RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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PJM Taps Ex-Direct Energy Exec as New CEO

By Christen Smith and Rich Heidorn Jr.

Manu Asthana | *PJM*

PJM on Monday named former Direct Energy executive Manu Asthana as its choice for president and CEO, ushering in a new era of leadership at the RTO after a tumultuous year of internal reorganization and executive departures. He will join PJM on Jan. 1.

"We welcome Manu to lead PJM into the future," PJM Chairman Ake Almgren said in a press release. "The electric industry is rapidly changing and PJM needs to continue to evolve. Manu comes to PJM with a wealth of experience from the electricity value chain and we are confident that he will bring new and important perspectives to the organization."

Asthana's two-decade career in the energy industry includes a stint as TXU Corp.'s chief risk officer and overseeing both power generation operations and energy trading for Direct Energy, a subsidiary of U.K.-based Centrica.

As president of Direct Energy Home in North America from 2015 through 2018, he led a staff of more than 2,600. The company, which offers retail electricity, home warranties, HVAC services and appliance rentals, claims to serve 3.4 million residential and small business customers in the U.S. and Canada.

Almgren said Asthana's expertise will enhance PJM's engagement with members and policymakers. Asthana has a bachelor's degree in economics from The Wharton School at the University of Pennsylvania.

Asthana, his wife, Aparna, and their family will relocate to the Philadelphia area from Texas, where he served on the boards of Texas Children's Hospital, the Houston Food Bank and

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Brouillette Poised to Become Energy Secretary

Deputy Energy Secretary Dan Brouillette before his confirmation hearing Nov. 14, as his wife, Adrienne, looks on. | © *RTO Insider*

By Michael Brooks

WASHINGTON — Deputy Energy Secretary Dan Brouillette appeared well on his way to taking over for his outgoing boss after facing little substantive questioning at his confirmation hearing Thursday and little, if any, opposition from Democrats.

Much of the hearing was taken up by members of the Senate Energy and Natural Resources Committee, on both sides of the dais, extolling the virtues of a particular

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Louisiana's Campbell Expands Beef with SPP

By Tom Kleckner

Louisiana PSC Commissioner Foster Campbell | © *RTO Insider*

Not content with pillorying SPP officials on their home turf, Louisiana Public Service Commissioner Foster Campbell has broadened his complaint over RTO expenses with a letter challenging SPP's and MISO's spending on offices and executive salaries.

Campbell on Nov. 7 filed a *letter* with SPP's and MISO's state commissions and the National Association of Regulatory Utility Commissioners' senior leadership, calling for a "thorough examination of [grid operators'] spending."

"Turning the American power grid into the electricity equivalent of an interstate highway system is probably a worthwhile goal, but I question how those RTOs freely spend our dollars," Campbell wrote, adding a new acronym to the industry's lexicon: Overspending Other Peoples' Money (OOPM).

The Louisiana commissioner described SPP's Corporate Center as a "150,000-square-foot Taj Mahal of an office building in a leafy 20-acre suburban setting fit for a Fortune 100 corporation." He said he hasn't been to MISO's corporate offices in Carmel, Ind., and was thus unable to compare them to SPP's "ornate offices."

"If MISO's offices are anything like SPP, then these two [RTOs] have a bad case of OOPM," he said.

Campbell also lambasted the salaries paid to the grid operators' top executives. He noted SPP's Nick Brown and MISO's John Bear

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technology and cordially asking Brouillette for his commitment and assurances that he would continue the Department of Energy's work in advancing the research and commercialization of those technologies, including LNG, carbon capture and sequestration, battery storage, and advanced nuclear energy.

Brouillette has been serving as deputy to Energy Secretary Rick Perry since August 2017, when the Senate confirmed him 79-17. He was considered by the committee in May of that year alongside eventual FERC Chairman Neil Chatterjee and former Commissioner Robert Powelson. (See *No Fireworks for FERC Nominees at Senate Hearing*.) Chatterjee was among those in a packed audience Thursday that included five National Laboratory directors and Brouillette's nine children.

Brouillette previously worked at the department in the George W. Bush administration as assistant secretary for congressional and intergovernmental affairs from 2001 to 2003. He worked as staff director for the House Energy and Commerce Committee for a year after leaving the department. Before returning to DOE, he had been a senior vice president for USAA since 2006.

President Trump formally nominated Brouillette on Nov. 7. Calling him "the obvious choice to replace Secretary Perry," Senate ENR Committee Chair Lisa Murkowski (R-Alaska) told Brouillette it was her "intention to try and move you through the committee process just as rapidly as possible." But regardless of if — or when — the Senate confirms him, Brouillette will take over leadership of the department, at least in an acting capacity, when Perry retires Dec. 1.

Baseload and Resilience

Sen. Steve Daines (R-Mont.) said his state's "balanced energy portfolio is coming under attack with the premature, forced closures" of two units at the coal-fired Colstrip plant because of "extreme, radical groups that litigate." He told Brouillette he believed "that there is a role for you and the Department of Energy to play in order to maintain baseload supply in Montana" before asking him to "commit to working with me and this committee to protecting and growing baseload power like Colstrip and maintaining a secure and balanced energy portfolio."

"It's been the policy of this administration, and possibly the previous administration, to pursue an all-of-the-above energy strategy," Brouillette replied. "In our view, diversity of energy supply means energy security, not only for our nation but for our allies across the world. ... Until we are able to develop battery storage that has more capacity, is longer lasting [and] is perhaps more flexible in some respects, it is important that baseload power exist, because without it, if we are objective and candid, the introduction of renewables to our electric grid is very, very difficult."

Through the department's in-development North American Energy Resilience *Model*, "we're going to look at these types of facilities and see if they fit that potential model and see if there's anything that we should be concerned about potentially about the loss of those" plants, he said.

Asked by reporters after the hearing how he would go about saving baseload plants, Brouillette answered, "It's not about saving the plants. It's about working with regulators; showing them the things that we're seeing; allowing the FERC to do its job.

"It's not about simply 'saving the plants.' It's about looking at the entirety of the grid, looking at the entirety of the energy sector and making sure that we have either distortions or artificial impacts on it that might preclude us from either adopting renewable technology or create some level of a security risk. ... We're looking at that resilience model as a way to show us in real time what's happening on the grid."

Senate ENR Committee ranking member Joe Manchin (D-W.Va.) greets Brouillette before the hearing begins. Sens. John Hoeven (R-N.D., left) and Steve Daines (R-Mont.) are pictured in background. | © *RTO Insider*

Ukraine Matters

The breezy hearing intersected briefly with the political firestorm taking place on the other side of Capitol Hill. Brouillette said he had no knowledge of or involvement in conversations with Ukrainian officials about matters at the heart of the House of Representatives' inquiry into impeaching Trump.

"I have not been involved in any of the conversations that are related to the House's inquiry," Brouillette told ranking member Joe Manchin (D-W.Va.). He did say the department has worked with Ukraine, "at their request, to help them interconnect their electricity grid [and] their pipeline grid," and that it has advised U.S. allies in Eastern Europe on building LNG import facilities as part of an effort to lessen their dependence on Russian natural gas.

Perry — along with U.S. Ambassador to the E.U. Gordon Sondland and Kurt Volker, special U.S. envoy to Ukraine — is one of the White House's "*three amigos*" on Ukraine policy, according to Sondland. Perry had traveled to Ukraine in May for the inauguration of President Volodymyr Zelenskiy and provided him with a list of suggestions for the supervisory board of Naftogaz, the country's state-owned energy company.

Sen. Ron Wyden (D-Ore.) asked if Brouillette was aware of "any contacts between Secretary Perry, or any other senior DOE officials, and representatives of Naftogaz."

"I am aware that the secretary met on occasion with individuals who were asking for assistance with the restructuring" of the company, Brouillette replied. But he said he was not aware of any conversations between Perry and Trump's personal lawyer, Rudy Giuliani, or anyone in the Ukrainian government about the makeup of the board. ■

CAISO/West News

CAISO Advances Systemwide Market Power Plan

By Hudson Sangree

FOLSOM, Calif. — CAISO is moving ahead expeditiously with a plan to stem systemwide market power, even though not everyone is convinced the effort is necessary or needs to move so quickly.

The project stems from *analysis* by CAISO staff and the ISO's Department of Market Monitoring earlier this year that detected a limited number of hours when the potential for the exercise of systemwide market power existed.

The report led to a sometimes tense meeting in August of the ISO's Market Surveillance Committee, in which participants voiced opposing views on the need for market power mitigation measures and the speed at which the process was moving. (See *CAISO Stakeholders Split on Market Power Efforts*.)

On Wednesday, Brad Cooper, CAISO's senior manager of market design policy, *briefed* the Board of Governors on the ISO's decision to kick off a stakeholder initiative to design a mitigation program. Staff issued a *conceptual proposal* in September and last month released a scoping *document* setting out the guiding principles for the effort.

Left to right: CAISO Governors Angelina Galiteva, David Olsen, Ashutosh Bhagwat and Severin Borenstein; and CEO Stephen Berberich. | © *RTO Insider*

Cooper said it has proven tricky to design a process that limits market power without unintended negative consequences. Of particular concern, he said, is being careful not to deter electricity imports from other states by controlling prices too much. Those imports will be necessary for meeting California's needs going forward, he said.

"We want to make sure we don't cut off our nose to spite our face, so to speak," Cooper said.

The predicted potential for noncompetitive conditions occurs at the ISO's balancing area level, not the local level, he said. It can involve hours when supply is constrained by transmission bottlenecks or a lack of resources, he said.

Though the problem isn't immediate, CAISO leaders and staff members are concerned that system market power could become more of a factor in the next few years. Starting in 2021, the retirement of fossil fuel plants and the inability of solar power to meet evening peak demand will create a much tighter energy market than today, according to CAISO projections.

Stakeholders, however, remain divided on the need for mitigation efforts, Cooper told the board. Electricity suppliers have argued there's no real evidence of the exercise of systemwide market power — only the potential for it to happen.

"PacifiCorp agrees with other stakeholders that nothing in the CAISO's system market power analysis indicates an urgent need for the CAISO to conduct a policy initiative to design and implement new price mitigation procedures to address system-level market power," the utility, a major exporter of energy into California, wrote in comments filed with the ISO.

The state's investor-owned utilities and the California Public Utilities Commission have contended the effort is critically important, he said.

"System market power mitigation is vital to ensure competitive outcomes in a market that has become structurally uncompetitive at the system level in a higher number of hour and intervals. When the market is structurally uncompetitive, market power can be exercised, and uncompetitive bidding practices can successfully drive up the price," Pacific Gas and Electric said in comments.

Staff plan to issue a straw proposal next month and bring a final plan to the board early next year so that it can be implemented by the spring of 2021 — before the anticipated shortfalls of summer that year. The designers are looking at a phased-in approach that will first address issues in the real-time market and then move to the day-ahead market in phase two, Cooper said.

Some commenters Wednesday took issue with the two-phased approach.

Raisa Ledesma Rodriguez, with the CPUC's Energy Division, said the phased-in effort may be insufficient to head off the exercise of market power. A representative from PG&E said the day-ahead market is where the greatest potential for problems occurs.

CAISO CEO Stephen Berberich told the board that applying market power mitigation measures in the day-ahead market is more complex than in the real-time market. Staff are moving ahead on the project with a sense of urgency, he said.

"Our analysis doesn't show a burning bridge at this point," but it's important get ahead of the issue, Berberich said. ■

California Officials Hammer PG&E over Power Shutoffs

Utility Criticized as CEO Predicts Another Decade PSPS

By Christen Smith

California officials hammered Pacific Gas and Electric executives on Monday over the utility's mishandling of multiple public safety power shutoffs (PSPS) that left nearly 2.4 million residents in the dark last month.

PG&E, Southern California Edison and San Diego Gas & Electric all implemented PSPS events in October after the National Weather Service issued multiple red flag alerts that predicted dry, windy conditions at the height of the state's wildfire season.

It was PG&E's dereliction of long-established protocols for public notification and emergency preparedness, however, that set the investor-owned utility apart from the rest, officials told the Senate Energy, Utilities and Communications Committee during a six-hour hearing Monday.

The California Senate Energy, Utilities and Communications Committee convenes Nov. 18 to discuss lessons learned from recent power shutoffs.

Marybel Batjer, Calif. PUC

"This was a world-class emergency response from the state of California," California Public Utilities Commission President Marybel Batjer said. "I was also provided with insight into how a tool like PSPS intended to protect people and communities from harm can, when implemented haphazardly, generate the opposite effect."

PG&E Response

California's IOUs began using PSPS as a wildfire mitigation tool only within the last decade after damaged transmission lines sparked some of the deadliest blazes in state history, including last year's Camp Fire that killed 85 people and leveled the town of Paradise.

Some officials, however, worry that utilities lean too much on the controversial practice to shield their companies from liability over faulty and neglected equipment. IOU shutoffs have nearly tripled since 2017, with 14 called so far this year.

PG&E CEO Bill Johnson

PG&E CEO Bill Johnson rejected that perception and said the utility has spent $30 billion over the last decade upgrading its transmission system. He blamed some of the company's reliance on PSPS on the growth of high-risk fire areas within its 75,000-square-mile service territory — up from 15% in 2012 to more than 50% in 2019 — and predicted that the utility will continue the practice for another 10 years while it completes system-hardening initiatives.

"Let me emphasize the basic fact that should be obvious … we don't actually want to turn anybody's power off," he said. "We recognize that living without power is more than just an inconvenience. For many, it's a hardship. None of us want to live in that world, but we are doing this to prevent the spread of deadly catastrophic fires we've experienced in the last few years."

But officials said PG&E seemed ill-prepared to manage the strategic shutoffs, despite months of preparation in coordination with state agencies.

Mark Ghilarducci, director of the governor's Office of Emergency Services, said despite his office's outreach to PG&E, the utility's response during last month's events lacked consistency and generated widespread confusion. He said PG&E didn't provide detailed and timely notification of planned outages to its affected customers and couldn't offer enough support via backup generators to critical medical baseline ratepayers or oversee other essential infrastructure during the three dayslong shutoffs that occurred on Oct. 9, 26 and 29.

"This was quite frustrating to us, particularly when we started to roll into these bigger problems, which we anticipated in those meetings that we talked about and wanted to address then," he said.

Some of those bigger problems included widespread communications outages that prevented customers from contacting emergency services or accessing updates about the shutoffs. Residents in Mendocino and Marin counties lost complete access — via landlines, cell phones or internet — after 1,600 cell sites failed.

Ghilarducci said the issues suggest that privately owned and managed telecommunications companies lack appropriate battery backups for extended power outages. Regulatory hurdles thwarted attempts to ship diesel generators from other states, further slowing the restoration process, he said.

"Given the utility's sole notification strategy for the public was to drive customers to a website that they couldn't get on because they couldn't get through the wireline system, it was a very frustrating loop of cascading failures that really created a major threat to life and safety," he said. "We have seen this scenario over and over now following one disaster after another."

Approximately 750,000 of PG&E customers de-energized during the Oct. 26 event went without power for a week or more, Ghilarducci said, because of the overlapping shutoffs

CAISO/West News

implemented before the utility could clear the lines for restoration.

"The details here matter," he said. "A detail about how you're going to put a community resource center in place and what's going to be there and how long it's going to be open and what kind of demographics are going to be served there … those details matter. You can't hit that with a 30,000-foot overview and then expect to have the ability to respond."

Indeed, the state's Government Operations Agency scrambled during the PSPS events called Oct. 26 and 29 to get PG&E's website running again after it crashed following an uptick in traffic — an issue acting Secretary Julie Lee said the state warned the utility about in advance. Other officials said the number and availability of PG&E's resource centers — where de-energized customers sought water, ice, blankets and power generation — fell short of best practices.

"These are fairly easy things that you think about ahead of time and you do well ahead of time and not at the moment of crisis," Batjer said. "That was well pointed out to PG&E's [officials], and they admitted it."

Johnson painted a different picture of PG&E's preparations, noting that the utility completed 18 months' worth of line inspections within four months, trimmed 7 million trees and cleared vegetation — including 500,000 dead trees — from its lines. Although he admitted removing brush and debris does nothing to protect transmission lines against high winds, he said it's a good start.

"Turning off power for safety is an effective tool and really only one of the many tools we are using," he said. "We will get better at using it."


Sumeet Singh, PG&E

Sumeet Singh, vice president of asset and risk management for PG&E's Community Wildfire Safety Program, told the committee that the utility is indeed getting better at managing PSPS events. During the Oct. 26 shutoff, PG&E restored service to 970,000 customer accounts within 12 hours — a far cry from the 51 hours spent resupplying 60,000 customers during a shutoff last year.

He also said the grid's design with long radial lines traversing high fire-risk areas presents challenges not faced in other service territories with higher customer densities. The structure means PG&E is focused on de-energizing lines with surgical precision and restoring power quickly to prevent more widespread impacts.

"The details here matter. A detail about how you're going to put a community resource center in place and what's going to be there and how long it's going to be open and what kind of demographics are going to be served there … those details matter. You can't hit that with a 30,000-foot overview and then expect to have the ability to respond."

— Mark Ghilarducci, director of the governor's Office of Emergency Services

Still, officials insisted the utility should have done more.

"While PG&E spent significant resources warning the public about the risks of the power shutoff events and what the public should do to prepare for an event, it is not clear that PG&E spent the time it should have to make sure the utility was prepared," Batjer said.

The SDG&E Model

Power shutoffs in SDG&E's service territory carried far less impacts last month compared to outages in IOUs to the north thanks to years of planning and investment, COO Caroline Winn told the committee.

"I think what's needed in California is to think beyond ourselves," she said. "PSPS is the right solution for now, but what's next? I've set that as an aspirational goal for our organization … how do we eliminate it? [At] SDG&E, that is our North Star."

Winn said a devastating rash of wildfires in 2007 that "hit home" for the utility's staff resulted in a cultural shift from reliability to public safety.

"Having gone through those experiences and saw those changes happen before my eyes, those were the fires that really changed the DNA of our company," she said. "Back at that time, there was really no proscriptive plan of how we should engineer our system to protect our infrastructure from the increasing threat of violent wildfires."

So, piece by piece, Winn said, SDG&E hardened its infrastructure: replacing bare wire and wooden poles with covered conductor and steel poles; hiring scientists and meteorologists to improve fire-risk forecasting; installing sectionalizing switches and weather stations on lines to monitor conditions; bolstering patrols of de-energized lines to ensure damage is mitigated before restoring power; and investing in falling conductor technology that will prevent broken wires from igniting.

"We have been very thoughtful about installing sectionalizing switches, which only limits shut offs to the most endangered communities," Winn said.

The utility also turned community engagement into a year-round event, she said, noting that SDG&E hosts open houses and town halls to share information about how to prepare for a power outage. TV stations start broadcasting PSPS notices during red flag warnings, while the utility itself notifies customers at 48, 24, and one to four hours before a shutoff.

"Our goal is that no customer is surprised," Winn said. "We want our customers to be able to plan around this."

So, when Santa Anna winds triggered four red flag warning in SDG&E's territory last month, the utility managed to de-energize just 25,000 customers, with outages resolved in less than 24 hours. Winn clarified that winds topped 80 mph in some areas, but no "major" fires tore through the territory either. For comparison, PG&E territory saw wind speeds exceed 100 mph.

Winn said the company's PSPS wasn't perfect: The event underscored the need for more backup generators and stronger coordination with nonprofit partners to speed up response time in vulnerable communities.

Ana Matosantos, California's cabinet secretary and energy czar, said the utility's actions — despite operating within the same regulatory scheme as PG&E — produced better outcomes for its customers.

CAISO/West News

California Energy Czar Ana Matosantos

"San Diego has made great strides in a much narrower way, for a much shorter period of time, impacting far fewer communities," she said. "When you look at all three utilities, the use of PSPS in terms of size of event, the duration, the back-to-back outages, it's a different story from all three."

