RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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Calif. to Halt Gas-powered Auto Sales by 2035

By Robert Mullin

California Gov. Gavin Newsom issued an executive order Wednesday that will prohibit the sale of all gasoline-powered automobiles in the state by the middle of the next decade.

The governor's *order* will require that all new passenger cars and trucks sold in California be emissions-free by 2035, accelerating the state's already ambitious goals of electrifying its transportation sector. The state currently has more than 725,000 EVs on the road and accounts for about 50% of the nation's EV sales.

The move is expected to reduce statewide automobile emissions of greenhouse gases by 35% and NO_x by 80%.

The order also directs the state's Air Resources Board to develop regulations mandating that 100% of all operations of medium- and heavy-duty trucks be emissions-free by 2045, "where feasible," with the mandate becoming effective in 2035 for all drayage trucks.

"This is the most impactful step our state can take to fight climate change," Newsom said in a statement.

The transportation sector accounts for more than half of California's carbon emissions, 80% of smog-forming pollution and 95% of diesel emissions, leaving the Los Angeles Basin and Central Valley with some of the dirtiest air in the country, the statement noted.

"For too many decades, we have allowed cars to pollute the air that our children and families breathe. Californians shouldn't have to worry if our cars are giving our kids asthma," Newsom said. "Our cars shouldn't make wildfires worse — and create more days filled with smoky

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Utilities Pledge to Build Largest EV Charging Network (p.21)

NJ BPU Outlines 'Shared Responsibility' EV Charging Plan (p.32)

CAISO Retiring, Incoming CEOs Field Questions

Elliot Mainzer (pictured), who will become CAISO's CEO on Sept. 30, answered stakeholder questions at the EIM's Regional Issues Forum along with retiring CEO Steve Berberich. (p.7) | *BPA*

Consumer Advocates Challenge PJM Board on Exelon, FE

By Michael Yoder

Ratepayer advocates challenged the PJM Board of Managers on Wednesday to take action against two stakeholders accused of bribing legislators in Illinois and Ohio, urging them demonstrate their independence from two of the RTO's biggest members.

West Virginia Consumer Advocate Jackie Roberts questioned board members at the Public Interest and Environmental Organizations User Group meeting, asking what PJM plans to do about FirstEnergy and Exelon and the criminal charges and allegations leveled against them.

Jackie Roberts, West Virginia Consumer Advocate | *© RTO Insider*

Exelon subsidiary Commonwealth Edison agreed to pay a $200 million fine to settle allegations that it bribed Illinois House Speaker Michael Madigan (D) in return for legislation that increased the company's earnings and bailed out its money-losing nuclear plant.

FirstEnergy was alleged to have spent $61 million in bribes and "dark money" campaign contributions and advertising to elect Ohio House Speaker Larry Householder (R) and his associates, who supported $1.5 billion in subsidies for the company's struggling nuclear plants. (See *ComEd to Pay $200 Million in Bribery Scheme* and *Feds: FE Paid $61 Million in Bribes to Win Nuke Subsidy*.)

Although federal prosecutors said most of the alleged bribes were paid by FirstEnergy Solutions (FES), FirstEnergy CEO Charles

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In this week's issue

EBA Canadian Chapter Annual Meeting

Overheard at the EBA Canadian Chapter's 1st Meeting

The Energy Bar Association's Canadian Chapter held its first annual meeting online Thursday, with discussions on cybersecurity and holding virtual adjudication hearings amid the COVID-19 pandemic.

The chapter, formed a year ago, was originally going to hold the meeting in D.C. in April, at the same time as the EBA Annual Meeting, but it was forced to reschedule it in an online format because of the pandemic. (See *EBA Holds Annual Meeting Online Successfully*.)

Here's some of what we heard.

Challenges of Cybersecurity on the Distribution Side

David Morton, chair of the British Columbia Utilities Commission, opened the conference with an anecdote about visiting the U.S. Department of Energy for a briefing on cybersecurity earlier this year (before the pandemic hit).

There were two briefings that day: one for those with top secret security clearance and those without. Morton attended the latter, "but I'm not sure it would have made any difference," he said.

"I couldn't even tell anybody about it anyway. ... I had to sign and swear I wouldn't share [the information he received] with anybody when I brought it back to my commission," Morton said. "So, what am I supposed to do with that information? How can I even apply it to any of the work that I do?"

Morton also pointed out that NERC's mandatory reliability standards only cover the generation and transmission side of the electric industry, leaving the distribution side vulnerable. "If you took out the distribution system in Greater Vancouver, that's just as bad as taking out the transmission system, at least to the 2.5 million residents in Vancouver," he said.

