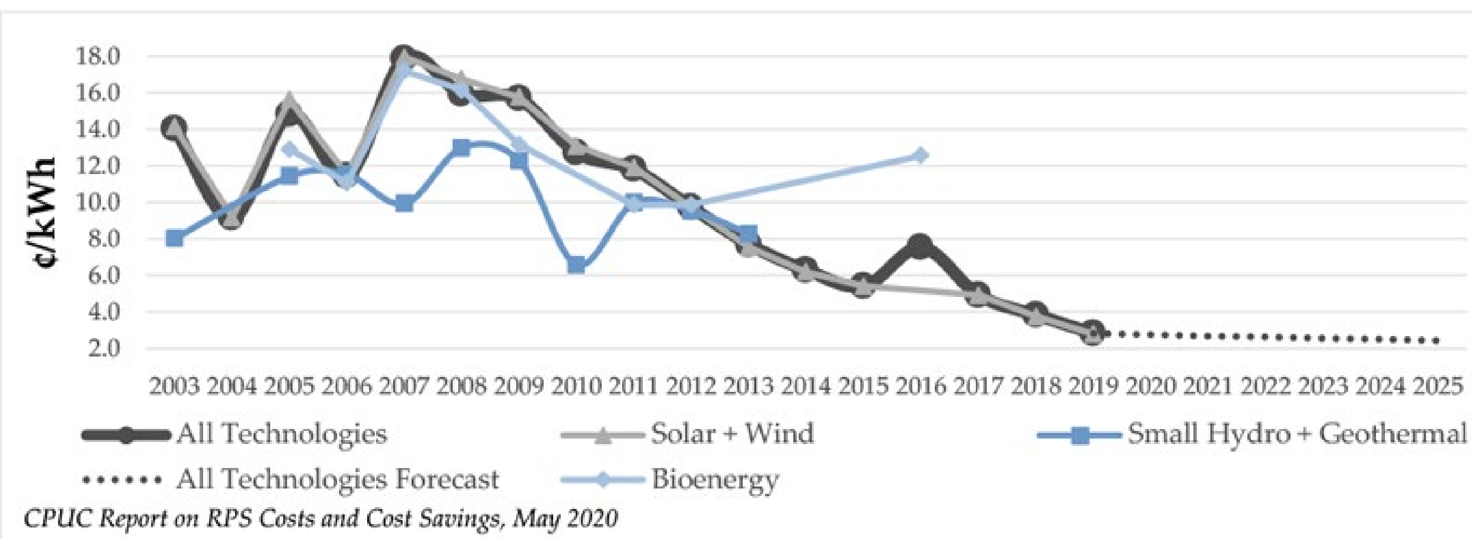
California's RPS program requires IOUs, electric service providers and community choice aggregators to purchase a third of their retail energy from renewable sources by 2020 and 60% by 2030. The state has a goal of using all carbon-free electricity by 2045 under Senate Bill 100, passed in 2018. (See *CPUC Approves Big Boost in Storage, Solar Targets*.)

The IOUs and small and multi-jurisdictional utilities (SMJUs) predicted they will meet or exceed their RPS procurement obligations this year, the report said. CCAs, which make up a growing segment of load-serving entities in California, forecast a procurement shortfall but said they were seeking additional resources.

The shortfall of resources among CCAs has been an ongoing concern for policymakers. (See *Calif.: CCAs, Decarbonization Pose Reliability Challenges*.)

The CCAs increased their procurement of renewables by 55% to 15,500 GWh and executed the majority of new RPS contracts in 2019, the CPUC said. Their total annual RPS procurement spending increased from $555 million in 2018 to $932 million in 2019, it said. ■

A solar array in California's Sacramento Valley | © *RTO Insider*



Historical trend of all load-serving entities' RPS contract costs by technology and year of execution from 2003-2025 (real $) | *CPUC*

ERCOT News

ERCOT Briefs

TAC Approves Revision Request via Email

ERCOT's Technical Advisory Committee on Wednesday unanimously approved a change to the Retail Market Guide by email vote after it canceled its previously scheduled meeting because of a limited number of items to consider.

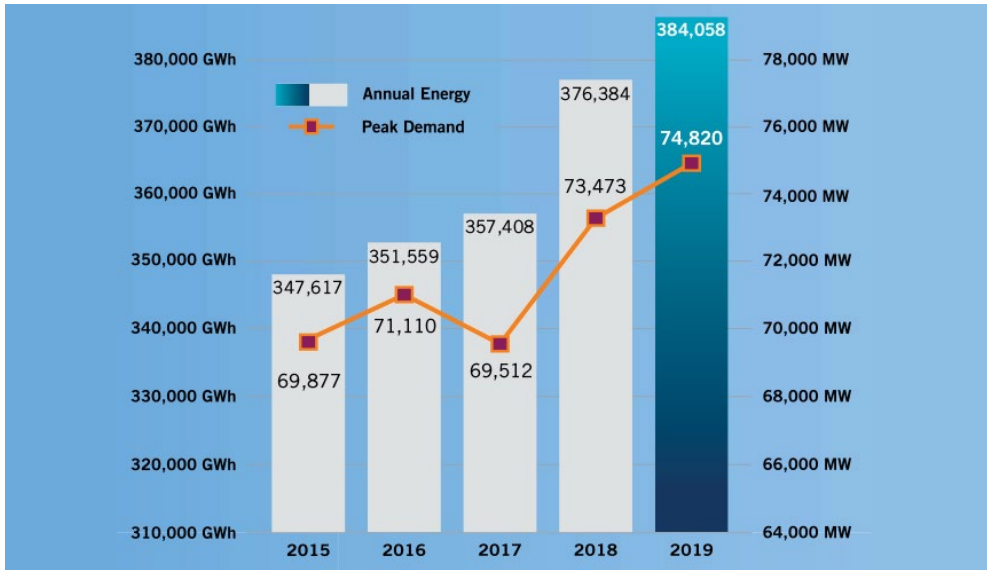
RMGRR163 removes a reference to a couple of legacy reports that will no longer be created. The committee's Retail Market Subcommittee approved the change on March 5.

The TAC is scheduled to meet next on *May 27*.

2019 State of the Grid Report Released

ERCOT has released its 2019 State of the Grid *report*.

The 15-page documents lays out the issues facing ERCOT in 2020 and beyond. It also recaps 2019, when the grid operator was able to maintain system reliability, despite peak electricity demand exceeding 74 GW and low power reserves forcing it to declare two energy emergency alerts.



2015-2019 Annual energy and peak demand | *ERCOT*

Annual energy usage was up 2%. It has increased 20% over the past decade. ERCOT's latest forecast indicates load will continue to increase. ■

— Tom Kleckner

NEPOOL Transmission Committee Briefs

FERC Order 845 Clarification

New England Power Pool participants seem to be in "overall agreement" with ISO-NE's approach to finalizing compliance with FERC Order 845, the RTO's director of transmission strategy and services, Al McBride, told the NEPOOL Transmission Committee on April 28.

One lingering difference is related to participants' concerns about the dynamic between New England's capacity network resource interconnection service (CNRIS) and network resource interconnection service (NRIS), McBride said.

The TC was discussing ISO-NE's April 20 request for clarification filed with FERC regarding Order 845 compliance, as well as the RTO's proposed response in terms of Tariff language (ER19-1951).

Order 845, approved in April 2018, set *pro forma* minimum standards for large generator interconnection procedures and agreements.

FERC rejected the RTO's proposed rules for obtaining surplus interconnection service (SIS). The commission on March 19 only partially accepted an Order 845/845-A compliance filing by ISO-NE and New England Transmission Owners (NETOs), ordering a further compliance filing within 120 days. (See *FERC OKs NETOs, Emera Maine Order 845 Filings*.)

Further changes will become effective March 19 once accepted by the commission, with a further compliance filing required by July 17, McBride said in presenting the RTO's plans.

The TC will review the Tariff changes again on May 27 ahead of a planned vote by the Participants Committee at its summer meeting in June.

Narrower Approach

NEPOOL counsel Eric Runge said the organization reviewed ISO-NE's April 20 request for clarification and contacted RENEW Northeast, which proposed the amendments that prompted NEPOOL to file its alternative and submit a protest last May.

"The only remaining issue here is surplus interconnection service," said Susan Muller of Boreas Renewables, presenting RENEW's analysis on SIS, the subject of which was last brought before the TC a year ago. (See *NEPOOL Rebuffs ISO-NE on 'Surplus' Interconnection*.)

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

RENEW says the RTO's request appears to eliminate all, or nearly all, SIS eligibility. It asked that NEPOOL clarify for the commission "that the identification of the need for any additional interconnection facilities should not cause the end of the expedited process, because interconnection facilities are typically needed and this would prematurely end the analyses for most, if not all, SIS requests."

Runge is writing a brief response to the RTO's request that would address both the amount of SIS available from an NRIS resource, and the expedited process and language regarding interconnection facilities, he said.

The commission rejected the RTO's proposed definition as it related to NRIS customers being limited to permanent service as opposed to periodic or other limited service.

Muller pointed out that while all generators have NRIS for provision of energy, only resources that have obtained a capacity supply obligation have CNRIS for provision of capacity.

She said Runge had a good suggestion in seeking some additional clarification from the RTO about when a resource has both NRIS and CNRIS, as "the relationship between those becomes very important in the context of surplus service."

"It's really important that there's clarity about the fact that these two services coexist," Muller said. "What we're really talking about is: Can two devices or two resources share NRIS when one of them also has CNRIS?"

Liz Delaney, director of wholesale market development for Borrego Solar, supported the RENEW proposal.

"My company is developing a lot of hybrid resources, and we're entering into this world where we're going to need clarity on these issues soon," Delaney said.

NETOs Settlement Close

The NETOs are nearing settlement with FERC staff and municipally owned power companies on pool transmission formula rates, with a commission administrative law judge on April 22 having ordered the hearing in abeyance until early June because of the COVID-19 pandemic.

On behalf of the NETOs, Eversource Energy's director of transmission rates and revenue requirements, Lisa Cooper, presented an update on the regional network service (RNS) settlement proceeding initiated by the commission in 2015 (EL16-19).

The commission determined that transmission formula rates appear to be unjust and unreasonable, as they may be insufficiently specific with respect to calculation of some components.

Reporting for the Participating Transmission Owners Administrative Committee, Cooper said the commission argued that the RNS formula rate (Attachment F) may not be synchronized with local network service formula rates of individual transmission owners, which could potentially lead to over-recovery of costs.

The original settlement filed on Aug. 17, 2018, was opposed by FERC trial staff and contested by municipal TOs, and the commission rejected the settlement on May 22, 2019.

The parties reached agreements in principle in October 2019, and all parties are in the process of reviewing settlement documents and redline tariff changes, Cooper said. ■

— Michael Kuser

MISO News

COVID-19, Electrification Stir MISO Futures Debate

By Amanda Durish Cook

MISO last week presented stakeholders a long-awaited set of transmission planning futures that it insists are final despite calls for an additional scenario that models an economic downturn stemming from the COVID-19 pandemic.

"Keep in mind, we're not trying to predict what will happen; we're trying to predict bookends of what could happen," MISO Planning Manager Tony Hunziker told stakeholders during a teleconference April 27 to discuss the three, 20-year future scenarios.

The RTO will begin relying on the *futures* starting with the 2021 cycle of the Transmission Expansion Plan (MTEP 21). The scenarios have undergone multiple alterations in response to stakeholder suggestions. (See *MISO Outlines Electrifying Tx Planning Futures*.)

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

Future II — previously Accelerated Fleet Change — assumes MISO members will 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.

Future III — Advanced Electrification — also assumes members fulfill their renewable plans and consumers adopt EVs. It foresees a sharp increase in demand from residential and commercial electrification, representing 50% energy growth. The RTO also experiences a minimum 50% renewable penetration level as carbon emissions dip 80% below 2005 levels.

MISO originally predicted a 60% energy growth in the electrification future but backed down on the estimate after pushback from stakeholders. The RTO plans to include more detailed time-of-use charging patterns for the 2022 MTEP cycle.

Calls for 4th Future

Hunziker said stakeholders sought more data and justification for MISO's electrification predictions. He also said some stakeholders asked whether the RTO would update economic assumptions based on the devastating impact of the coronavirus pandemic.

Hunziker said it's simply "too early to tell" the pandemic's long-term effects on the energy industry.

MISO Director of Economic and Policy Planning Jesse Moser said the RTO continues to believe it doesn't need to develop a fourth future that models a major economic slowdown despite the pandemic.

"Our view today is that this appears to be a shorter-term impact," Moser said. "We think we're in a good place right now. … We'll come back and see what happens."

Hunziker said any lasting effects on load depend on how long shelter-in-place directives remain in place and whether the virus resurges in the fall. He also reminded stakeholders that it's an election year, and challengers to incumbent candidates have extensive energy policy plans.

Moser said the RTO will specifically review electrification assumptions next year. But by summer it will have spent "pretty close to a year" defining the futures and must lock down its assumptions.

"No future is going to be perfect. If we do our job, they will land somewhere in this range of scenarios," Moser told stakeholders.

But some stakeholders disagree, maintaining that MISO should consider stagnant economic conditions and stationary load growth in the scenarios — or develop a fourth future dedicated entirely to the possibility.

David Carr, special counsel to the Mississippi Public Service Commission, said the RTO's electrification and demand predictions are simply too high, especially considering the pandemic's side effect of paralyzing economies.

"There is in fact significant uncertainty on near- and long-term energy demand," Carr said during an April 15 Planning Advisory Committee teleconference. He added that resource retirements and additions will increasingly be thrown into upheaval. He reminded stakeholders that economists predict that the crisis is triggering the worst downturn since the Great Depression.

Carr asked MISO to take an extra "three to six months" to re-evaluate the futures and make sure they account for the possibility of a lower end of decarbonization and load growth.

But Sam Gomberg of the Union of Concerned Scientists pointed to the decade following the Great Recession "as a reminder that there are two sides of the coin to this uncertainty." He said renewable generation expansion and technological advancements gained steam over the last economic downturn and recovery.

Some stakeholders countered that this slump is shaping up to eclipse all other downturns in magnitude. Others pointed out that projects approved in MTEP 21 won't go into service until several years after 2021, which they said is safely outside of the current pandemic. Still others said it isn't realistic to expect that the depressed load seen in the months with social distancing will reverberate 20 years into the future.

WEC Energy Group's Chris Plante said the RTO is still in need of a fourth future that contains more conservative electrification estimates to serve as a foil for Future III.

Others said a fourth future could serve to temper load forecasts in a post-COVID-19 world.

But Xcel Energy's Carolyn Wetterlin said Future I does represent the low end — and even dips lower — than what her company expects in terms of renewable buildout.

During MISO's April 21 Informational Forum, CEO John Bear held firm that the RTO will not add a fourth future and reminded stakeholders that the futures are meant to bookend a range of future possibilities. In MISO, large economic transmission projects that show benefits under all three futures are selected for inclusion in annual transmission plans.

"These are not meant to be deterministic … or spot-on 20 years into the future," Bear said. "It's easy to lose sight of that."

Bear said the RTO "simply doesn't know" what, if any, long-term impacts the pandemic could introduce in the energy industry. He also reminded stakeholders that futures capture 20 years, not just the immediate future.

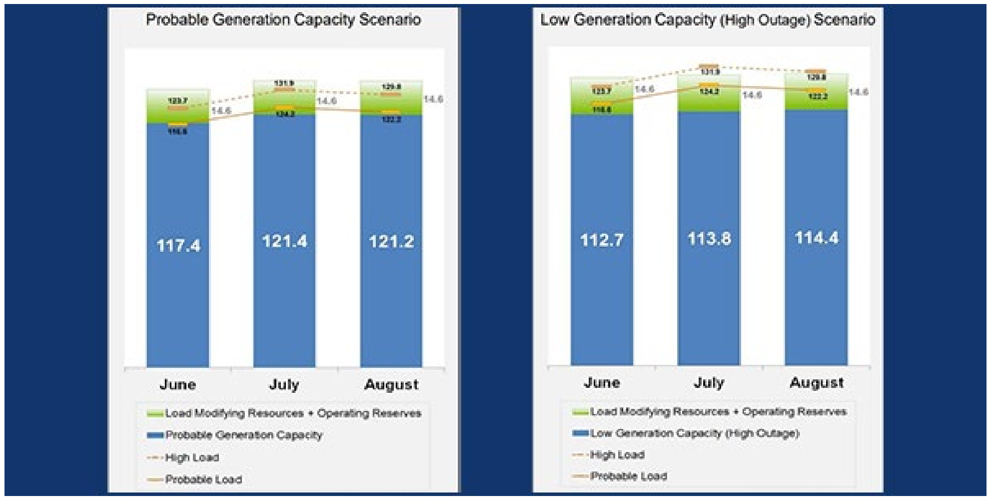
"We do plan on looking at the state of the world a year from now" to study any lasting load impacts in annual planning, Bear said. ■

| © RTO Insider

MISO News

MISO Preps for Balmy Summer with Pandemic Effects

By Amanda Durish Cook



MISO summer resource adequacy projections | © *RTO Insider*

A forecast for warmer-than-usual weather means MISO will likely have to declare an emergency this summer — even without heavy loads or a high volume of generation outages, the RTO said April 28.

The RTO is *projecting* a 125-GW summer peak and 152 GW of total capacity on hand to manage the load before generation outages are factored in.

"We expect higher load than usual … but we have adequate resources," Executive Director of Energy Operations Rob Benbow said during a summer readiness conference call.

MISO's all-time summer peak of 127 GW occurred July 20, 2011. MISO last year *registered* a 121-GW summer peak in mid-July, far short of the nearly 125-GW peak forecast. The RTO last year had 149 GW of available capacity to cover peak demand.

Benbow warned that challenges await if MISO experiences high load coupled with high outages in July or August, circumstances that would likely prompt it to declare an emergency and dip into load-modifying resources and operating reserves.

The National Oceanic and Atmospheric Administration forecasts "warmer-than-normal temperatures for a majority of the MISO footprint," Resource Adequacy Coordination Engineer Eric Rodriguez said.

In a probable scenario, MISO will have about 117.4 GW worth of capacity for a 116.6-GW average load during June. July contains the most risk, with even a probable load of 124.2 GW eclipsing its 121.4 GW of available resources. In August, the RTO still runs the risk of tapping into its emergency stack, with a probable 122.2 GW of load exceeding its 121.2 GW worth of nonemergency resources.

MISO is all but certain to declare emergency procedures during all three months should it experience even lower available capacity than in a probable scenario. Benbow said it also is preparing for the possibility of hurricanes in MISO South.

"On top of that, we'll run into challenges with COVID-19," he said, adding that MISO expects to continue to encounter difficulties forecasting day-ahead load as lockdowns and social distancing measures persist into the summer.

The RTO expects forced generation outages this summer to exceed its five-year average but still remain below the summer of 2018, when outages neared 25 GW in all three months. Outages will hit about 23 GW in June, then hover around 15 GW in July and August, it said. A fraction of the increased generation outage activity in June can be put down to impacts from the coronavirus pandemic.