Southern California Edison

Like its IOU counterparts, Southern California Edison said its PSPS events only cut off power to a tiny fraction of its service area — less than 2% of its 5 million customers.

Phil Herrington, SCE

Phil Herrington, SCE's vice president of transmission and distribution, said the utility develops its own fire-risk forecasts and uses high-definition cameras to monitor line conditions. Field workers will also install some 6,000 miles of covered conductor by 2023, three years ahead of schedule.

"We used granular real-time weather [information] to de-energize sections rather than entire lengths [of transmission line]," he said. "The ability to use the weather to make de-energization decisions and having the technology to do so, it serves a vital purpose."

Both SCE and SDG&E said they deployed these more cost-effective mitigation tools to prioritize "undergrounding" where it's most effective. The technique, which trenches electricity infrastructure below ground, costs approximately $3 million per mile — a pricey solution that IOUs say takes longer to build — and to troubleshoot during outages.

"It's over eight times more expensive than covered conductor," Herrington said. "There will be areas that are so consequential in the event of a wildfire that undergrounding is the best option and we will deploy it when necessary."

Officials pushed Herrington on the utility's responsiveness to cell tower outages during the shutoffs and pointed out that its process for registering medical baseline customers leaves out residents who aren't account holders. He said the company offers zip code-based PSPS alerts to residents' cell phones as a backstop — though such messages failed in some parts of the utility's territory last month because of the outages.

"San Diego has made great strides in a much narrower way, for a much shorter period of time, impacting far fewer communities. When you look at all three utilities, the use of PSPS in terms of size of event, the duration, the back-to-back outages, it's a different story from all three."

— California Energy Czar Ana Matosantos

"We do look at lines and if they have telecommunications; that is one of the many factors we consider in the restoration sequence," he said. "PSPSes are just one of the many ways customers could lose power, so that is why we are encouraging customers to register as medical baseline customers. It could be an earthquake, it could be a major storm, where there won't be warning."

It's not enough for Ghilarducci, who said bolstering cell sites will help assure a resilient system — something utilities have a stake in too.

"That means cell sites need to be hardened with battery or fuel backup beyond four hours to know they will sustain for multiple days," he said. "Protecting the backline from fires or earthquake damage. It's a simple request that we are asking and it's a priority on the part of the utilities to do that."

CPUC Action

Batjer said PG&E's response provided a "sharper understanding" of how "one entity's decisions can result in broad societal costs," admitting that it's her agency's responsibility to prevent it from happening again.

"Although the utilities are ultimately responsible for managing their electric systems, the CPUC cannot and should not stop demanding better ways to reduce the scope and impacts of power shutoffs without compromising public safety," she said. "This cannot and should not be repeated."

The CPUC launched an investigation into PG&E's shutoffs last week to determine if the utility followed state law. (See *Calif. PUC Orders Investigation of Power Shutoffs*.) Batjer also issued a show-cause order and said a preconference hearing scheduled for Dec. 4 will give the utility a chance to convince the commission why it shouldn't be sanctioned for its actions, though she doesn't expect much in the way of changed behavior.

The commission will also work with utilities to expand their wildfire mitigation plans and create a Safety Policy Division dedicated to the enforcement of public safety during emergency events. It's a conversation that must include telecommunications companies too, Batjer concluded.

"Despite the importance of the regulatory processes and actions we have put in motion, they are meaningless to the public unless they translate into real-world demonstrations that utilities are truly taking actions that prioritize the safety of the public," she said.

State officials also won't give PG&E another decade to harden its grid and discontinue power shutoffs. Matosantos said the state's timeline "has been very clear."

"We cannot have another year like this year," she said. "We have to be looking at our goals and progress in a matter of days, weeks and months and what has to happen at every point in time before next fire season." ■

"We cannot have another year like this year. We have to be looking at our goals and progress in a matter of days, weeks and months and what has to happen at every point in time before next fire season."

— California Public Utilities Commission President Marybel Batjer

CAISO/West News

Calif. PUC Orders Investigation of Power Shutoffs

PG&E Blacked Out Millions of Residents in Late October

By Hudson Sangree and Robert Mullin

The California Public Utilities Commission opened an investigation Wednesday into the massive power shutoffs that placed millions of residents in the dark several times in October as part of efforts to prevent utility-sparked wildfires.

The purpose of the inquiry is to determine "whether California's investor-owned utilities prioritized safety and complied with the commission's regulations and requirements with respect to their late 2019 public safety power shutoff [PSPS] event," according to the *order instituting investigation* (OII).

"It is important for the CPUC to determine if the utilities complied with using public safety power shutoffs as a last resort and to collect the knowledge gained towards any revisions needed for next year," Commissioner Genevieve Shiroma said. "It is essential our protocols and the utilities' practices provide the best service and protections for customers in the face of wildfires."

The state Public Utilities Code has given utilities authority for more than a decade to intentionally blackout parts of their grids to protect public safety, particularly in the dry windy conditions each fall that have given rise to the state's most devastating wildfires. But the immense scope of this season's blackouts far exceeded anything that's occurred before.

PG&E shut off power to 729,000 residential and business customer accounts over three days starting Oct. 9, the PUC said. It turned off electricity to 975,000 customers in 38 counties Oct. 26. And it shut down power to nearly 516,000 customers three days later on Oct. 29.

The average household size in California is about 2.6 residents per home, according to the U.S. Census Bureau, meaning the blackouts may have affected approximately 1.6 million residents, 2.15 million residents and 1.14 million residents, respectively, after accounting for the roughly 15% of *PG&E customers* that are commercial or industrial users.

Southern California Edison and San Diego Gas & Electric also blacked out customers, but not on the scale of PG&E. SCE's largest shutoff occurred Oct. 30, affecting 86,000 customers, while SDG&E blacked out 24,600 customers Oct. 29.

PG&E transmission equipment is suspected of igniting the Kincade Fire, which began Oct. 23 and destroyed 374 structures in Sonoma County. | © *RTO Insider*

The CPUC first wants to know if the IOUs adequately notified the public, communicated with first responders and protected public safety during the blackouts.

"In later phases of this proceeding, the commission may consider taking action if it finds violations of statutes or its decisions or general orders have been committed and to enforce compliance, if necessary," the CPUC order said.

The CPUC's Safety and Enforcement Division will conduct the investigation in conjunction with outside consultants, it said. The IOUs must file initial responses to the OII by Dec. 13.

The investigation will examine whether regulations governing PSPS could be improved, the order said.

"The commission opens this investigation as a companion to ... the commission's rulemaking to examine utility de-energization of power lines in dangerous conditions," it said. "This investigation will serve as a forum for taking evidence to evaluate both the effectiveness and impacts of all phases of the PSPS events."

'Where is Safety?'

Public speakers Wednesday said the shutoffs have upended their lives, leaving them fearful and uncertain.

Will Abrams and his family lost their Sonoma County home in the Tubbs Fire of October 2017, running for their lives as their neighborhood burned down around them. The fire leveled parts of the city of Santa Rosa and surrounding communities, killing 22 people and destroying more than 5,600 structures.

The Abrams family had to leave their home during one of the first two PG&E shutoffs in October, then had to evacuate again as the Kincade Fire swept through Sonoma County during a subsequent PSPS event later in the month.

Like many others, they didn't know where to go to protect themselves. As they drove south through the San Francisco Bay Area, they saw wildfires along the freeways, and Abrams said he wasn't sure how far to drive before his family would be out of danger.

"I think many folks in California are wondering, 'Where is safety?'" Abrams told commissioners.

"Many Californians are debating about whether California is still safe," he added, saying the state is on the front lines of climate change. "Is this a safe place to live?"

Nevada City Mayor Reinette Senum laid out the "laundry list" of impacts PG&E's shutoffs had on her Sierra Foothills town, including the closure of "mom and pop" businesses, grocery stores and schools, the loss of internet, cell phone and 911 service, and the disruption to tourism.

"Basically, we were sent back into the Dark Ages," she said.

Senum cautioned the commission about the downstream "unintended consequences" of upending the local economy in her region, which is vital to supporting environmental efforts that protect the Bay Area's watershed from the toxic legacy of goldmining.

A catastrophic fire like the one that devastated the town of Paradise in November 2018 would scorch the soil in the region and release heavy metals that could leach into the water supply for 25 million end users, including farmers and ranchers in California's Central Valley and wine country growers, she warned.

Senum advocated for a public takeover of PG&E to put the grid "back in the hands of the people."

"We have everything to lose, and we have everything to gain," Senum said. "We will take better care of the transmission lines and make sure to decentralize the energy production so that it's as safe as possible and as reliable as possible."

She said continued shutoffs mean "we will cease to exist as a community."

"And the CPUC and PG&E, and all the citizens of California, are going to lose the best stewards of your watershed." ■

CAISO/West News

Conflict Escalates over PG&E Settlement with Insurers

By Hudson Sangree

A fight over potential payments to insurers and wildfire victims has heated up in the Pacific Gas and Electric bankruptcy case and is scheduled to be a major topic of a hearing today before U.S. Bankruptcy Judge Dennis Montali in San Francisco.

New homes rise amid dead trees in an area of Santa Rosa, Calif., destroyed by the Tubbs Fire in October 2017. | © *RTO Insider*

Wildfire victims and California Gov. Gavin Newsom have challenged PG&E's proposed $11 billion settlement with insurance companies and hedge funds — known in the Chapter 11 case as the subrogation claimants — that are seeking reimbursement for insurance payments.

PG&E has hailed the settlement as a milestone in its bankruptcy, which was brought about by billions of dollars in wildfire liability. The utility has asked Montali to approve the agreement at the Nov. 19 hearing.

Newsom's lawyers, however, said in a *court filing* Nov. 8 that the settlement "is yet another example of legal maneuvering by parties apparently more focused on securing procedural advantages for their own pecuniary interests than on reaching a fair and expeditious resolution of this bankruptcy."

"Many of the holders of subrogation claims are sophisticated financial institutions that bought the claims at a discount after the insurers paid out claims," it said. "Certain of those institutions [including Boston-based Baupost Group] also hold equity in PG&E and may be seeking to leverage the settlement of subrogation claims to better position those holdings."

Newsom asked the judge to delay deciding the matter to allow a competitive process to play out between PG&E and a group of the utility's bondholders, whose alternative Chapter 11 reorganization plan Montali admitted Oct. 9. (See *Judge Admits Takeover Plan as PG&E Starts Blackouts*.)

The governor said he wants to continue the closed-door mediation sessions he began with PG&E and its creditors, including wildfire victims, earlier this month. The sessions include a retired bankruptcy judge whom Montali appointed as a mediator at PG&E's request. (See *Pressure Grows for Public Takeover of PG&E*.)

The official Tort Claimants Committee (TCC), which represents fire victims, also objected to the $11 billion all-cash agreement. The settlement would lock up those funds, potentially to the detriment of fire victims, the TCC lawyers said. Insurance companies and financial speculators would be given priority, with no guarantee PG&E would have enough liquidity to pay victims' claims, they said.

"It is time to call this settlement what it is: a mistake," the TCC lawyers wrote. "The debtors have given away all their cash and placed the wildfire victims in a position of full risk in this case."

In its current reorganization plan, PG&E has offered fire victims $8.4 billion in cash, but to increase its offer — as many expect will happen — the utility might have to offer a cash-stock combination, the TCC told the judge.

PG&E's stock fell to a record low of $3.80/share Oct. 28 after it blacked out more than 2 million residents to prevent its from equipment sparking wildfires — yet it also fell under suspicion for sparking the 78,000-acre Kincade Fire in Sonoma County.

Its stock rebounded to $7.06/share at the close of trading Nov. 12 after several reports in the financial press that PG&E would increase its offer to fire victims to $13.5 billion, the same as bondholders proposed in their alternative reorganization term sheet.

Wildfire Liability Still to be Determined

The amount that fire victims may ultimately be owed is still in question.

PG&E and the TCC agreed Nov. 11 to extend the date for wildfire victims to file claims from Oct. 21 to Dec. 31, so that more claims may be submitted. There has yet to be an accounting of the number or amount of individual victims' damage claims.

Proceedings to estimate the amount of PG&E's wildfire damages are taking place before a different federal judge in San Francisco. The estimation process is a typical part of bankruptcies involving large numbers of victims.

And blame for one of the biggest fires of the past two years remains in doubt.

Investigators with the California Department of Forestry and Fire Protection (Cal Fire) determined PG&E equipment sparked the Camp Fire in November 2018. That blaze killed 86 people and destroyed more than 14,000 homes in the town of Paradise.

Cal Fire investigators also found PG&E equipment ignited 21 of the 22 wine country (also called North Bay) fires in October 2017.

They also found a private landowner's faulty wiring started the Tubbs Fire, which leveled an entire neighborhood in the city of Santa Rosa, killing 22 residents. Victims, however, believe jurors should determine who's to blame. A trial to decide if PG&E caused that blaze is slated to start in Jan. 7. The result could add billions of dollars to PG&E's wildfire liabilities. ■

ERCOT News

Texas PUC Briefs

Commission Approves Sharing Names of El Paso Electric Suitors

Texas regulators last week *granted* a request by staff and Texas Industrial Energy Consumers (TIEC) for a list of investors behind the investment fund involved in a $4.3 billion acquisition of El Paso Electric. An administrative law judge had ruled against the intervenors' request during discovery in October (*49849*).

TIEC's attorney Katie Coleman, a partner with Thompson & Knight, noted during the Public Utility Commission's open meeting Thursday that the state's Public Utility Regulatory Act allows the PUC to require a utility or its affiliates to identify owners of more than 1% of the company.

"This seems pretty straightforward," Coleman said. "We have a fund that consists of private equity coming in to buy a Texas utility. We are asking, 'Who is that fund? Who provides this capital?' This is going to be [EPE's] long-term source of capital. We feel it's relevant to get a list of the investors and their ownership shares."

Eversheds Sutherland's Lino Mendiola, representing J.P. Morgan Investment Management's Infrastructure Investments Fund (IIF), said the investors behind the $12.2 billion fund were not trying to hide anything and offered to share a list of the pension funds that make up the top 100 investors. The fund is composed of 517 limited partners and three general partners, he said.

"It's an open-ended infrastructure fund. It invests in buy-and-hold strategies. It's not a hedge fund," Mendiola said. "These are passive investors: limited partners that have no ability to control capital deployment. They don't control the fund; they don't control any company in the fund. Our argument is the identity of the passive investors, who change over time and who have no control over anything, are not relevant."

The commission determined otherwise. "If this were a contract dispute, we might give you the discovery win," Commissioner Arthur D'Andrea told Mendiola.

The PUC will hold a public hearing on the merger Nov. 20 to 22 in Austin. Coleman said TIEC could likely review the list before then and address any issues during the hearing.

The identities of IIF's investors have also drawn the attention of consumer watchdog Public Citizen, which has *protested* the proposed deal at FERC (*EC19-120*). FERC and the Texas PUC are among several regulatory agencies that must approve the acquisition.

EPE and IIF *announced* the deal in June. It is expected to close in the first half of 2020.

Briefings on CenterPoint Rate Case

The commission *requested* briefings from CenterPoint Energy and intervenors following a discussion attempting to iron out a preliminary order approving CenterPoint's Houston electric utility rate case (*49421*).

The commission discussed and adopted several ring-fencing proposals made by staff and TIEC, including requirements limiting CenterPoint's dividend payments to an amount not to exceed its net income and suspending the payments if the utility's credit rating falls below a certain level.

CenterPoint Houston Electric's adherence to the PUC's 60-40 debt-to-equity ratio would require it to make an $800 million payment to its corporate parent, the company said.

The commission asked CenterPoint and the intervenors to file briefings on whether the recommended 60-40 capitalization would "necessitate noncompliance" on CenterPoint's part. It also asked the parties to suggest options to avoid or mitigate the conflict.

An ALJ in September *reduced* the utility's proposed $154.6 million rate increase to $2.6 million, or 0.11% of its present rate base. CenterPoint CEO Scott Prochazka made the decision a central point of the company's third-quarter earnings report. (See *Hot Summer Yields Positive Earnings for CenterPoint*.)

PUC Approves ERCOT 2020-21 Budget

The PUC approved ERCOT's *2020-21 biennial budget* and its 55.05-cents/MWh administrative fee. The budget includes $268.3 million in 2020 and $275.2 million in 2021 for operating expenses, project spending and debt-service obligations (*38533*).

The system administrative fee has remained level since 2016. The fee and the budget were approved by ERCOT's Board of Directors in June. (See "Board Approves Budget, Change Requests," *ERCOT Board of Directors Briefs: June 11, 2019*.)

AEP's Purchase of Oncor South Texas Assets OK'd

The commission approved the sale of Oncor's distribution facilities in the Rio Grande Valley cities of McAllen and Mission to AEP Texas for $18 million. (*49402*). The deal affects approximately 3,000 residential and small commercial customers in the area.

Gexa Energy Docked $35,000

In other business, the commission:

- Agreed to consider a rehearing request by two landowners over its earlier selection of a preferred route for the second of two 345-kV transmission lines needed to integrate about 470 MW of the city of Lubbock's load into ERCOT. (See "Commission Approves 1 of 2 Lubbock Projects," *Texas PUC Briefs: Sept. 26, 2019*.) Applicants Oncor and Lubbock Power & Light said the two routes have "very similar characteristics, and either one would be a reasonable option" in submitting additional testimony. The move allows the commission to further contemplate and consider the scope of the rehearing (*48668*).
- Ordered retailer Gexa Energy to pay $35,000 in administrative fees and issue refunds to 7,610 customers for using misleading energy charges on electric bills (*49930*). Gexa has already refunded more than $10,423 to 37,122 current customers. The penalties raised the commission's assessments in 2019 to $2.96 million, according to the PUC's Oversight and Enforcement Division and the Customer Protection Division. The commission has also ordered more than $89,800 in customer refunds through its enforcement actions this year (*50019*).
- Approved requests by Entergy Texas and EPE to adjust their energy-efficiency cost recovery factors. Entergy can recover $8.01 million in costs (*49493*) and EPE $5.47 million in costs (*49496*) for the 2020 program year.
- Agreed to intervene in three FERC dockets: MISO's proposal to prevent generating resources expecting full or partial outages lasting more than 90 days of the planning year's first 120 calendar days from participating in a fixed resource adequacy plan and the RTO's Planning Resource Auction (PRA) (*ER20-129*); MISO's Tariff changes regarding the market procurement of short-term reserves (*ER20-42*); and Wolverine Power Supply Cooperative's Federal Power Act Section 206 complaint that MISO's PRA fails to establish an appropriate forward price signal (*EL19-102*).

— Tom Kleckner

ISO-NE News

NEPOOL Markets Committee Briefs

ESI and Forecast Energy Requirement

In a two-day meeting last week, the New England Power Pool Markets Committee continued work on ISO-NE's proposed Energy Security Improvements (ESI) proposal, with discussions on LNG supplies, market mitigation and a second demand curve.

The RTO has five months to file a long-term fuel security mechanism under FERC's second extension since its original order last July (*EL18-182*). The new deadline is April 15, 2020.

The RTO's lead analyst for market development, Ben Ewing, started the two-day meeting by *presenting* on the forecast energy requirement (FER) and clearing energy imbalance reserve (EIR) awards to clear the constraint.

The FER constraint ensures that the RTO can meet forecast load throughout the next operating day. It currently is applied after the clearing of the day-ahead market through the reserve adequacy assessment (RAA) process, an "out-of-market" approach, Ewing said.

Under ESI, the FER will be applied in the clearing of the day-ahead market — satisfied by physical generation, net scheduled interchange and EIR awards.