Clockwise from top left: Mary Anne Aldred, Ontario Energy Board; BCUC Chair David Morton; EBA Canadian Chapter President Gordon Kaiser; and Louis Legault, Régie de l'énergie du Québec. | *EBA*

Vancouver, Canada

"I do think it would be appropriate to raise the bar somewhat on standards," said Alex Foord, chief information officer for Ontario's Independent Electricity System Operator. "The larger entities ... are going to come along and do the right thing. The challenge is when you get into smaller [utilities] ... they don't have the expertise, the sophistication and the time to do it. But candidly, that's no excuse for the lack of action; they owe it to their consumers to do better."

Cintron Shares Experiences with Virtual Hearings

Chief ALJ Carmen Cintron | *EBA*

FERC Chief Administrative Law Judge Carmen Cintron gave attendees a candid behind-the-scenes look into how she transitioned the commission's Office of Administrative Law Judges from in-person to virtual hearings after the pandemic hit.

The pandemic "caught me, to use an American expression, with my pants down. We had modeled for the whole United States being under a nuclear attack; we had modeled for hurricanes; we had modeled for everything, except a pandemic," she said.

The office was immediately able to transition to virtual settlement conferences, which aren't as complicated as hearings, Cintron said. Its settlement success rate has actually risen to 92%, from its usual 89%. "We attribute this to the fact that the business entities, the decision-makers, can actually participate without having to travel" to D.C.

Meanwhile, Cintron postponed imminent hearings until the office's IT department set up Cisco's Webex platform and the ALJs trained in using it and practiced by simulating hearings. The first virtual hearing began May 6 and lasted 16 days. One of the parties filed a motion to halt the proceeding, arguing that its virtual nature was a violation of due process, but it was denied by Cintron.

Though she said the process has been an overall success — with even the party that filed the due process motion responding favorably after their hearing was over — Cintron said it has not been without challenges, mostly owing to technical problems. It was immediately clear from her opening remarks that she is not a fan of Webex, and later in the discussion, she said she wants to migrate to Microsoft Teams. The different parties' varying degrees of computer proficiency and internet bandwidth were early frustrations. ALJs also needed to obtain up to three separate computer monitors in order to conduct hearings in their homes.

Cintron said she anticipates the online-only format to continue into next year. Even once the crisis ends, she expects hearings to be a mixture of in-person and virtual. ■

— Michael Brooks

FERC/Federal News

New Study Offers Alternative to Carbon Pricing

By Michael Kuser

Environmental policymakers should abandon the social cost of carbon (SCC) and adopt a more practical metric tied to net-zero-emissions goals, according to a new study.

The *study*, led by Noah Kaufman at Columbia University's Center on Global Energy Policy and published in *Nature Climate Change* last month, notes that SCC estimates — intended to represent the "optimal" CO_2 price that maximizes net benefits to society — range from "under $0" per ton of CO_2 to more than $2,000/ton.

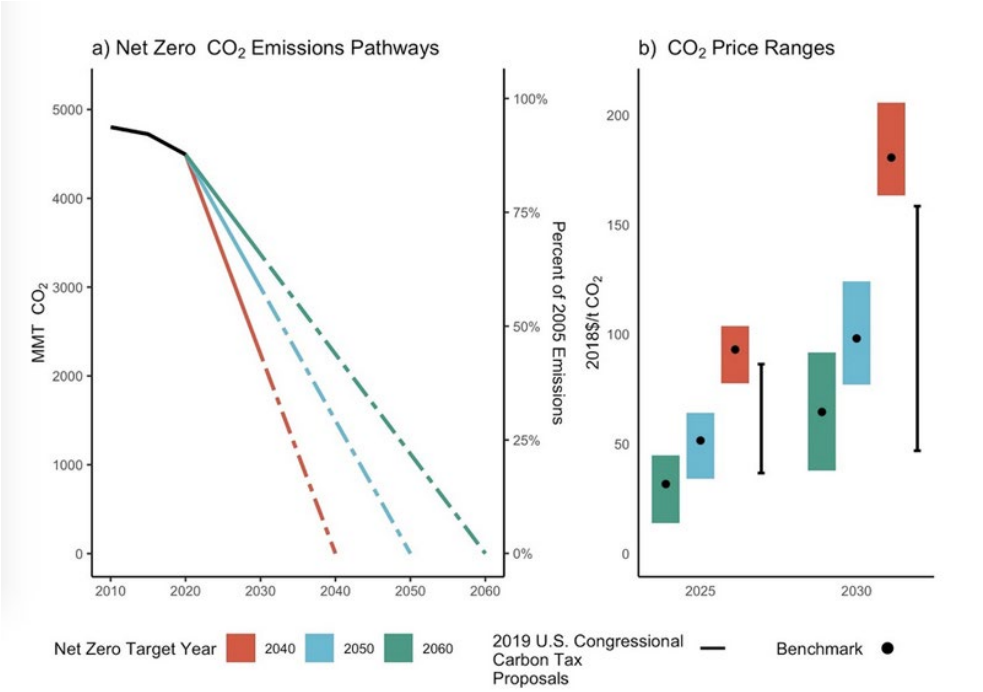
"The wide range of SCC estimates provides limited practical assistance to policymakers setting specific CO_2 prices," Kaufman says. Instead, Kaufman and his coauthors recommend what they call the "near term to net zero" (NT2NZ) approach, which they say can eliminate much of the uncertainty, although they acknowledge it "balances benefits and costs only imperfectly."