As of April 20, 19.5 GW of planned generation outages had been canceled or rescheduled as a result of the pandemic. About 1.1 GW of those outages are tentatively rescheduled for early June, but more generation owners are planning to reschedule in the fall.

MISO outage coordinator Trevor Hines said generation owners are rescheduling outages thoughtfully, with concern for summer conditions. He said the outage disruptions so far will not affect reliable operations.

The RTO has also seen 101 — or about 16% — of its planned transmission outages changed since the pandemic required utilities to separate personnel, limiting some maintenance activity. Half have been canceled altogether, with the other half to be spread out over May and June, Hines reported.

Continuity in Uncertainty

South Region Operations Director Tag Short said that as MISO moves into summer, it will focus on "business continuity" even as staff remain physically separated between control rooms in three different states and working from home.

Short said MISO will continue working with states "to gain access to test kits so our control room personnel can be tested in advance of shift changes."

The RTO is already monitoring the body temperatures of control room staff and distributing face masks for employees that remain on-site. Its janitorial staff is also sanitizing facilities more often.

"We tried to reduce as many touch points as possible, and that's not easy when they share a bathroom and a kitchen," Short said of MISO's control room staff.

Manager of Forecast Engineering Blagoy Borissov said load continues to track about 10% lower than normal since closures and lockdowns became the norm in MISO states. He added that morning and evening ramps remain flatter than usual.

Borrisov said MISO's forecasting team had to "freeze" its forecasting model prior to the pandemic taking root in the footprint so the model wouldn't make load shape adjustments or match the forecast to recent history, which is temporarily an unreliable benchmark.

"We are pretending that our load forecasting model has not been updated since March 13," Borissov explained.

Borissov said an inevitable uptick in load will be difficult to anticipate as temperatures rise and states begin testing the relaxation of pandemic measures.

MISO will continue to restrict visitors to its facilities through at least June 1. Vice President of System Planning Jennifer Curran last week said it's "too early" to tell when the RTO can return to normal operations. ■

MISO News

DTE to Cut Spending in Response to Pandemic

By Amanda Durish Cook

DTE Energy on April 28 said that it will cut $60 million in operations and maintenance expenses to counteract sagging energy sales caused by social distancing measures in Michigan.

CEO Jerry Norcia said he expects lower electricity sales from the state's COVID-19 pandemic shutdown to shave anywhere from $30 million to $50 million off DTE's 2020 operating earnings. The company's estimates are based on Michigan starting to return to work in mid-May.

"We have spent a lot of time over the last few weeks understanding the potential financial impacts of the pandemic [and] building and implementing a plan to react to these challenges," Norcia said during an earnings call.

CFO Peter Oleksiak said operating *earnings* for the first quarter were $320 million ($1.66/share) compared to the $374 million ($2.05/share) earned in the first quarter of 2019.

The lower earnings were also attributable to a mild winter in the utility's territory.

"Overall, this quarter was warmer than normal and was the sixth warmest on record. DTE Electric earnings were $94 million for the quarter, which was $53 million lower than in 2019," Oleksiak said.

Norcia said that while DTE's financial team was updating its year-end forecast, it found that higher winter temperatures along with "potential sales impacts and additional costs associated with COVID-19" dashed its 2020 financial plan.

"These changes are larger than the contingency that we normally carry in our annual plan. When we rolled all of this up, we saw $60 million of earnings pressure that we needed to offset," he said.

The $60 million reduction in spending will involve "a list of one-time items to reduce cost in the near term that are not sustainable over the long-term." DTE will freeze hiring, minimize overtime, tap its own employees for some consultancy and contract work, and cut business travel, Norcia said.

He also said DTE will "postpone nonessential work, always with maintaining safety as our highest priority."

"With all these lean actions, I am confident we will achieve our financial goals for the year without sacrificing safety or customer service," Norcia said.

Residential load has "been stronger with more people at home," increasing 10 to 11%, while commercial has dropped by 16 to 18% and industrial has fallen 40 to 46%, according to the CEO.

"We believe we have seen the bottom for our load at this point. Michigan remains under the stay-at-home order with only essential businesses operating, and our load has been pretty consistent over the last several weeks," Norcia said.

For the entire year, Norcia said DTE projects a 3 to 4% increase ($40 million to $50 million) in residential electricity sales, a 6 to 9% decline ($50 million $75 million) in commercial sales and an 18 to 22% decline ($20 million to $25 million) in industrial sales.

"Under a less favorable scenario, we would have to reassess our economic recovery plans," Norcia said. "The pace at which load returns is one of the largest variables of our economic recovery plan."

A DTE Energy essential employee during the pandemic | *DTE*

Spending Plans

Norcia also said DTE is prepared to cut more spending, should it come to that.

"We have over $2.5 billion in operations and maintenance to manage through lean times, as well as the benefit of investing in incremental operations and maintenance ahead of schedule in previous years," he said.

"We faced recessionary pressures before in 2008 and 2009, and we came through that time stronger than ever. … We are facing similar pressures, and I am confident that we have built a robust plan to respond to these challenges."

DTE itself implemented a work-from-home edict in mid-March, with more than half of its employees commuting virtually.

Norcia said the company will restart "construction and maintenance activities in early May and ramp up through the month." However, he said he expects office employees will remain working from home into summer.

DTE has also recently promised Michigan regulators additional work on its integrated resource plan. Early this year, the Public Service Commission blocked the company's first 15-year IRP, finding that the utility didn't adequately factor in the benefits of renewable energy. (See *Michigan PSC Orders DTE to Redo IRP*.)

The commission approved a revised IRP in April. This time around, DTE promised energy-efficiency programs, more ambitious energy savings goals and cutting some proposed demand response pilot programs until more is known about them (*U-20471*).

The PSC also ordered DTE to conduct further analysis of its proposed 2029/2030 retirement of the coal-fired Belle River power plant, saying the first analysis was "inadequately justified because the avoidance of new environmental upgrade costs was not considered in the analysis."

Finally, DTE committed to filing its next IRP by Sept. 21, 2023, two years sooner than required by state law.

The company on April 23 commissioned its 168-MW Polaris Wind park, currently the largest operating wind facility in Michigan. The facility is the first of four new wind farms DTE plans to bring online in 2020. ■

MISO News

CMS Energy Stays Course Despite Virus Havoc

By Amanda Durish Cook

CMS Energy executives last week said they will stick to planned long-term investments and complete decarbonization plans despite uncertainties wrought by the ongoing COVID-19 pandemic.

However, the Michigan-based parent company of Consumers Energy also said it would institute some temporary cost-control measures.


CMS Energy CEO Patti Poppe | *Whirlpool*

"Our long-term investment thesis remains unchanged despite the near-term uncertainty presented by COVID-19. Over the years, we've been good stewards of the balance sheet, maintaining a healthy level of liquidity, and we plan conservatively. We still have a large and aging system and need a significant investment," CEO Patti Poppe said during an April 27 first-quarter earnings call. "Our system remains in great need of replacements and upgrades, and that won't go away as a result of the current pandemic."

Consumers in February announced plans to achieve net-zero emissions by 2040. (See *Consumers Energy Accelerates Zero-carbon Target*.)

"Our net-zero carbon and methane goals remain as important today as the day we established them," Poppe added.

The company so far seems financially unfazed by the onset of the coronavirus pandemic, *reporting* net income of $243 million ($0.85/share) for the first quarter of 2020, compared to $213 million ($0.75/share) for the same period last year.

CFO Rejji Hayes said Consumers has been experiencing 20 to 25% declines in commercial and industrial load based on its smart meter readings. However, Hayes said Consumers' electric segment is more than 60% residential and offers the "highest margins."

"The [commercial and industrial] load reduction has been partially offset by residential load, which is up over 5% over the same time frame, presumably due to mass teleworking and self-quarantine measures," Hayes said. "So any uptick in growth in the residential segment should partially offset the expected declines we anticipate in the commercial and industrial segments."

Despite the optimism, Consumers will implement a hiring freeze, minimize overtime and decrease travel and training expenses to save money, Poppe said.

"We have already implemented an initial wave of cost-control measures. Needless to say, we are not here to represent that any downside scenario can be overcome, particularly given the unprecedented nature of this global pandemic. However, we are confident that we can minimize the financial risk in 2020 without jeopardizing our long-term value proposition to our customers and investors," Hayes said.

Poppe said CMS will take advantage of a recently approved measure by the Michigan Public Service Commission that allows deferred accounting for uncollectible account expenses above currently approved rates.

She also noted that Michigan regulators are reviewing other utility costs related to COVID-19. She said CMS hopes to defer other pandemic-related expenses, "including sequestration and quarantine-related costs."

CMS currently reports that 11 of its more than 8,000 employees have tested positive for the virus.

"We're thankful that seven of those coworkers have been able to return to work, and each identified case has yielded fewer and fewer ancillary cases of contact, which means our social distancing is working," Poppe said. ■

NYISO News

NYISO Contemplates 500-MW Boost for SENY Reserves

By Michael Kuser

A December 2018 transformer explosion at a Consolidated Edison substation in Queens, N.Y., caused a power outage at LaGuardia Airport. | *Con Ed*

NYISO may shift 500 MW of the statewide reserve requirement to Southeastern New York (SENY) in order to boost resource flexibility and provide ready access to resource capability following a contingency event, ISO officials said last week.

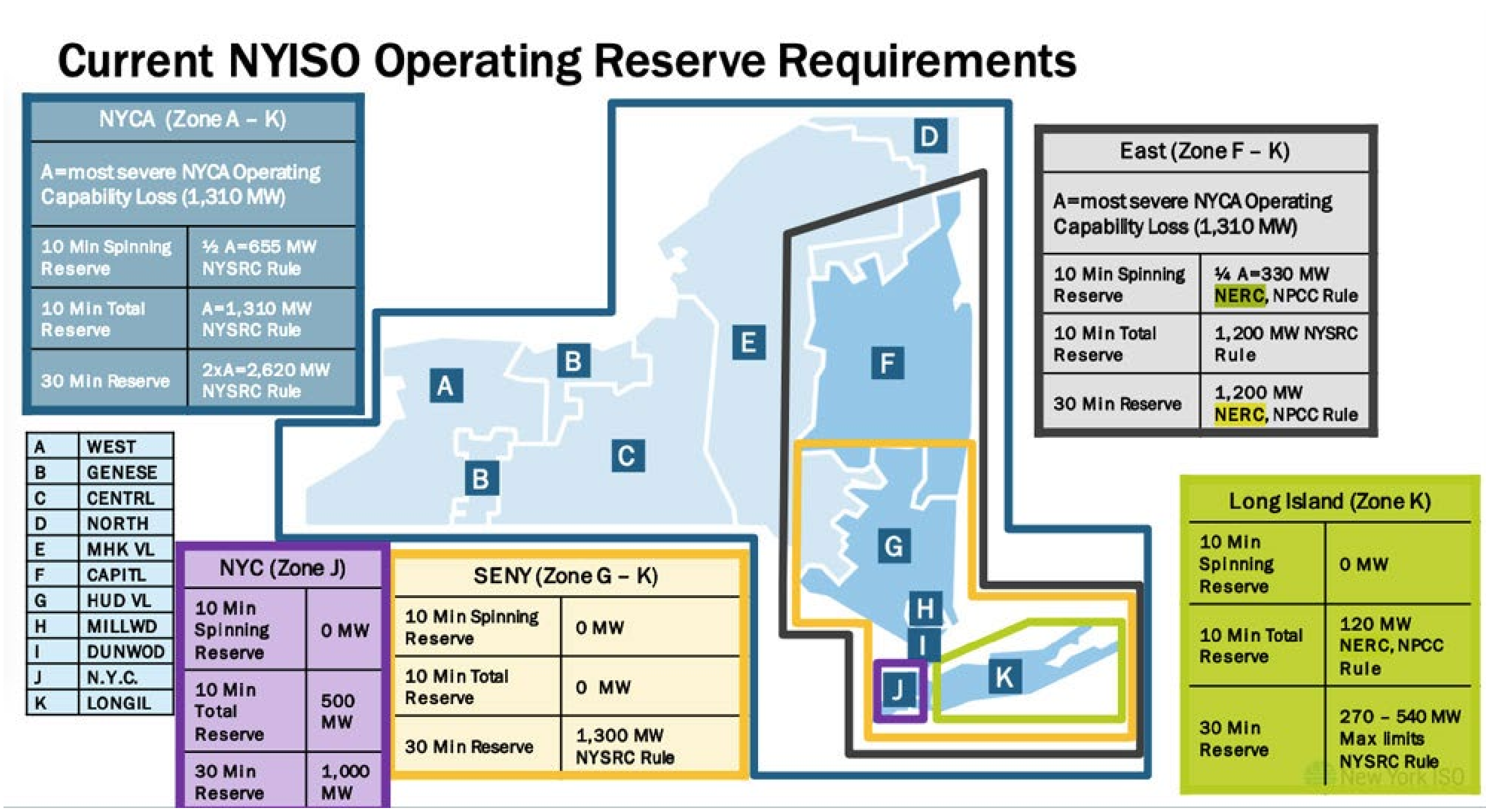
The proposal would not change the New York Control Area's 2,620 MW of 30-minute total reserves but would add to the existing 1,300 MW of reserves in SENY, the Installed Capacity/Market Issues Working Group heard during a teleconference April 27.

However, the proposal would not add to the existing reserve requirements currently applicable to Zones J and K covering New York City and Long Island, respectively. The proposal seeks to increase the current 30-minute reserve requirement for the broader SENY region, which encompasses Zones G through K. The proposal would also reduce the city's real-time reserve requirements to 0 MW during thunderstorm alerts.

"The proposal here is to have a reserve requirement that allows us to bring transmission facilities back to normal transfer criteria following a contingency," said Ethan Avallone, the ISO's technical specialist in energy market design, who presented the *analysis* on reserves for resource flexibility.

The proposal is based on the current system topology. However, it was acknowledged that NYISO continually evaluates its reserve requirements to account for material system changes.

"In the future, if we have to re-evaluate the requirement to account for anticipated transmission upgrades, or after any large change to transmission, we would still look to procure



| *NYISO*

NYISO News

enough reserve to bring transmission facilities back to normal transfer criteria in that case," Avallone said.

Market Mechanics

Absent procuring the proposed additional SENY reserves, NYISO could at times need to use out-of-market actions to return transmission facilities to normal transfer criteria, Avallone said.

The additional reserves would be procured at all times in the day-ahead and real-time markets.

"Up until this point, the reserve requirement for SENY is designed to allow the ISO to take the system back to emergency transfer criteria, and if the system doesn't recover post-contingency, out-of-market actions may potentially be taken to bring the transmission facilities back to normal transfer criteria," he said.

Couch White attorney Kevin Lang, representing New York City, asked how often NYISO has needed to resort to out-of-market actions for such cases. The ISO did not have immediate access at the meeting to the specific data to quantify the frequency. It was asked to provide such data as part of future discussions related to the proposal.

"You're looking at procuring these additional reserves on an ongoing basis, so there's a payment required for that from Zone J," Lang said. "If you've only been required to use out-of-market actions once a year or once every two or three years, then there isn't a justification for increasing these costs to Zone J and adding this new requirement, even though it's just shifting the location for procuring reserves from NYCA to SENY."

The ISO needs to demonstrate a reason to increase the reserve requirement to SENY, Lang said. Without knowing how many times the grid operator has needed to resort to out-of-market actions, market participants "have no way of knowing whether this is really necessary, or whether this is just a hypothetical concern," he said.

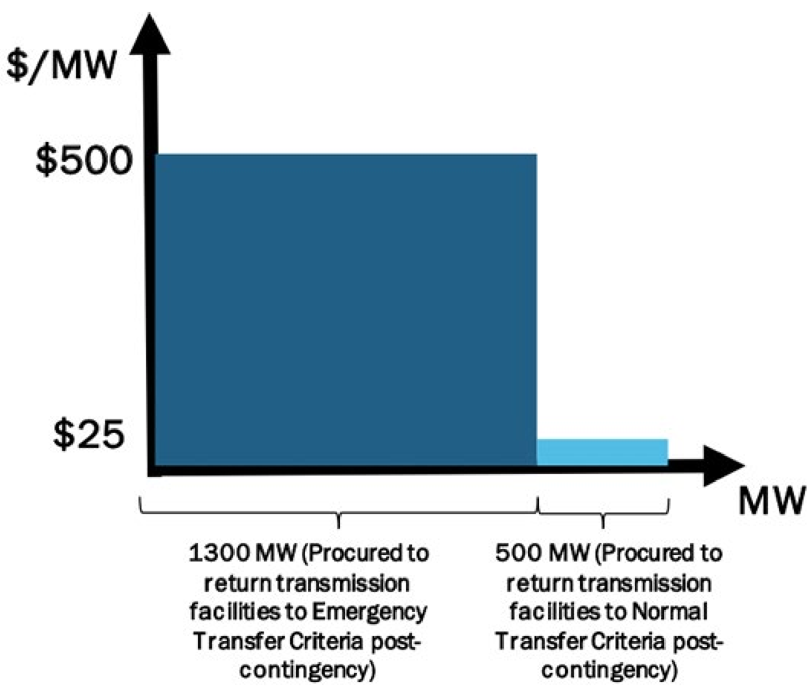
"We look at this proposal as a market-based way to reflect the flexibility operators are looking for on a reliability basis into the market," Avallone said.

Luthin Associates' Aaron Breidenbaugh, who represents a group of nonprofit institutional customers known as Consumer Power Advocates, echoed Lang's concern.

"Right now, with what's going on in New York City and what's going on in our state, this isn't the time to start layering more costs on New York City customers," Breidenbaugh said.

Mark Younger of Hudson Energy Economics suggested that NYISO not look at the data only in terms of what percent of the time the ISO had to take out-of-market actions to secure the transmission, but what portion of time there was a contingency that required action by the ISO.

"Contingencies are rare," Younger said. "We have reserves to make sure we can operate when contingencies happen, so looking at it in terms of all time is not the appropriate way to do it."



Proposed SENY 30-minute reserve demand curve | *NYISO*

Consumer Impact Analysis

In addition to estimating potential energy market impacts, NYISO will estimate both the potential short-term and long-term capacity market impacts of the proposal using revised reference prices calculated for the 2020/21 capability year installed capacity demand curves, said NYISO Senior Manager and Consumer Interest Liaison Tariq Niazi.

He presented an *outline* of the methodology to be used in a consumer impact analysis of the proposed change in SENY reserves.

Niazi assured stakeholders that the results of the consumer impact analysis would be presented before seeking approval before the Business Issues Committee and Management Committee. "So just in case we have to revise the analysis, I think there should be time. ... We actually seek to present the impact analyses at least 30 days before seeking a vote at BIC," he said.

NYISO also will evaluate reliability and environmental impacts, as well as the impact on transparency as part of its consumer impact assessment. In terms of the future timeline, if the proposal obtains stakeholder approval, the ISO would seek to begin developing the necessary software in 2021 to facilitate implementing the proposed enhancements in 2022.