NEPOOL rules prohibit *RTO Insider* from quoting stakeholders' comments during the meeting. However, after the meeting, ISO-NE and other speakers approved the quotes attributed to them to amplify their written presentations.

"Including the FER in the day-ahead will provide a clear market solution to ensuring we're able to meet the forecast load in real time and will better signal the cost of having a reliable operating plan, and provide compensation and incentives for those resources we're relying on for meeting that reliability requirement," Ewing said.

The day-ahead clearing typically results in excess supply to meet the FER and operating reserve requirements, making supplemental commitments in the RAA process rare — with zero in 2019 to date, he said.

The RTO is proposing to begin compensating that excess "online" capacity — the capability, or headroom, of scheduled generators above what they cleared in the day-ahead market.

The FER would create a second demand curve in addition to the existing one for bid-in energy demand of market participants. Similarly, it would result in a second constraint, simultaneously clearing physical energy supply offers and energy options to satisfy the FER.

The day-ahead LMP would remain the incremental cost to satisfy another unit of bid-in energy demand. The FER price is the incremental cost to satisfy another unit of forecast demand.

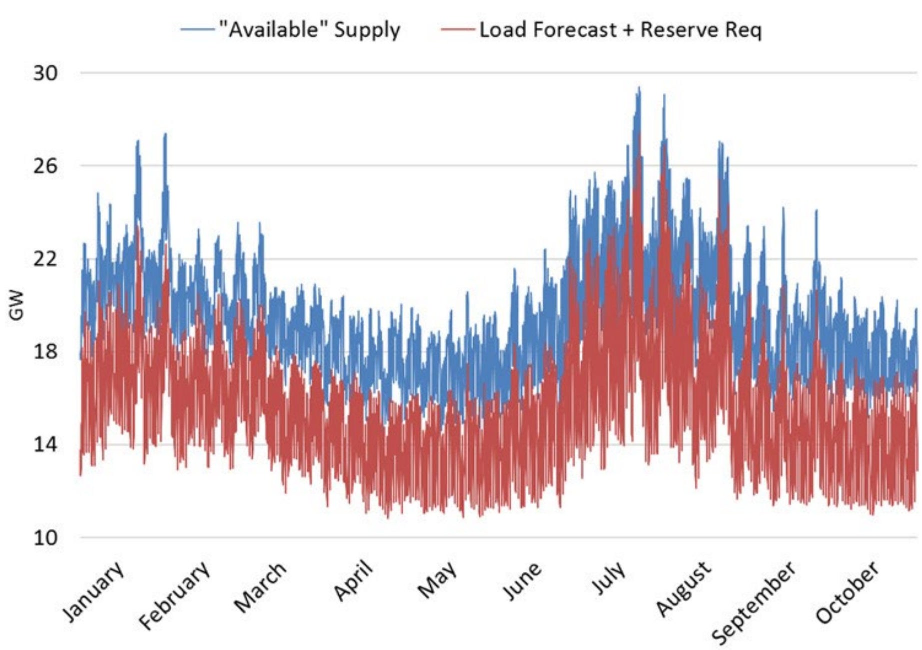
"An online EIR approach is reasonable and practicable, and we will be glad to consider refining it further as technology permits," Ewing said.

"I think this is a big step toward resolving some of our issues," Brett Kruse, vice president of market design at Calpine, told *RTO Insider* after the meeting.

Interchangeability between the different products has been an issue for Calpine all along the design process, he said.

"I'm not sure that some product bifurcation isn't necessary, but I'm finally getting an appreciation of why [ISO-NE planners] are doing things without regard to which option they get paid for, and why they currently think that they should all get one price," Kruse said.

The schedule calls for further discussion by the MC over the next few months and a vote on Tariff language and submitted stakeholder amendments at its March 2020 meeting ahead of a vote in April by the Participants Committee.



Day-ahead total hourly supply vs. demand (2019) | *ISO-NE*

Enhancing ESI Impacts Analysis

ISO-NE economist Chris Geissler and Todd Schatzki of Analysis Group *presented* enhancements to the modeling used in the impact assessment of ESI, with Schatzki taking the lead for a "look under the hood" at the specifics of three key changes to the modeling: evaluation of non-winter months independent of winter months; enhancements to the model's fuel inputs and logic; and adding price-responsive demand (PRD) to EIR.

The RTO is responding to stakeholder concerns and will evaluate non-winter months independent of winter months but will not aggregate the studies into a single annual case, he said.

"Separate analysis of winter months will allow continued focus on the energy security outcomes that are of greatest concern during the winter months and will enhance the information given to the committee as it deliberates the proposed rule changes," Schatzki said.

Modeling of fuel supply accounts for storage and delivery limitations, while modeling EIR ensures that there is enough energy available to meet the forecast energy level in each hour, he said.

The planners are analyzing resource-level fuel inventory based on multiple parameters:

- Initial, beginning of winter, inventory levels;

ISO-NE News

- Trigger levels for replenishment: balancing costs of refilling too frequently (holding costs) and costs of refilling too infrequently (lost revenues);
- The replenishment lag: one day for trucks, four for barges; and
- Replenishment rate: Different replenishment rate for resources relying on trucks and barges. The rate is projected to be 33% higher with ESI.

"Re-evaluation of fuel parameters will allow the model to better represent potential market and reliability impacts associated with ESI," Schatzki said.

The New England States Committee of Electricity (NESCOE) submitted a *memo* expressing its concern that a market power analysis "might not show a problem if it fails to evaluate the conditions that could create vulnerability to exercise of market power (such as a tighter supply/demand balance), or if it fails to model 'real world' conditions."

Schatzki said changes in global LNG prices could affect the LNG supply at the terminal.

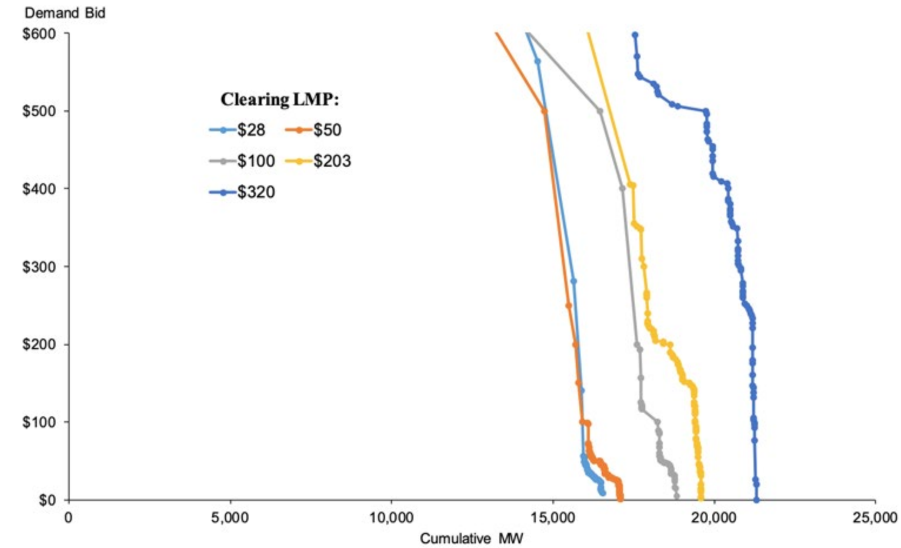
"In principle, if LNG prices went way down or way up, that might affect the LNG storage decision and the eventual in-winter supply, given the resulting risk of forward committing to LNG supplies," Schatzki said. "A lot of that procurement happens in advance of the winter."

Schatzki said his company's analysis was "very conservative."

"We assume every day that the terminal, in this case Repsol, is full every day," Schatzki said. "And whether that's a reasonable assumption or not ... we made the conservative assumption that there is fuel available."

On EIR, Schatzki said that properly accounting for day-ahead energy and EIR interactions requires modeling PRD.

"Without price-responsive demand, the model cannot substitute between energy and EIR, but including price-responsive demand allows the model to endogenously solve for energy and EIR quantities," he said.



A sampling of physical demand offers and virtual demand offers at 5 p.m. showed price responsive demand is relatively inelastic, with small changes in cleared energy quantity associated with large changes in price.. | *Analysis Group*

Market Power Analysis and Mitigation

Concurrent with discussions regarding conceptual mitigation approaches, ISO-NE will conduct a market power assessment (MPA), according to a *memo* submitted by Mark Karl, the RTO's vice president of market development.

The central purpose of an MPA is to determine whether market power is an empirically supported concern. If so, an MPA helps to identify the specific conditions, frequency and extent to which individual participants may be able to profitably exercise market power, the memo said.

ISO-NE Chief Economist Matt White said the memo addresses stakeholder concerns by laying out what the RTO expects External Market Monitor David Patton to address in his market mitigation analysis:

- How mitigation of co-optimized day-ahead energy and ancillary services are implemented in other regional markets where Potomac Economics is also the EMM, and the EMM's perspective on the effectiveness of those mitigation measures;
- Whether and how the mitigation lessons from those regions could be usefully applied to the co-optimized day-ahead energy and ancillary services market proposed by ISO-NE;
- Any expectations regarding potential competitiveness of the proposed day-ahead energy and ancillary services market in New England, given the information presently available and Potomac Economics' experience; and
- Its perspectives on must-offer requirements for resources with capacity supply obligations (CSOs).

"Our understanding is this is a voluntary market, and if there is any change that will be known to stakeholders before moving forward," White said.

Stakeholder Proposal Updates

Jeff Bentz, NESCOE director of analysis, reiterated the states' position.

"We continue to believe that the possible modifications to the strike price formula, a must-offer requirement as part of a market power mitigation approach and no [replacement energy reserves] in the non-winter months, benefit consumers and will do so without adversely impacting the changes ISO-NE is trying to achieve," Bentz said.

"Our main concern continues to be market power and mitigation, and the must-offer requirement is only a component of this, so we look forward to the continued work on mitigation in the following months," he said.

Christina Belew, of the Massachusetts attorney general's office, confirmed that the office has withdrawn its alternative *proposal* prepared by London Economics that recommended a simple auction format of sealed bids with a uniform clearing price.

With respect to proposed amendments to ISO-NE's ESI design, Belew said, "We wanted to let you know that the three amendments we offered in September are still in play, and depending on how ESI develops over the coming months, we may re-urge one or more of them, perhaps offer new ones.

"Like NESCOE, we have requested additional analysis that we haven't received yet, so the results are going to inform our actions," Belew said. "We expect to be back with substantive comments after the first of the year."

ISO-NE News

NESCOE Intent on EER Revisions

Bentz presented NESCOE's *proposal* for Tariff revisions regarding energy efficiency resources (EER) and related capacity obligations during scarcity conditions.

He said that NESCOE is seeking stakeholder feedback and intends to move forward in proposing a Tariff change that would implement Shaping Option A as taken from the Demand Resources Working Group final *report issued in July*.

Shaping Option A would estimate hourly EER performance as a function of established on-peak EER savings and system load levels.

"Under the current implementation, such resources are guaranteed to always incur a penalty during any event that occurs outside of on-peak or seasonal peak hours, which contradicts the language in the FERC order," Bentz said.

FERC ruled in May 2014 that energy efficiency capacity performance payments should be calculated only for capacity scarcity conditions occurring during peak hours (*ER14-1050*).

Providing certainty to EERs is important to New England states, he said.

EERs are not similarly situated to other capacity resources because they do not actively perform in real time — they represent a predetermined level of load reduction that is constant as a percentage of that resource's load — and therefore are not able to respond to the ISO-NE proposal's performance incentive.

NESCOE will work with the RTO to create the appropriate Tariff and manual changes needed to implement Shaping Option A and present those changes at next month's MC meeting ahead of a vote in January 2020. The organization will then seek a Participants Committee vote in February.

IMM Reports Q3 Energy Costs down 27% Y-o-Y

The RTO's Internal Market Monitor issued a quarterly *report* showing summer 2019 energy and capacity market costs down significantly, with energy costs at $967 million, down 27% from a year ago, driven by a decrease in natural gas prices and lower loads.

Wholesale market costs totaled $1.74 billion, a 26% decrease from $2.36 billion in summer 2018, IMM David Naughton said.

COO Vamsi Chadalavada reported earlier in the month that prices in the region's energy markets have been hitting historic lows. (See *NEPOOL Participants Committee Briefs: Nov. 1, 2019*.)

Naughton highlighted that two new rule changes went into effect on June 1: delayed commercial operation rules; and must-offer requirements for do-not-exceed (DNE) dispatchable capacity market resources such as wind. Early market reaction has been consistent with expectations, he said.

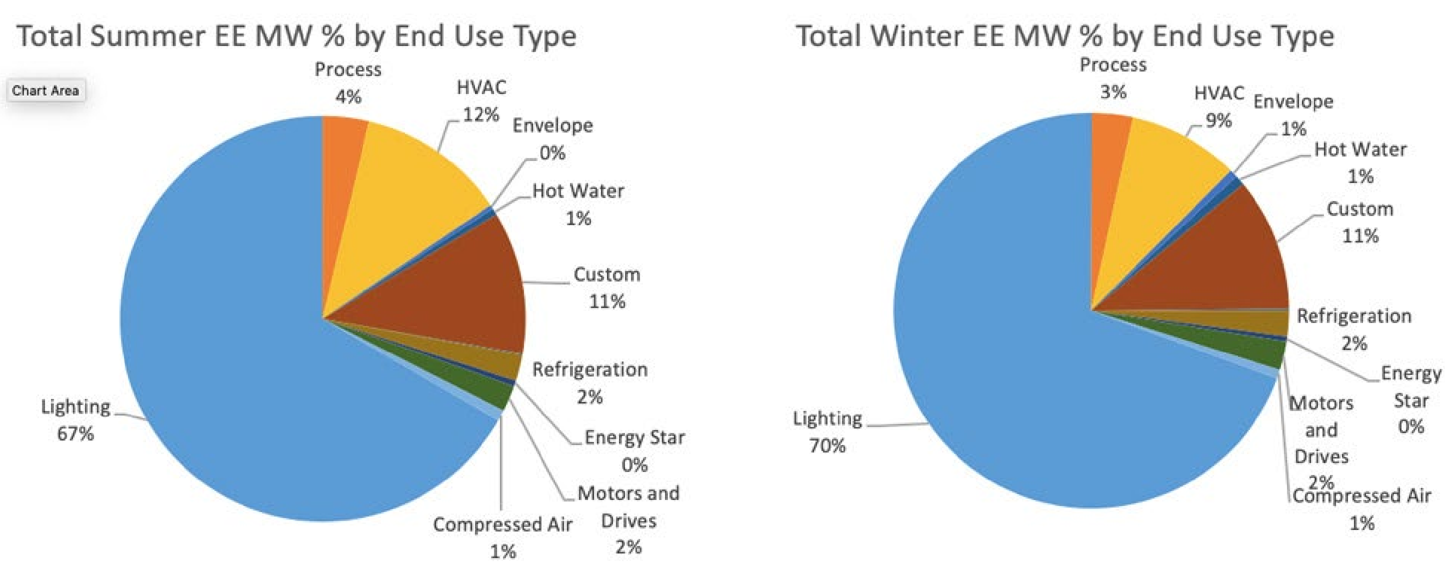
The first change shifted responsibility for covering "undemonstrated" capacity from the RTO to the participant, to address new resources that fail to meet their commercial operation target. Late resources that fail to shed their CSOs in secondary markets face a failure-to-cover charge for the "undemonstrated" capacity.

Over the first three months, 19 resources, predominantly demand response, were charged $500,000 for capacity shortages. Charges declined as resources reacted by offloading CSOs.

In addition, he said three new gas-fired generators with a combined CSO of more than 1,000 MW achieved commercial operation and did not incur failure-to-cover charges: Canal 3 (333 MW), Bridgeport Harbor 5 (484 MW) and the Medway Peaker (195 MW).

Naughton said wind generation offer behavior changed as expected now that DNE dispatchable generators with CSOs must offer all of their expected real-time generation into the day-ahead market. DNE wind generators increased their quantity of energy offered in the day-ahead market and offers reflected the expected level of real-time production, Naughton said.

Cleared volumes increased in the first month but declined to pre-rule change levels as offer prices began to increase, while cleared virtual supply at wind nodes decreased from 25% to 16% of real-time wind production.



ISO-NE has a wide diversity of energy efficiency measures, though lighting is dominant. | *ISO-NE*

ISO-NE News

State Changes to GIS, Rules

The MC by a show of hands unanimously approved sending changes to the NEPOOL Generation Information System to the GIS Operating Rules Working Group.

The Maine Public Utilities Commission and the Massachusetts Department of Energy Resources requested the changes, which relate to the Maine renewable portfolio standard and the Massachusetts Clean Peak Standard (CPS).

The Maine Legislature in September made several changes to the state's RPS that require changes to the GIS.

The CPS was signed into law in August, and the addition of the CPS certificates to the GIS would require, at a minimum, the addition of "CPS Resources" and "Clean Peak Standard" to various provisions of the rules, NEPOOL Counsel Lynn M. Fountain said.

The changes to the GIS and the rules related to the CPS would become effective on July 1, 2020.

Sunset of Fuel Security Reliability Review

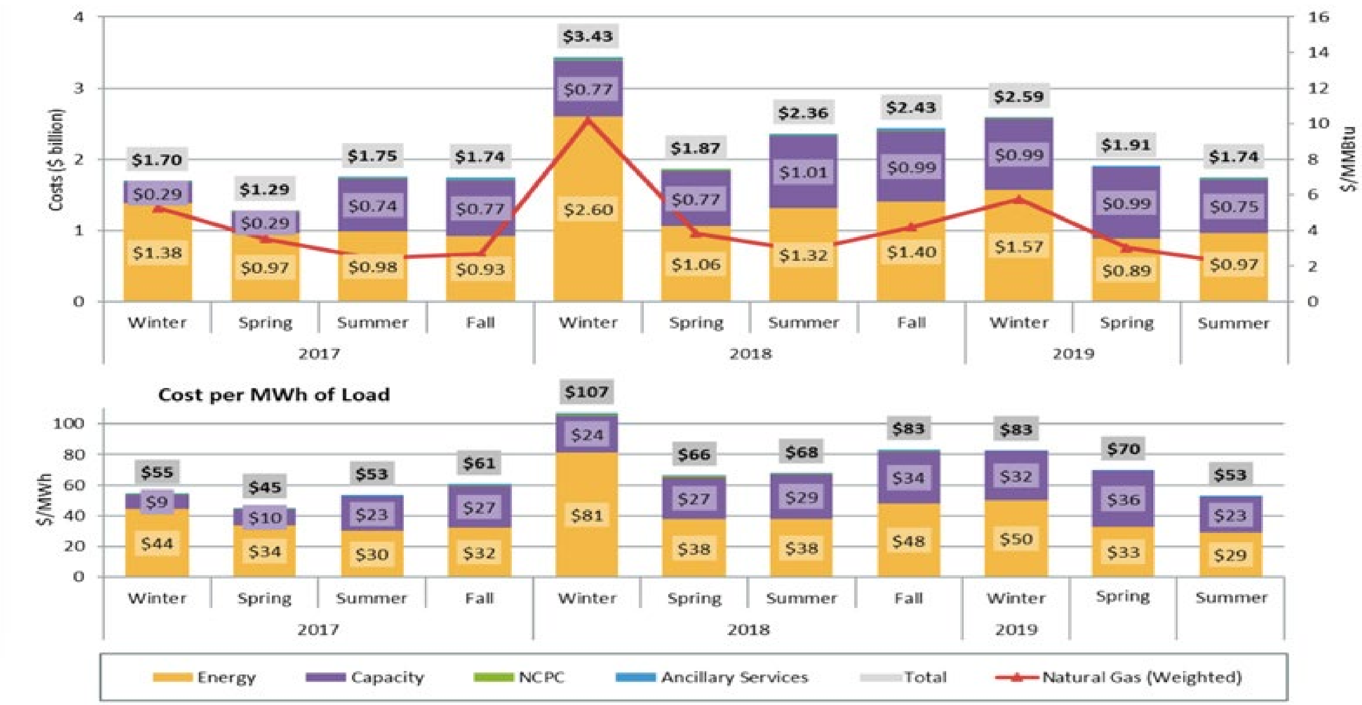
The MC voted to recommend the PC approve the sunset of the fuel security reliability review provisions following Forward Capacity Auction 14, one year earlier than currently planned.