The authors say the SCC is undermined by the large uncertainties over risk aversion levels, attempts to assign monetary values to noneconomic climate damages and the appropriate discount rates — the value placed on future generations.

The NT2NZ approach proposes a four-step methodology:

1. Select a net-zero CO_2 emissions date.
2. Select an emissions pathway to the net-zero target that balances the risks of even higher temperature changes with the additional costs of decarbonizing faster.
3. Estimate CO_2 prices consistent with the emissions pathway in the near term (e.g., next decade).
4. Periodically update steps 1-3 using an "an adaptive management strategy."

"Focusing on the near term means that CO_2 price estimates should not be unduly influenced by assumptions about the highly uncertain long-term evolution of technologies and



a) Historical emissions (black) and CO_2 emissions pathways consistent with a straight-line path to net-zero CO_2 in the target year. b) Illustrative ranges of CO_2 prices in 2025 and 2030 needed to reduce U.S. net CO_2 emissions on each of the three emissions pathways (NT2NZ CO_2 prices; bars). The black dots reflect benchmark scenario NT2NZ CO_2 prices. The whiskers represent the ranges of CO_2 prices in proposals to Congress in 2019. | *Noah Kaufman, et al.*

Table 5: Social Cost of Carbon Estimates Developed by New York State Agencies per Metric Ton of Carbon Dioxide in 2018 U.S. Dollars, 2020-2050

Year of emissions	3 percent discount rate
2020	$52
2030	$62
2040	$73
2050	$86

Source: GAO analysis of data from New York Public Services Commission, Order Establishing the Benefit Cost Analysis Framework. | GAO-20-254

| *GAO*

FERC/Federal News

behavior," Kaufman said. "Adaptive management can enable jurisdictions to stay close to the desired emissions pathway without making policy details contingent on assumptions about highly uncertain long-term variables."

To illustrate the approach, the study looked at three straight-line emissions pathways from 2020 levels to net-zero CO_2 emissions targets in 2060, 2050 and 2040. It resulted in benchmark prices in 2025 of $32, $52 and $93 per metric ton (in 2018 dollars), respectively. The price roughly doubles by 2030, "reflecting a much higher annual growth rate than typical CO_2 price estimates based on the SCC or rising at the rate of interest," the authors write.

Complementary policies such as more aggressive energy efficiency measures and regulations that lead to higher coal retirements could lower the 2050 CO_2 price by $10 to $20/ton, with the price rising by the same amount with less aggressive policies.

The authors acknowledge that uncertainties present in the SCC approach — such as near-term clean energy innovation and fossil fuel prices — also impact the NT2NZ method. "But the NT2NZ approach avoids much larger uncertainties, including assigning monetary values to climate change damages," they say.

The Climate Leadership and Community Protection Act (*CLCPA*) signed by Gov. Andrew Cuomo last year requires the Department of Environmental Conservation (DEC) to establish a carbon price — based on either abatement or damage cost estimates — that state agencies can use to consider the societal value of actions to reduce GHG emissions in their decision-making.

The DEC this summer provided draft *regulations* on the value of carbon to fulfill the CLCPA requirements. The *comments* that the department receives will be part of the public record.

"It'd be great if the state took a look at our method when developing its [emissions] plan," Kaufman told *RTO Insider*.

Pricing emissions, however, should not be conflated with spending on climate change, he said.