Pallavi Jain, a NYISO market design specialist, *presented* a related project to revise ancillary services shortage pricing.

The shortage price for the current 1,300-MW SENY 30-minute reserves is $500/MWh, and the ISO proposes a shortage price value of $25/MWh for the 500-MW increase in the SENY 30-minute reserve requirement.

The ISO has proposed to increase the initial $25/MWh shortage pricing value for these additional SENY 30-minute reserves to $40/MWh upon implementation of the subsequent proposed enhancements related to the separate ongoing effort to re-evaluate the current reserve shortage pricing values for all products and locations. However, for the reserve requirements applicable to Zones J and K, the ISO is not proposing to increase the current $25/MWh shortage pricing value because of the limited number of eligible suppliers in New York City and Long Island. ■

NYISO Management Committee Briefs

COVID-19 Impacts Continue on Operations

NYISO will stop sequestering the operations teams at one of its two control centers even as the COVID-19 pandemic continues to reduce demand for electric power throughout New York, especially in New York City.

"We have made a decision, based on a number of factors, including the number of cases we are seeing locally in the capital region, that it is not necessary to continue to have operators sequestered at both control room sites," NYISO Executive Vice President Emilie Nelson told the Management Committee on Wednesday.

"We plan to transition next week to have a single sequestered site at our Carmen Road facility," Nelson said. "We will then be able to operate the Krey facility in a non-sequestered mode, but certainly with stringent, best practices in place from a health perspective."

Most of the ISO's staff continue to work effectively from home, she said.

In addition, the joint Board of Directors/MC meeting scheduled for June 15-16 will be held remotely, Nelson said.

COVID-19 Weighs on Load

The average location-based marginal price for March was $17.11/MWh, down from "the very low" $21.11/MWh in February and $34.91/MWh in March 2019, Vice President of Operations Wes Yeomans said as he delivered the CEO/COO *report*.

"The lower prices are not totally surprising as you move into March and to lower load from the impacts of the virus and lower fuel prices," Yeomans said. "And about half the marginal price on average of last year — and again not totally surprising, given the situation."

Demand Forecasting Manager Charles Alonge presented the estimated *impacts* of the pandemic on NYISO demand through April 24.

"As you've noticed, we've been in a very consistent system pattern over the past four weeks with respect to the load deficit, which has leveled off at minus 8%" systemwide, Alonge said.

"The first quarter of 2020 was generally much warmer than average, and over the last two weeks, we have seen colder-than-average temperatures — some of you have experienced snow two weeks ago," Alonge said. "Therefore, demand deficits have been ameliorated to some extent by colder-than-average weather over the past two weeks."

As reported at the mid-month MC meeting, the biggest impact on load was seen in New York City's Zone J, which also has the largest commercial percentage of load in the New York Control Area.

"Zone J is posting morning ramp load levels 20% below normal at 8 a.m.," Alonge said.

Customer Satisfaction Trends Higher

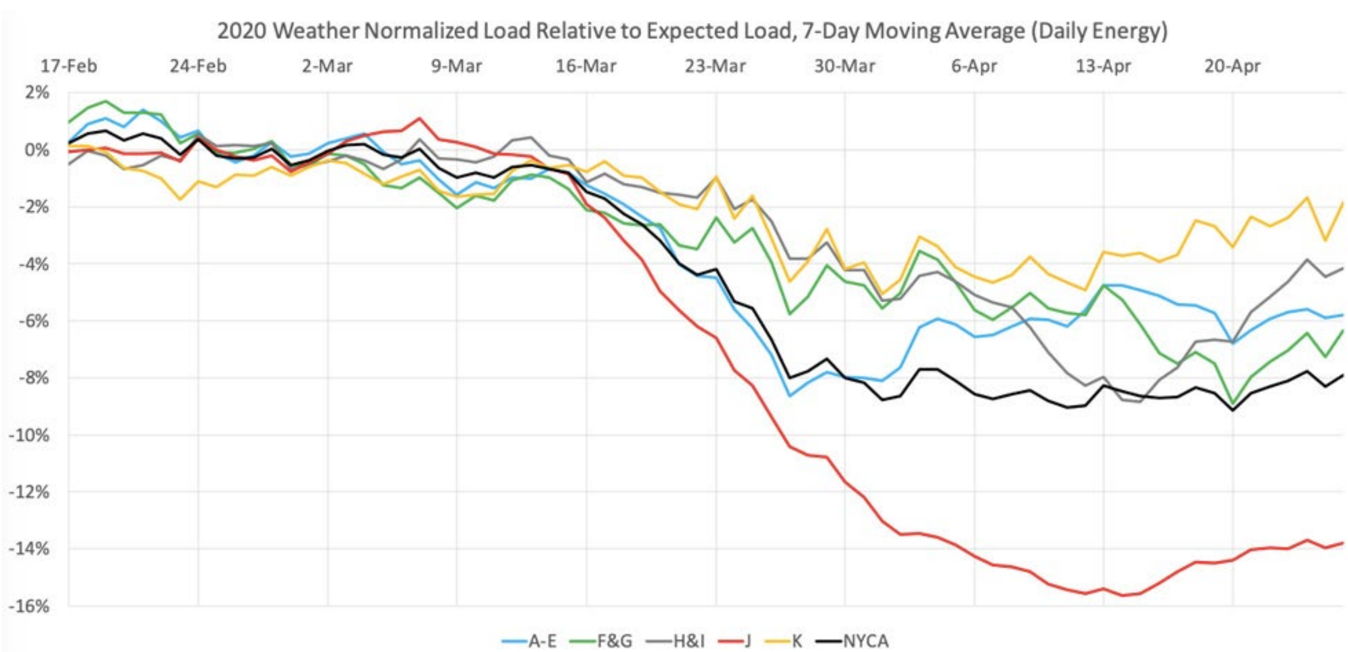
An annual performance assessment and customer satisfaction *survey* conducted by the Siena College Research Institute (SCRI) shows NYISO last year scoring the highest marks — or matching the record — since a new platform was adopted in 2016.

"We simultaneously assess customer satisfaction and an assessment of the NYISO's performance offered both by market participants and CEOs over the course of the year," SCRI Director Don Levy said. "The 2019 final score for satisfaction at 91.1, and the performance assessment score of 76.7 are merged to achieve a unified score by combining 60% of the satisfaction score and 40% of the performance assessment."

The year-end combined score was 85.4, he said.

The performance assessment score of 76.7 matches the ISO's score from last year exactly, with a collective score of 75 equating to slightly above very good, Levy said.

Opportunities for improvement include explanation of policies and procedures; transparency; considerations of individuals' input; comprehensive long-term planning for the state's electric power system; advancing tech-



Regional impacts of COVID-19 on NYCA daily energy patterns | *NYISO*

NYISO News

nological infrastructure; and providing factual information to policymakers, stakeholders and investors.

Bylaws Revisions Re. Press Access Approved

The MC approved changes to its own bylaws to make clear that nonmembers, including the public and press, may attend committee meetings in person or by teleconference.

Kevin Lanahan, NYISO vice president for external affairs and corporate communications, presented the *revisions*.

The press-related bylaws proposal was prompted by a request by *RTO Insider* to allow its reporters to attend committee meetings by teleconference, which the bylaws at the time forbade. (See *Bid to Limit NYISO News Coverage Fails*.)

Nonmembers must register beforehand and "announce their presence at the beginning of or upon entering the meeting by stating their name and any organizational affiliation(s)," according to the proposal.

"We made clear under this change that any recording in any format of the MC, and this will also go for the other committees, is prohibited except by the ISO," Lanahan said. "This is a new change, a significant change. This language does not exist yet in the bylaws anywhere."

The changes also clarify that the secretary, ISO staff and its counsel and advisers may attend and participate in discussions at meetings of the committee, including executive sessions, and clarifies that the Public Service Commission includes the Department of

	Summer Peak Load Window		Winter Peak Load Window	
HB	6 Hour	8 Hour	6 Hour	8 Hour
12		5.0%		
13	12.5%	10.0%		
14	18.75%	17.5%		5.00%
15	18.75%	17.5%		5.00%
16	18.75%	17.5%	18.75%	17.50%
17	18.75%	17.5%	18.75%	17.50%
18	12.5%	10.0%	18.75%	17.50%
19		5.0%	18.75%	17.50%
20			12.5%	10.0%
21			12.5%	10.0%
Top 4 Hours	75%	70%	75%	70%

Summer and winter capability period months will receive the set of weightings as shown here. | *NYISO*

Public Service.

The bylaw changes now move for votes by the Business Issues Committee and Operating Committee, Lanahan said.

Tailored Availability Metric OK'd

The MC also approved Tariff changes for the tailored availability metric project and recommended the board approve a FERC filing under Section 205 of the Federal Power Act for a May 1, 2021, implementation.

Associate Market Design Specialist Emily Conway presented the *project* as part of the ISO's "Grid in Transition" process to adapt to increasing amounts of renewable energy on the system. (See *NYISO Focus Turns to Grid 'Transition'*.)

The tailored availability metric project is a market design based on analysis done for availability-based resources using the equivalent forced outage rate (EFORd) to determine the seasonal derating factor (AEFORd).

The EFORd is the portion of time a unit is in demand but is unavailable because of forced outages and derates. Under the project changes the ISO will weight peak months more heavily in the AEFORd calculation. ■

— Michael Kuser

NYISO customer satisfaction and assessment of performance final 2019 score | *SCRI*

NYISO News

Pandemic to Sting C&I-dependent Utilities, Researchers Say

By Michael Kuser

The economic fallout from the COVID-19 pandemic will weigh most heavily on utilities most dependent on commercial and industrial load, two power industry researchers told the Northeast Energy and Commerce Association (NECA) on Thursday.

About 60 participants tuned into NECA's "Pandemic, Power Demand and Profits" webinar to learn how the stay-at-home orders and the contraction in U.S. second-quarter GDP are impacting the utility industry.

The U.S. has only 4% of global population but accounts for a third of the world's COVID-19 cases. The webinar examined where a recession will hit hardest in the U.S. electricity industry — and who could ride through the storm relatively unscathed.

The panel also looked at how the pandemic will affect the level and shape of load in future, and whether commercial load will become lower and flatter than before the shutdown.

Load Composition Determines/ Downturn Fate

Panelists Hugh Wynne and Eric Selmon, both longtime international power project developers, together founded Power Research Group and head up utilities and renewable energy research at investment consultancy SSR.

The pandemic shutdown finds Selmon holed up with his wife and children in Tel Aviv, Israel, while Wynne is doing the same on the coast of Maine.

Wynne said the pair's research indicates the recession will impact power sales most severely in those regions — and among those utilities — with the highest share of C&I load.

"Over the last couple of decades, changes in GDP can explain about 40% of the annual variation in commercial and industrial electricity revenues," Wynne said. "In the residential sector, there is not a very strong correlation between GDP and revenues from residential demand, and that has important consequences.

"Conversely, regions that have high levels of residential demand will be cushioned from that impact. And importantly, because this recession was triggered by and coincides with the state lockdowns, a second development will alleviate the financial burden on these utilities, and that is the increase in residential demand during the lockdowns," he said.

Residential demand is up about 10 to 15% nationally over the past month, which will have a material mitigating effect on the downturn in C&I revenues from the utilities' perspective — it won't offset it completely, but it will reduce the reduction in revenues, Wynne said.

At the retail level, rates for electricity vary dramatically by customer segment.

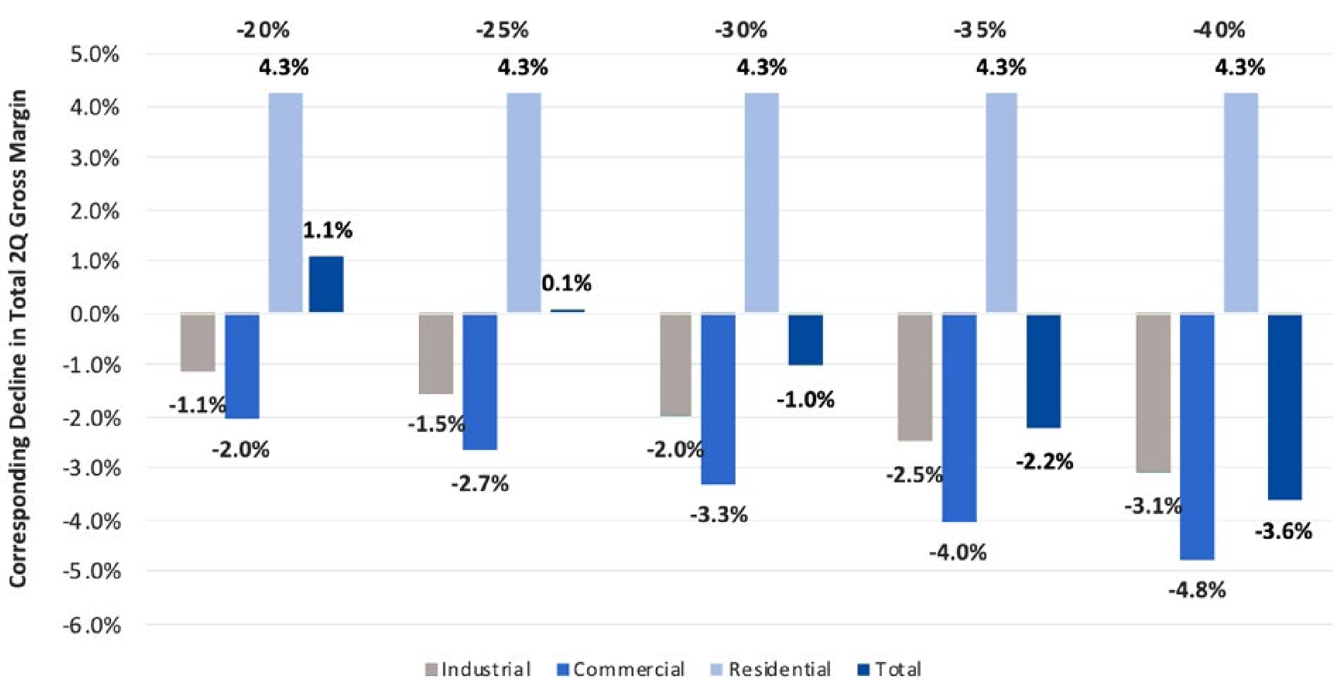
"Residential rates are by far the highest, commercial rates perhaps two-thirds on average nationally, in terms of the residential rate, and industrial revenues per megawatt-hour are perhaps a half of the residential rate," Wynne said.

As a consequence, the downturn in C&I demand will have a less-than-proportional impact on utility revenues while the increase in residential demand as the lockdowns persist will have a greater-than-proportional impact, he said.

New York vs. New England

In terms of individual utilities and regions, Selmon and Wynne concentrated on the Northeast and found some utilities better positioned because of their high levels of residential demand.

National Grid and Emera, for example, have very high levels of residential demand in their electricity sales profiles at 70% and 52%, respectively. The pair categorized Avangrid and Eversource Energy as moderately well situat-



Impact of lower C&I revenue, and 10% higher residential sales, on utilities' Q2 gross margins at various rates of quarterly GDP growth | *EIA, SSR*

NYISO News

ed to absorb the impacts from the downturn, at 45% and 40%, respectively, and others such as Consolidated Edison, at 32% residential demand, not well positioned.

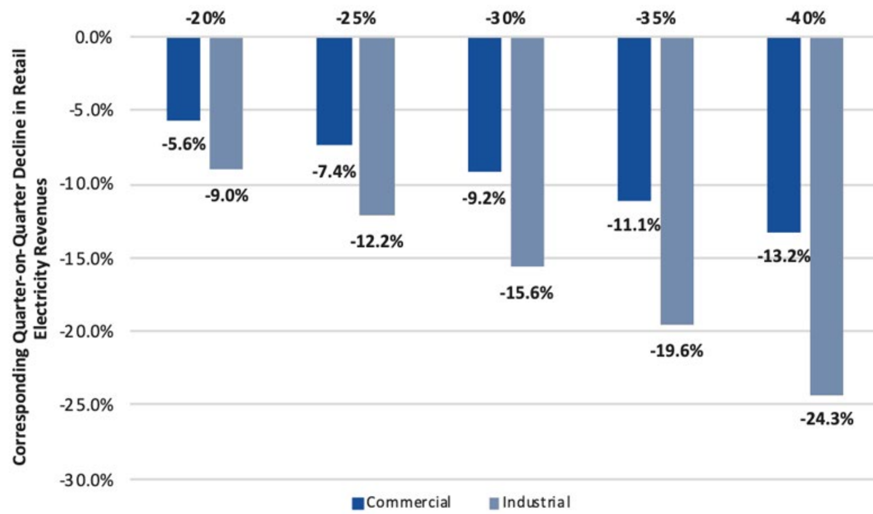
"In Con Ed's case, almost two-thirds of demand comes from the commercial segment, and that renders them particularly vulnerable to the economic contraction," Wynne said.

He pointed to peak load having fallen markedly in NYISO Zone J (New York City) in the four weeks following the state's closure of nonessential businesses on March 22. (See "COVID-19 Weighs on Load," *NYISO Management Committee Briefs: April 29, 2020*.)

Selmon noted that "the country experienced a fairly mild winter, but particularly in the Northeast and parts of the Midwest, it was significantly colder than average in March and April, so when you weather-adjust, you would see a greater impact: a greater decline in peak loads from before the lockdown."

In contrast to New York City and its concentration of commercial demand, New England as a whole is much more heavily weighted to residential demand, Selmon said.

"New England is different from other parts of the country in being more gas generation, so here there's less of a stack to shift around," Selmon said. "When demand declines you will see more of an impact on heat rates. In other parts of the country the heat rates have held up fairly well ... in Texas demand is actually up." The Midwest was already seeing a decline in industrial demand before the lockdown because an industrial recession appeared to be starting, but now the region is seeing declines in commercial load as well, he said.



Estimated change in utilities' Q2 2020 C&I electricity revenue at various rates of quarterly GDP growth | *EIA, SSR*

Gross Margins and the Long View

Industrial demand is about a quarter of total demand nationally, yet the contribution of the industrial segment to utility gross margins nationally is only about an eighth of the total.

On the other hand, residential demand is about a third of total demand nationally, but the contribution of those residential customers to utilities' gross margins is slightly over half.

"What we've done here is to translate our estimate of the decline in C&I revenue, and our estimate of the increase in residential revenue, to show their impact on the total gross margin of utilities in the second quarter," Wynne said.