The RTO's assistant general counsel, Chris Hamlen, *presented* the proposed changes to Market Rule 1.

The MC in September approved amending Market Rule 1 to limit the retention of resources needed for fuel security to a two-year maximum.

The RTO wants the change to become effective prior to March 13, 2020, the FCA 15 deadline for retirement delist and permanent delist bids. ■

— Michael Kuser



The IMM reported total costs this summer were less than in 2018, with both energy and capacity prices lower. | *ISO-NE*

MISO News

MISO Makes U-turn on Cost Allocation Policy

Stakeholders Warn Cost-causation Issues Remain

By Amanda Durish Cook

CARMEL, Ind. — MISO on Wednesday dismayed some stakeholders when it doubled back on a cost allocation proposal that would have lowered voltage thresholds and raised cost minimums for economically beneficial transmission projects.

FERC rejected MISO's first cost allocation filing in June, finding it would have violated the principle of cost causation because projects proposed under the local economic transmission category would be required to demonstrate regional benefits while only being cost-shared on a local level.

That plan also sought to lower the regional market efficiency project (MEP) voltage threshold from 345 kV to 230 kV while keeping the current $5 million cost minimum for those projects, a measure that FERC did not address in its rejection.

In September, MISO circulated a proposal that sought to address the local project issue by lowering the voltage thresholds for regional MEPs to 100 kV, while increasing cost minimums to $25 million, a move intended to cover local projects with wider benefits. The plan would have also set a 100-kV threshold for interregional MEPs with PJM or SPP, without a cost minimum. (See *Key Details Change in MISO MEP Cost Allocation Plan*.)

MISO's latest proposal, revealed during a Wednesday conference call of the Regional Expansion Criteria and Benefits Working Group (RECBWG), would restore key points of the original filing, including setting the voltage threshold for regional MEPs to 230 kV and observing a $5 million cost minimum. It would also require that local economic projects between 100 and 230 kV be allocated only locally.

| © RTO Insider

But unlike the rejected plan, the proposal would also stipulate that local projects be reviewed on a local basis only, and not have to show regional benefits. MISO Senior Manager of System Planning Jarred Miland said the RTO now plans to perform only local benefit-to-cost analyses for local economic projects that are based on transmission pricing zones. If the lower-voltage projects show at least a 1.25:1 benefit-to-cost ratio to the transmission pricing zone where the project is located, then the costs of that project would be allocated to that zone.

MISO would first screen projects for possible benefits, then test them in modeling, Miland explained during Wednesday's call.

"Since there's not regional test, there's not regional allocation. The difference is the local economic projects are going to be locally allocated to the local" transmission pricing zone, Miland said.

Blind to Benefits?

But several stakeholders said MISO's new proposal is still at odds with cost causation.

They said MISO is wrongly presuming that all sub-230 kV projects cannot deliver regional benefits. Some asked if the RTO planned allocation exceptions for highly beneficial lower-voltage projects.

"I would say right now, the plan is what the plan is. There's no intention to try to make those projects regional," Miland responded. He said the new proposal is similar to MISO's current practice, where all projects below 345 kV cannot be considered MEPs.

"We're still dropping down from 345 kV to 230 kV. So that still helps," Miland said, adding that MISO would still be positioned to approve more MEPs than it does now.

LS Power Manager of Transmission Policy Pat Hayes argued that because MISO would already screen lower-voltage projects for footprint-wide benefits, it wouldn't take much additional effort to estimate regional benefits.

"You just can't turn the model off and shield yourself from seeing adjusted production costs," he argued.

MISO officials confirmed that they would see possible regional benefits in modeling lower-voltage projects but wouldn't share them externally.

'Head in the Sand'

WEC Energy Group's Chris Plante said the regional economic benefits of projects 230 kV and below exist even if MISO doesn't name them.

"The first proposal failed because we failed to identify beneficiaries of projects. This proposal is akin to putting a bucket of sand in the corner and sticking your head in it. Just because we don't look elsewhere and don't identify beneficiaries, doesn't meant they don't exist. … I think that this thought process is dead-on-arrival at FERC — it's not going to fly," Plante said.

Clean Grid Alliance's Natalie McIntire agreed, saying MISO is choosing to be willfully blind to some project benefits and setting itself up to block some beneficial projects from proceeding.

"There isn't a clear path forward for lower-voltage projects that bring wider benefits to zones," she said.

However, other stakeholders said the new allocation plan was reasonable and that the 230-kV threshold isn't arbitrary. Some pointed out that MISO only discloses regional benefits for projects 345 kV and above.

Plante said MISO might "temper" its proposal by making cost allocation "optional" for the zone that might host a regionally beneficial local economic project. That way, single zones wouldn't be forced to foot the bill on projects positioned to benefit other transmission pricing zones, he said.

Miland said stakeholder opinions on the September proposal can be broken down into "those that didn't like what we did and those that did like it." MISO said a majority of its state regulators wanted it to follow FERC's June rejection and refile the proposal, this time scrapping the local economic project category altogether, leaving projects below 230 kV again relegated to the RTO's "economic other" project category, which also dictates that smaller economically beneficial projects are allocated to the transmission pricing zone where they are located.

Still other stakeholders said they didn't support MISO's proposed $25 million threshold or the competitive bidding exception for reliability projects that it determines have an immediate need. As in the first filing, the new plan would exempt from competitive bidding any MEPs needed within three years to mitigate reliability issues. The new proposal preserves that option.

MISO maintains that its proposal will better "align who pays with who benefits over time from a regional transmission expansion perspective."

Stakeholders on the call asked if MISO has met with FERC staff to vet its newest proposal. Staff said they had not.

"We've been trying to weigh the feedback we received with what we think is the best path forward," Miland said. "This hasn't been taken lightly by any means internally here in MISO. This has been a full-time job for several of us for a handful of months."

The change in tack on lower-voltage projects pushes out MISO's refiling target.

"We were hoping to get a filing out the door before Thanksgiving. That's probably not going to happen now," Miland said. ■

Louisiana's Campbell Expands Beef with SPP

Continued from page 1

are paid eight and 16 times, respectively, as much as FERC Chairman Neil Chatterjee ($155,500). Campbell cited 2017 data for Brown ($1.5 million in total compensation) and said Bear receives $2.8 million in compensation.

Bear's salary matches up with the 2017 IRS Form 990 available through nonprofit tracker GuideStar. Brown's 2016 Form 990 shows his total compensation was $1.2 million.

Campbell contrasted the CEOs' salaries with Louisiana's "1.6 million electric customers, many of whom live at or below poverty level." He said SPP and MISO charge the state's investor-owned utilities nearly $31 million a year to dispatch energy.

The letter would sound familiar to those who were present last month in Little Rock, Ark., when Campbell livened up the SPP Regional State Committee's October meeting at the RTO's corporate headquarters by criticizing the facility's $62 million price tag and senior executives' salaries. Several observers found his comments to be political, as Campbell is up for election next year. (See "Louisiana's Campbell: SPP Spending 'Extravagant,'" *SPP Regional State Committee Briefs: Oct. 28, 2019*.)

SPP said it "respectfully but wholeheartedly disagrees" with Campbell's allegations.

Spokesman Dustin Smith said the grid operator provides "significant" savings to ratepayers in its footprint and listed several examples to back up his point:

- The *$570 million in savings* to participants in the Integrated Marketplace.
- "Conservative" cost-benefit studies that indicate the RTO's services produce *$2.2 billion in annual savings* across its 14-state region.
- FERC's 2018 State of the Markets *report* indicating the SPP region enjoys the nation's lowest wholesale electric costs.

"To anyone who questions SPP's affordability, stewardship or ethics, we welcome the opportunity to provide answers," Smith said.

MISO spokesperson Allison Bermudez would only say that the RTO, "as we have for the past 20 years, continue to be good stewards of our members and those customers we work together to serve."

Louisiana utilities Entergy Louisiana and Southwestern Electric Power Co. both said RTO membership is worth the costs.

Entergy spokesman Mike Burns said the company's MISO membership has been a "highly effective tool in helping control costs and keeping our rates among the lowest in the nation." After netting out the RTO's administrative costs, Louisiana customers realized an estimated $560 million in savings between 2014 and 2018, "largely because of MISO's organized power markets, which allow power plants to be dispatched more efficiently, resulting in a lower delivered cost of energy," he said.

"Customers also see significant cost savings from MISO members sharing generation reserves across the organization's footprint, producing long-term benefits," Burns said.

SWEPCO's Peter Main said the utility's customers benefit from SPP's regional markets through reduced fuel costs and more efficient transmission planning. However, he also said SWEPCO is concerned about the RTO's rising costs. SPP's Board of Directors last month approved a record increase in the administrative fee, from 39.4 cents/MWh to 43 cents. (See "Directors Approve 9.1% Administrative Fee Increase for 2020," *SPP Board of Directors/MC Briefs: Oct. 29, 2019*.)

"SWEPCO and other SPP members remain concerned about the growing costs of RTO operations," Main said. "We are actively involved in efforts to ensure that the RTO is cost-effective, efficient and providing good value for our customers."

SPP is equally concerned about costs. First-year board Chair Larry Altenbaumer created and led a task force focused on finding opportunities to increase value and improve affordability for SPP's members and stakeholders. The group determined there is work to be done around the edges. (See *SPP Value Group Finds No 'Silver Bullets'*.)

RTO Insider asked regulatory commissioners in both regions for comment on Campbell's letter. Arkansas' Kimberly O'Guinn and Missouri's Scott Rupp responded.

O'Guinn, who is the RSC's president this year, said she didn't agree with Campbell's assessment, but she "appreciated" his concerns about the costs of participating in SPP.

"The RSC is conscious of SPP's costs as well as other issues that impact utilities and ultimately the customers," she said. "Therefore, the majority of the RSC regularly participates in monthly calls and quarterly business meetings to educate ourselves on these matters and engage in dialogue with the SPP Board of Directors and staff, members and stakeholders."

O'Guinn said the Arkansas Public Service Commission finds that SPP's services and the Integrated Marketplace have "resulted in net benefits to ratepayers" and justified the commission's decision to allow certain utilities to transfer functional control of their transmission assets.

"Along with financial benefits," she said, "participation in SPP has provided increased reliability and a decrease in required reserve margins."

Rupp said the Missouri Public Service Commission believes "there is a large amount of benefit from RTO membership." He cited back-of-the-envelope figures from SPP's last regional cost allocation report that indicated Evergy's Missouri subsidiaries Kansas City Power & Light and KCP&L Greater Missouri Operations enjoyed 3.97 and 2.15 benefit-to-cost ratios, respectively.

He also said the PSC requires the state's utilities to file studies every three years that justify their RTO membership.

"In the past few years we have waived the study, believing firmly that benefits are realized and the cost of the study would not be a good expenditure of resources," Rupp said.

He also noted that that there have been few instances of load shed despite recent severe storms and floods in Missouri. "Before RTO membership, there would have been a shedding of load in Missouri." ■

Amanda Durish Cook contributed to this article.

SPP's corporate campus | *Nabholz Construction*

MISO News

MISO to Address Affected-system FERC Order

By Amanda Durish Cook

CARMEL, Ind. — MISO is revising how it handles generator interconnections along its seams with neighboring balancing areas in a bid to satisfy several recent FERC mandates.

FERC issued the directives to MISO, PJM and SPP in September after finding that their joint operating agreements lack transparency around how they manage their affected-system impact studies. The commission ordered that study procedures must contain:

- easily referenced business practice manuals;
- descriptions of modeling standards;
- clearer modeling details for interconnection customers;
- a description of how MISO and SPP study the impacts on each other; and
- descriptions of how the three RTOs monitor each other's systems during the course of each of their interconnection studies.

Compliance filings are due from the RTOs by Feb. 3.

FERC's directives were the product of 18 months of examination after EDF Renewable Energy complained about the RTOs' affected-system coordination. (See *Affected-system Rules Unclear, FERC Says*.)

At a Nov. 12 meeting of the Interconnection Process Working Group (IPWG), MISO resource interconnection engineer Sumit Mundade said the RTO's interconnection staff have worked up "preliminary language" in JOAs with both PJM and SPP to comply with all six directives. MISO has set aside time through January to continue revising its JOAs, he said.

Mundade said MISO and SPP won't be able comply with FERC's requirement that they set specific dates to exchange affected-system information and study results; they will instead propose they use "formula dates" based on the start of the studies and include deadlines for data exchanges.

"With MISO and now SPP's adoption of a three-phase group study process, fixed calendar dates are not optimal because kick-off dates are not fixed in advance," Mundade explained.

MISO will also add JOA language to clarify that its study criteria only apply to facilities in its own footprint.

"FERC wanted to know whose criteria applies to which facilities," Mundade said. "SPP study criteria apply to SPP facilities, and MISO criteria apply to MISO facilities."

MISO is also proposing to apply its external resource interconnection service study criteria when it studies SPP and PJM interconnection projects, rather than using its network resource interconnection service criteria.

"FERC only asked us to describe this, not change anything," Mundade said.

MISO still faces the task of explaining how it monitors neighboring transmission systems for impacts during interconnection studies. Mundade said that while monitoring will include "an identification of MISO projects with potential impacts to the SPP or PJM transmission system based on each RTO's criteria," those JOA revisions are still in the works.

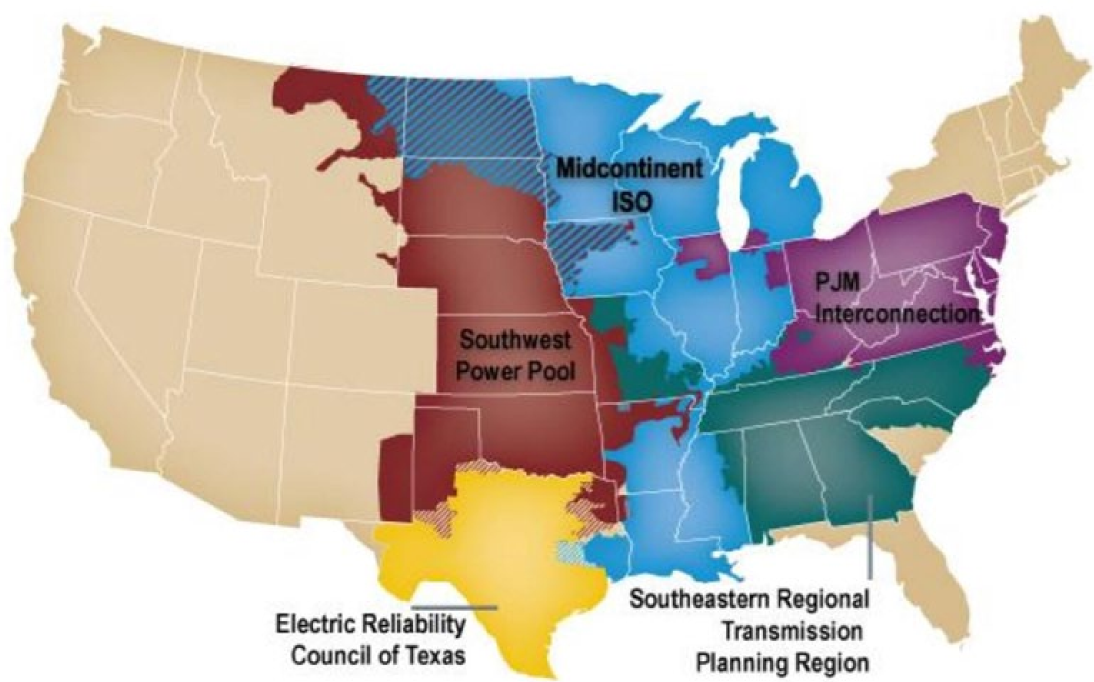
The RTO has also not yet decided how it will detail the process used to determine projects' queue priority in an affected-system analysis and how it will allocate the costs of network upgrades required on an affected system.

"The proposed language is under development," Mundade said, promising to return to the IPWG in January with more specifics.

In addition to the two compliance filings, MISO plans to make two separate filings to change some aspects of the JOAs with SPP and PJM.

Pending approval from its neighbors, MISO will add separate JOA language requiring it and SPP to share cost estimates and construction schedules of network upgrades and to synchronize information-sharing with PJM so studies line up more closely with PJM's interconnection timeline.

The additional filings will also make clearer that interconnection customers bear the costs of the affected-system studies. Mundade said the separate JOA filings contain affected-system changes not required by FERC but represent improvements nonetheless. ■



MISO seams | *MISO*

MISO News

Water Scarcity No Threat to Footprint, MISO Finds

By Amanda Durish Cook

CARMEL, Ind. — MISO's grid will be only minimally susceptible to the impacts of possible water scarcity in the future, in part because of increased adoption of renewables, new RTO models show.

The RTO will only have a "relatively modest" need for incremental new generation to meet demand under water scarcity, Senior Adviser Eli Massey *told* stakeholders at a Planning Advisory Committee meeting Wednesday.

"The results of this first round of modeling suggest that MISO isn't susceptible to either a short-term or long-term water scarcity scenario," Massey said.

The modeling relied on data from Sandia National Laboratory to estimate the "water intensity factor" for MISO generation, which represents the relationship between the amount of cooling water and fuel needed to produce 1 MWh of energy. That data point was cross-referenced with estimates for the volume of water available for generation under short- and long-term scarcity conditions.

Most water scarcity concerns can be mitigated by economically redispatching MISO's resource portfolio "around low to moderate water scarcity." He also said the continued evolution of the resource portfolio toward renewables "is moving MISO in a direction that makes it less susceptible to water scarcity in the future."

"Wind doesn't need water," he said.

MISO doesn't collect cooling water use statistics from its members, and Sandia could only provide usage stats for about half the generation in its footprint, Massey said. He said MISO consulted with Sandia and the National Renewable Energy Laboratory on their methodology to fill in missing estimates.

MISO modeled both a six-year drought and recovery, and a 15-year water scarcity scenario in which water available for generation is limited by varying degrees. Scientists have repeatedly predicted that climate change, bringing long dry spells and more severe flooding, will *intensify* water shortages in some geographic areas. RTO staff did not mention climate change during the presentation.

Massey said energy served by MISO's thermal resources is disrupted only in the most extreme water shortage scenarios.

"MISO is always looking at environmental issues or operational risks to reliability," Massey explained to stakeholders. "We always felt like we thought we were OK, but we never quantified it."

The effort is MISO's first attempt to understand the potential impacts of water scarcity,

The Fermi 2 Power Plant on Lake Erie | *DTE Energy*

Massey said, adding that the RTO will perform more analyses, possibly on a seasonal or subregional level, to understand the impacts of water constraints in the footprint.

"This isn't the only avenue we're exploring. MISO is partnering with NREL and other labs to understand water risk," Massey said.

He also said MISO may explore requesting more accurate water use statistics from its thermal generation operators. He asked stakeholders to communicate their interest in having the RTO analyze more detailed data. ■

MISO News

MISO Renewable Study Shows More Tx, Tech Needed

By Amanda Durish Cook

CARMEL, Ind. — MISO's system can operate on 50% renewable generation if the RTO greenlights dramatically more transmission and ups reserve requirements, and if its members embrace new technologies, new study results show.

MISO laid out the possible realities of a 50% scenario at a special Nov. 14-15 *workshop* to discuss the third round of results of the RTO's ongoing Renewable Integration Impact *Assessment*.