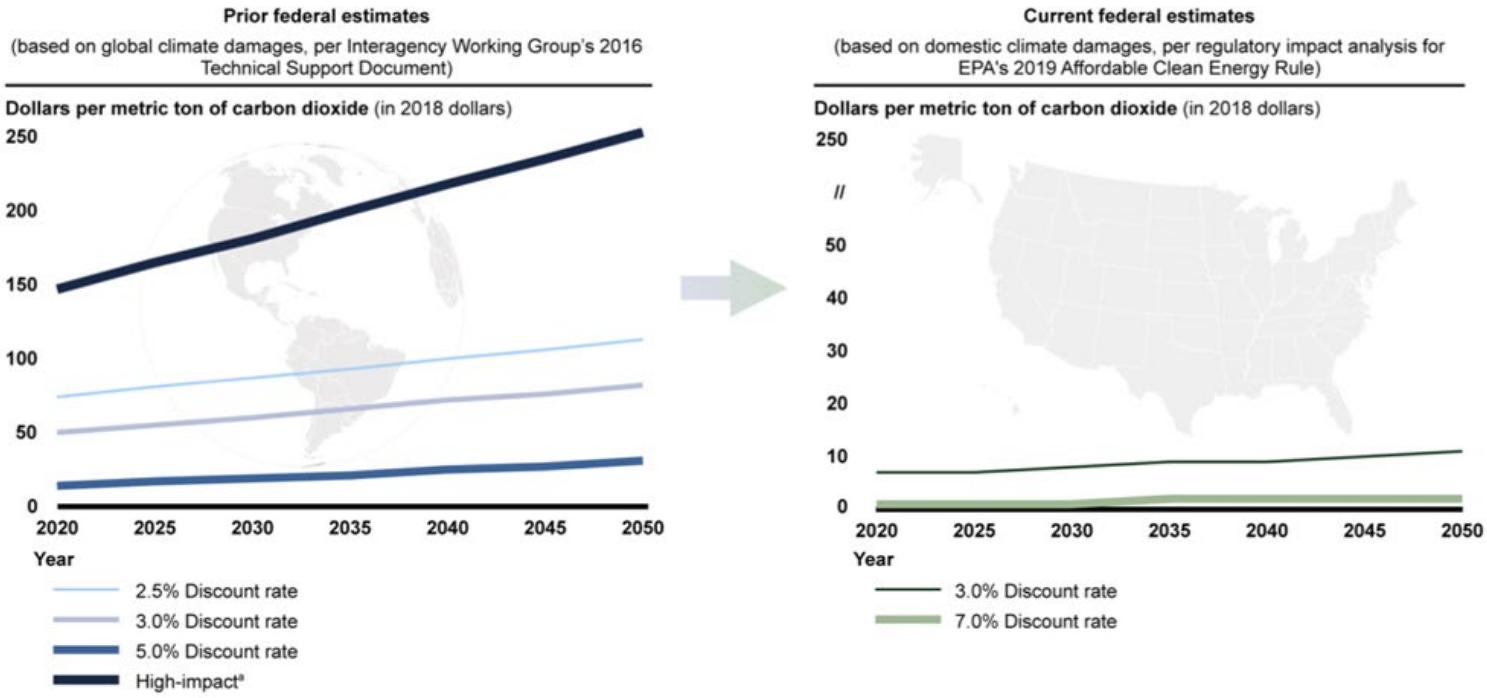
Speaking at a Sept. 9 *webinar* about the possibility of a green stimulus package from Congress after the presidential election, he said, "There's a pretty big caveat: Spending on clean energy is a really ineffective way to reduce emissions, at least by itself."

Kaufman recommended keeping expectations low for progress toward deep decarbonization.

"When you look at the data on the impacts of the nearly $100 billion in spending on clean energy from the 2009 stimulus, or the quarter-trillion dollars worldwide, you can find some really good outcomes for clean technology projects. But on emissions? No real evidence that it moved the needle," Kaufman said.

Throwing money at clean technologies is not a climate strategy, he said. The core of climate policy strategies are policies that directly address emissions, such as regulatory standards and prices.

"The surest way to drive a climate policy analyst crazy is to describe a climate plan based on how much it's spending," Kaufman said. "Spending can be a great complement to climate plans, making them cheaper, more effective, more equitable. That's what Europe is doing right now. But if you want to reduce emissions, regulate emissions." ■



| GAO

FERC/Federal News

CERAWeek 2021 to be Virtual

CERAWeek organizers said last week that they are planning a virtual conference next year, citing "continuing uncertainty" surrounding the COVID-19 pandemic and advice from experts.