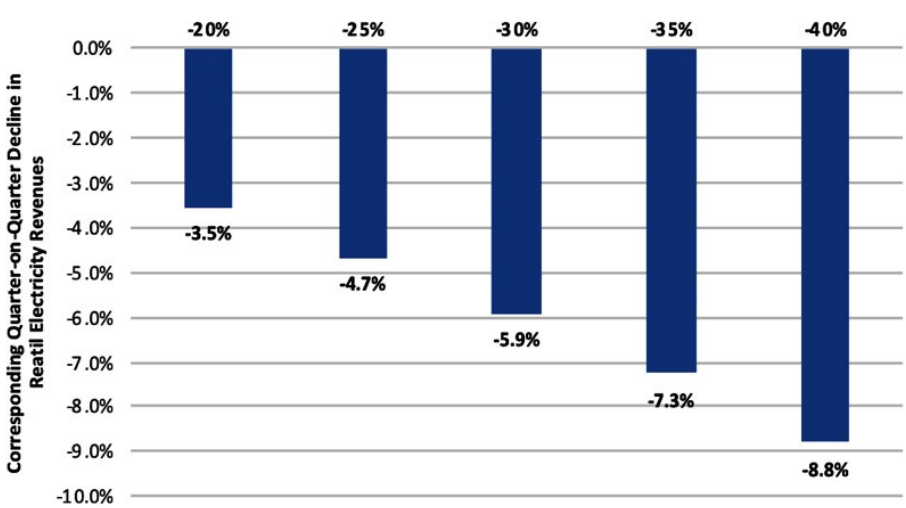
In Wynne and Selmon's central case of a 30% decline in second-quarter GDP, the decrease in industrial revenues will probably erode the total gross margin of the utilities by about 2%. Combining the industrial profile with a 3.3% decline in commercial revenues and an offsetting 4.3% increase in residential revenues would result in a 1% decline in utility gross margins during such a quarter.

Over the second half of the year, "we're concerned that the experience of Asia may portend a recurrence of COVID-19 in the future," Wynne said. "In Asia there's a group of island nations — Singapore, Hong Kong and Taiwan — that noted considerable initial success in combatting the spread of COVID. But in each of those countries, there have been renewed outbreaks of the disease and authorities have been forced to reintroduce social distancing measures, and in some cases, particularly Singapore, those new measures are stricter than the ones initially imposed.

"With such a recurrence likely in the U.S., particularly in the fall flu season, we foresee a re-imposition of social distancing by state health authorities, and possibly, in extreme cases, a re-imposition of lockdown."

Such an eventuality would mean that the typical V-shaped economic recovery chart would instead be a sawtooth pattern resulting from a slower return to normal with alternating quarters of expanding and contracting GDP, he said.

As a result, wholesale electricity markets may see persistent reduced power demand and prices, and regulators will look less favorably on revenue increases and rate base growth, Wynne said. In turn, lower and flatter load profiles may limit opportunities for investment in generation and transmission. ■



Estimated change in utilities' Q2 2020 retail electricity revenue at various rates of quarterly GDP growth | *EIA, SSR*

PJM News

PJM Outlines Revised MOPR Compliance Filing

By Michael Yoder

PJM last week shared its initial response to FERC's April 16 rehearing orders on the minimum offer price rule (MOPR), which required the RTO to make an additional compliance filing by June 1.

The commission rejected rehearing of its June 2018 order declaring PJM's capacity market unjust and unreasonable (*EL16-49-001*, *et al.*) and virtually all of its December 2019 ruling spelling out the expanded MOPR (*EL16-49-002*, *et al.*) but provided clarification on several points. (See *FERC: RGGI, Voluntary RECs Exempt from MOPR*.)

Lisa Morelli, PJM | © *RTO Insider*

Lisa Morelli, PJM director of capacity, demand response and compliance, gave the Markets and Reliability Committee a *presentation* Thursday highlighting where FERC's directives diverged from PJM's initial compliance filing in March. (See *PJM Makes MOPR Compliance Filing*.)

Morelli said PJM will share how it is addressing each issue cited by the commission in future meetings. "In many cases, we're still working through the interpretation of these items in developing what our compliance approach is," Morelli said.

State Subsidy Definition

FERC agreed with PJM that renewable energy credits (RECs) are not considered state subsidies if they are used and retired for voluntary obligations rather than for state-mandated renewable portfolio standards.

The commission also backed PJM's position that fees paid by resources under the Regional Greenhouse Gas Initiative are not state subsidies but clarified that RGGI payments to specific generation units are subsidies and subject to MOPR.

Morelli said one of the biggest surprises in the ruling was the denial of rehearing requests seeking to exempt state default service procurements from the definition of a state subsidy, a ruling she said PJM will have to address in its new filing.

FERC's directive can be read broadly to cover any resource that contracts to supply generation to a load-serving entity that won tranches of load in a default service auction, she said. But she said references to "specific winning resources" suggests "there are also more narrow readings that are reasonable, as well."

Impacts to MOPR Floor Prices

PJM's initial compliance filing based MOPR floor prices for energy efficiency on the verifiable level of savings. But FERC directed that the EE floor price be based on net cost of new entry (CONE) or — for existing resources — net avoidable-cost rate (ACR).

The net CONE and ACR must include the cost of measurement and verification, Morelli said, prompting PJM to examine whether further revisions may be needed to address the issue.

The commission also said net ACR should be based on resource-specific revenues rather than zonal averages, as PJM had suggested.

FERC also said PJM's compliance filing should not contain any substantive changes to its existing MOPR rules; until the December order, MOPR applied only to new natural gas resources. Morelli said the order creates two different MOPR floor levels — one for new-entry natural gas and the expanded MOPR for state-subsidized resources.

New/Existing Capacity Resources

FERC clarified that only the cleared portion of a resource's megawatts will be treated as an existing resource.

The commission denied a requested clarification that demand resources should be considered existing if they had previously cleared an auction regardless of the number of megawatts offered. The commission said demand resources increasing the number of megawatts they offer year to year must explain that the increase is not connected to additional construction costs or state subsidies that make the uprate possible.

Resources not subject to the Capacity Performance must-offer requirement, including demand response and intermittent renewables, will be treated as new resources if they seek to re-enter the capacity market after sitting out an auction.

Bilaterally procured capacity from a state-subsidized resource cannot serve as replacement capacity for unsubsidized capacity resources, the commission said, clarifying that public power self-supply entities cannot engage in voluntary, bilateral contracts with unaffiliated third parties without triggering the MOPR.

Morelli said PJM tried to balance FERC's directive that public power is state-subsidized with not impeding normal commercial activity in contracting between public power and merchant entities. "We're still evaluating this provision and whether it will indeed have an impact on our compliance filing."

Stakeholder Responses

Tom Hyzinski of GT Power Group asked how PJM's additional compliance filing could affect the capacity auction dates.

Morelli said the intention was to run the first auction about six and a half months after receiving FERC approval on its compliance filings. She said the auction has been set up as a "floating schedule" contingent upon receiving FERC approval, with PJM still anticipating that it could hold an auction by the end of the year.

Bruce Campbell, director of regulatory affairs for CPower, said that because FERC rejected rehearing requests to exempt EE from the MOPR, there needs to be a "fairly robust resource-specific offer methodology" established. Campbell asked PJM to give the process immediate attention recognizing that they will be new for staff and stakeholders.

"I think it's incumbent on parties to really get a good understanding of how that will work before we push up against the deadline," Campbell said.

PJM Independent Market Monitor Joe Bowring invited stakeholders concerned with the EE methodology to contact his office. "We'll provide a template," he said. "We're committed to make it work efficiently."

PJM will hold a stakeholder "listening session" regarding the FERC orders in a special meeting of the Market Implementation Committee on *May 6* and a detailed session at the MIC's regular meeting *May 13*. Rehearing requests are due to FERC by May 18, three days after the deadline for comments on PJM's March compliance filing.

The RTO will also hold a final information session — tentatively scheduled for May 28, pending the agenda for the Markets and Reliability and Members committee meetings — before making its new compliance filing. ■

PJM News

PJM Monitor Defends FRR Analyses in MOPR Debate

Continued from page 1

The Monitor issued an *analysis* on the impact of Exelon's Commonwealth Edison leaving the capacity market for an FRR in December and one on *Maryland*'s options April 17.

The ComEd report's first scenario concluded net load charges would increase 23.6% if ComEd procured all of its capacity obligations outside of the BRA at the offer cap — $254.40/MW-day — rather than the $195.55/MW-day clearing price in the 2021/22 Base Residual Auction.

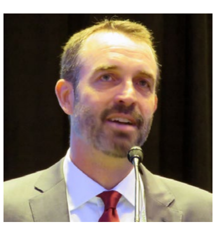
In a second scenario, the Monitor calculated that ComEd's load charges would decrease 5% if the price negotiated for its capacity were equal to the locational deliverability area's (LDA) clearing price. The report contended the first scenario was more plausible, "given Exelon's assertions that the current total revenue from energy, ancillary and capacity markets is not adequate for its nuclear plants."

Only one of six scenarios in the Maryland analysis showed possible cost savings for Maryland ratepayers (5.4%), while the other scenarios saw increases of 5 to 43%. (See "Monitor: Maryland FRR Likely to Increase Capacity Costs," *FERC: RGGI, Voluntary RECs Exempt from MOPR*.)

Maryland Public Service Commission Chair Jason Stanek | *Md. PSC*

FRR "is not an easy exit ramp to choose," said Maryland Public Service Commission Chair Jason Stanek, who also appeared on the panel on pursuing state clean energy policies under the expanded MOPR.

Lower Reserve Margin



Rob Gramlich, Grid Strategies | © *RTO Insider*

But Rob Gramlich, president of Grid Strategies, said FRRs won't necessarily raise costs. "The cost-reducing effect of FRR is known — the lower reserve margin. All other things [being] equal, that clearly has the effect of reducing prices," he said. The FRR unforced capacity (UCAP) obligation for the ComEd zone is 23,385 MW — about 2,700 MW (10.4%) less than ComEd's requirement of 26,112 MW under the BRA.

Gramlich said the Monitor's analyses are based on improper assumptions, including that generators outside the LDA would be paid more under FRR than what they would earn in the PJM auction. Half the scenarios assumed prices at the offer cap for the applicable LDA. The $254.40/MW-day in the ComEd LDA is 30% above the $195.55/MW-day clearing price in the 2021/22 BRA.

He said the analyses only look at the next BRA and assumed "MOPR has no cost impact going forward, thus finds no savings" under FRR.

Gramlich also said the Monitor ignores the flexibility in FRR for portfolio-based penalties. Four-hour storage, which gets little capacity value in the BRA, can be included in FRR entities' portfolios to avoid performance penalties, he said.

"I'm not necessarily advocating for FRR," Gramlich said. "There are good and bad FRR approaches. ... My point is nobody should be surprised that states are trying to accomplish their own objectives, and I think the rhetoric around FRR meaning a retreat from markets is not accurate. And studies saying FRR necessarily raises costs [are] also not accurate."

Exelon also has challenged the Monitor's analysis. Exelon's Jason Barker told PJM stakeholders in February that the ComEd analysis was not "a credible or useful tool for understanding the value of an FRR for Illinois customers." (See *Exelon Challenges PJM Monitor's ComEd FRR Analysis*.)

Bowring was unyielding last week. He said his firm's reports are not attempting to predict what the final capacity prices would be under FRR but to give low and high price estimates of the economic impacts on consumers. He said the reports are conducted with detailed analysis using defined input assumptions so others can evaluate the results.

He said the increase in costs under FRR would be even larger once state subsidies to nuclear and renewable resources are factored in. "It appears to be demonstrably cheaper to stay with the markets, and if you need to do additional subsidies on the side, you can do that" for a lower total cost than FRR, Bowring said.

Market Power

Bowring said FRR would be a weaker variant of cost-of-service regulation and noted that imports into capacity market delivery areas are limited by capacity emergency transfer limits, which he said are relatively low compared to capacity requirements. The concentrated ownership of capacity that can meet the state's capacity requirements gives local generation owners market power.

"It's the state bargaining with monopolists who have better information [and] more knowledge about the cost of the resource and the nature of the resource," Bowring said. "It's not an equal negotiation. So basically, you're giving market power to the generators in the FRR, and that's the really critical point."

He noted that generators within an FRR area are not required to participate, giving them leverage over pricing. "If you don't think you're going to get a fair price — a price equivalent to what other people are being paid for capacity — then you don't have to participate and the FRR can't occur," he said.

Capacity Transfer Rights

Bowring said that while Gramlich pointed out that the reliability requirement would be lower in an FRR, he ignored that capacity transfer right (CTR) payments would go down significantly, causing prices for consumers to rise.

Gramlich insisted the CTR payments are "not a factor."

"That number is identical to the ... excess payments [the Monitor] assumes for that external generator to sell into a constrained area. ... That's not the case if you pay that external generator a competitive price."

Gramlich said the Monitor's market power concerns are "partially contrived by the assumption that states would prefer to choose resources that are internal to their state. Well, the state doesn't have to do that. ... In some ways the analysis assumes bad FRR design by choosing the generators, thereby conferring market power to them rather than competitively soliciting power from internal and external generators."

New Jersey

Gramlich said the expanded MOPR has been "the worst thing since the California flawed initial market design [to] the cause of RTOs and competition," saying it will result in almost 32 GW of unmet state renewable portfolio standard demand by subjecting almost 8,800 MW (UCAP) of nuclear and renewable resources to the rule.

The shortfall will increase by 2035 with the addition of 7,500 MW of offshore wind from New Jersey and again with Virginia's adoption

PJM News

of a 100% clean energy standard, he said. (See *Va. 1st Southern State with 100% Clean Energy Target*.)

The New Jersey Board of Public Utilities is accepting comments until May 20 on alternatives to the state's participation in the capacity market, with reply comments due June 24 (Docket EO20030203).

Bowring said a report on New Jersey's FRR options should be released in a few weeks. He declined to speculate on its findings, saying it would be market-sensitive information. "I doubt it would be very different" from the previous analyses, he added.

New Jersey's contract for offshore wind — a long-term contract with built-in escalators — "sounds a lot like some of the old PURPA [Public Utility Regulatory Policies Act] contracts that were signed that ended up costing New Jersey customers billions of dollars in excess of market value," Bowring said.

Maryland's Approach

Stanek said the Maryland PSC has been reviewing the Monitor's analysis for the state and is working with its legislators in Annapolis to determine its best move. He said it is also closely looking to see what actions Illinois and New Jersey take.

"We're taking a slower approach," he said. "We would like to see what the next BRA auction results are. One thing we can agree on is that they're not going to be terribly out of line compared to the last auction."

Beyond that, he said, there are no guarantees.

"I don't believe that we've made a good use out of the past two years fighting FERC, working on this MOPR. I think all parties — whether you're [the] renewable sector, you're a state regulator, you're a … merchant generator — I don't foresee that this current capacity market … is going to continue in the current state. So, we need to use our resources to figure out what comes next. True, we'll have a few more BRAs in the coming future. But we need to plan for the next phase so that states can pursue their public policies."

Returning to the Bargaining Table

Sarah Novosel, managing counsel and senior vice president for government affairs for Calpine, said she was grateful that FERC acted on rehearing only four months after its December order, allowing those who oppose it to make their case before the appellate courts.

Sarah Novosel, Calpine | © *RTO Insider*

"I'm hopeful that it's now going to allow the legal issues to be put into the courts where they belong — they need to be sorted out by the court — and really allow FERC and parties to focus on the compliance process. Because that's really what we need to do, is … get the compliance order issued and get the auctions started again."

Novosel said her company — which filed the FERC complaint that resulted in the December order — is open to additional negotiations to address concerns over renewables.

"Calpine, and I think other generators, are open to coming back to the bargaining table," she said. "We've got the order now, and we've gotten to the point where we really do need to get some data from the auctions. … Let's see where the prices are heading."

One way for offshore wind to participate under MOPR, she said, would be for PJM to adopt something similar to New England's Competitive Auctions with Sponsored Policy Resources (CASPR) two-stage construct. Under CASPR, ISO-NE will clear the Forward Capacity Auction after applying the MOPR to new capacity offers to prevent price suppression. In the second Substitution Auction, generators nearing retirement that cleared in the primary auction could transfer their obligations to subsidized new resources that did not clear because of the MOPR.

Carbon Pricing

Bowring, Gramlich and Novosel all expressed support for carbon pricing, which was the subject of a second panel.

Susan Tierney, senior adviser for the Analysis Group, discussed her analysis on NYISO's carbon pricing proposal, which she said could be only one of the many tools the state will need to meet its ambitious goals under the 2019 Climate Leadership and Community Protection Act: 70% of electric supply from renewables by 2030 and 100% from zero-carbon resources by 2040.

Solar will have to triple in five years, and energy storage will have to grow tenfold in the next decade, she said. Meanwhile, the state expects to lose two of its nuclear generators in the next few years.

"It took 60 years to get to 28% renewables [penetration]. So, this is a huge lift that is going to have to take place," she said. "New York should really [use] every tool under the sun. … No one knows how they will accomplish these goals, so innovation is absolutely critical."

Tierney said passage of the law "changed the tone of [NYISO's] stakeholder discussions in a very big way," broadening support.

The ISO is now awaiting state action on its plan. (See *NYISO Focus Turns to Grid 'Transition.'*)

"The NYISO has always said that … taking a proposal to FERC would really require some signal from the state — the politicians — that there was interest in having FERC entertain this," she said.

Discussions with New York Gov. Andrew Cuomo's office have been derailed by the coronavirus pandemic, leaving timing uncertain.

"What's going to happen may also be timed to the next elections and new appointments to FERC," she said.

Emanuel Bernabeu, PJM's director of applied innovation and analysis, discussed the RTO's efforts to model carbon pricing in parts of its footprint and ways to limit leakage, which it shared with stakeholders in February. (See *PJM Panel Weighs Impact of Pa., Va. Joining RGGI*.)

Bernabeu said the PJM's next steps will be to model RTO-wide carbon pricing and higher prices — \$25/ton and \$50/ton, compared with the \$7/ton and \$15/ton modeled previously. He cautioned that the previous results cannot be extrapolated. "Everything is very highly nonlinear," he said.

Karen Palmer, director of Resources for the Future's (RFF) Future of Power Initiative, noted that Virginia is planning to join the Regional Greenhouse Gas Initiative in 2021. "That's a big addition," she said. "It's going to substantially increase the number of emitting generators under the RGGI cap."

Pennsylvania Gov. Tom Wolf has said he wants the state to join RGGI also, but he is facing opposition from the Republican-controlled legislature. (See *Critics: Pa. RGGI Hearing Stacked with Detractors*.)

"We've done some modeling showing that if Pennsylvania wants to do a cap and trade, joining RGGI is a good idea because it's going to be cheaper than going it alone. And also … there are ways you can target revenues from the allowance auctions that could help reduce emissions leakage." ■

PJM CEO Introduces Himself

Ex-Energy Trader, Raised in Middle East, Returned to Philadelphia After 25 Years

Continued from page 1

Chicago and Houston

Asthana graduated Wharton with concentrations in finance and entrepreneurial management. After learning to trade Treasury bond options at the Chicago Board of Trade for Swiss Bank Corp., he moved to Texas in 1997 to work for a company that was acquired by TXU Energy.

He held a number of roles in his 12 years at TXU, including chief risk officer. "When I left the company, I was running their trading business, running their commercial market operations and asset management ... all of the commitment, dispatch and economic analysis and market-related decision-making around what was at that time one of the largest fleets of generators in the state of Texas."