Jordan Bakke, MISO | *© RTO Insider*

To reach 50% renewables, MISO could retire 17 GW of its existing thermal fleet and add about 100 GW of renewable capacity. Results show even at a 50% renewable penetration, "the majority of the thermal fleet remains available to maintain adequacy," Policy Studies Manager Jordan Bakke said.

According to the study, renewables would reach 50% of the generation mix as utility-scale solar proliferates in MISO South while wind generation multiplies in the northwestern portion of the footprint. MISO also foresees distributed solar generation becoming more commonplace and concentrated near major cities.

The RTO also said the complementary characteristics of wind and solar generation — on a daily and seasonal basis, solar is generally available when wind isn't as plentiful — "decreases the probability of not serving load during periods of high risk."

MISO's current generation interconnection *queue* contains 569 projects with 89 GW of estimated capacity, including 51 GW worth of solar and 22 GW of wind. According to a recent *report*, MISO expects about 3.5 GW of new wind generation to interconnect this year and more than 6 GW to come online through-out 2020.

MISO reported that it executed 43 generation interconnection agreements in 2019, breaking the previous record of 38 set in 2003. However, the RTO also reported 157 project withdrawals so far this year, just short of the record 168 withdrawals set in 2017.

President of Market Development Strategy Richard Doying said MISO now is nearing 20 GW of wind generation, which can have zero marginal cost.

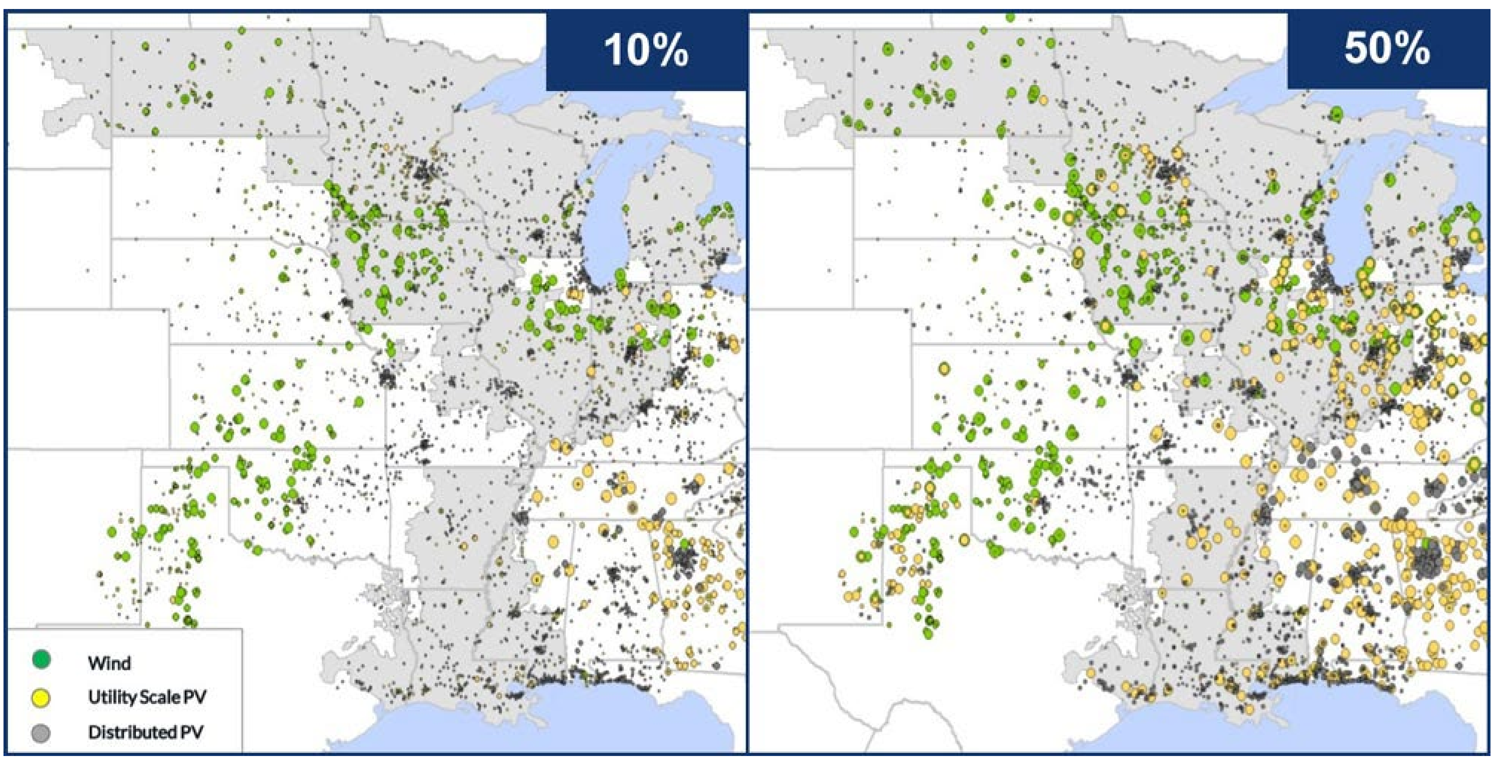
"That is the right economic price, but it's terrible for baseload generation," Doying said at an Organization of MISO States meeting in October.

Pad Reserves?

The latest results also line up with earlier studies that conclude MISO's daily loss-of-load risk compresses into a sharper risk during a smaller set of hours later in the day under a high-renewables scenario. (See *MISO Renewable Study Predicts Later Peak, Narrower LOLE Risk*.)

At 40% renewables, MISO may need to increase its reserve requirement to manage quick changes in load, the study found.

MISO research and development adviser Long Zhao said the RTO will need ramping capability to manage discrepancies between early evening reductions in solar generation and increases in wind generation and load. Going forward, sunset would probably be a particularly challenging time of day for MISO to manage, Zhao said.



MISO at 10% and 50% renewables | *MISO*

MISO News

When renewable generation climbs from a 40 to 50% share of the generation mix, it begins to nudge out nuclear and natural gas resources footprint-wide in economic dispatch. MISO envisions its footprint will contain a wind-dominated northern region, a southern region where solar and natural-gas fired generation begin jockeying for position, and a central region that draws on both types of renewables. It also found a significant increase in imports as renewables climb to 50% — more than 10 GW in some cases during summer days. Today, MISO does not exceed 5 GW in imports, even on summer days.

Veriquest Group's David Harlan said he had a problem with MISO assuming that solar generation could replace the baseload generation of MISO South. He argued that solar's production capability is simply not predictable enough for heavily industrial areas of the South.

"In MISO South, we have a heavy industrial load planned to be served by coal and nuclear and later by combined cycle," Harlan said.

Clean Grid Alliance's Natalie McIntire asked if the shorter and more pronounced loss-of-load risk is good or bad from MISO's standpoint.

MISO adviser Brandon Heath said the sharper risk is simply a future reality. "It's neutral. It's not a good thing or a bad thing just yet," he said.

Miles and Miles of Lines

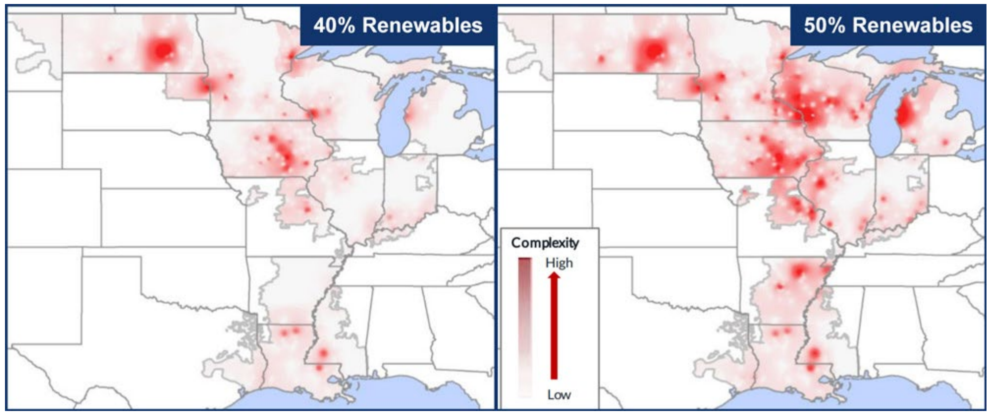
It's not until renewables take a 40% share of the generation mix that MISO foresees a need for transmission projects to "significantly reduce curtailment." Without transmission solutions, renewable additions beyond a 40% penetration cannot continue displacing thermal generation because there isn't enough transmission capacity, the RTO found.

"We see needs at the very beginning, but the needs are very small. We see energy adequacy needs when we get to 40%," Bakke said.

MISO Policy Studies Engineer Yifan Li said while some areas might exhibit needs for local transmission solutions, there's no need for anything major beyond the normal annual planning cycles until 40% renewable penetration.

"From the bulk amount of energy flow paths to deliver energy and reduce curtailment, an overall systemwide [extra-high-voltage] rebuild is not needed until the 40% milestone," he said.

But McIntire pushed back on the idea that a 40% renewables mix is the inflection point



MISO transmission additions at 40 to 50% renewbles | *MISO*

for new transmission needs. She argued that MISO will require steady transmission build-out as renewable generation rises.

"I just don't want us to minimize that message. We're going to need significant transmission before 40%," McIntire said.

Li agreed that annual transmission buildouts would continue to be needed, but at the 40% penetration level, MISO's usual annual plans would fail to keep pace with transmission capacity needs.

"I like to compare it to a fever. ... Our system is having a high fever around 40% renewables without significant amount of additional transmission," he said.

At a 40% penetration, Li said, about 80 new transmission projects located all over the footprint might provide the necessary energy delivery. The bundle of projects includes 2,400 miles of 345-kV and lower-voltage lines, 320 miles of 500-kV lines, 270 miles of 765-kV lines and 410 miles of HVDC lines.

At 50% penetration, an additional 70 projects across the footprint could help, including 590 miles of 345-kV and lower-voltage lines, 820 miles of 500-kV, 2,040 miles of 765-kV and 640 miles of HVDC. Li said the transmission additions would be particularly helpful in reducing wind curtailment in the northern part of the footprint, where wind capacity will be ubiquitous.

"We evaluated more than 11,000 [transmission project] candidates," Li said. MISO staff have repeatedly said the results will not be used directly in transmission planning. They also clarified the study was not conducted with the goal of carbon reduction, saying it only demonstrates the challenges the system might encounter as solar and wind generation flourish.

"That's a lot of transmission," McIntire quipped to laughter. She urged MISO to examine the benefits of co-located storage and other ways to maximize existing transmission capability before it starts studying new transmission plans.

Other stakeholders agreed that MISO was suggesting a need for a staggering amount of transmission. Some said the jump in transmission needs from a 30% to 40% share of renewables seemed too high to be believable.

No Agenda

"We do see these drastic needs at certain intervals. It's a non-linear trend as we deploy renewables," Bakke said. "That discontinuity at very high renewable levels requires more transfer capacity."

Bakke said MISO will begin relying more on regional energy transfers, which in turn will become more unpredictable, leading to a need for increased EHV thermal line capabilities.

"Existing infrastructure becomes inadequate for fully accessing the diverse resources across the MISO footprint," Bakke said.

Not only will the footprint eventually need new physical lines, but it will require more technology on transmission lines, including synchronous condensers, more transformers and HVDC capabilities, staff said.

"As we see more renewable integration, we see additional types of technology needed to help support the system," Bakke said. "It's a portfolio of solutions that best enable renewable deployment in the system."

Bakke said MISO is making no proposals for new technology or lines as a result of the study. "We're trying to point out where we see these issues ... to see if our processes should change

Continued on page 22

MISO News

MTEP 19 Advances to MISO Board Committee

By Amanda Durish Cook

MISO's 2019 Transmission Expansion Plan (MTEP 19) will advance to the Board of Directors without any recommended changes tacked on by the RTO's Planning Advisory Committee.

The plan cleared the committee's October email vote with six sectors in favor, none opposed and three abstentions. The PAC's vote is only considered advisory.

The $3.97 billion, 479-project plan now moves to the board's System Planning Committee for a comprehensive *review* Friday. The full board will vote whether to approve it at its Dec. 10 meeting as part of MISO Board Week in Indianapolis.

The PAC proposed no changes to the expansion plan, with a pair of motions to convert the Helena-to-Hampton Corners project into a market efficiency project and to delay MISO's first storage-as-transmission project for more analysis both failing in the same email vote. (See *Changes Proposed for MTEP 19 as PAC Vote Nears*.)

MTEP 20 Gains Unique Study

At the same meeting, MISO proposed to conduct a special North Region operational limitation impact study for MTEP 20 in addition to the usual slate of planning studies.

Project Manager Sandy Boegeman said the study, added at stakeholders' behest, will analyze the Minnesota-Wisconsin transfer limitation, known as MWEX.

"Due to the voltage stability nature of this constraint and its location between high renewable penetration areas and customers in the eastern areas of MISO, it presents a valuable opportunity to better understand the implication of a non-thermal constraint within the MISO footprint," the RTO said.

"This study got a fair amount of support from stakeholders. And we think we have the bandwidth to do this," MISO Director of Planning Jeff Webb said. The RTO will discuss the scope and objectives of the study at the PAC early next year, he said.

MISO promised unique, targeted studies to identify possible transmission projects in lieu of a fresh set of planning futures for MTEP 2020. (See "Special MTEP 20 Studies," *Changes Proposed for MTEP 19 as PAC Vote Nears*.)

The MISO Board of Directors in March | © *RTO Insider*

Even with MTEP 19 not yet finalized, MISO is already *expediting* a substation expansion for MTEP 20. Michigan Electric Transmission Co. is planning to expand its Riverview substation to accommodate new load requested by Consumers Energy near the city of Kalamazoo, Mich. The RTO said the 18-month project deserved fast-track status to avoid overloads. It will add the substation expansion to the Appendix A list of projects in MTEP 20. ■

MISO Renewable Study Shows More Tx, Tech Needed

Continued from page 21

and what we need on the system long-term," he said.

MISO found that a diversity of technologies and geography improves the ability of renewables to serve load. Bakke said storage facilities, the load-taming abilities of electrification and other demand-side management can enable more renewable penetration. He also noted that thermal generation can begin scheduling outages during times where renewable output is predicted to be abundant.

The RTO also said the number and severity of thermal overloads starts to increase at a 20% renewable penetration and becomes widespread especially in the western portion of the footprint at a 50% penetration. It said it will need more thermal mitigations on higher-voltage lines. Likewise, it will encounter dynamic stability issues beyond a 20% penetration.

To counter small-signal instability, MISO said it may need must-run units equipped with power system stabilizers or specially tuned batteries to support grid reliability beyond a 30% penetration.

But MISO now says frequency response performance remains stable up to 60% renewable penetration. The newest result is even more optimistic than its July announcement that its grid can withstand major reliability risks even when renewables reach 40% of the generation mix. (See *MISO: Grid Can be Stable at 40% Renewables*.)

"We see needs on the thermal side greater than needs on the voltage side," Bakke said.

WPPI Energy's Steve Leovy said MISO may need to more thoroughly examine steady-state issues starting with the generation interconnection queue. He recommended the RTO screen for such issues there.

Where's the Storage?

McIntire pointed out that much of future solar development is predicted to be solar paired with storage, which could change what system needs MISO identifies.

Examining how storage can help a future fleet mix will be included in the upcoming phase of MISO's renewable impact study. Stakeholders have repeatedly asked the RTO to study heavy wind and solar generation balanced by storage facilities. Some stakeholders predicted that if storage is optimizing wind and solar generation, MISO won't forecast nearly as many energy delivery issues.

McIntire urged that the next phase of the study examine other less traditional solutions.

"Largely you've been looking to transmission and the existing thermal generation," she said.

Bakke asked stakeholders to send his team examples of nontraditional solutions for evaluation. ■

National Grid Vows to Expand NY Gas Service

By Michael Kuser

National Grid's U.S. division saw half-year profits rise 16% on new rate agreements and cost-cutting measures, but the company is now facing political pressure from New York Gov. Andrew Cuomo over its decision to deny natural gas service to residents of New York City and Long Island under a moratorium on new hook-ups.

"I'm confident that we'll be able to address the issues raised by the governor in his recent letter within the expected time scales," CEO John Pettigrew told analysts last week on a call covering the first half of the U.K.-based company's accounting year ending Sept. 30.

Cuomo on Nov. 12 gave the company 14 days to connect all customers or he would seek "to revoke National Grid's certificate to operate its downstate gas franchise."

New York Public Service Commission Chair John Rhodes on Oct. 11 signed an order directing National Grid subsidiaries Brooklyn Union Gas (KEDNY) and KeySpan Gas East (KEDLI) to connect 1,100 of 3,300 customers that had been denied natural gas service connections (Case *19-G-0678*).

"A decade ago, National Grid identified the need for incremental gas supplies to serve low growth in the downstate region," Pettigrew said.

National Grid relied on a pipeline being developed by Williams Co. called the Northeast Supply Enhancement project, otherwise known as the NESE pipeline, which includes an underwater line across New York Bay to service the city and Long Island.

"In May this year, following further delays to permits for this project, and therefore the potential lack of incremental supply to serve that load, we took the difficult decision to stop processing applications for new or expanded gas services in our service territory," Pettigrew said.

Badar Khan, recently appointed interim president of the U.S. business, was managing the situation in New York and was unable to join the earnings call, Pettigrew said.

National Grid CEO John Pettigrew | *National Grid*

Following the PSC order last month, the company has sought to expand demand response and energy efficiency programs, and to arrange for compressed natural gas to be delivered by barge and truck to service those mandated customer hook-ups, he said.

"So in terms of the downstate New York, as I've said earlier, the projections are that we're going to see demand increasing over the next decade," Pettigrew said. "So the work that we're doing is really to understand what are the options that are non-pipeline options and potentially how far can that stretch out. The costs are recoverable through our rate filings in terms of provision of service to customers."

The CEO highlighted the company's $300 million Metropolitan Reliability Infrastructure project for the Brooklyn gas system, expected to be complete in December 2020.

"On the electricity side, we've invested $110 million in the Gardenville substation rebuild in upstate New York," Pettigrew said. "This substation is critical to the local region, providing residents and businesses with affordable sources of renewable power and is vital to system reliability."

National Grid reported it successfully completed a rate filing for Massachusetts Electric with new rates going into effect Oct. 1.

The company said that in the second half of the fiscal year, it will continue work on moving its KEDNY/KEDLI rate filing at the PSC, as well as grid modernization, electric vehicle and advanced meter infrastructure plans across its jurisdictions.

"With the KEDNY and KEDLI rate case, we provided data to support a four-year settlement with a proposed base return on equity of 9.65%," the company said.

National Grid also announced a goal to become net zero for its own carbon dioxide emissions by 2050.

"We set ourselves a target in 2008 to reduce them by 80% by 2050," Pettigrew said. "Actually, when we got to the end of the last fiscal year, we'd achieved 68% reduction against 1990, so we thought it was really right to demonstrate a more ambitious target ... [and] we also know that we've got a role to play in enabling net zero more broadly in the economy."

Quotes courtesy of *SeekingAlpha*. ■

NYISO News

NYPSC OKs Rebuilding Upstate Tx Lines

By Michael Kuser

The New York Public Service Commission on Thursday granted the New York Power Authority a certificate of environmental compatibility and public need to rebuild about 86 miles of upstate transmission lines (Case 18-T-0207).

The Moses-Adirondack 1 and 2 lines extend from the St. Lawrence Power Project's Moses-Saunders Power Dam switchyard in Massena to the Adirondack substation in Croghan. Thursday's order also grants NYPA the right to build several upgrades to both the switchyard and the substation.