IHS Markit, the London-based global information firm that holds CERAWeek each March in Houston, said in an email Thursday that it will continue to monitor the situation and "take guidance" from city officials as to in-person gatherings.

CERAWeek 2020 was one of the first business casualties of the coronavirus pandemic when organizers canceled it in early March. At the time, COVID-19 had infected more than 88,000 people worldwide and killed almost 3,000, including one in the U.S. (See *CERAWeek Canceled as COVID-19 Virus Spreads*.)

The annual event is one of the world's largest energy conferences. The last in-person CERAWeek in 2019 drew more than 5,500 government officials, industry executives and thought leaders from around the globe.

CERAWeek 2021 will be held March 1-5 under the theme, "The New Map: Energy, Climate and Charting the Future," based on the title of co-founder Daniel Yergin's latest *book*.

"We will examine the dramatic changes reshaping the global landscape and what they mean for the energy future," CERAWeek co-Chair James Rosenfield said. He said he has been pleased with the positive response to the online CERAWeek Conversations, "all of which have been aimed at bolstering the community through this era."

"CERAWeek now has become a platform for ongoing engagement throughout the year," he said. ■

— Tom Kleckner

EPA Administrator Andrew Wheeler addresses CERAWeek in 2019, the last time the event was held in person. | © *RTO Insider*

CAISO/West News

CAISO Retiring, Incoming CEOs Field Questions

By Hudson Sangree

CAISO CEO Steve Berberich will retire today after nine years as head of California's grid operator. His replacement, Elliot Mainzer, who served for the past seven years as head of the Bonneville Power Administration, will take over tomorrow.

At a time of great change for CAISO, the two CEOs answered stakeholder questions in a roundtable discussion Sept. 22 hosted by the Western Energy Imbalance Market's Regional Issues Forum. John Prescott, chair of the EIM's Governing Body, moderated the discussion.

Many of the questions dealt with the challenges CAISO faces as it struggles with capacity shortfalls, the switch to carbon-free energy and its expanding role in Western energy markets.

The most candid answer of the hourlong meeting came from Berberich, when Prescott asked him about the rolling blackouts of Aug. 14-15 and the energy emergencies CAISO declared over Labor Day weekend.

Massive heat waves across the West and a scarcity of resources during evening peak demand times pushed CAISO too close to the edge, Berberich said. ISO staff had warned that capacity shortfalls could occur under just such circumstances, and now the state must move quickly to head off similar shortfalls next summer, he said.

"In a nutshell, resource adequacy needs to be redesigned, and I don't mean in a two-year regulatory, litigated process," Berberich said. "It better happen pretty damn fast, or we're going to have these same issues next summer, and I don't want Elliot to have to deal with the same crap I've had to deal with over the last 30 days. So, if there's any legacy I could [leave], it's that this has to happen, and it has to happen soon."

Elliot Mainzer | *BPA*

Steve Berberich | *© RTO Insider*

Berberich previously faulted the California Public Utilities Commission, which oversees procurement, for failing to heed CAISO's warnings. (See *CAISO Blames Blackouts on Inadequate Resources, CPUC*.)

CAISO, the CPUC and state Energy Commission are compiling a report on the causes of the August blackouts, which will probably be released after he retires, Berberich said. Some, including the California Community Choice Association, have called for an independent audit of that report. (See *CalCCA Seeks 'Objective' Review of Blackout Report*.)

It appears, Berberich said, that California generators were exporting energy in the day-ahead market even as the state struggled to meet demand in the real-time market, but the exact nature of the exports and their effects must still be determined, he said. Another problem may have been that some load-serving entities weren't scheduling all their demand in the day-ahead market, he said.

"There are a lot of moving parts on this thing," Berberich said.

The biggest problem, however, was clear, he said. It was the "head of the duck" in California's distinctive "duck curve" demand trend. The duck's head is also called the net peak: the hours after sun goes down and solar power rolls off the system but demand remains high.

> **"It better happen pretty damn fast, or we're going to have these same issues next summer, and I don't want Elliot to have to deal with the same crap I've had to deal with over the last 30 days."**
>
> — Retiring CAISO CEO Steve Berberich

"From a resource adequacy perspective, you have to cover all of the hours, and the way renewables work, you have to rethink these old ways of doing things," Berberich said.

"It's clear to everyone the sun doesn't work in the evening and the wind doesn't always blow, particularly when it's hot with high-

CAISO/West News

pressure systems sitting over California and the West," he said. "So now you're left with what? Right now, you have to use the gas fleet and imported power. And the gas fleet has been retiring here in California. And I've known this for some time, and I've told people … for some time, [that] there are going to be limits on imports when you have these heavy load periods throughout the region.