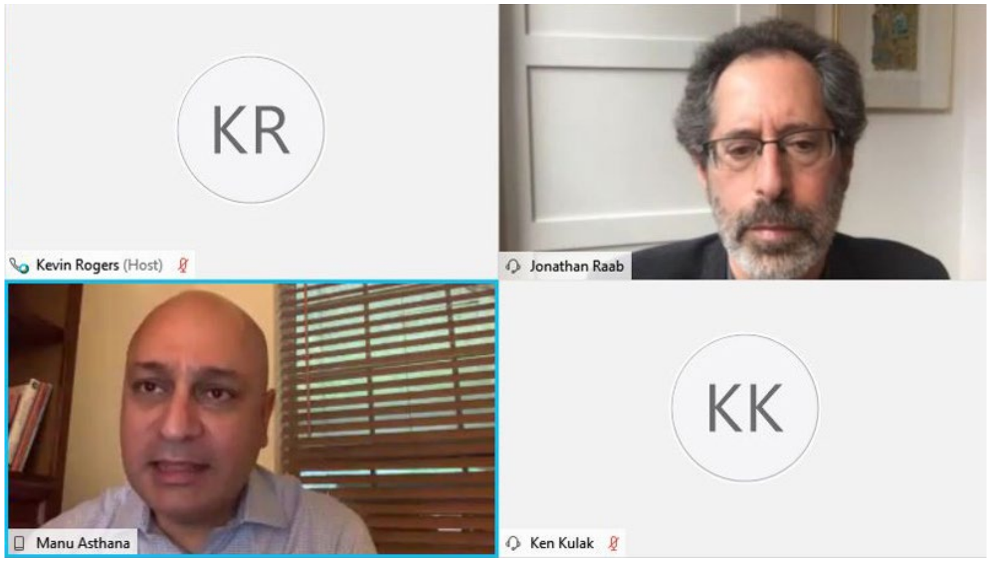
Asthana remained with TXU for about two years after it was taken private in 2007 — in what was the *biggest leveraged buyout in history* — but grew restless. "I had done everything I came there to do; learned everything I came there to learn. It was time to leave."

He joined Direct Energy in 2010 and began "running their trading business, then took on their power generation operation." After the company sold its power plants, he was "tasked with turning around the performance of" Direct's retail energy business. Two years later, he "was tasked with also turning around the performance of the home services business."

He resigned as president of Direct Energy Home in December 2018 after almost nine years. "I had gotten to the same point I did with TXU, where I accomplished more or less everything I came to do," he explained.

Asthana previously told *RTO Insider* that he continued working with Direct through April to "ensure a successful leadership transition" and spent much of the rest of the year doing charity work before being tapped by PJM.

Direct, like some other retail electricity suppliers, has had a series of well-publicized regulatory scrapes. "I'm very proud that my team's efforts to continuously improve in these areas led to customer complaints falling by two-thirds during my tenure," he told *RTO Insider* after his hiring was announced in November. (See *New PJM CEO Defends Direct Energy Stewardship*.)



PJM CEO Manu Asthana (bottom left) and Moderator Jonathan Raab at the Energy Policy Roundtable in the PJM Footprint.

After his Texas experience at TXU and Direct, Asthana said, he was looking "to do something that had an impact beyond just the organization that I worked for. I wanted to have a broader impact. And I thought that PJM was uniquely positioned in the energy transformation that's happening."

3 Priorities

Asthana said he came to PJM with three priorities. The most important: ensuring the grid's reliability.

He also places a premium on personnel development. "I believe strongly that leaders grow people," he said.

His other priority is working with PJM's stakeholders — "including, very importantly, our states" — "to solve difficult problems and try to get our markets to a stable place where they can continue to deliver the efficiencies and the reliability that is required."

"A lot of people tell me, 'Hey, can you find a way to make the stakeholder process more efficient, more effective, to get things done through the process?'" he said. "I'd like to reframe for all of us our stakeholder process. I don't see it as a problem to be navigated. I see it as a significant strength of the organization.

"We have tremendous capabilities, tremendous passion to do the right thing and to get the market structure right and to get the rules right for the long term. I think there is disagreement on what the right actions are depending on what the topic of discussion is. But the diversity of thought and the amount of passion and energy that our stakeholders bring to our process I think is a significant asset for PJM."

Moderator Jonathan Raab — who helped facilitate the creation of PJM's current Consensus-Based Issues Resolution (CBIR) process a decade ago — asked Asthana if he thought additional changes were needed in stakeholder rules.

The stakeholder process works well for many routine issues, but it has shown an inability to reach consensus on major contentious issues, according to a May 2017 *study* by Christina Simeone, director of policy and external affairs for the Kleinman Center for Energy Policy at the University of Pennsylvania. Simeone said some of the problems are the result of compromises made under the Governance Assessment Special Team (GAST) process that led to CBIR. (See *Can RTO Stakeholders Find Consensus on Big Issues?*)

"I'm hearing a range of things," Asthana said. "Some people are satisfied; some people are not satisfied" with the effectiveness and efficiency of the process.

"I think since I've been here, I do think that the process ... our stakeholders together are very

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capable of solving difficult problems. And I think we are starting to do that."

As an example, he pointed to the approval in March of tougher credit rules, which cleared the Markets and Reliability Committee with a 90% sector-weighted vote. (See *PJM Members OK Tighter Credit Rules*.)

Finding the Balance on MOPR

Such consensus was not possible, he acknowledged, on one of the first issues he had to consider after starting work in January: PJM's response to FERC's December order expanding the MOPR to new state-subsidized resources.

Asthana said PJM's Jan. 21 *rehearing request* and March 18 *compliance filing* sought to support states' rights to choose their generation mix while also recognizing the reliance resource providers and investors have on a "stable, predictable" capacity market (EL16-49, ER18-1314, EL18-178).

The RTO held 10 meetings with stakeholders to gain feedback on how it should proceed.

"One of the points of feedback I had coming in the door was, 'Hey, it would be really nice if PJM were to listen more,'" he said.

He noted the "very, very, disparate sets of inputs" on issues such as the timing of the first auction under the new rules and the flexibility that should be afforded individual units.

"I'm sure there are … a number of opinions on how we did, but I really hope that our stakeholders feel that they were listened to and that their thoughts were reasonably considered, and we took a balanced approach."

The wind and solar industry trade groups said they were relieved that PJM's interpretation of the order would allow new renewable generation to clear the capacity market in the short term. PJM's conclusion that voluntary renewable energy credits are not state subsidies and its decision to allow an asset life of up to 35 years means that new wind and solar projects will be able to bid below the default MOPR floor values and clear the market, officials for the organizations said. (See *MOPR May Not be Death Knell for Renewables in PJM*.)

Maryland Public Service Commission Chair Jason Stanek, who spoke later in the forum, said he was grateful for PJM's efforts, although he would have liked more time to plan for the next Base Residual Auction. (PJM said it will hold the next auction within six-and-a-half months after the commission's acceptance of the compliance filing.) "Under the circumstances … I don't believe PJM could have done a better job in balancing the interests of a very disparate group of parties," he said.

2035 and Beyond

The MOPR battle, Asthana said, has "unfortunately overtaken the discussion" on how the RTO can help the states plan for the future. He said he has asked his staff to envision what market rules and transmission planning will be needed in 2035 and beyond if states achieve their decarbonization targets, including large offshore wind projects planned off of Virginia, Delaware and New Jersey.

"I think PJM can play a large role in helping think through the most efficient way to plan the transmission grid to facilitate that offshore wind," he said. "I think it's very inefficient if we try to plan one project at a time or even one state at a time." ■

PJM Analyzes Potential COVID-19 Generation Losses

RTO Could Withstand 40% Loss in Summer; 60% in Spring

By Michael Yoder

PJM could support the loss of up to 40% of installed generation capacity on a summer day and up to 60% on a spring day in a worst-case scenario situation in which units were knocked offline from a COVID-19 outbreak among plant workers, the RTO said last week.

Ray Lee, senior engineer in generation, and Jason Sexauer, senior engineer for outage analysis technologies, presented the *generator availability analysis* to stakeholders during PJM's weekly coronavirus call Friday.

Lee said the analysis was intended to determine the maximum generation loss PJM could handle without curtailing power to the hardest hit areas. The analysis began by considering the impact of an outbreak at one plant spreading and disabling a generating company's entire fleet, he said.

Sexauer said the 40% and 60% outage levels in the scenario are about twice as many outages as typically occur during summer and spring. "These scenarios are worst case, far and above what we normally screen for from an operational perspective," Lee said.

PJM has not seen any generator outages from the pandemic thus far, they said.

Analysts used overlay maps to compare the highest levels of COVID-19 infection within the PJM footprint with generator locations, Lee said, focusing specifically on New Jersey, the Interstate 95 corridor from New Jersey to D.C., and Chicago and its suburbs.

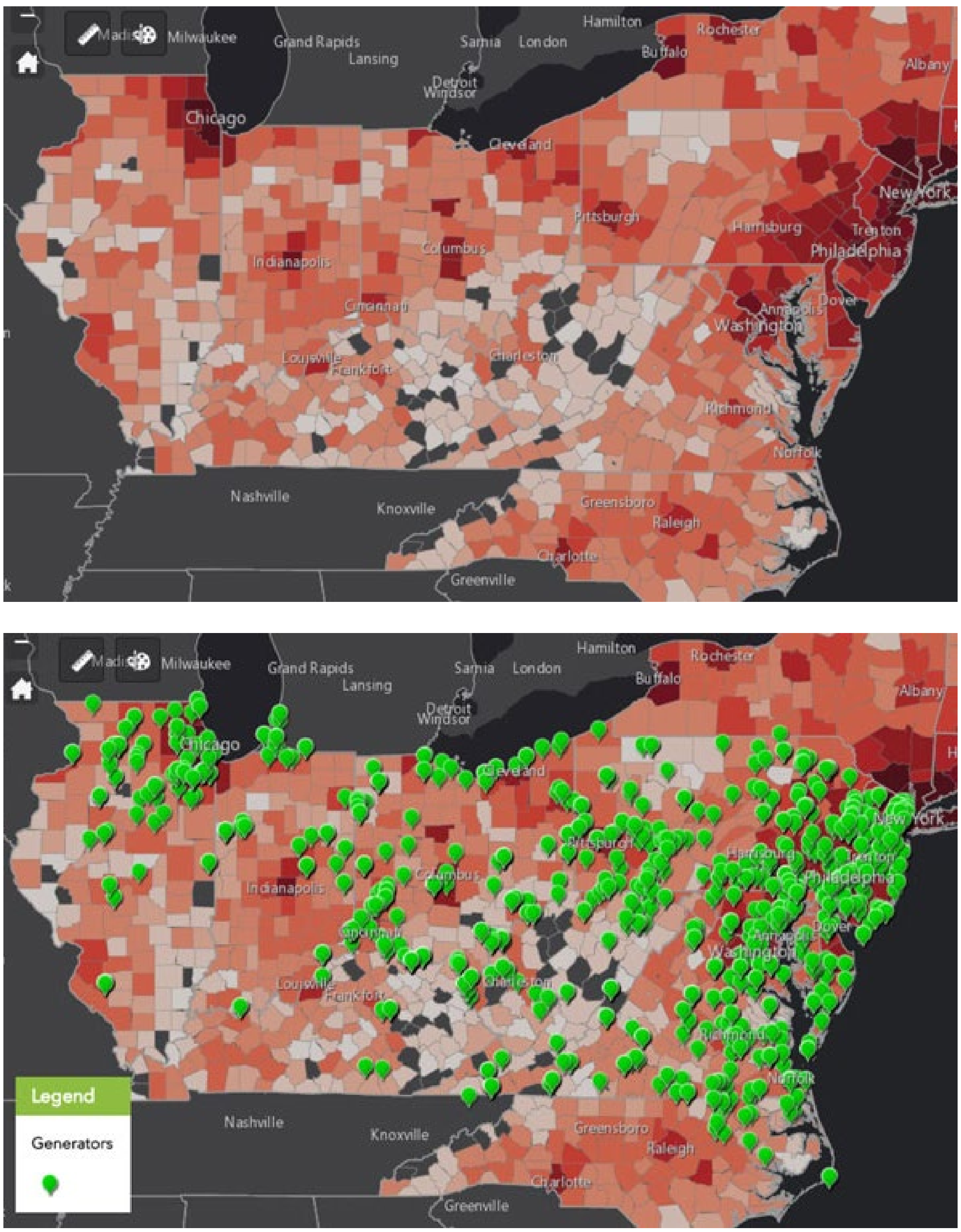
Lee said coal-fired and combined cycle plants were judged most likely to be impacted by an outbreak because they require higher numbers of on-site personnel to operate.

The final step in the planning process was to define the appropriate time frames for outbreaks at the sites, Lee said.

Because of uncertainty over how long the pandemic will last, PJM decided to perform the studies for the spring and summer peak loads. The findings "could then be used to potentially consider proactive actions, such as limiting future outages if we're seeing a trend towards these worst-case scenarios," he said.

Sexauer said four steps were used in the process for calculating the outages, including: selecting the hypothetical generation units that would go offline; building an "all-in case" for May 4 and July 7 using normal load on those dates; creating an "all-out case" where all scheduled transmission and hypothetical generation outages from COVID-19 were applied; and running a DC/AC contingency analysis on the hypothetical cases to look for thermal overloads and "non-converged contingencies," in which no solution is found.

He said that while running the analysis, PJM found that thermal issues with the grid were more prevalent in the spring and voltage collapse issues were more prevalent in the summer. About 5,200 cases were analyzed, requiring two days of computer runs. ■



An overlay map of generators located within the PJM footprint compared with cases of outbreaks of COVID-19 | *PJM*

PJM News

PJM Members Committee Briefs

Retiring PJM Board member Susan Riley and Chair Ake Almgren | *PJM*

PJM's Annual Meeting, which was to have been held Monday in Chicago, was canceled because of the coronavirus pandemic. But the RTO held its Members Committee meeting via teleconference nonetheless, feting Board Member Susan J. Riley and former Vice President of Planning Steve Herling on their retirements.

Riley Feted on Retirement

Riley, who took over as interim CEO after the tumultuous fallout of the GreenHat Energy default, was honored on her retirement from the RTO. The former CFO for Eastern Outfitters, Riley had served on the PJM Board of Managers since 2005.

Riley guided the organization after former CEO Andy Ott announced his retirement effective June 30, 2019, following an independent probe into the GreenHat debacle that concluded PJM staff ignored red flags about the company's assets as it amassed 890 million MWh of financial transmission rights while putting up only $60,000 in collateral. (See *PJM CEO Andy Ott to Retire*.)

Riley held the interim post until new CEO Manu Asthana took over Jan. 1. (See *PJM Taps Ex-Direct Energy Exec as New CEO*.)

A certified public accountant, Riley served in senior finance roles for The Children's Place, Abercrombie & Fitch, Mount Sinai Medical Center of New York, Colgate-Palmolive, Dial Corp. and Tambrands.

Riley said her work at PJM provided a unique experience because it gave her direct interaction with the RTO's "constituents." Understanding the diverse interests of PJM members was both a challenge and a pleasure, she said, adding she was impressed to see stakeholders working together to solve problems.

"The results of your hard work through compromise and member meetings is a system that delivers reliable and cost-effective electricity to over 65 million people day in and day out," Riley said.

Members Committee Chair Steve Lieberman, director of regulatory affairs for American Municipal Power, said Riley's listening skills, responsiveness to stakeholders and ability to make hard decisions illustrated "what a fantastic leader Sue is."

Lieberman praised Riley for "taking ownership" following the GreenHat default, which he said was "not a shining moment for PJM."

"She made it a personal issue to make sure that it would not, could not, occur again," Lieberman said. "On behalf of PJM, she repeatedly owned up to the deficiencies of PJM. She took hard questions" from members. (See *Report: 'Naive' PJM Underestimated GreenHat Risks*.)

Lieberman said he was equally impressed with Riley's ability to step into the CEO role after Ott left. Several top PJM management personnel were out of their positions within a few months, and Lieberman said Riley was able to hold the RTO together until replacements could be found.

"The ground felt a little shaky from my perspective, but Sue figuratively took the reins and steered us through those uncertain times," he said.

Board Chair Ake Almgren thanked Riley for her "many contributions to PJM."

"Through all these years, I looked forward to Susan's work ethic and her active leadership and very strong commitment to PJM," Almgren said.

Almgren, Robinson Re-elected; Newcomer Replaces Riley

The MC re-elected Almgren and member Charles Robinson, while selecting *Margaret "Margo" Loebl*, to replace Riley. Loebl, who has 30 years' experience with Fortune 500 companies in finance, accounting and risk management, is the former CFO of *AgroFresh Solutions*, which provides technologies and services to extend the shelf life of fresh produce.

The board waived its term-limit policy for Almgren, who has been on the board since 2003, to allow him to serve an additional year to "ensure a successful leadership transition." Since 2016, PJM rules have *limited* board members to five three-year terms.

PJM Sees Potential $26M Revenue Drop from Pandemic

PJM CFO Lisa Drauschak told members the RTO is planning for as much as a $26 million reduction (8.3%) in its Schedule 9 revenues because of reduced energy use during the coronavirus pandemic and is cutting expenses and lining up additional financing in response.

Schedule 9 revenues, which are collected based on transmission usage, represent 85% of PJM's total income, Drauschak said.

The RTO collected $81 million in Schedule 9 revenue in the first quarter, and its budget anticipated an additional $231 million for the rest of the year, assuming 783 TWh of electric consumption.

But March load was 6.6% below budget and April is expected to be 7.5% below projections, reflecting both shelter-in-place orders and unusually warm weather.

Because of uncertainties over the length of the pandemic, PJM developed three scenarios for load:

- Scenario A: 723 TWh, reflecting a 14.4% reduction through May before ramping up to normal, would reduce Schedule 9 revenue for the remainder of the year to $224 million.
- Scenario B: 693 TWh, a 14.4% reduction through August before ramping up to normal, would produce $213 million in Schedule

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9 revenue for the second through fourth quarters.

- Scenario C: 670 TWh, a 14.4% reduction from the total for the year, would generate only $205 million in additional revenue, an overall reduction of $26 million (8.3%).

The most optimistic scenario would leave PJM with an $18 million reserve at year-end; the most extreme scenario would reduce the reserve to only $3 million. "PJM is not expecting to fall below zero" in reserves, Drauschak said.

The RTO has cut some operating expenses in response to the lower revenues and unexpected pandemic-related costs, she said. It also executed a short-term $50 million liquidity support agreement with PNC on April 23 and *asked FERC* to increase its borrowing authority to $200 million. A ruling from the commission is expected by May 26.

The RTO is cutting expenses through a freeze on new hires and reductions in spending on travel and training.

To address cash flow issues, PJM has a $150 million line of credit. It expects its peak borrowing to be between $130 million and $139 million, likely in the third quarter.

Return to 'Normal' not Close

Scott Heffentrager, senior director of physical security, briefed members on Pennsylvania's plan for reopening its economy but said Montgomery County, where the RTO is headquartered, is still seeing too many new COVID-19 cases to contemplate a return to business as usual.