"I see this as a smart, careful, timely project that's valuable for the statewide system needs and the statewide renewable energy needs," PSC Chair John B. Rhodes said. "It's well designed, has good minimization of impact with the very good use of existing right of way, attention to land use, attention to habitats and as a result is, on balance, very much in the public interest."

NYPA proposed to divide the project into two phases, the first consisting of replacing 78 miles of the two lines currently configured as single circuits on separate wooden H-frame structures with two new single-circuit lines on steel monopoles.

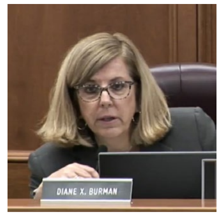
The initial operating voltage would be 230 kV, with the second phase involving replacing the remaining length of the transmission lines with two single circuits on steel monopoles and upgrading the Moses-Saunders switchyard and the Adirondack substation to operate at 345 kV.

NYPA proposed to construct the project entirely within an existing right of way, except for a 1-mile reroute at the State University of New York at Canton campus.

CES Budget for 2020

The commission also approved a 2020 operating budget of nearly $13 million for the New York State Energy Research and Development Authority to run the state's Clean Energy Standard and related programs (Case 15-E-0302).

The order authorizes NYSERDA to reallocate up to $12,138,093 of uncommitted system benefits charge, energy efficiency portfolio standard and renewable portfolio standard funds and $824,791 of previously authorized — but unspent — 2018 CES compliance period funding to cover administrative costs for next year's RPS and zero-emission credit programs.



Commissioner Diane Burman

Commissioner Diane Burman dissented on the CES budget, saying, "I appreciate the work that NYSERDA does, but this budget request seems very bulky to me."

The commission performs good due diligence by "not just accepting from utilities a bulky budget, and we work with them in streamlining that as much as we can and really trying to figure out what is absolutely appropriate and necessary," Burman said.

Consent Agenda

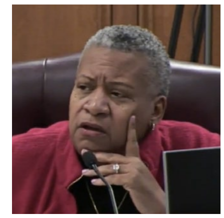
The PSC approved nearly $5.2 million in sales of street lighting by National Grid to three municipalities in order for the towns to install and profit from more energy-efficient lighting. The sales were for Utica ($4.1 million), Dunkirk ($1 million) and Medina ($70,000).

Burman abstained from several items on the consent agenda, including those related to National Grid's natural gas subsidiaries in Brooklyn and Long Island, and to Consolidated Edison's gas business, because "we are not addressing some of the core issues around gas, and therefore, looking at these in isolation is very troubling to me."

The National Grid items were for tariff filings to modify the companies' gas tariff schedule to establish non-firm demand response service classes. The Con Ed items regarded revisions to its daily delivery service to institute a voluntary physical storage program, and to interruptible gas service program violations or strike rules.

Rhodes on Oct. 11 signed an order forcing National Grid subsidiaries Brooklyn Union Gas (KEDNY) and KeySpan Gas East (KEDLI) to connect 1,100 of 3,300 customers that had been denied natural gas service connections (Case 19-G-0678). KEDNY has approximately 1.2 million customers, and KEDLI has 590,000 customers.

National Grid found itself at odds with Gov. Andrew Cuomo last week when he issued a letter demanding that its gas subsidiaries connect all customers to whom it had denied service under a moratorium on new hook-ups or he would seek "to revoke National Grid's certificate to operate its downstate gas franchise." (See related story, *National Grid Vows to Expand NY Gas Service*.)


Commissioner Tracey Edwards

Commissioner Tracey Edwards said she wanted "to make sure that the definition of critical care customers is inclusive, so that it speaks to areas of refuge; it speaks to hospitals and nursing homes. I want to make sure that it includes assisted living facilities and homeless shelters, so I would like some follow-up information to make sure we're looking at critical care in an overall perspective and not leaving anyone out."

Burman also concurred with comment on items related to municipal tariff filings to modify the municipalities' electric tariff schedules to include rules and regulations governing the purchase of renewable energy from new distributed generators and to implement net metering schemes.

The two items "appear to be addressing in a proper way the need for these tariffs. ... These cases as well as others have sought to modify the tariffs on a voluntary basis because they're not subject to the utility tax," Burman said. "I'm flagging this because I want us to be looking at how the munis are doing it differently. ... However, we really do need to watch if there are any negative ramifications to the customers, especially on the cash-out that goes to the developers."

Burman concurred on a petition by 1115 Solar Development for compensation according to the Alternative 2 capacity value calculation set in the Value of Distributed Energy Resources (VDER) transition order, noting that a PSC staff white paper on the subject from last January did not mean that the commission thought of it "as a done deal." ■


The NYPSC held its regular monthly session in Albany on Nov. 14.

PJM News

LS Power Challenges PJM Analysis of Transource Alternative

By Christen Smith

VALLEY FORGE, Pa. — Transource Energy's alternative configuration for its Independence Energy Connection project doesn't pass PJM's cost-benefit test, LS Power said last week.


Sharon Segner, LS Power | © RTO Insider

Sharon Segner, vice president of LS Power, told the Transmission Expansion Advisory Committee on Thursday that her company's review of the newly proposed path for the eastern segment of the project only carries a benefit-cost ratio of 1, far below PJM's 1.25 threshold.


Nick Dumitriu, PJM | © RTO Insider

PJM's analysis, however, produces a 1.6 cost-benefit ratio. Nick Dumitriu, of the RTO's market simulation department, said the new configuration — which scraps plans for a nearly 16-mile-long transmission line in favor of tying into existing infrastructure in York County, Pa., and Harford County, Md. — will cost $496.17 million and realize $844.81 million in congestion benefits.

Segner said PJM's base case used to calculate the ratio doesn't consider the impact of a nearby project that would alleviate congestion on the Hunterstown-Lincoln 115-kV line. PJM plans to present both projects to the Board of Managers in December for inclusion in the Regional Transmission Expansion Plan, Dumitriu said.

"We just want to get to the right answer, and I think that's everyone's objective," Segner said. "These areas are somewhat interrelated, and that's where it gets kind of complicated. … We have reason to believe the cost-benefit ratio will look pretty different when the Hunterstown project is in the model.

"It may make sense to go ahead with the settlement version, but it should be based on the correct analysis," she added.

Transource filed the second configuration for the IEC East project with Maryland and Pennsylvania regulators last month after settling with landowners and state officials long opposed to the original route. (See *Transource Files Reconfigured Tx Project*.)

Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project | Transource Energy

PJM selected the original configuration for the $383 million IEC — its largest market efficiency project to date — during the 2013/14 long-term planning window to address congestion in the AP South interface. The RTO has since reviewed its benefits to the grid six times, determining in each round that the project remains the most effective way to reduce load costs.

The RTO's most recent analysis, completed in September, determined the original configuration would generate a $856 million reduction in congestion costs over the next 15 years, with a benefit-cost ratio of 2.1 — well above PJM's 1.25 threshold required for inclusion in its RTEP.

Protesters argued, however, that the need for the eastern segment of the project could be met by using towers for existing 230-kV lines. Maryland's Power Plant Research Program urged the state's Public Service Commission to suspend the project while PJM studied the market efficiency of this alternative and three others — a request that was granted in January. (See *More Info Needed on Tx Line Options, MD PSC Says* and *Cancel Transource Line, Md. Panel Says*.)

PJM's analysis determined that the protesters' preferred configuration would require upgrades at the Furnace Run substation in York County in order to alleviate potential reliability violations. The plan will cost $125 million more than the original IEC and produce $12 million less in congestion benefits to the region, according to PJM's most recent market efficiency update.

Still, Transource and the protesters have settled on the alternative configuration, despite the reduced benefits and additional cost. Both plans sit before regulatory agencies in Maryland and Pennsylvania awaiting a final decision.

Meanwhile, PJM must update its RTEP to include the alternative plans for the IEC.

"We are going to give the board the complete picture of what's going on," said Ken Seiler, PJM's vice president of planning. "There's a lot of moving parts and a lot of variables, and we will make sure the board has the right information."

Seiler added that "at some point," the plans must move forward. "The area is congested and will be congested until we get some of these projects built," he said.


Alex Stern, PSE&G | © RTO Insider

Alex Stern, manager of transmission strategy and policy for Public Service Electric and Gas, agreed.

"At some point, you need to focus on what needs to get done," he said. "I think PJM is doing that and obviously that's part of prioritizing, and you need to prioritize what's in the best interest of planning and developing a cost-effective grid versus what's in the best interest of needlessly perpetuating a competitive process." ■

PJM News

PJM Operating Committee Briefs

DR Load Forecast Error Still Unsolved

VALLEY FORGE, Pa. — PJM staff told the Operating Committee last week that questions still remain about why their load forecast veered so far off course during a two-day spell of hot weather across the region last month.

Rebecca Carroll, PJM | © RTO Insider

Speaking at the committee's Nov. 12 meeting, Rebecca Carroll, PJM's director of dispatch, said staff's backcasting analysis found that an early-arriving cold front in the ComEd and FirstEnergy zones on Oct. 2 impacted temperatures during the two-hour demand response event, accounting for a portion of the 4,500 MW of anticipated load that never materialized on the system. (See *PJM, Stakeholders Baffled by DR Event*.)

That same analysis, however, revealed that temperatures in the Mid-Atlantic and AEP zones were higher than initially forecast — meaning the missing load and unusual price signals have a different, unknown cause.

"According to all of our data, the load in AEP should have come in higher and quicker and more significant than what it did, even though we called the pre-load management in this area," she said. "There's several hundred megawatts we can't account for."

The trouble began Oct. 1, when PJM's peak load exceeded its forecast by 5,500 MW, knocking the RTO into a spinning reserves event and triggering shortage pricing for three five-minute intervals. Carroll said PJM also called upon 800 MW of shared reserves from the Northeast Power Coordinating Council to compensate.

The following morning, operators lost a 765-kV line in the AEP zone, and 2,000 MW of generation called upon the day before failed to start. Those losses, in combination with a peak load forecast of 131,000 MW and anticipated congestion over the Hyatt transformer and the Peach Bottom-Conastone 500-kV line, prompted staff to call up 725 MW of long-lead DR resources for a pre-emergency load management event. The decision triggered a performance assessment interval (PAI) that lasted from 2 p.m. until approximately 4 p.m. in the AEP, Dominion, Pepco and BGE zones.

PJM's Operating Committee meets Nov. 12 at the Training and Conference Center in Valley Forge, Pa. | *© RTO Insider*

What should have happened next, according to several stakeholders, was a rise in LMPs for those zones, set by DR operating during the PAI. Instead, prices in the AEP zone tanked, and 4,500 MW of load never came onto the system.

PJM had hoped backcasting could solve the mystery of the missing megawatts, but Carroll said last week that more answers will likely come when the official DR data become available next month.

"I don't buy this missing load argument," said Dave Mabry, of McNees Wallace & Nurick. "I'm not sure we've got a missing load issue as much as we have a forecast issue. It seems like there is something else going on with the backcasting."

Mabry suggested that a large industrial-use customer participating in DR could account for the "missing nodal load" — a possibility that Joseph Mulhern, a senior engineer at PJM, said staff were still considering.

"That's one of the things that we are trying to look into now … mapping the nodes where we see this behavior to demand response customers," he said. "It's the first time we've looked into anything like this, so we aren't sure what we will get or what the outcome will look like."

He said staff attribute "a significant amount of missing load to DR," but not all of it. He also said a lack of visibility at the distribution level and the rarity of 90-degree weather in October may also have played a role.

"When there is an unusual day that's not got a lot of history, that can lead to errors," he said.

Black Start Packages Anticipated in 'Early 2020'

PJM's Janell Fabiano said that stakeholders will present new rules for black start resource fuel requirements in "early 2020."

Stakeholders began meeting in July 2018 to *reconsider* whether the existing fuel requirement of 16 hours proved sufficient given PJM's focus on resilience in recent years. The group is also considering ways to mitigate high-impact, low-frequency events across all black start resources and fuel types.

The D.C. Office of the People's Counsel, Calpine, PJM and Monitoring Analytics continue to work on four similar plans to define fuel assurance and tweak the hourly reserve

PJM News

requirement. Fabiano said stakeholders will bring the finalized packages to both the OC and the Market Implementation Committee for votes early next year. Changes will not move forward without support from both committees, she said.

Winter Weekly Reserve Target Endorsed

The OC endorsed weekly winter reserve *targets* for 2019 that remain unchanged from last year. The targets for December, January and February are 22%, 28% and 24%, respectively.

Part of the reserve requirement study, the targets help staff coordinate planned generator maintenance scheduling during the winter and cover against uncertainties associated with load and forced outages.

PJM also sets a 0% goal for its loss-of-load expectation (LOLE) in the winter, preferring instead to expect higher LOLEs throughout the summer.

Preliminary Day-ahead Scheduling Reserve Requirement Approved

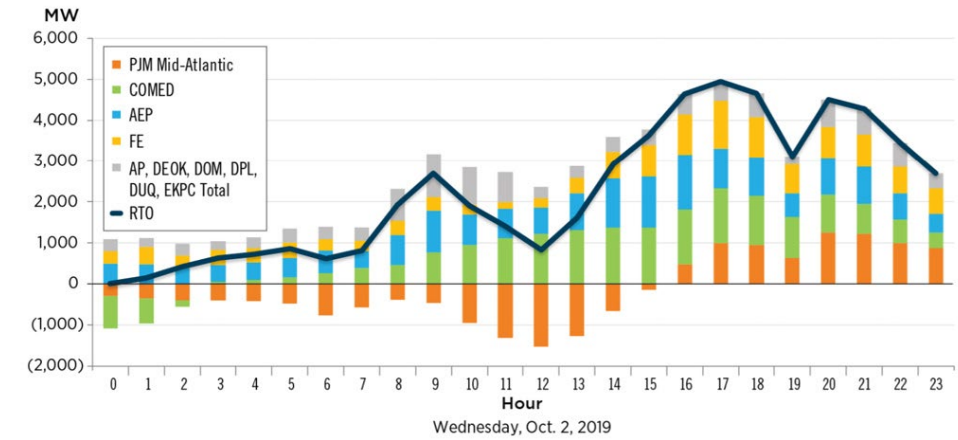
The committee also endorsed PJM's new day-ahead scheduling reserve *requirement* (DASR) of 5.07%.

The DASR is the sum of the requirements for all zones within PJM and any additional reserves scheduled in response to a weather alert or other conservative operations.

PJM will seek endorsement for the change at the Markets and Reliability Committee and implement the new requirement in Manual 13 revisions.

Stakeholders Sunset NERC Ratings Initiative Task Force

Stakeholders approved PJM's *request* to sunset the 2011 NERC Ratings Initiative Task Force.



Zonal contribution to load forecast error on Oct. 2, 2019. | *PJM*

The group held more than 30 webinars over three years to address a NERC alert that asked RTOs to "verify that field conditions are consistent with established ratings."

The task force created an automated process to notify members of pending NERC outages. Since adopting the new procedures, PJM has received 1,386 outage and derate tickets, completing about 65% of submitted requests. About 9% impacted the system, according to PJM's data.

OC Meetings Moving to Thursday in 2020

PJM's standing committee week will look a little different in 2020.

The OC will convene on Thursdays, while PJM's Planning Committee and Transmission Expansion Advisory Committee will move to Tuesdays. The MIC will remain on Wednesdays.

PJM Manuals Endorsed

- *Manual 03A*: Energy Management system (EMS) Model Updates and Quality Assurance (QA) — Cover-to-cover periodic review. Adds a new section on PJM's modeling philosophy.
- *Manual 3*: Transmission Operations — Cover-to-cover periodic review. Updates dozens of terms and values in sections 1, 3, 4 and 5 and Attachments A and B.
- *Manual 14D*: Generator Operational Requirements — Minor changes identified through the Distributed Energy Resources Ride Through Task Force that apply to distribution-connected generators connected to radial distribution lines of voltage less than 50 kV. The revisions also direct DERs to appropriate transmission owner engineering and construction standards, a standalone document on PJM's website. The term "generating facilities" was also added in section 7.1.1: Generator Real-Power Control. ■

— *Christen Smith*

PJM MIC Briefs

Manual Revisions for Must-offer Exception Rules Endorsed

VALLEY FORGE, Pa. — The PJM Market Implementation Committee on Wednesday endorsed Manual 18 *revisions* that implement the new must-offer exception process approved by FERC last month. (See *FERC to PJM Gens: Use or Lose Capacity Rights*.)

The changes, endorsed by the Markets and Reliability Committee in April, require existing capacity resources not offered in three consecutive auctions to change to energy-only status. A resource receiving a must-offer exception must also file a plan showing how it will satisfy Capacity Performance requirements or forfeit its capacity interconnection rights. Resources would be granted exceptions for no more than two auctions. (See *Load Interests Endorse PJM-IMM Must-offer Proposal*.)

Manual 15 Clarifications on VOM Costs

PJM offered a first read of Manual 15 revisions that clarify that market sellers can only change the format of maintenance adders — such as $/MMBtu, $/MWh or $/start — during the annual review period for energy offer components.

Staff will add section 2.6: Variable Maintenance Costs to reflect this after promising to do so in the proceedings for *ER19-210*, PJM's filing to include variable operations and maintenance costs in energy offers. FERC partially accepted the RTO's Tariff revisions in April but asked for more clarity on what maintenance costs sellers can include in their energy market offers. (See *FERC to PJM: Clarify Allowable Costs for Energy Offers*.) FERC accepted that compliance filing in August.

PJM will seek endorsement from the MRC in December and from the Members Committee and Board of Managers in January.

Border Rates

PJM presented a first read of *revisions* to Manual 27: Open Access Transmission Tariff Accounting that will reflect FERC's recent order on border rate calculations (*ER19-2105*).

In June, PJM transmission owners submitted a filing that updates the yearly border charge to prevent network integrated transmission service (NITS) customers — network load located outside the RTO's boundaries but served from within — from subsidizing border and non-zone service rate customers who use transmission service through and out of PJM. (See *Settlement Hearing Set for PJM Border Dispute*.)

FERC accepted the TOs' filing subject to refund, with an implementation date of Jan. 1, 2020, but also set a paper hearing and settlement procedures for involved parties to work out their differences over the proposed methodology behind the rates.

Ray Fernandez, of PJM's market settlements development department, said the manual revisions will move forward but acknowledged that refunds will be issued if changes to the methodology are approved in a settlement.

Fuel-cost Policies

Stakeholders from the MIC special session for fuel-cost policies brought updated proposals to the committee on Thursday, five months after a first round of debates among stakeholders produced no further consensus. (See *PJM Stakeholders Still Divided on Fuel-cost Policies*.)

PJM moved off the status quo and offered an alternative *package* of rule changes that included a much desired "impact factor" when assessing penalties on market sellers for breaking their fuel-cost policies. A joint stakeholder *plan* and another *sponsored* by the Independent Market Monitor would also offer impact factors — though the specific calculations differ — and reduce penalties when market sellers self-identify violations.

Adrien Ford, ODEC | © *RTO Insider*

Adrien Ford of Old Dominion Electric Cooperative said the joint plan aims to "encourage a culture of compliance" among market sellers.

"According to PJM, 75% of the penalties were assessed on generators that had no market impacts," she said. "That's why we want to introduce the impact factor. We are just trying to say, 'Look, if there's an impact, there should be a penalty. If there's no impact, there should be a penalty, but it should be a traffic ticket approach.'"

While PJM's plan would reduce penalties by 50% when market sellers self-identify, the RTO did not agree with stakeholders' creation of a safe harbor provision that protects against situations "not contemplated by the fuel-cost policy." Melissa Pilong, of PJM's operations analysis and compliance department, said the provision would encourage market sellers to provide less detailed fuel-cost policies.

Then there's the issue of temporary fuel-cost policies and PJM's ability to revoke existing policies, potentially forcing market sellers to submit a zero cost-based offer. Current practice allows market sellers to provide temporary policies that include just heat rate and selling hub — a rule that PJM's alternative package would eliminate.