"And that's exactly what transpired," Berberich said. "The net peak or the head of the duck has to be provided for just like the 4 and 4:30 peak has to be provided for, and this is not news. We've been talking about this for a long time. We've said this publicly. We've had these filings. The resource adequacy program in California is not now matched up with the realities of working through a renewables-based system."

The approximately 1,500 MW of battery storage that's scheduled to come online by next summer will help but may not be the panacea some imagine, he said.

"Storage is going to play an important role, but you also have to think through how that storage is going to be charged, how it's going to be discharged and how the economics will work," Berberich said.

CAISO is seeking to deal with import shortfalls through its Resource Adequacy Enhancements Initiative by requiring commitments from out-of-state generators and lining up dedicated transmission heading into the summer of 2021. (See *CAISO Seeks 'Firm' Tx for Resource Adequacy*.)

Mainzer's First Conversation

"I unequivocally agree that we really need a candid and clear-eyed assessment of what happened in August so that we can identify the causal factors … [and] can craft solutions that affect the underlying issues," Mainzer said during what he described as his "first conversation" as incoming head of CAISO. (See *CAISO Names Bonneville Power Administrator as New CEO*.)

Markets need to be based on firm resource adequacy frameworks, he said.

"This is clearly going to be topic No. 1 for the state … and others across the West," said Mainzer, a California native. At the same time, "it's absolutely axiomatic that we must meet California's clean energy goals."

State law (SB 100) requires LSEs to supply customers with only carbon-free energy by 2045.

Both Mainzer and Berberich stressed the need to continue reaching out to stakeholders across the West, especially as the EIM seeks to add a day-ahead market to its current interstate real-time operation. The governance of the EIM is especially important to those outside the state, who worry about CAISO exerting too much control, he said.

"We need to be humble and listening," Berberich said. "That's probably the most important learning we have from [the EIM]," which has achieved more than $1 billion of benefits for its members across the West, according to CAISO.

Berberich said Mainzer is a good listener and will continue the dialogue.

Mainzer said he had to work with multiple, diverse constituencies to incorporate wind into BPA, a hydroelectric powerhouse, and to allow the federal power marketing administration to join the EIM, which it's scheduled to do in 2022. (See *Customers Probe BPA on EIM Impact*.)

"A guiding pillar of my philosophy will be a lot of outreach, a lot of listening and … just trying to harness the incredible intellectual capital of folks in our industry and trying to get those best solutions identified and right into the heart of operations," Mainzer said.

He said his knowledge of the Northwest and California will serve him well.

It's vital to "just really sit down and take the time to listen to folks [and] have that open, honest and rigorous dialogue," he said. "People need to feel as though their perspectives are heard and understood. You're not going to agree with everything everybody says, but at the end of the day, people need to feel that sense of participation and stakeholder engagement."

Mainzer said he hoped to get back to face-to-face meetings if the threat of COVID-19 passes. Online meetings are a poor substitute, he said.

"Let's go get that vaccine and get back to some three-dimensional relationships," he said.

Chairman Prescott called Berberich and Mainzer pre-eminent energy leaders and said he expects Mainzer to do great things at CAISO. As for Berberich, he said he doesn't think retirement will stick. "I just have a feeling we're going to see your smiling face somewhere in the industry." ■

CAISO/West News

Calif. to Halt Gas-powered Auto Sales by 2035

Continued from page 1

air. Cars shouldn't melt glaciers or raise sea levels threatening our cherished beaches and coastlines."

Newsom's order requires state agencies to partner with the private sector to speed up deployment of "affordable fueling and charging options" and to ensure that all Californians have "broad accessibility" to EV markets. The order does not prevent residents from owning gasoline-powered cars or selling them on the used car market.

The governor's office is assuming that zero-emission vehicles "will almost certainly be cheaper and better" than traditional vehicles by the time the rule goes into effect, according to the statement.

"The upfront cost of electric vehicles are projected to reach parity with conventional vehicles in just a matter of years, and the cost of owning the car — both in maintenance and how much it costs to power the car mile for mile — is far less than a fossil fuel-burning vehicle," the statement said, citing a BloombergNEF *study*.

Newsom also positioned the move as an economic opportunity for the state and U.S. automakers. EVs are California's second-biggest export, Newsom said during a press conference.

"If American manufacturers do not commit to zero emissions, they're not going to be able to sell their cars globally. They're not going to be able to sell their cars in China, in India, in Israel, in Ireland, [which] are also committed to similar goals that California is advancing," Newsom said in a video posted on Twitter.