Gov. Tom Wolf has a three-phase *reopening plan*. All 67 counties are currently in the "red" stage's stay-at-home rules, with only life-sustaining businesses in operation.

It plans to move to the "yellow" stage for 24 mostly rural counties on May 8. That will ease stay-at-home restrictions, although the state will continue to require telework where feasible.

The final "green" stage, which will lift the safety order and stay-at-home restrictions, will require counties to average less than 50 new positive cases per 100,000 residents over 14 days. That computes to 415 new cases over two weeks in Montgomery County (~30/day).

The county averaged 204 positive cases a day over the last two weeks, Heffentrager said. "So, we're well behind the criteria to move from red to yellow."

Herling Retires

After a 30-year career at PJM, Steve Herling will retire on June 30. He began his career in May 1990 as a professional engineer, working his way up to vice president of planning for in 2004 before beginning his transition last year as executive consultant.

Ken Seiler, Herling's successor as vice president of planning, provided remarks in recognition of Herling's retirement, joking that he was "someone to look up to" as the tallest person on the PJM campus. Seiler said Herling was affectionately referred to as the "tower of power" among PJM staff, and thanked him for hiring him in June 2000.

Herling was one of the original architects of the Regional Transmission Expansion Plan in 1998, Seiler said, and was widely regarded as one of the most knowledgeable people on PJM's staff.

"Steve knows the bulk power system of our region like nobody else," Seiler said. "And our lawyers love to have him testifying at the regulatory hearings because he literally knows everything there is to know seemingly off the top of his head."

Herling said it was hard to believe he had been with the company for 30 years. He said he had many wonderful experiences being a part of the RTO.

He said he mostly wanted to thank the planning staff who worked under him, saying he could not have done half of his accomplishments without their dedication.

"It's easy for us to look good when we have such a strong group of people backing us up," Herling said. "I'm sure there will be a lot more success stories in PJM's future."

New CEO Comments

PJM CEO Manu Asthana said he would never have imagined making his first Annual Meeting address over teleconference.

Asthana, who took over leadership on Jan. 1, said he also would have never envisioned the amount of change in the world during the first four months of his leadership of the RTO. He said the COVID-19 pandemic has created unique challenges for PJM and himself personally to come up to speed in his role.

Asthana said he chose to come to PJM because he wanted to have an impact on an organization that is directly affecting 65 million people each day. He said he had seen the rapid energy transition taking place in the U.S., driven by technologies as well as environmental preferences and policies, and he saw PJM being at the center of that revolution.

"It's been quite an interesting time to take over as CEO of a complex and important organization like PJM in the middle of this disruption," Asthana said. "It's hard to believe it's only been four months in the role, but it has been a meaningful and impactful and pretty stressful four months."

Tariff, OA Changes

The committee approved administrative *revisions* to the Tariff, Operating Agreement and Reliability Assurance Agreement as recommended by the Governing Document Enhancement & Clarification Subcommittee. ■

— Michael Yoder and Rich Heidorn Jr.

PJM executives and Independent Market Monitor Joe Bowring held a panel discussion on the events of 2019. | *PJM*

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PJM End-of-life Tx Proposals Near Vote

By Michael Yoder

PJM stakeholders debated for nearly two hours Thursday over transmission owners' spending on end-of-life (EOL) projects, suggesting there is little chance for compromise on an issue that has been disputed for years within the RTO.

Three EOL proposals were given first reads at Thursday's Market and Reliability Committee meeting, setting up votes at the next MRC meeting on May 28. The proposals — which would require TOs to share how they make EOL determinations and potentially open at least some replacement projects to competition under the Regional Transmission Expansion Plan (RTEP) — are the result of deliberations over six special MRC meetings since December.

Three Proposals

A *proposal* by a group of PJM stakeholders, including American Municipal Power and Old Dominion Electric Cooperative, would require TOs to notify PJM and stakeholders of any facility nearing the end of its life at least six years before its retirement date so that the project could be included in five-year planning models and opened to competitive bidding. It would also modify the supplemental project definition to exclude EOL projects, which would be made a new category of regionally planned projects. It was endorsed by the PJM Industrial Customer Coalition, the Public Power Association of New Jersey, Consumer Advocates of the PJM States (CAPS) and the D.C. Office of the People's Counsel.

LS Power supports the stakeholder package but would require six years' notice for lower-voltage facilities and at least eight years' notice for facilities of 230-kV and above.

PJM also offered a *package* requiring TOs to identify EOL projects five years in advance. Projects that "overlap" with RTEP violations would be included in a competitive window seeking regional solutions. Like the stakeholder and LS Power plans, PJM's proposal would require each TO to have a formal program for EOL determinations. The RTO said it would prevent TOs that don't already have a EOL determination process from using a "run to failure" asset management approach.

Under current rules, said Mark Ringhausen, vice president of engineering for ODEC, some TOs don't identify EOL projects, choosing instead to replace "pieces and parts."

"Some have told me that they never make EOL determinations," Ringhausen said.

Divergence of Plans

But PJM disagreed with the stakeholder proposal on the RTO's jurisdiction over EOL facilities, saying the Consolidated Transmission Owners Agreement (CTOA) transferred to PJM only the responsibility to prepare an RTEP "for the enhancement and expansion" of the transmission system to meet demands for firm transmission service. Section 5.2 of the CTOA says, "PJM shall not challenge any … sale, disposition, retirement, merger or other action."

PJM also said its role is limited by two FERC rulings involving CAISO, which concluded that equipment replacements that result in only incidental increases in system capacity are asset management decisions under TOs' exclusive control, not planning matters subject to FERC Order 890. (See *'Asset Management' not Subject to Order 890, FERC Rules*.)

Dave Souder, PJM senior director of system planning, said the proposal honors the TOs' responsibility over asset management decisions while allowing the RTO to determine when an RTEP project is more cost-effective than a TO's proposed replacement. "We believe the PJM package takes a reasonable approach," he said.

Several parties, including AMP and ODEC, insisted the FERC rulings do not preclude their proposal. They said the PJM proposal lacks transparency and would not require TOs to have EOL criteria or to share the list of EOL projects with stakeholders. Souder said PJM hasn't decided whether the retirement list would be public.

Ed Tatum, AMP's vice president for transmission, said PJM data from 2019 show \$4.8 billion in TO supplemental projects, about 75% of which are for EOL assets that could benefit from longer-range planning. Robert Taylor of Exelon said he disagreed with the \$4.8 billion statistic, saying the dollar amount appeared to combine supplemental and baseline projects, inflating the number by as much as \$1.5 billion.

Tatum conceded that the retirement of a transmission asset should be determined by the TO that owns it. But he said PJM should take over planning once a retirement decision is made.

"Asset management includes operational maintenance activities, as well as the decision as to when an asset has reached the end of its life," Tatum said. "But asset management ends at that point, and planning begins. … We need to have the assurance that this is being planned by an independent organization that is not bound by its stockholders to put together a construction project."

Greg Poulos, CAPS | © *RTO Insider*

CAPS Executive Director Greg Poulos said the advocates are frustrated that the TOs have "dug in" and been unwilling to negotiate a compromise. (See *Stakeholders Seek TO 'Engagement' on End-of-Life Tx*.)

"We're supposed to be working together and not going straight to legal arguments," Poulos said. "The stakeholder process does not work if we're just going to go to FERC with things."

The TOs filed a *"statement of legal and contractual issues and reservation of rights"* with the MRC on Wednesday. The statement said the stakeholder and LS Power proposals infringe on TOs' contractual rights and are attempts to "rewrite" the CTOA and relitigate FERC rulings.

'Scorched-earth' Tactics

Alex Stern of Public Service Electric and Gas said TOs worked hard for a compromise problem statement and issue charge when EOL was brought up at Planning Committee meetings last year but that an agreement could not be reached. (See *PJM Members Debate Dueling Tx Replacement Plans*.)

Stern said he still had hope that a compromise could be reached during the special stakeholder process in the MRC over the last five months. But he said the packages that emerged are an attempt "to leverage the stake-

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holder process" to force PJM to make a filing at FERC that individual stakeholders should be making themselves.

"If stakeholders want to challenge the FERC-approved paradigm governing the authority of TOs to make determinations regarding the end of the useful life of their asset … there's absolutely nothing stopping them from doing so," Stern said.

John Horstmann of Dayton Power & Light agreed, calling the EOL stakeholder meetings a "scorched-earth process" to force PJM into a Federal Power Act Section 205 filing. Horstmann said the issue should have been brought to FERC as a Section 206 filing rather than going through the stakeholder process.

Stakeholders filing under Section 206 must first prove the RTO's existing rules are unjust and unreasonable to win FERC approval of changes. A PJM filing under Section 205 would not need to make that showing, needing only to convince the commission that its *new* rules are just and reasonable.

The Members Committee has Section 205 *filing authority* over the Operating Agreement (OA); the PJM Board of Managers has Section 205 authority over the Reliability Assurance Agreement and the Open Access Transmission Tariff (excluding provisions under the exclusive control of the TOs).

The stakeholder and LS Power proposals would require changes to the *OA*.

PJM said its proposal would only require manual changes. LS Power's Sharon Segner disagreed, saying FERC Order 1000 requires such planning process rules be included in the OA. She also said the PJM proposal fails to eliminate "redundancy between the supplemental and regional planning process" that would require an OA fix.

Stern said the focus on EOL by some of the stakeholders seems to be less on planning criteria and appropriate decision-making to ensure local and regional grid reliability, and more on the dollar amount being invested. He said transmission decisions are supposed to be made on ensuring the reliability of the grid and not the cost.

"PJM certainly has a role to play in planning, but it is not to decide how a transmission owner goes about addressing the impact of the end of useful life of an asset," Stern said.

Tatum said he agreed with Stern's assertion that planning shouldn't be based solely on costs. But he said he would have more confidence that projects were being done in the most cost-effective way if PJM was conducting the planning.

Tatum said the TOs "unfairly discount" the importance of the PJM stakeholder process and the rights of the rest of the stakeholders. He said that since the inception of PJM as an RTO, the TOs demanded many of the provisions in the OA so they could have control over the new entity that was being developed.

"It's not just [TOs that are] concerned about reliability and keeping the lights on," Tatum said. "We all have a vested interest in that. But we see a majority of planning being driven outside of [the RTEP] process. Independent planning is essential in order to have successful markets, and we're moving away from that."

Susan Bruce, representing the PJM ICC, said industrial customers have seen their transmission bills increase "exponentially" over the past two years, largely because of EOL costs. Aligning the EOL asset management process with RTEP would ensure the transmission investments being made are cost effective and well planned, she said.

"Industrial customers want to see a reliable and robust grid, but they also want to make sure that their investment in transmission is optimized," Bruce said.

Costs

Citing PJM statistics, Horstmann said that only 30% of the RTO's transmission system is less than 40 years old, causing a glut of assets nearing their EOL that must be replaced. He said a high price tag is inevitable no matter who oversees the planning.

"You're looking at a lot of money over the next period of years to basically maintain what we have, let alone improvements," Horstmann said. "To me, that's the elephant in the room here. This [dispute] just sort of dances around the edge of that problem."

Tom Hyzinski of GT Power Group asked how much would be saved by identifying EOL projects six years in advance and making it subject to competitive bidding.

Ringhausen cited a Brattle Group *report* that showed 30% savings from competitive bidding. "You're talking tens of billions of dollars," he said. (See *Study Findings Clash on Value of Competitive Tx*.)

Next Steps

PJM's Jim Gluck said the MRC will schedule one more special session (May 11 or May 15) to discuss the packages and seek opportunities for consensus before the three proposals are brought to sector-weighted votes May 28. The package with the most stakeholder support and meeting the two-thirds threshold will be brought back to special meetings to draft governing document language. The package receiving the greatest support will become the main motion for a vote of the MC. ■

| © RTO Insider

PJM MRC Briefs

Action on Hybrid Resource Initiative Deferred on Venue Question

The PJM Markets and Reliability Committee deferred a vote on a proposed *issue charge* to consider rule changes for hybrid resources after members questioned the RTO's plan to assign it to a new senior task force.

PJM has more than 10,000 MW of co-located generation and energy storage hybrid resources in the interconnection queue. RTO staff intend to focus the effort primarily on solar-battery hybrids, which represent more than 95% of the total, with the remainder wind-battery and gas-battery.

Since introducing the issue charge at the March MRC meeting, PJM added to the education topics the interconnection queue process for hybrids, including how existing material modification rules apply. It also pushed the start date from May 1 to July in response to concerns over the MRC's workload. (See *PJM MRC Moves Forward on Storage, Hybrids*.)

FERC has scheduled a technical conference on the "technical and market issues" raised by the growth of hybrid resources for *July 23*. (See *FERC Sets Tech Conference on Hybrid Resources*.)

PJM's Scott Baker said staff recommended creating a senior task force because of the varied issues raised by hybrid configurations. "There's enough cross-functional [issues] here between planning, markets and operations to warrant this being a separate group," he said.

Under Manual 34, a senior task force reports to a senior standing committee (the MRC or Members Committee) and is created for "consideration of specific issues that have the potential for large dollar or major policy impacts."

Scott Baker, PJM | © *RTO Insider*

Dave Anders, PJM | © *RTO Insider*

Dayton Power & Light's John Horstmann said that while he supported the initiative, it should be a task force under one of the standing committees — the Market Implementation Committee, Operating Committee or Planning Committee — rather than a senior task force.

"To the extent it crosses MIC, OC or PC interests, there is no reason the other committees can't be invited" to the meetings, he said.

PJM's Dave Anders acknowledged that the RTO has had "a bit of a struggle" with assigning new projects because of conflicts between concept and practice.

"In theory, we could invite others to a task force under the MIC, but in practice that doesn't always happen," he said. "The senior task force seems to get more attention and … participation."

Horstmann said he was "frustrated" because he and others in the Stakeholder Forum "met for quite a few months to develop clearer" rules for such assignments in Manual 34.

"We think we've fixed this problem, but it hasn't been presented to members for endorsement," he said.

After discussion, MRC Chair Stu Bresler decided to defer action on the issue charge so staff could reconsider the assignment.

Horstmann explained after the meeting that the members created a table for inclusion in Manual 34 listing "the different types of stakeholder groups with a description of their function and use, including the expected length of time that they would meet."

Emerging Technologies Subcommittee Proposed

Stakeholders also expressed concerns about the reporting structure for a new Emerging Technologies Advisory Subcommittee (ETAS) that PJM proposed to support its *Advanced Technology Pilot Program (ATPP)*. The ATPP provides a testing ground for studying the viability of integrating new technologies that could enhance system reliability, operational and market efficiency, and resilience.

Eric Hsia of PJM reviewed the subcommittee's *charter*, which the MRC will vote on May 28. Hsia said PJM was acting on the issue based on stakeholder feedback and the RTO's recognition that it currently doesn't have a forum to discuss emerging technologies and pilot programs.

The subcommittee would identify operational, planning and markets-related issues and make recommendations, Hsia said. In addition to hosting technical education sessions on emerging technologies, it would create and review ATPP procedure documentation to incorporate stakeholder feedback into the process and provide additional transparency. PJM would continue to maintain authority over the ATPP, and the subcommittee would not make decisions on selecting specific pilot projects. The group also would identify benefits of new technologies and obstacles to implementing them.

Gary Greiner, director of market policy for Public Service Enterprise Group, said he supports the idea but that the subcommittee should not report to the MRC, as proposed.

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"I think most of what you're going to see would be operations-based. I'm wondering why it wouldn't be down at the standing committee level," he said. "I really think there's value in having those issues pass through that lower-level layer to be fully vetted."

Hsia said staff did discuss having the ETAS report to a standing committee but decided on the MRC as its parent because of "the nature of pilot programs and the cross-functional nature of the discussions." Many issues that come before the new group would involve planning as well as operations, he said.

Paul Sotkiewicz of E-Cubed Policy Associates asked if there was a way to combine the solar hybrid resources issue previously discussed with the ETAS as a way to pare down the number of stakeholder groups.

"It's just becoming unwieldly to follow all of the committees at this point," Sotkiewicz said.

Bresler, PJM's senior vice president of market services, said the location of the committee is "one thing we'll examine prior to bringing this back for a vote."

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said the ETAS will help stakeholders understand the functionality and benefits of emerging technologies.

Poulos noted that Thursday's MRC agenda included several emerging technologies, including hybrid storage and HVDC converters.

"I'm glad that PJM is getting ahead of this," Poulos said.

'Credit' Subcommittee Proposed to Change to 'Risk Management'

PJM gave a first read to a *proposal* to rename the *Credit Subcommittee* as the Risk Management Subcommittee and amend its charter to broaden its authority to include market risk.

Under the revised *charter*, the renamed subcommittee also would be elevated, reporting to the MRC rather than the Market Implementation Committee. Chief Risk Officer Nigeria Poole Bloczynski said the change would acknowledge that the broader consideration of risks "may incorporate aspects outside of the sole purview" of the MIC.

Anders said the restructured group would be a venue for considering risk management as a wholistic topic. He previously 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 — was the best venue for considering a planned problem statement over a credit risk issue the RTO identified in February. (See "Scope, Name Change for Credit Subcommittee?" *PJM MIC Briefs: March 11, 2020*.)

Bloczynski noted the committee's charter has not been revised since 2010.

"Risk management seems to be an afterthought. No one thinks about it until there's a problem," she said. The MRC will be asked to endorse the revised charter at its next meeting.

The revised mission statement says the committee will "discuss and recommend" ways to address market and credit risk issues. It will not "manage, govern or otherwise set policy for PJM."

Sharon Midgley of Exelon said she thought the charter change should be considered in tandem with how it will potentially impact the scope of the MIC.

"Anything that we'd talk about credit or markets related at this committee, we're going to want to make sure that the participants in the MIC are aware of it because that impacts them as well," Midgley said.

Greiner said he views "market risk" as a term that can be defined differently depending on who is being asked. He said he would like to see PJM put a clear definition of the term in the charter.

"If you have a definition for market risk, it's going to help inform the scope of what we're doing here," Greiner said. "I think it's probably best to embed it in the charter itself so we can get a sense of what's in and what's out."

Sotkiewicz encouraged PJM to include market design risks in the scope of the charter. He said having a core group of PJM staff and possibly stakeholders working together to look at market designs and finding problems that are there before they turn into a major issue that results in a FERC filing or a financial hit to membership would be of great benefit.

"Those risks are always going to be out there, and if we can get ahead of the game, we in the membership would be much better off," Sotkiewicz said.

Surety Bonds

The MRC heard a first read of a *proposal* to allow market participants to use surety bonds as collateral.

Bonds can be less expensive than letters of credit but are dependent on the credit and risk profile of the market participant, PJM said.


John Horstmann, Dayton Power & Light | © *RTO Insider*

The MIC endorsed two proposals in October 2018, with 61% supporting use of surety bonds as collateral for all market purposes except financial transmission rights, with a $10 million cap per issuer for each member and a $50 million aggregate cap per issuer.