"If a fuel-cost policy were to be revoked and mitigation would be offered at zero, the incentives for the generation owner would be, in many cases, submit a forced outage," said E-Cubed Policy Associates President Paul Sotkiewicz, representing Elwood Energy. "From a reliability standpoint, I can't imagine why PJM would want to do that."

PJM staff bristled at the implication that they would revoke fuel-cost policies randomly and at will, noting that the RTO would act in good faith to discuss issues with a market seller first.

Glen Boyle, PJM | © *RTO Insider*

"We've never revoked a policy," said Glen Boyle, a manager in PJM's operations analysis and compliance department. "But we need to have the ability to do so."

Ford said existing manual language about revocation "isn't precise" and leaves too much undefined for market sellers.

"The market sellers are just looking to understand when and why something might be revoked and not be forced into a must-offer obligation or a must-offer of zero," she said. "I don't think it's reasonable to have this unclear, looming threat that can really turn things completely upside down for a company. The more we talk about it, the more uncomfortable I am with the status quo."

Boyle agreed that further consensus could be reached where the RTO allows temporary fuel-cost policies to be submitted alongside their permanent counterparts in the event that revocation occurred. ■

— Christen Smith

PJM PC/TEAC Briefs

Critical Infrastructure Vote Delayed Again

VALLEY FORGE, Pa. — The PJM Planning Committee deferred voting again on a problem statement and issue charge for a proposed review of the RTO's critical infrastructure management.

The second delay follows a plea from Exelon and other transmission owners on Thursday to hold off on the issue until after a webinar scheduled for Friday to address stakeholders' concerns about a proposed Tariff attachment that creates a process to mitigate existing facilities on NERC's CIP-014 list. (See "Critical Infrastructure Vote Deferred," *PJM PC/TEAC Briefs: Oct. 17, 2019*.)

"A number of things on this issue charge could be removed or modified," said Pulin Shah, director of transmission strategy and contracts for Exelon. "The M4 [attachment] hasn't been approved. We are still working through this process. A lot of the things that are in here may or may not even be applicable [after the webinar]."

He clarified that a second 30-day delay would give stakeholders more time to "focus the scope on the areas of concerns that everyone has alignment on in terms of creating new CIP-014 facilities."

DER Ride Through Task Force Sunset

PJM wants to sunset the Distributed Energy Resources Ride Through Task Force after saying its work considering a default standard is done.

The RTO said distributed energy resources currently function on settings designed to respond to unexpected system malfunctions that disrupt power flow. Some sources "ride through" the event, providing much-needed reliability, while others trip off to prevent system damage. Solar panels and other DERs also can't tell the difference between a transmission fault and a distribution fault, causing inappropriate responses and overstressing the system.

The task force had been considering ways to fix this problem — even going so far as to bring in federal experts to help develop new standards — but decided against an RTO-wide rule because of the uniqueness of local distribution systems. (See *DER Ride Through Task Force Considers New Direction*.) Instead, the task force suggested that PJM create a recommendation when a local distribution system lacks an official policy.

Competitive Transmission Proposal Fee Restructuring

As PJM moves forward with its *proposed* fee restructuring for competitive transmission proposals, stakeholders remain concerned about the associated revisions to Manual 14F required as part of the update.

The revisions, borne out of a stakeholder motion endorsed by the Markets and Reliability Committee last year, will codify the comparative cost framework the RTO will use to evaluate these projects. (See "PJM Unveils Flat Fee Cost-containment Plan," *PJM PC/TEAC Briefs: Aug. 8, 2019*.) Since implementation of FERC Order 1000 in 2014, PJM has reviewed 850 competitive proposals, of which less than 20% included cost-commitment provisions.

TOs continue to question the appropriateness of revisions proposed by both PJM and the *Independent Market Monitor* that would memorialize an ongoing collaborative role between the two entities in reviewing competitive transmission proposals. (See *PJM TOs Wary of Cost Containment Rules*.)

In an effort to bridge the gap, LS Power proposed a paragraph that would clarify PJM's precedence over the Monitor in reviewing proposals, a suggestion that fellow TOs found promising but still imperfect.

Some 77% of stakeholders at the PC approved of PJM's current proposal. PJM's Mark Sims said staff will take the restructured fee and its associated Operating Agreement and manual changes to the MRC for endorsement next month.

Mark Sims, PJM | © *RTO Insider*

Manual 19 Revisions Endorsed

Stakeholders endorsed revisions to *Manual 19: Load Forecasting and Analysis*, a periodic cover-to-cover review that also removes load forecast model overview from the manual and adds it to an annual white paper. The revisions also update sections 3.2, 3.4 and 4.2 to update the weather-normalization procedure for peak load and energy to be directly tied to the load forecast model.

Supplementals from AEP, ComEd, Dominion, PSE&G

American Electric Power *wants* to replace 18 remaining ELF-SL8-4 Type SF6 breakers at its Sullivan 765/345-kV and Rockport 765-kV substations in Rockport, Ind., after documenting more than 16 issues, including compressor failures, since 2002.

Commonwealth Edison *proposed* a $200,000 rebuild of its Quad Cities-Cordova 345-kV line to fix obsolete relays and servicing difficulties. The line is an intertie between PJM and MISO and needs the upgrade to address equipment condition, performance and risk.

A second ComEd project to rebuild 16 miles of the 345-kV Kendall-Lockport double-circuit towers, increase the line rating and eliminate 10.5 miles of wood poles that are 60 years old will cost $12 million, Exelon said. The utility considered two other $20 million solutions as part of its review process but instead settled on a cheaper plan to install quad-circuit towers between the Kendall and Lockport substations, string 138-kV conductor and cut part of line 9117 over new towers.

Dominion Energy wants to spend $69 million to preserve its remaining outdoor equipment at the Mt. Storm substation in West Virginia. The utility proposes installing a second gas-insulated substation (GIS) building in the switchyard to house the breakers and switches for Lines 550 and 536 and two generators. The existing GIS building would be expanded to include breakers and switches for lines 529, 572 and Capbank 3.

The company also presented a $400,000 plan to install a 1,200-ampere, 50-kAIC circuit switcher and associated equipment to feed a new transformer at Poland Road.

Finally, Public Service Electric and Gas proposed a $39 million plan to build a new 230-kV substation in Echelon, N.J., to alleviate the overloaded Marlton substation nearby. The utility also considered building a $68 million 69/13-kV substation but decided on the less expensive proposal because it decreases the amount of exposure and increases the reliability of the 230-kV circuit. ■

— Christen Smith

PJM News

Anbaric Seeks FERC Help on OSW Tx

Files Complaint After PJM Stakeholder Initiative Stalls

By Rich Heidorn Jr.

Anbaric Development Partners asked FERC on Monday to order PJM to allow developers of offshore transmission "platforms" to obtain injection rights, saying the RTO's Tariff violates the commission's open access requirements and is discriminatory.

The transmission developer said it was forced to file its complaint after a stakeholder initiative to consider changing PJM's rules stalled in September.

PJM's Tariff allows merchant transmission developers to obtain transmission injection and withdrawal rights for DC facilities or controllable AC facilities connected to a control area outside the RTO. Under a problem statement approved in February, stakeholders considered allowing merchant transmission developers to request injection rights for non-controllable AC transmission offshore. But after six special sessions, stakeholders opted against recommending changes. (See "PJM Recommends Sunsetting Offshore Wind Special Sessions," *PJM PC/TEAC Briefs: Sept. 12, 2019*.)

"The nature and scope of fundamental open access rights under the PJM Tariff cannot be left to the whims and commercial interests of stakeholders," Anbaric said in its *complaint*. "Put simply, the PJM Tariff does not contemplate the interconnection of transmission platform projects and denies them the opportunity to interconnect to the PJM transmission system and obtain meaningful and material interconnection rights."

In response to the complaint, PJM spokesman Jeff Shields said the RTO "has been and will continue to engage with members, project developers, and impacted states on the procedures that will enable states to integrate offshore wind into their generation portfolios."

Bottlenecks

Anbaric and other transmission developers have argued that having individual wind farms build separate radial lines to shore will be more expensive, more environmentally intrusive and less resilient than networked open access facilities that multiple wind farms could use. (See *Anbaric Pushes Offshore Grid Plans*.)

Theodore Paradise, Anbaric | *© RTO Insider*

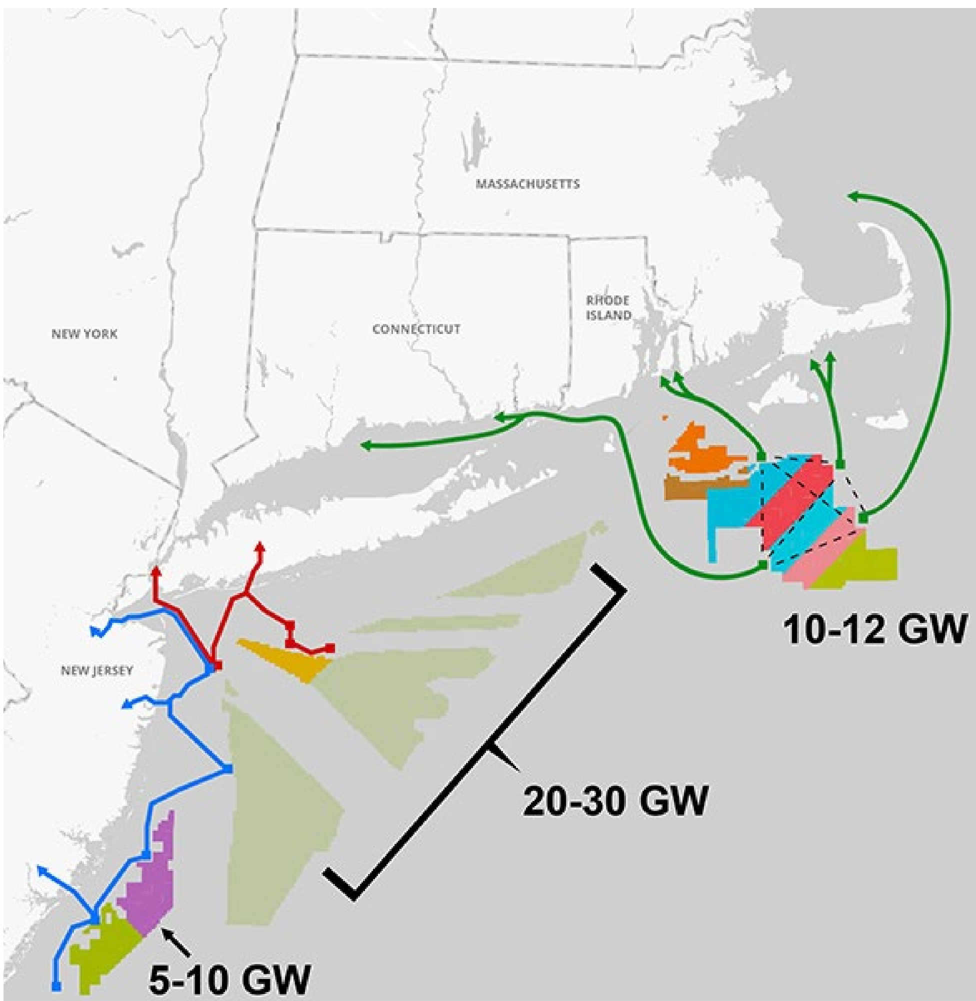
"What we've seen is — and this is true in New York and New England too — if you're going to scale offshore wind up past the first couple thousand megawatts, radials are going to run into a bottleneck," Theodore Paradise, Anbaric's senior vice president for transmission strategy, said in an interview. "There's not enough interconnection points."

The company said there are no technical reasons for blocking transmission platform projects, citing transmission built to deliver onshore wind from Texas' Competitive Renewable Energy Zones and California's Tehachapi Pass.

Ed Krapels, Anbaric | *© RTO Insider*

Anbaric CEO Ed Krapels said he'd like to see PJM adopt the European model of allowing states to offer solicitations for multiple transmission developers to compete for OSW transmission.

"That's how the Dutch and the Germans are now getting responses from wind generators that don't even require long-term contracts," he said in an interview.



Anbaric envisions a network of transmission "platforms" that could deliver up to 52 GW or more of offshore wind generation to PJM, NYISO and ISO-NE. | *Anbaric Development Partners*

Continued on page 31

PJM News

PJM Taps Ex-Direct Energy Exec as New CEO

Continued from page 1

Child Advocates.

Year of Change

PJM's year of change began in February when longtime CFO Suzanne Daugherty announced her retirement amid the RTO's overhaul of its credit policies and financial risk procedures following the default of GreenHat Energy.

Daugherty found herself the target of PJM members' ire after GreenHat amassed 890 million MWh of financial transmission rights while putting up only $600,000 in collateral.

Her retirement was announced by CEO Andy Ott, who himself retired in May, two months after an independent probe into the GreenHat debacle concluded PJM staff ignored red flags about the company's assets and exhortations from other members about the portfolio's financial shortcomings. (See *'Naive' PJM Underestimated GreenHat Risks*.)

Manu Asthana (right) and then-Direct Energy CEO Badar Khan, (left) announce a $5 million donation to Texas Children's Hospital in 2015. | *Direct Energy*

The executive departures continued after interim CEO Susan Riley stepped in for Ott. In September, Riley announced the resignation of Vice President Denise Foster and the restructuring of the State and Member Services Division that she had headed. Foster had no role in the GreenHat episode. (See *Stakeholders, States in Dark over PJM Personnel Moves*.)

Last week, General Counsel and Senior Vice President Vince Duane resigned after more than 16 years "to pursue other opportunities."

Almgren said Riley will resume her position with the board once Asthana assumes his role next year.

"We highly appreciate Sue Riley for her leadership during this challenging time," he said. "She has been working with PJM management, members and policymakers in dealing with the many issues at hand at PJM and has laid a strong foundation for Manu to build on going forward." ■

Anbaric Seeks FERC Help on OSW Tx

Files Complaint After PJM Stakeholder Initiative Stalls

Continued from page 30

Anbaric — which helped build the 660-MW Neptune HVDC cable linking PJM to Long Island and the 660-MW Hudson project connecting Manhattan to the RTO — envisions a network of transmission "platforms" that could deliver 52 GW or more of offshore wind generation to PJM, NYISO and ISO-NE.

New England's states are seeking 5,200 MW of OSW by 2035, and New York has ordered 9,000 MW by 2035.

New Jersey has a goal of developing 3,500 MW of OSW by 2030. The state's Board of Public Utilities in June 2019 selected a 1,100-MW project off the coast of Atlantic City and plans additional solicitations for 1,200 MW in 2020 and 2022. Last week, the BPU held a stakeholder meeting at which officials discussed developing a separate solicitation for offshore transmission.

Maryland has ordered the development of at least 400 MW of offshore wind generation by 2026, at least 800 MW by 2028 and 1,200 MW by 2030.

In Virginia, Dominion Energy plans to develop 2,600 MW of OSW in three 880-MW phases between 2024 and 2026.

Relief Sought

In March 2018, Anbaric submitted interconnection requests for two proposed AC transmission platform projects, each requesting 1,100 MW of injection rights. PJM told the company it would need to partner with a generator to obtain the rights under current rules.

In June 2018, Anbaric submitted an interconnection request for a proposed DC transmission platform project seeking a 1,200-MW injection into Public Service Electric and Gas' transmission system in North Brunswick, N.J. More than a year later, after completing a feasibility study that assumed the injection, PJM informed Anbaric on Nov. 1 that it would only model the project without injection rights. Anbaric said the project has obtained almost all its required environmental permits.

Anbaric said it was seeking relief like that granted by FERC's Order 845, which required RTOs to improve the interconnection process and expand the definition of "generating facilities" to include electric storage. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

It said the current rules effectively give offshore generation developers a right of first refusal like one that the commission outlawed for incumbent transmission owners in Order 1000.

Anbaric asked FERC to order PJM to revise its Tariff to remove the requirement that all merchant transmission facilities interconnect with another control area and to create a new category of merchant transmission facilities called a "remote generation resource interconnection platform" (ReGRIP).

The company also asked the commission not to order a PJM stakeholder process, saying that could result in delays that would prevent states from issuing solicitations for offshore transmission.

Krapels and Paradise said they are hopeful the commission will respond to the PJM complaint with an order that sets a precedent for other RTOs, saying they have similar concerns in New York and New England. ■

SPP News

SPP Strategic Planning Committee Briefs

Members Debate Retaining Load in an Uncertain Future


Board Chair Larry Altenbaumer | © *RTO Insider*

JUNO BEACH, Fla. — Convening a Strategic Planning Committee meeting last week in South Florida, SPP Board of Directors Chair Larry Altenbaumer apparently couldn't resist adding a little local flavor to the proceedings.

Altenbaumer focused the committee on the future and a plan "for how to get there" by quoting from Jimmy Buffett's "*Changes in Latitudes, Changes in Attitudes*":

> *"Oh, yesterday's over my shoulder,*
>
> *So I can't look back for too long.*
>
> *There's too much to see waiting in front of me,*
>
> *And I know that I just can't go wrong."*

After quoting Margaritaville's most famous resident, Altenbaumer told the committee during its Nov. 12 meeting at NextEra Energy's corporate headquarters that SPP's new strategic plan needs to focus on what the RTO delivers "that is better than other options that are out there."

"Focus on our performance and effectiveness and the quality of the services we provide," he said.

The committee will spend the near term developing an official SPP vision statement. "There's a sentiment that SPP should consider a vision at this juncture," Altenbaumer said.

The SPC will begin revising SPP's strategic plan in April after taking feedback it gathers from the board and Members Committee in January. "Critical areas of focus" will include effective communication, strengthening relationships, a Western strategy and transmission planning in an uncertain future.

SPP Senior Vice President of Engineering Lanny Nickell outlined three "areas of competition" to consider: competition between RTOs, ensuring SPP doesn't lose load to ERCOT and keeping load where it is.

"How do we compete for loads that are not in an RTO?" he asked, rhetorically. "How do we compete, as a region, for loads that love the renewable resources and low prices? They're looking for opportunities to add warehouses and data centers. How do we compete for those? As loads move off the transmission system and onto the distribution system, is that an issue we need to look out for, or be aware of, and compete for?"


The Strategic Planning Committee gathers at NextEra's headquarters Nov. 12. | © *RTO Insider*

"If you're trying to contain costs, you have to make sure you're keeping all the load you have," NextEra Energy Resources' Holly Carias said. After adding Entergy as MISO South in 2013, MISO's administrative fee fell below SPP's, she said.

SPP will raise its administrative fee by 9.1% in 2020 to a record 43 cents/MWh. (See "Directors Approve 9.1% Administrative Fee Increase for 2020," *SPP Board of Directors/MC Briefs: Oct. 29, 2019*.) That has raised concerns among some members who have seen several loads on the SPP-ERCOT seam transfer into the Texas grid.

"Reality is rate cases," Southwestern Public Service's Bill Grant said. "Asking for recovery of all these expenses and having to justify transmission increases … a lot of customers are not enamored with the rising cost of transmission … on their bills."

Staff Working on HITT Escalation Process

In briefing the committee on the Holistic Integrated Tariff Team's (HITT) recommendations, COO Carl Monroe described an escalation process that starts with staff that worked on an issue addressing questions around that issue before it potentially ends up at the SPC or before the board.

"We're trying to get the teams responsible for facilitating the issue to resolve those issues too," Monroe said. "We suspect there will be times where there are disagreements over whether it's a good recommendation or being implemented as intended. Is it going in the direction where it will be improving something?"

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SPP COO Monroe to Retire in Early 2020

By Tom Kleckner

Carl Monroe speaks at a recent SPP meeting. | © RTO Insider

SPP COO Carl Monroe, one of the key players behind the grid operator's growing footprint, has said he will retire in early 2020.