"This is about strengthening our competitiveness [and] encouraging more manufacturing jobs," he said.

'Strong Action'

Newsom's order met with predictable praise from environmental groups.

"In the midst of a historic wildfire crisis, Gov. Newsom is taking strong action to protect California's economy and the health of its people," Environmental Defense Fund President Fred Krupp said in a statement. "His announcement today will not only address the single largest source of climate and air pollution in California, but is a major step toward boosting his state's economic competitiveness and helping Californians who are suffering extraordinary harms from air pollution."

Krupp added that the new rules will position California "to win a new generation of jobs building affordable zero-emission vehicles — jobs that Europe and China are also hoping to capture."

"With this announcement, California has the opportunity to be the center of the global clean transportation industry and once again to lead the nation in addressing climate change," Annie Notthoff, California director of the Natural Resources Defense Council, said in a statement. "The past years of apocalyptic wildfires, record temperatures and droughts have made climate change and pollution all too real for everyone in the Western U.S. — most of all low-income households and communities of color."

The move also sparked criticism.

Thomas Pyle, president of the American Energy Alliance, an advocacy group backed by fossil fuel producers, castigated the measure for allowing "bureaucrats in Sacramento" to make buying decisions that families should make for themselves.

"Right now, 97% of Americans decide to buy a car with an engine powered by gasoline. They make that decision for all kinds of reasons, including safety, size, range, comfort and, in many instances, because an electric vehicle is too expensive," Pyle said in a statement. "The governor knows that today's engines are cleaner, more efficient and more powerful. He also knows that there is no such thing as an environmentally perfect vehicle. This is not only a bad idea, and a bad deal for the state of California, it's insulting to consumers and families." ■

| *California Energy Commission*

CAISO/West News

Avista Rule Violates Own Tariff, FERC Finds

By Robert Mullin

Avista violated its own tariff by requiring the Bonneville Power Administration to acquire firm point-to-point transmission service to deliver operating reserves from a resource located outside Avista's balancing area to a BPA customer situated within, FERC ruled Sept. 17 (*EL20-36*).

Under FERC's *pro forma* Open Access Transmission Tariff, load-serving transmission customers must obtain operating reserves along with transmission service. Reserves can either be purchased from the transmission provider or a third party, or be self-supplied.

BPA purchases network transmission service from Avista to serve customer load located within the utility's BA, an arrangement that historically included the purchase of operating reserves. In 2018, the federal power marketing administration notified Avista that it would begin to self-supply those reserves from its own generation outside the BA.

"This was the first instance in which an Avista transmission customer had opted to self-supply operating reserves," FERC noted in its order issued at its monthly open meeting.

Avista then informed BPA that it would need to acquire additional firm point-to-point transmission service to deliver the self-supplied reserves in the utility's territory. The utility also noted it had revised its business practice manual to reflect the requirement.

BPA responded with a complaint to FERC, contending that the new self-supply business practice violates the Federal Power Act because:

- it is unduly discriminatory and preferential by imposing additional costs on BPA's self-supplied operating reserves that are not applied to Avista's reserves;
- it is unjust and unreasonable to require transmission customers to pay an additional charge to self-supply reserves; and
- Avista had not filed the business practice manual change with FERC under FPA Section 205.

BPA contended that it was delivering the same reserve product designated to meet the same contingencies, the only difference being the location of the supply. It also argued that there is no NERC reliability factor that justifies treating reserves from off-system resources differently from those originating from internal resources.

"Furthermore, Bonneville asserts that when Avista receives off-system operating reserves from the Northwest Power Pool Reserve Sharing Group, Avista does not procure additional firm point-to-point transmission service," FERC noted.

Avista countered that, in order to be comparable to its supply of operating reserves and fully serve load, BPA's reserves must be delivered to the AVA.SYS delivery point on the utility's system, the point from which it deploys all operating reserves within its system.

Avista argued that it would not be sufficient for BPA to deliver those reserves to the AVA.BPAT delivery point, which represents the boundary between the entities' systems, because it is considered neither a source nor sink.

Furthermore, Avista contended that BPA could not use its firm network transmission service to deliver the operating reserves from AVA.BPAT to AVA.SYS because the utility's tariff stipulates that network transmission service is used to deliver capacity and energy from the customer's designated network resources to its network loads, while the BPA generation being set aside as operating reserves would not be supplying network load.

BPA responded that the commission did not have to resolve the issue of where the operating reserves are delivered but should address Avista's disparate treatment of each's reserves. BPA said it would be willing to deliver its self-supplied reserves to any point as long as Avista's resources are subject to the same requirements.