A second proposal allowing surety bonds as collateral for all market purposes including FTRs won 58% support. It would set a $20 million cap per issuer for each member and a $100 million aggregate cap per issuer. PJM said it supports the first proposal, citing limited experience in the use of surety bonds in FTR markets and the large size of past FTR defaults.

In December 2018, the MRC agreed to defer action on the proposals until completion of the independent consultants' report on the GreenHat default. It was deferred again in April 2019 pending appointment of a chief risk officer and appointment of a new CFO.

If the *Tariff change* is approved, PJM said it will require use of bond companies on U.S. Treasury Department's certified list and a minimum credit rating of A with S&P Global Ratings; A with Fitch Ratings; A2 with Moody's Investors Service; or A with AM Best. PJM also will require acceptance of one-day payment demand terms.

The MRC will consider endorsement on May 28, with the MC taking it up in June.

Governing Documents Cleanup

In its only voting action aside from approving the minutes for the MRC's March meeting, the committee approved administrative *revisions* to the PJM Tariff, Operating Agreement and Reliability Assurance Agreement, as recommended by the Governing Document Enhancement & Clarification Subcommittee. ■

— Rich Heidorn Jr. and Michael Yoder

SPP Joint Quarterly Stakeholder Briefing

Sugg says RTO to Open Very Carefully in Months Ahead

SPP CEO Barbara Sugg assured stakeholders that the RTO is taking very careful steps to re-open while the COVID-19 pandemic still rages, making clear it will be a slow process.

"We don't want a flood of people back in the office," Sugg said during the Joint Quarterly Stakeholder briefing April 27.

She said SPP must first see a 14-day downward trajectory of cases in Arkansas, where it is based. "That hasn't happened yet," she said.

As of Thursday, Arkansas had more than 3,200 confirmed cases of COVID-19. Almost 1,300 of those cases have recovered, but 59 Arkansans have died. Sugg said no employees have tested positive for the virus.

The downward slope of confirmed cases is just one trigger SPP must meet before allowing its 622 employees to return to its Little Rock headquarters. Staff will return in five phases, 20% of the employees at a time.

"We're in no hurry. This conservative approach to returning to the office will be extremely critical," Sugg said. "We're not calling it [return to work]. We're calling it return to office. We're not really working from home. We're really working from about 500 different places."

SPP Extends Wind, Renewable Penetration Marks

Bruce Rew, senior vice president of operation, backed off recent statements that wind could become SPP's No. 1 source of generation in 2021.

"If we keep up the way we're going, wind may be our No. 1 resource in 2020," he said.

Rew was speaking several hours after the grid operator set new records for wind and renewable penetration. Both records came at 1:24 a.m. CT on April 27, with wind accounting for 73.2% of the fuel mix and renewables for 78.2%.

Rew said SPP has enough wind generation to exceed an 80% penetration level but that 75% might be more realistic. He said wind energy's low prices would dampen more traditional generation forms, increasing its share of the fuel mix.

SPP has 22.7 GW of wind registered in its market. Wind output in the first quarter was up from the previous year.

Asked whether there is an upper limit to the amount of wind generation SPP can provide, Rew said, "As long as we have the resources to manage reliability, there's no upper limit."

Maintenance Outages Being Deferred Until Winter

COO Lanny Nickell said some member companies are deferring generator maintenance activities that would normally take place in the spring.

"We're performing analyses to understand the implications of canceled and deferred outages, and we'll share that information with our members so they can take precautionary actions and develop more informed plans," Nickell said. "We expect to have excess generation capacity in winter 2021, which gives some headroom to take more outages then."

SPP has seen a continued drop in load, with a reduction of between 5 and 7% for the week of April 19, as compared to historical load patterns.

FERC Makes Accommodations for COVID-19

FERC liaison Patrick Clarey said the Office of the Secretary has issued a notice that allows entities to seek deadline extensions and waivers of commission orders, regulations, tariffs and rate schedules. (See *FERC Relaxing Deadlines, Enforcement*.)

The Office of Enforcement is postponing all previously scheduled audit site visits and investigative testimony. Technical conferences scheduled through May will be conducted via conference call or webinars, or postponed, and settlement conferences will continue through conference calls, Clarey said. Schedules will be posted to the FERC *calendar*.

Clarey said FERC's 1,400 employees are working safely from home.

RSC Endorses Z2 Credits' Elimination

The Regional State Committee met virtually for a brief discussion before the quarterly update, taking time to unanimously endorse a revision request (*RR 401*) that ran into opposition from renewable and independent generation developers before the Markets and Operations Policy Committee. (See "SPP MOPC Briefs: April 14, 2020," *MOPC Approves 2nd Run at Z2 Credits Elimination*.)

The change eliminates Z2 revenue credits for sponsored transmission upgrades, replacing them with incremental long-term congestion rights (ILTCRs). EDF Renewable Energy again complained that SPP's version of ILTCRs is "woefully inadequate" and not as "robust" as those in other markets.

SPP CEO Barbara Sugg addresses her virtual audience during the Joint Stakeholder Briefing.

Kansas Corporation Commissioner Shari Feist Albrecht told the group that the RSC and Organization of MISO States' Seams Liaison Committee (SLC) hopes to conclude its work by the end of the year. The committee, composed of regulators from both RTOs' states, have been working for almost two years on improving the grid operators' interregional planning processes and other seams issues.

The SLC has scheduled a *conference call* on May 11 to review reports and studies from the RTOs' market monitors. SPP's Market Monitoring Unit has produced a study on *coordinated transaction scheduling* and MISO's Independent Market Monitor has delivered an analysis of *market-to-market coordination*. (See *Monitor Casts Doubts on MISO-SPP CTS Benefits*.)

KCC staffer Christine Aarnes told the RSC that the Cost Allocation Working Group plans to bring a *white paper* on a proposed byway facility cost allocation review process to the committee's July meeting for its approval.

Noting there is more generation than load in some areas, Aarnes said, "Byway facilities intended for local traffic are being used for highway traffic to export that energy."

The CAWG is working on the Holistic Integrated Tariff Team's recommendation to evaluate a narrow process through which 100- to 300-kV regionally funded byway project costs can be fully allocated on a region-wide basis. The review includes new and existing facilities under Schedule 11 of the Tariff. ■

— Tom Kleckner

SPP News

Public Citizen Seeks Rehearing of El Paso Electric Order

By Tom Kleckner

Emboldened by its victory in an affiliate case involving Goldman Sachs, consumer advocacy group Public Citizen last week asked FERC to reconsider a ruling involving another investment bank, JPMorgan Chase.

Public Citizen filed for *rehearing* of FERC's March 30 conditional approval of JPMorgan's acquisition of El Paso Electric (EC19-120). (See *FERC Conditionally OKs JP Morgan's Purchase of EPE*.)

JPMorgan is funding its $4.3 billion purchase of EPE through a web of financial affiliates, led by its Infrastructure Investments Fund (IIF) and Sun Jupiter Holdings. Sun Jupiter is the sole shareholder of Merger Sub, a corporation formed for the purpose of merging with and into EPE, with EPE as the surviving entity. Sun Jupiter is also an indirect, wholly owned subsidiary of IIF Sun Jupiter Ultimate Holdings.

Tyson Slocum, Public Citizen's energy program director, told *RTO Insider* that the order was a result of FERC's "deeply flawed" paper hearing process, in which commissioners consider the written evidence in private before issuing a decision.

"FERC can pick and choose what it wants to focus on and what it wants to ignore," Slocum said. "They simply ignored the evidence [of self-dealing] we provided.

Public Citizen said FERC's order, which directed the companies to file a mitigation plan addressing market power screen failures, ignored evidence that "JPMorgan's affiliation with IIF poses a risk to the rates of El Paso Electric's captive customers." The group noted that the commission declined "to address the arguments related to whether the IIF companies are affiliated with JPMorgan and/or J.P. Morgan Investment [Management]."

The commission agreed with the applicants' assertion that any affiliation between the IIF companies with JPMorgan would not change its analysis under the Federal Power Act.

Public Citizen said FERC cannot decline enforcement under the FPA and "must make a determination of whether JPMorgan Chase & Co. is affiliated with the IIF shell companies seeking to acquire El Paso Electric, as JPMorgan's affiliation with IIF — and the impact that affiliation has on rates — has been the only contested issue of this entire proceeding."

JPMorgan Chase's New York City headquarters | *JPMorgan*

Tyson Slocum, Public Citizen | © *RTO Insider*

"I don't think they can lawfully decline to address the cornerstone of their obligations under the Federal Power Act," Slocum said.

In the filing, Public Citizen pointed to FERC's April 27 decision granting Public Citizen's protest and ruling that Goldman Sachs Renewable Power Marketing was an affiliate of The Goldman Sachs Group investment bank. (See *FERC: New Goldman Unit an Affiliate*.)

The group said the Goldman Sachs ruling "demonstrates the need for" JPMorgan to produce the operating agreements, management services agreements, limited liability company operating agreements and all other corporate documents "that describe the powers and responsibilities of the various parties within each IIF shell company."

"Such documents are necessary to determine affiliation of JPMorgan Chase & Co. with IIF," Public Citizen said. "The issue of JPMorgan's affiliation with IIF is necessary for FERC to determine whether the acquisition of El Paso Electric by IIF is consistent with the public interest."

Public Citizen said evidence that JPMorgan instructed IIF to purchase 120 million shares of a power company held by the investment bank indicates the new owners' "self-dealing" could increase rates for EPE's captive customers.

Slocum said his organization will also be intervening in Xcel Energy's proposed *$680 million sale* of its 760-MW Mankato Energy Center in Minnesota to Denver-based Southwest Generation. Southwest Generation is owned by institutional investors advised by J.P. Morgan Asset Management. ■

SPP News

SPP Board/Members Committee Briefs

Directors Approve Zonal Planning Criteria, Z2 Elimination

SPP's Board of Directors last week approved the first two revision requests stemming from the Holistic Integrated Tariff Team's (HITT) 15-month effort to help the grid operator adapt to the evolving grid and electricity markets.

Gathering virtually for its first meeting since the COVID-19 outbreak began, the board on April 28 signed off on both measures. The changes were previously advanced by the Markets and Operations Policy Committee, Strategic Planning Committee and Regional State Committee.

RR 391, which establishes uniform local planning criteria within each transmission pricing zone under the Tariff's Schedule 9, received pushback, in line with the frequent tension between transmission owners and customers in SPP's 19 zones.

As written, RR 391 places the responsibility on the zone's host TO to facilitate a "consensus-driven" criteria for reliability upgrades, rather than have individual TOs submit their local planning criteria to SPP, to ensure all customers in the zone pay equally for the same types of transmission upgrades. Schedule 9 calculates network service request charges as a ratio share of the monthly annual transmission revenue requirement.

For many transmission customers, the issue was the loss of the words "collaboration" and "consensus" in the RR's final language.

Golden Spread Electric Cooperative's Mike Wise said the RR failed to convey the HITT report's intent.

"The language did fall short," said Wise, a HITT member. "We spent a huge amount of time discussing how the host utilities in a zone should develop a collaborative process. Certainly, the language should have been a consensus-driven process within each zone. Neither of those words showed up anywhere, and I think we fell short because of that."

Mike Wise, Golden Spread Electric Cooperative | © RTO Insider

"As a [transmission and distribution user], a small transmission customer being invited to a meeting is one thing. Having your opinion heard or taken into consideration is two completely different things," Oklahoma Municipal Power Authority General Manager David Osburn said. "I'd like to see a little more teeth, to see the [TDUs] and customers have more meaningful input in the process."

"The Tariff language … simply requires the big utility in the zone, or the [facilitating TO] to call a single meeting and, based on that, file or not file zonal planning criteria that the FTO determines to be in their best interest," said consultant Jack Madden, who represents several Texas cooperatives. "We believe this is a far cry from what was hammered out during the HITT discussions."

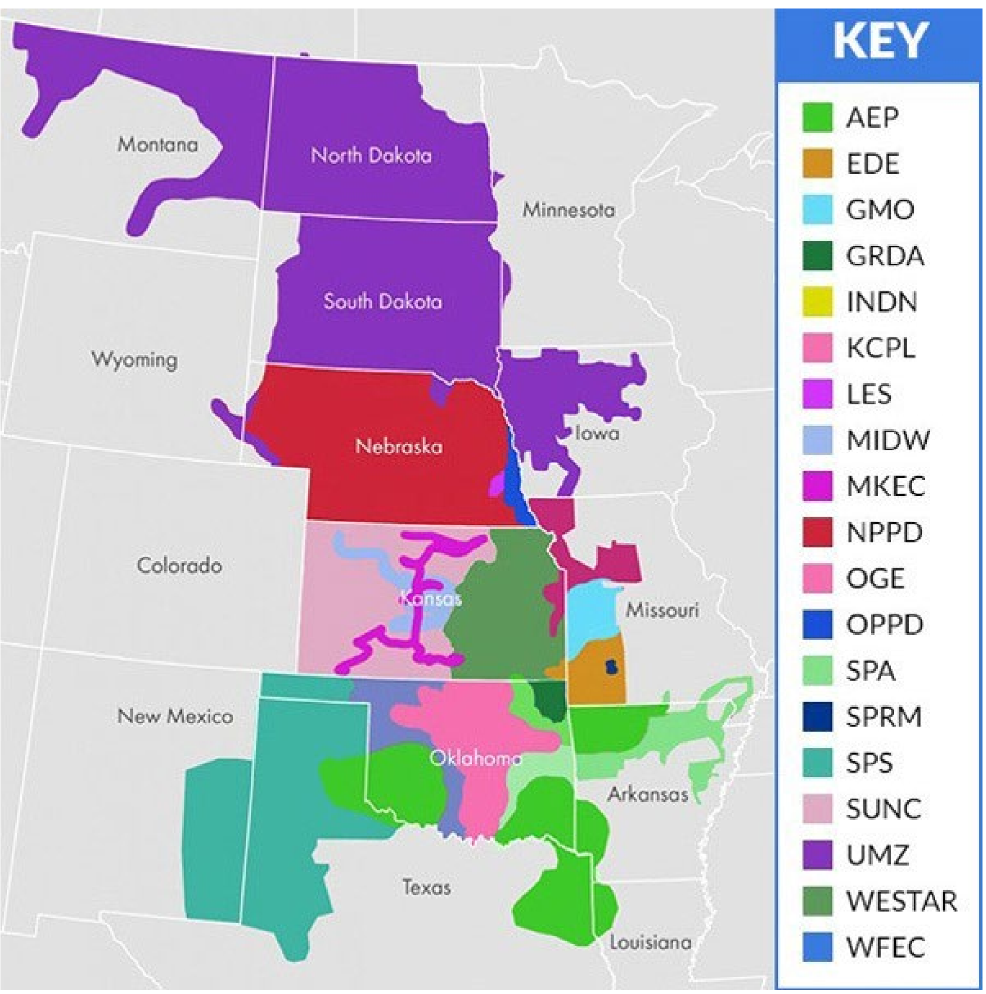
Antoine Lucas, SPP's vice president of engineering, tried to clarify matters by pointing out that it's up to the entities within the zone to reach agreement.

"Nothing in this language prohibits TOs in the zone from working together to define what consensus means to them and how they want to organize themselves," he said. "We want to ensure everyone in the zone will have comparable criteria."

Osburn and three others on the Members Committee voted against RR 391. Wise abstained.

The second Tariff change, RR 401, faced a smoother path to approval, with only one abstention. The measure replaces credits under Tariff Attachment Z2 for certain network upgrades with incremental long-term congestion rights (ILTCRs). It replaces a previous attempt to change the Tariff, which was rejected in January by FERC (ER20-453). (See FERC Order Keeps Z2, Aids EDF's Sponsored Project.)

Dan Simon, outside counsel for EDF Renewables, spoke out against the measure as he has



SPP's transmission pricing zones | SPP

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during previous stakeholder groups, saying SPP's current ILTCR rules are "inadequate."

"I think most people would agree. No one has selected the ILTCR option," he said, calling for SPP to improve the ILTCRs "so they're more in line with other RTOs."

SPP staff wasted no time in *filing* the change at FERC, doing so the day after the board meeting and asking for an effective date of July 1.

The HITT concluded its work last year, handing off its 21 recommendations to various stakeholder groups. The recommendations encompassed four categories: reliability, marketplace, transmission planning and cost allocation.

Directors Suspend Competitive Upgrade

The board sided with recommendations from SPP and the Oversight Committee to suspend a previously approved competitive interregional upgrade, pending negotiations with the seams partner and FERC approval.

The 345-kV Wolf Creek-Blackberry project in Kansas and Missouri was approved by the board last year and included in the *2020 SPP Transmission Expansion Plan*, which the board passed in January. Part of the 105-mile project, projected to cost $152 million, would be on the Associated Electric Cooperative Inc. (AECI) transmission system and constructed by AECI.

Because AECI is not a TO under SPP's Tariff, staff must reach an agreement with it to outline the project's scope and define cost allocation for its work. The entities have agreed to a joint study schedule to conclude in May, after which they would finalize an agreement that must be approved by FERC before SPP can allocate funds to AECI for the latter's portion. (See "SPP, AECI Agree to Joint Study," *SPP Seams Steering Committee: April 2, 2020*.)

The OC said were SPP to commence its competitive process and issue a request for proposals without reaching an agreement with AECI, "there is significant risk that millions of dollars would be spent on a [competitive selection process] that results in nothing."

SPP COO Lanny Nickell said were the project not suspended, staff would have to meet a Tariff deadline and begin the RFP process by July without a negotiated agreement and FERC approval in hand.

"There are risks associated with not suspending the project and beginning the RFP process," Nickell said. "It could impose costs on members if AECI does not ultimately agree to what they have to do on their end."

For the time being, AECI is projected to spend up to $2 million on a substation. "But if other upgrades are needed to accommodate this request, that opens up a whole series of discussions with AECI and our members, because that would create additional costs," Nickell said.

Wise said he thought the OC made the correct decision.

"This falls in line with what I've been advocating, which is achieving a higher degree of quality in transmission buildouts," he said. "These are 40-year assets that have to be paid by all consumers in the footprint. We need to ensure AECI pays its fair share."

"The idea to initiate a process where the clock would be running, and those members wanting to participate would have to start spending time and money to develop a bid, doesn't seem prudent," said Brett Leopold, with independent transmission utility ITC Great Plains.

"This project can still be suspended or canceled at a later date if it's not deemed to be right," Evergy's Kevin Noblet said. "Sending an RFP out on the street when the only thing at risk is a few hundred thousand dollars, if that, seems like a risk worth taking."

Evergy was one of four member companies to oppose the recommendation. Two other members abstained.

COVID-19 Alters Sugg's Transition Plan

Delivering her inaugural CEO report to the board and committee, Barbara Sugg had to admit her transition into the position held for 16 years by the retired Nick Brown was "not exactly turning out like I had expected."

Sugg, who was selected to replace Brown in January, had intended to spend much of her first 90 days in the role traveling across the footprint and visiting with SPP's many stakeholders. (See *Sugg Prepares to Take 'Dream Job' at SPP*.)