Monroe is a 22-year veteran with SPP. As executive vice president and COO, he has been responsible for operations across the RTO's 14-state balancing authority area and administration of the wholesale electricity market.

"It has been the opportunity of a lifetime to work at SPP and a privilege to work alongside such bright, talented and caring people in the interest of a worthwhile shared mission," Monroe said in a *statement*. "SPP is poised for continued success, which I'll observe with great interest, but the time is right for me to begin a new chapter with regard to family, travel and other experiences."

"I've had the great privilege of working with Carl during his entire career at SPP," Mike Wise of Golden Spread Electric Cooperative — one of the RTO's more prominent members — told *RTO Insider*. "I believe his personal efforts, contributions and leadership were critical to the tremendous development and success of the Southwest Power Pool."

Monroe has been credited with the expansion of SPP's service territory from eight to all or part of 14 states. He also led the organization's recent growth into the Western Electricity Coordinating Council, where the RTO will begin offering reliability coordination and market services over the next two years.

"In nearly 15 years as a director at SPP, I've met no one with greater knowledge of markets and operations or with such ability to collaboratively address complex issues," Board of Directors Chair Larry Alternbaumer said.

"Carl has helped to shepherd us through tremendous change and growth. We just wouldn't be where we are today without his leadership," CEO Nick Brown said.

An SPP spokesman said Monroe's responsibilities for westward expansion, implementing the Holistic Integrated Tariff Team's recommendations and other duties "will be transitioned to other members of the officer team."

Monroe's retirement — along with Brown's in April 2020 and the year-end departures of former board Chair Jim Eckelberger and Directors Phyllis Bernard and Harry Skilton — will wipe out much of the leadership that has been in place at SPP since 2004.

The COO vacancy has opened up a potential slot for inside candidates for Brown's position. SPP is looking at both internal and external candidates for the CEO's position.

Monroe joined SPP from Entergy, originally being hired to manage the RTO's growing information technology department. He was elected as an officer and promoted to executive vice president and COO in 2004. ■

SPP Strategic Planning Committee Briefs

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HITT's yearlong work resulted in a package of 21 recommendations intended to integrate renewable energy's growth, boost reliability, and improve transmission planning and the wholesale market. The recommendations have since been parceled out to the SPC and other stakeholder groups. (See *SPP Board Approves HITT's Recommendations*.)

Several committee members who participated on the HITT pointed out that they agreed on the package as a whole but still had concerns about individual recommendations.

"This very same conversation is reflective of some of the conversations and discussions at HITT. This is the kind of difficulty we saw coming," said Oklahoma Gas & Electric's Greg McAuley, who called into the meeting. "These are some very big changes that are being proposed. Without a lot of due diligence or thorough analysis, we can't say it's a package deal and it's all or nothing."

"Anything that came through the HITT as a recommendation came with the understanding that it was a general idea," Lincoln Electric System's Dennis Florom said. "With the development of language that comes through the process, we may end up with something where there is no unity."

Nickell reminded the committee that the Markets and Operations Policy Committee sets the RTO's policy.

"HITT didn't include the full membership. MOPC will have the opportunity to weigh in as a full membership body," he said. "It's important that MOPC expresses why or why not a certain policy [being] advocated is better than what the HITT recommended, and the SPC needs to understand that."

SPC Agrees to 2 HITT Recommendations

The committee approved two actions it was assigned by the HITT: a draft strawman that adds an "understanding and evaluation of technological advances" to SPP's strategic plan and a continued "high priority" focus on seams issue.

The HITT report identified technological advances as presenting opportunities for SPP "to provide improved service, higher reliability assurance, greater market efficiencies and tools to manage the evolving generation portfolio." The SPC agreed that staff should report to the committee about potential technological breakthroughs developed through their work with stakeholder groups, NERC, the Electric Power Research Institute, the ISO/RTO Council and other industry groups.

The committee agreed SPP should continue to "foster mutually beneficial cooperative and joint transmission projects with its neighboring systems to support broader interregional planning." The comprehensive effort should include identifying how to plan, estimate and "optimize" the facilities on an interregional level. ■

— Tom Kleckner

Company Briefs

Black Hills to Invest $2.9B, Consolidate, Embrace Wind

Black Hills Corp. last week said it intends to spend $2.9 billion on capital investments through 2023 as it establishes new transmission lines, invests more heavily in renewables and navigates regulatory consolidation.

The company is investing $57 million into a 40-MW wind project in Wyoming that could grow to 52 MW. Natural gas efforts include consolidation and a new $54 million Natural Bridge Pipeline. Also, the company submitted a request to FERC for a 60-MW, 20-year power purchase agreement through which it would supply Wyoming Electric, beginning in 2023. Another 25-year PPA in Colorado is expected to bring 60 MW of wind generation to Colorado Electric beginning in mid-November.

More: *Daily Energy Insider*

Orsted to Bring Solar-plus-storage Project to Texas

Ørsted announced plans last week to build the 460-MW solar-plus-storage Permian Energy Center in West Texas, near oil and gas infrastructure in the Permian Basin. The company said the center, which is expected to be completed in mid-2021, will make it the first developer to own onshore and offshore wind, solar PV, and storage.

The storage facility, which will be built across a 3,600-acre site in Andrews County, will operate at 40 MWh and run alongside a 420-MW solar array.

More: *GreenTech Media*

SunPower to Split into 2 Publicly Listed Companies

SunPower said last week it intends to split into two publicly traded companies in the second quarter of 2020, separating its operation that manufactures solar panels from its storage and energy services.

The panel manufacturer will be named Maxeon Solar Technologies and headquarter in Singapore, with manufacturing operations in France, Malaysia, Mexico and the Philippines. The remaining company will keep the SunPower name and maintain its headquarters in Silicon Valley, with Tom Werner continuing to serve as CEO. It will also keep its parent's new solar panel factory in Oregon.

As part of the deal, SunPower partner Tianjin Zhonghuan Semiconductor will make a $298 million investment in Maxeon. Jeff Waters, CEO of SunPower's Technologies business unit, will head Maxeon.

More: *Reuters*

Federal Briefs

Coalition Files Lawsuit to Block Proposed Power Line

La Grande, Ore.-based groups Stop B2H Coalition and Greater Hells Canyon Council filed a lawsuit in federal court last week seeking to block Idaho Power's proposed Boardman-to-Hemingway transmission line, which would run through Baker and Union counties in Oregon.

The groups contend the Bureau of Land Management and Forest Service, which authorized the proposed 293-mile, 500-kV transmission line, failed to adequately review potential environmental effects. They claim the 170-foot towers would obstruct views from the Oregon Trail Interpretive Center.

Jim Kreider of La Grande said the group filed the lawsuit because of the pending legal deadline to challenge the authorization of the proposed route. BLM's record of decision for the line was signed on Nov. 17, 2017, and legal challenges to the decision had to be filed within two years. "We had until [last] Friday to do something," Kreider said. "The clock was running out. The only thing we could do was file litigation to keep this alive."

More: *Baker City Herald*

Court Halts Trump Admin's U-turn on Bifacial Solar Modules

A bid from Invenergy to temporarily halt the Trump administration's decision to reimpose tariffs on bifacial solar panels has been granted.

Invenergy filed a complaint two weeks ago alleging the U.S. trade representative's turnaround was "unlawfully entered" because it did not allow for notice or comment prior to pulling the exclusion. The withdrawal, which was slated to take effect last Friday, is now delayed until Nov. 21 or until a judge rules on Invenergy's request for a permanent injunction. The temporary order could also be extended.

The administration granted bifacial panels an exemption from the broader U.S. solar import tariffs in June, in part because the bifacial supply to the country was "highly limited." However, in October, the administration reversed course on the exemption.

More: *GreenTech Media*

Energy Department Grants Millions to Advance Solar Technologies

The Department of Energy last week announced its selections for $128 million in projects in 22 states to advance solar technologies.

Through the Office of Energy Efficiency and Renewable Energy's Solar Energy Technologies Office, the department will fund 75 projects that aim to advance research and development in photovoltaics, concentrating solar-thermal power, soft costs reduction, innovations in manufacturing and systems integration.

"At DOE, we're working to ensure that solar is more affordable for every American by reducing regulatory burdens and increasing the security and resiliency of our solar energy supply," Secretary Rick Perry said.

More: *Department of Energy*

TVA in Long-term Deals to Sell Power

Tennessee Valley Authority CEO Jeff Lyash said 85% of the 154 local companies that buy power from the company have agreed to new 20-year deals and carry a 3.1% monthly rebate on wholesale power rates. The deals will replace existing agreements or follow expiring ones.

The company's biggest customer, Memphis Light Gas & Water, has not signed a long-term deal. The Memphis utility is currently exploring other power generation options. MLGW has been a TVA customer for 85 years and represents roughly 10% of the agency's revenue. Middle Tennessee Electric Membership Corp. also has not agreed to a long-term deal.

More: *The Associated Press*

Emails Show Sondland Kept Perry Apprised of Ukraine Push

U.S. Ambassador to the E.U. Gordon Sondland kept several Trump administration officials, including Energy Secretary Rick Perry, apprised of his effort to get Ukraine to launch investigations that President Trump would later discuss in a July call with his Ukrainian counterpart, emails reviewed by *The Wall Street Journal* show.

On July 19, a day before Trump was initially scheduled to speak to Ukrainian President Volodymyr Zelenskiy, Sondland emailed a group of administration officials including Perry to say that Zelenskiy was prepared to assure Trump that he would open investigations into former Vice President Joe Biden and his son, Hunter. Perry has denied any knowledge of the administration's push for the investigations.

Sondland will be one of eight witnesses to testify publicly this week in the House of Representatives' impeachment inquiry. Perry has refused to comply with the House's subpoena to testify. His last day as secretary is Dec. 1.

More: *The Wall Street Journal*

State Briefs

CALIFORNIA

Sen. Wiener to Propose Turning PG&E into Public Utility

State Sen. **Scott Wiener** said last week he plans to introduce a bill to the Legislature early next year that would require Pacific Gas and Electric to become a government-owned utility, though he said details are "still very preliminary."

Wiener said his proposal isn't intended to compete with other efforts to transform PG&E and should be considered alongside San Jose Mayor Sam Liccardo's push to create a customer-owned cooperative and San Francisco's offer to buy the utility's local power lines and operate them.

More: *San Francisco Chronicle*

SCE Strikes Settlement over Wildfires, Mudslides

Southern California Edison has agreed to pay $360 million to public agencies affected by wildfires and mudslides in the last two years, attorneys involved in the deal said last week. The settlement closes 26 lawsuits involving 23 public entities filed against the utility, including Los Angeles County, which will receive $78 million.

Public entities sued SCE over expenses and damage they incurred during and after the 2017 Thomas Fire, the Montecito mudslide and the 2018 Woolsey Fire. The settlement allocates $150 million for agencies affected by the Thomas Fire and subsequent mudslide, and $210 million for the Woolsey fire, including $13.7 million for the city of Malibu. A portion of the settlement will be used by the agencies to repay the state Office of Emergency Services and the Federal Emergency Management Agency for their help during the incidents.

SCE's equipment sparked the Thomas Fire, which scorched the Montecito hills in Santa Barbara County and caused a mudslide that flowed into a nearby town, killing a total of 23 people. The utility then stated in a corporate filing last month it could also be found responsible for the Woolsey Fire, which was the biggest fire in L.A. County history. Its estimated liability for the fires and mudslide could reach $4.7 billion.

More: *Los Angeles Times*

State Bucks Lightbulb Rollback with Tougher Standard

The Energy Commission last week voted to enact tougher energy efficiency standards for lightbulbs, pushing back against a rollback from the Trump administration. A new rule from the U.S. Department of Energy eliminated energy efficiency standards for half the bulbs on the market.

The vote essentially eliminates the sale of incandescent and halogen bulbs. The state banned the sale of such pear-shaped bulbs in 2018, but the new rule will now extend to all other shapes of bulbs.

More: *The Hill*

KENTUCKY

Residents Debate How Net Metering Impacts Low-income Families

The Public Service Commission heard from utilities and more than 40 solar advocates as part of its review of the state's net-metering rules, which set the value rooftop solar customers receive from utilities for the excess power they put back on the grid.

Both sides say they are fighting to protect low-income communities. The utilities said the more people who put solar panels on their homes, the fewer are left to pay for utility investments. They claim the costs are insignificant now but will increase as more people buy solar panels. Because low-income families are less likely to be able to afford solar panels, they end up taking on more of the cost.

However, several solar advocates said solar panels are helping lower costs for low-income customers. The Mountain Association for Community Economic Development (MACED) said with the right programs, solar panels are a solution to offset soaring electricity costs for low-income families. A representative said MACED has helped facilitate 10 solar installations for low-income customers over the last two years, and the organization has planned 17 more projects.

More: *WFPL*

MAINE

Special Commission Examining Storage Benefits

The Energy Storage Commission is examining the economic, environmental and energy benefits of storage in the state, having held two meetings so far, with a third and final one scheduled for today. The 14-member group, which is made up of lawmakers and representatives in the industry, will file a report by Dec. 4 with recommendations for the full Legislature.

The commission's attention is pointed at lithium-ion batteries. The state needs to create storage for the renewable energy it produces, but unlike other states, it has no policies or incentives to entice developers to invest in the battery units. The two big questions the group will need to tackle: What are the right incentives for the state, and what's the best way to pay for them?

At its first meeting Oct. 22, Todd Olinsky-Paul, the project director for the Clean Energy States Alliance in Vermont, advised the group to not bother with studies and pilot projects. He referenced California, New York and Massachusetts as states that already having battery projects up and running or in development.

More: *Portland Press-Herald*

MASSACHUSETTS

Atlantic Bridge Compressor Station Gets Final Approval

The state Office of Coastal Zone Management last week approved a 7,700-horsepower natural gas compressor station over the objections of multiple municipalities, saying it is consistent with the federal Coastal Zone Management Act. That approval is the last of four that the project needs.

The compressor station proposal is part of Enbridge's Atlantic Bridge project, which would expand its pipelines from New Jersey into Canada. Enbridge received initial approval for the station in January 2017 from FERC. The company also needed several state permits, all of which have now been granted.

Robert Hedlund, mayor of the city of Weymouth, said he was "very disappointed" in the approval because it was issued despite recent changes "dramatically reducing" the demand for gas and need for the project. Alice Arena, executive director of the Fore River Residents Against the Compressor Station, said the ruling is a blow to the residents of Weymouth, Braintree, Hingham and Quincy.

More: *The Patriot Ledger*

MICHIGAN

Utility Customers See $4B+ in Rate Relief from Federal Tax Cuts

The Public Service Commission last week approved $75 million in rate refunds for customers of Indiana Michigan Power. With the rate refund, savings from the 2017 Tax Cuts and Jobs Act (TCJA) exceed $4 billion, the commission said.

PSC staff worked with the state's regulated utility companies to tally the impact of the TCJA, which cut the corporate tax to 21% from 35%. The corporate savings are being returned to ratepayers through monthly bill credits and longer-term adjustments. The typical customer using 500 kWh/month will see a decrease of 11 cents on their monthly bill.

More: *Michigan Public Service Commission*

NEBRASKA

OPPD Approves Plans to Create State's Largest Solar Farm

The Omaha Public Power District (OPPD) Board of Directors last week approved plans with a 7-1 vote to create the state's largest solar farm capable of generating up to 600 MW, with a natural gas backup option.

The facility's location has yet to be decided, but OPPD CEO Tim Burke said it will be in the eastern part of the state and the company could start accepting proposals as soon as last Friday. Construction should start in late 2020 and be completed by 2023.

OPPD plans to invest 350 MW of natural gas fueled generation as a backup. An additional 250 MW of natural gas generation equipment will be needed to replace the energy generated at North Omaha Station Units 1, 2 and 3 by the end of 2023. The station will stop burning coal, shut down three of the five turbines and use the remaining two to burn natural gas beginning in 2024.

More: *KPTM*

NEVADA

EV Charging Station Goes Live in Jean

Two DC fast chargers were added at Terrible's Road House in the town of Jean along Interstate 15, about 30 miles south of Las Vegas. It is the fifth station in the state and will allow electric vehicles to reach an approximately 80% charge in 20 to 30 minutes. The fast chargers offer two different connector types, which can charge most of the current EVs.

There are existing stations on U.S. Highway 95 in Fallon, Hawthorne, Tonopah and Beatty. There is also a station under construction in Indian Springs that is scheduled to be online in February. NV Energy is also working to develop 13 additional charging sites throughout the state with completion planned by the end of 2020.

More: *Las Vegas Review-Journal*

NEW YORK

Cuomo Threatens National Grid with Loss Revocation

Gov. Andrew Cuomo threatened to revoke National Grid's license to operate downstate and accused the utility of "mishandling" its gas supply system and recklessly disregarding its obligations as a public utility.

Cuomo's letter gave the utility 14 days to provide a satisfactory plan to meet customers' demand for gas. Otherwise, he would direct the Public Service Commission to begin proceedings to revoke its license.

A $1 billion natural gas pipeline sought by National Grid was opposed by environmental activists, who argued it would destroy ecosystems and undermine efforts to reduce the state's dependence on fossil fuels. The utility imposed a moratorium days after the pipeline was blocked in May, saying it could not guarantee a future gas supply for all its potential customers. In the months since, it has refused at least 2,000 requests for service.

More: *The New York Times*

PENNSYLVANIA

FBI Eyes How Pipeline Approved

The FBI has opened a corruption investigation into how the Wolf administration came to issue permits for construction on a multibillion-dollar Sunoco Mariner East project to carry volatile natural gas liquids across the state. At nearly $3 billion, it is one of the largest construction projects in state history.

The focus of the investigation revolves around whether Gov. Tom Wolf and his administration forced environmental protection staff to approve construction permits and whether the administration received anything in return. The administration has declined to comment.

The 300-mile Mariner East 1 was built in the 1930s to transport gasoline. It was renovated and began carrying natural gas liquids in 2014. Construction permit applications were submitted in 2015 for two wider pipelines, Mariner East 2 and 2X, designed for the same purpose but stretching farther. Both were projected to be open in 2017, but Mariner East 2 began operating that December while 2X could be complete in 2020.

More: *The Associated Press*

SOUTH CAROLINA

Santee Cooper to Close Winyah Generating Station

Santee Cooper said its business plan includes the gradual closure of the Winyah Generating Station in Georgetown, which is one of the company's final remaining coal-fired stations. The first two coal units are slated to close in 2023 with the final two closing in 2027.

"The business plan is basically going to be reducing emissions, reducing debt [and] keeping our customer prices stable," company spokesperson Nicole Aiello said. "By retiring the coal units at Winyah, we're initially going be saving $90 million a year. After 2027, when all four units are closed, we're going to be saving about $170 million a year."

Aiello also said the station's closing will reduce the company's emissions by 40%. Other officials said that once the plan is fully executed, 25% of the company's generation will be sustainable and about 50% would consist of natural gas.

More: *WPDE-TV*

WISCONSIN

Regulators Approve Rate Increases for WE, WPS

The Public Service Commission last week approved the first rate increases in four years for We Energies and Wisconsin Public Service, both subsidiaries of WEC Energy Group. Customers can expect rate increases of 0.66% and 1.6%, respectively, in 2020.

The PSC separately approved rate decreases for Madison Gas and Electric and Alliant Energy to account for lower-than-expected natural gas prices.

As part of the WEC rate cases, the commission ruled that neither utility can use ratepayer money to subsidize home charging stations for electric vehicles. The utilities wanted to spend up to $7.5 million to offer $1,000 rebates for customers who install the equipment as part of a two-year pilot program, in which participants would pay higher rates for electricity used during the day and lower rates at night.

More: *Madison.com*