Those plans were waylaid by the COVID-19 pandemic after she had met with a dozen different companies.

"The roadshow stopped just as soon as it started. I'm really disappointed I had to cancel many of those meetings," she said. "COVID-19 may have sidelined me right now, but I look forward to getting back on the road."

Sugg has continued to conduct virtual meetings and has made individual calls with each of the regulatory commissioners in SPP's footprint. "It's good for those commissioners

| SPP

to hear from me so we can start building trust and respect that is mutual."

Saying it's "inevitable" that an employee will eventually test positive for COVID-19, Sugg said, "We continue to hope for the best and prepare for the worst."

There is a silver lining to the pandemic. With the reduction in travel and meeting expenses, SPP has over-recovered about $2.5 million in administrative fee revenues through March. Sugg said that with "lots of meetings planned to be virtual for many months to come," that number will grow.

However, the pandemic has also resulted in lower demand, "putting pressure on 2020 rates," she said. SPP has also incurred about $340,000 in net savings by increasing and using the engineering staff, rather than consultants, to manage the interconnection queue.

Sugg said resolving seams issues with SPP's neighbors remains one of the grid operator's key goals. "We remain committed to win-win solutions on the seams," she said.

Lowest Prices Ever for Integrated Marketplace

Keith Collins, executive director of the SPP Market Monitoring Unit, shared with directors and members a draft of the 2019 State of the Market report that found the footprint's energy prices were the lowest since the Integrated Marketplace went live in 2014.

Day-ahead prices averaged about $22/MWh and real-time prices averaged about $21/MWh, down from $25/MWh in 2018, Collins said. With gas prices below $2/MMBtu, also among the lowest since 2014, natural gas-fired resources frequently set market prices.

Collins also said the region's frequently constrained areas have all been removed, partly

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because of transmission additions that have shifted congestion and leveled the footprint's market prices. He said the MMU believes Central Oklahoma and the Tulsa area could potentially become frequently constrained areas in the future.

According to the report, the reliability unit commitment process' make-whole payments rose 55% to nearly $70 million last year. Collins attributed the increase to more resources being brought on from the RUC processes, including manual commitment for capacity needs.

The MMU also said wind generation continues to catch up with coal. Wind resources accounted for 27% of all generation in 2019, up slightly from 23.5% the year before. Coal generation, meanwhile, fell from 42% in 2018 to 35% last year.

The report outlined recommendations for SPP's market, including improving price formation during emergency and scarcity conditions, improving outage coordination, increasing flexibility and enhancing the ability to assess a range of transmission planning outcomes.

Collins said the MMU has noticed several concerning trends, including a 70% increase in scarcity intervals, increased negative pricing during the overnight hours, and increased generator outages and emergency conditions.

"Scarcity intervals highlight an increase in the volatility that occurs in the real-time market," Collins said. "It's driven by short-term, ramping-related scarcity events that happen on the system. That's why we've been supportive of ramping products."

The MMU's market-enhancing recommendations include improving price formation during emergency conditions and scarcity events, incentivizing capacity performance, and updating and improving outage-coordination methodology.

"It's important to set proper prices during these types of events," Collins said. "Scarcity events are actually reflecting events that are happening on the system. You want the power flowing in the right direction, particularly when scarcity events occur."

SPP has already formed the Generator Outage Task Force to improve outage coordination.

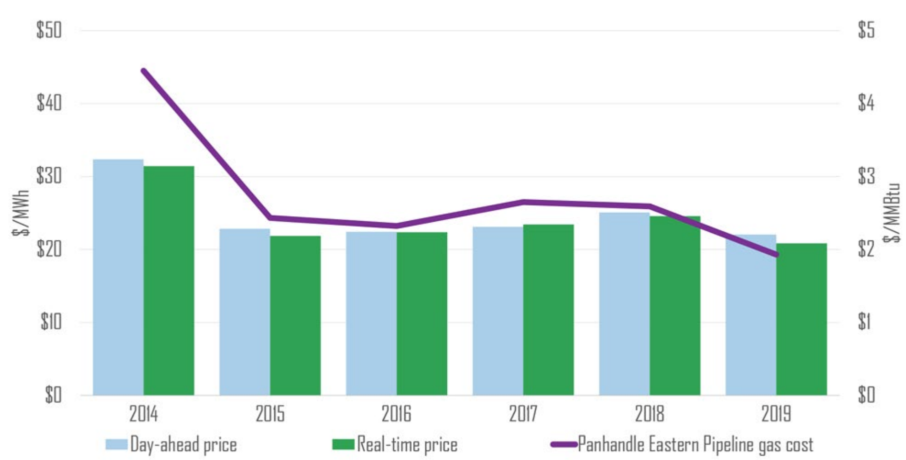
Staff Strengthening TRC Credit Practices

Director Graham Edwards, chair of the Finance Committee, said the Credit Practices Working Group (CPWG) has spent the last 18 months trying to strengthen the use of credit in SPP's transmission congestion rights (TCR) market. The work follows the 2018 GreenHat Energy default in the PJM market, which left members liable for more than $100 million. (See *FERC Orders PJM to Unwind GreenHat Settlements*.)

The group is recommending increasing the minimum capitalization for participants in the TCR market to either at least $20 million in assets or $10 million in net worth, or by increasing alternative collateral requirements. The CPWG is also recommending a strengthened credit application and minimum collateral on all TCR portfolios.

The Finance Committee has approved the recommendation and sent it through the stakeholder process for Tariff language development.

The board approved the committee's recommendation that it accept accounting firm BKD's 2019 audit report and findings. BKD said it did not find any issues or concerns in its review of SPP's accounting practices.



SPP's energy prices are the lowest since the Integrated Marketplace went live in 2014. | *SPP Market Monitoring Unit*

Digital Release for 2019 Annual Report

The virtual meeting marked another break in tradition for SPP. The RTO's annual report was posted digitally instead of being placed in each director and member's chair.

Entitled "*Integration*," the report includes former CEO Brown's final introductory message and focuses on the five major initiatives facing SPP: seams issues, transmission, Western expansion, the HITT recommendations and providing member value.

Consent Agenda Includes Exit Fee Changes

The board's consent agenda, unanimously endorsed by the committee, included *revisions* to SPP's bylaws and membership agreement that define the exit fees for transmission-owning and non-transmission-owning members upon their withdrawal.

FERC in December scuttled SPP's alternative proposal of a $100,000 exit fee and rejected a rehearing request. It also directed the RTO to make a compliance filing that ensures non-TO members pay a lower fee should they leave (*EL19-11*). (See *FERC Denies Rehearing of SPP Exit Fee Decision*.)

Other items on the consent agenda included:

- An amendment to the membership agreement that allows Roughrider Electric Cooperative, embedded in the Integrated System as a Basin Electric Power Cooperative member, to join SPP as a TO. Roughrider, a non-transmission-owning member of SPP as of April 30, will transfer functional control of its transmission facilities to the RTO, pending FERC approval. The IS joined SPP in 2015. (See *Integrated System to Join SPP Market Oct. 1*.)
- The nomination of Kansas Electric Power Cooperative CEO Suzanne Lane to the Human Resources Committee.
- Revising the Corporate Governance Committee's scope to use independent executive search firms to replace a director or fill a vacancy on the board.
- Baseline resets for five previously approved transmission projects. (See "Members Approve 1 RAS, Retirement of Another," *SPP MOPC Briefs: April 14, 2020*.) ■

— Tom Kleckner

Company Briefs

Duke Energy Aims to Double Renewable Sources by 2025

Duke Energy last week said it wants to double the renewable energy it produces or purchases, aiming for 28% by 2025.

Renewable advocates believe the company can achieve the goal by speeding up the retirement of its fossil fuel plants.

In a separate report, Duke said it has reduced carbon emissions from its electricity generation by 39% from 2005 levels. More renewables will be needed to hit future goals, which include reducing carbon emissions by 50% by 2030 and becoming net-zero carbon by 2050.

More: *WAFE*

ESA Announces Annual Board of Directors Elections

The Energy Storage Association last week elected **John D. Hewa**, CEO of the Virginia-based Rappahannock Electric Cooperative, as chair of its board of directors. He succeeds Troy Miller and will serve a one-year term.

ESA named Kiran Kumaraswamy, Peter Muhoro and Jacqueline DeRosa as named vice chair, treasurer and secretary, respectively. It also appointed a new board member in Jeff Bishop, co-founder and CEO of Key Capture Energy.

More: *Power Engineering*

Ørsted Says OSW Projects Face Delays

Ørsted last week said that five of its U.S. offshore wind projects totaling nearly 3 GW may face delays because of the COVID-19 crisis and slowed permitting.

The company confirmed two of its smaller projects — the 120-MW Skipjack in Maryland and the 130-MW South Fork in New York — are all but certain to be delayed beyond their 2022 completion dates. On top of that, Ørsted said its three largest projects — the 704-MW Revolution Wind in Rhode Island and Connecticut; the 880-MW Sunrise Wind in New York; and the 1.1-GW Ocean Wind in New Jersey — also face "increased risk of delays." CEO Henrik Poulsen said the company does not currently see a risk to its power purchase agreements and still hopes to finish its three largest projects on time in 2023-2024.

Despite the uncertainty, the company said its operating profit for this year's first quarter rose 33% compared to the same period last year and it has "no indication" the pandemic will significantly impact its earnings this year.

More: *GreenTech Media*; *CNBC*

Q Cells Takes Top Share of US Distributed Solar Module Market

Wood Mackenzie Power & Renewables last week released its first-quarter U.S. photovoltaic "leaderboard" and had Q Cells at the top of both the residential (25.2%) and commercial/industrial (13.3%) markets.

The company's residential market share has nearly doubled since 2019 (14.1%) and marks the first time in the history of the list that a company has claimed a 25% or greater share of the residential market.

Q Cells' rise came in September 2019 when it opened its panel manufacturing factory in Dalton, Ga. The facility is the second-largest solar panel manufacturing plant in the Western Hemisphere and can produce as many as 12,000 modules per day.

More: *pv magazine*

Rivian, Ford Cancel Plans for Lincoln-branded EV

Rivian and Ford last week announced that their joint project to build a Lincoln-branded electric vehicle has been canceled as the auto industry struggles to navigate the COVID-19 pandemic.

"Given the current environment, Lincoln and Rivian have decided not to pursue the development of a fully electric vehicle based on Rivian's skateboard platform. Ford Motor Co.'s strategic commitment to Lincoln, Rivian and electrification remains unchanged and Lincoln's future plans will include an all-electric vehicle," Lincoln said in a statement.

More: *Chicago Tribune*

Federal Briefs

Emissions Declines Will Set Records this Year, IEA Says

Global greenhouse gas emissions are on track to drop nearly 8% this year, the largest drop ever recorded, as worldwide lockdowns to fight the COVID-19 pandemic have triggered an unprecedented decline in the use of fossil fuels, according to a report released by the International Energy Agency last week.

The report found that by mid-April, energy use in many countries was 17 to 25% lower than it was in 2019. The IEA expects many governments to start relaxing restrictions later this year, but even then, global carbon dioxide emissions are projected to fall by roughly 2.6 billion tons for the year.

The report also noted that in past crises, global emissions typically shot back up once the initial shock passed. If countries start to help their economies by relaxing environmental rules or subsidizing polluting industries like coal or steel, the resulting rebound in emissions could be even larger than the decline.

More: *The New York Times*

First Solar, Origis to Deliver Solar to Knoxville Board

The Tennessee Valley Authority last week announced it has entered into a contract with First Solar and Origis Energy for two solar projects totaling 212 MW in Tennessee and Mississippi that will supply electricity to the Knoxville Utilities Board.

TVA signed a 20-year power purchase agreement with First Solar for its 177-MW Ridgely Energy Farm in Tennessee, while the other 35 MW will come from Origis Energy in the form of a 200-MW project in Mississippi.

Through the TVA Green Invest scheme, KUB has secured enough carbon-free electricity to equal 8% of its annual electric load.

More: *Renewables Now*

Former TVA Chairman Blasts Company for Promotions During Pandemic

Former Tennessee Valley Authority Chairman S. David Freeman last week blasted the utility for its current advertising campaign during the COVID-19 pandemic.

Despite recent solar farm additions, Freeman and others claim TVA is not doing enough to be a leader in promoting alternative energy and aiding its customers in being more energy efficient. They say as wind and solar power has gotten cheaper, Memphis Light Gas and Water and other local companies might be better off splitting from TVA.

"The way TVA spends money today is so much different than in the past," Freeman said. "In my day, people came to TVA because they were proud to work for an agency that was making a real difference in people's lives."

More: *Chattanooga Times Free Press*

More Lawmakers Join Suit Challenging Trump Power Plant Rollbacks

More than 70 Democratic lawmakers from the House of Representatives and Senate have joined a lawsuit challenging the Trump administration's rolling back of Obama-era power plant regulations.

EPA's Affordable Clean Energy rule, finalized in August, gives states more time and authority to decide how to implement technology to reduce emissions from coal-fired plants than the Clean Power Plan under President Barack Obama.

"We will continue to oppose this administration's willful misinterpretations of environmental laws that seek to justify rolling back critical public health protections and undermine future administrations' ability to safeguard our environment and the American people," the lawmakers wrote.

More: *The Hill*

IG Finds Companies Claiming 45Q Credits Didn't Follow EPA Reqs

Most of the money claimed through a tax credit under Section 45Q of the Internal Revenue Code over the past 10 years were by companies that had not been complying with its requirement, according to the Treasury Department's Inspector General for Tax Administration.

The credit incentivizes the use of still-developing technology to remove carbon from the atmosphere. The IG released a report last week that determined 10 entities had claimed more than $1 million each between 2010 and 2019, and that their combined claims made up 99.9% of credits given. It found that about 87% (nearly $894 million) of the claims from the entities were made while they were not in compliance with requirements from EPA.

The investigation said the IRS has already taken action against four of the 10 entities, but an IRS spokesperson declined to say whether it would be taking additional actions.

More: *The Hill*

State Briefs

ARKANSAS

Entergy Gets OK for Farm in Searcy

The Public Service Commission last week approved Entergy Arkansas' application for its 100-MW Solar Searcy project.

The project, which would be the state's largest utility solar farm at 800 acres, will be the first utility array to feature battery storage. It will also bring the company's solar output to 281 MW from three solar installations.

The project is expected to be completed next year.

More: *Arkansas Business*

CALIFORNIA

CEC Clarifies Solar, Energy Storage Installers as Essential Workers

The Energy Commission last week clarified statewide orders in response to the COVID-19 pandemic and identified solar photovoltaic and energy storage installers as essential electricity industry workers.

The state public health officer designated essential critical infrastructure workers needed to support critical sectors, including the construction and energy sectors. The list is updated as needed but says essential workers for the electricity industry includes "workers who maintain, ensure or restore the generation, transmission and distribution of electric power."

The list includes workers who are needed to supply electricity to households and businesses, as well as electricians who are necessary to maintaining the operation of construction sites and projects. The installation and maintenance of photovoltaics and energy storage projects have the added importance of supporting the resilience and continued operations of critical equipment and infrastructure across the state that requires uninterrupted power, according to the commission.

More: *California Energy Commission*

KANSAS

Johnson Corner Solar Project Begins Commercial Operation

Sunflower Electric Power and Lightsource BP last week said their $37 million Johnson Corner Solar Project has begun commercial operations in Stanton County.

Lightsource BP is the project's owner and operator and will sell all the energy to Sunflower under a 25-year power purchase agreement. The project can deliver 20 MW of on-peak electricity, which more than doubles the state's utility-scale solar capacity (14.1 MW).

More: *Solar Industry*

MASSACHUSETTS

State Suing Dynamic Energy Solutions for Violations

Attorney General Maura Healey last week filed a lawsuit against solar energy development company Dynamic Energy Solutions for allegedly damaging protected wetland resources in Williamsburg and polluting the West Branch Mill River.

The suit alleges Dynamic failed to follow pollution control requirements when it built an 18.5-acre solar array on a hillside above the West Branch Mill River in Williamsburg. As a result, it says, Dynamic caused sediment-laden stormwater to discharge in extreme amounts from the site, damaging the surrounding environment in violation of federal and state laws protecting water and wetland resources.

Healey's office is seeking civil penalties and a permanent injunction requiring Dynamic to restore the damaged wetlands and other areas.

More: *WWLP*

MISSOURI

Eminent Domain Bill Takes Aim at Grain Belt Express Project Again

SB 618, a measure that would severely hinder or possibly kill the Grain Belt Express transmission line project via the abolishment of eminent domain, is headed to the House of Representatives.

A provision in SB 618 would essentially block the project's developers from using eminent domain to secure property along its 780-mile-long route. The House Special Committee on Regulatory Oversight and Reform approved the language last week as lawmakers reconvened to pass a budget during a pandemic-shortened legislative session. The language has support in the full House and is expected to be voted on this week, but it faces uncertainty in the Senate.

More: *Energy News Network*

NEBRASKA

Judge Orders Injunction Preventing NPPD from Ending Power Contracts

U.S. District Court Laurie Smith Camp last week issued a permanent injunction preventing Nebraska Public Power District from canceling power purchase agreements with three wind farms, saying the farms "have shown as a matter of law that they did not default on their obligations under the PPAs."

Laredo Ridge Wind, Broken Bow Wind and Crofton Bluffs Wind filed a lawsuit last year alleging NPPD was improperly attempting to cancel its 20-year PPAs years before they were set to expire. According to the lawsuit, NPPD attempted to use Global Investment Partners' 2018 acquisition of the farms and other assets from NRG Energy as the basis for the contract termination, claiming they constituted a default under terms of the agreements.

NPPD said its management and legal staff are reviewing the ruling to determine what its next step will be.

More: *Lincoln Journal Star*

OHIO

AEP Conesville Plant Burns Last Bit of Coal

AMERICAN ELECTRIC POWER

American Electric Power's Conesville coal-fired plant burned its last load of coal last week as it prepares to be decommissioned on May 31.

The plant lasted 62 years, with its first unit coming online on Dec. 26, 1957. Five more units would come online over the next 21 years. A small staff will remain on site to shut down the unit and transition to new property owners.

AEP announced in October 2018 that the plant would be closing in May 2020 and based its decision on operating costs and the outcomes of competitive generation auctions.

More: *The Columbus Dispatch*

WISCONSIN

Dane County Airport Solar Farm Approved

The Public Service Commission last week voted 3-0 to approve construction of Madison Gas and Electric's $16.8 million, 9-MW solar farm at the Dane County Regional Airport. The 58-acre farm will be the largest in the county and larger than any currently operating farm in the state.

The commission determined the project would not affect nonparticipating utility customers as the county will pay for the entire cost, as well as MGE's 9.8% return on equity invested. Under a 30-year contract, the county will pay 5.8 cents/kWh and receive credit for any generation in excess of its own use. The county estimates it will save about $137,000 in the first year compared to buying electricity at the standard rate.

Construction is expected to begin this spring, with the plant entering service later this year.

More: *Wisconsin State Journal*