'Inappropriate' Restriction

In its order, FERC noted the proceeding contained no dispute about whether self-supplied operating reserves deployed from designated network resources within Avista's BA can use a transmission customer's existing network service and not be required to obtain additional service.

"Indeed, Avista acknowledges that it does not reserve and use additional transmission service for its own operating reserves," the commission wrote.

The question, FERC clarified, is whether Avista may require that reserves outside its territory must obtain additional firm service.

"We find that the transmission used by operating reserves deployed from designated network resources — regardless of whether those resources are located within Avista's balancing area or outside it — is part of the network transmission service for which the network transmission customer has paid," FERC found.

The commission noted that a previous opinion determined that "operating reserves 'are reservation services that do not require additional transmission.'"

"We are not persuaded by Avista's arguments that the location of the operating reserves, or the fact that Bonneville lacks designated network resources within Avista's balancing area, justifies the assessment of additional transmission charges for operating reserves that are provided in conjunction with taking transmission service," the commission said.

FERC additionally ruled that Avista was violating its own tariff by not allowing network transmission service customers to use their service to deploy reserves from outside the BA.

"Specifically, section 28.3 of Avista's tariff states that Avista 'will provide firm transmission service over its transmission system to the network customer for the delivery of capacity and energy from its designated network resources to service its network loads on a basis that is comparable to the transmission provider's use of the transmission system to reliably serve its native load customers,'" the commission said.

"Avista's requirement to reserve and use additional firm point-to-point transmission service to transmit operating reserves deployed from designated network resources located outside of Avista's balancing area inappropriately restricts the network transmission customer's use of its network transmission service," FERC continued.

But the commission would make not issue a determination over whether BPA's operating reserves deployed from resources are eligible to use the existing transmission service.

"The record is unclear about whether the Bonneville resources from which it will deploy operating reserves meet the requirements to be designated as network resources under the Avista tariff, and nothing in this order finds that the resources that Bonneville wants to rely on for the operating reserves at issue are designated network resources under Avista's tariff," the commission concluded. ■

CAISO/West News

FERC OKs CAISO Cost Recovery Plan for Gas

In Concurrent Order, Commission Approves ISO's Order 831 Compliance Filing

By Hudson Sangree

CAISO last week won FERC approval for its second effort to implement market rule changes to allow generators to recover the costs of higher natural gas prices (*ER20-2360*).

The changes emerged from CAISO's Commitment Costs and Default Energy Bid Enhancements (CCDEBE) initiative. FERC rejected an earlier filing by the ISO in 2019, saying its generous multiplier for gas resources was neither fact-based nor warranted.

CAISO's revised plan, which eliminated the multiplier, measured up, FERC said.

"We find that CAISO's CCDEBE proposal will allow resources that face high gas costs resulting from inter-day variation in natural gas prices to reflect those costs in their reference levels," FERC said. "By reflecting the actual costs of these resources in reference levels, CAISO's proposal will facilitate a more efficient dispatch of its system."

Order 831 Compliance

The ruling was one of two that FERC issued Sept. 21 involving CAISO's efforts to comply with Order 831.

Issued by FERC in 2016, Order 831 requires ISOs and RTOs to raise the hard caps on supply bids from $1,000 to $2,000. Offers over $1,000 require suppliers to justify their costs. It's meant to allow supply resources, especially gas generators, to earn prices sufficient to recover their operating costs during periods of high demand, thereby helping to ensure reliability.

To comply with the order, CAISO proposed revising its Tariff with a two-tier bid cap structure. The plan includes a soft cap of $1,000/MWh — which would apply to all energy bids except for virtual bids and those for non-resource-specific system resources — and a hard cap of $2,000/MWh, which would apply to all energy bids.

CAISO's Department of Market Monitoring objected, arguing that the ISO's proposed provision regarding verification and recovery of minimum load cost bids was unclear and unsupported.

FERC dismissed the objection and said the revisions complied with the requirements of Order 831, subject to a further compliance filing to update certain eTariff records (*ER19-2757*).

"We find that, as required by Order No. 831, CAISO's Tariff revisions proposed herein and reflected in the 2020 CCDEBE proposal set forth the process for CAISO to verify that a resource's bid above $1,000/MWh reasonably reflects that resource's actual or expected costs," FERC wrote.

'Natural Gas Price Volatility'

In the cost-recovery ruling, FERC said it had rejected CAISO's 2019 CCDEBE proposal because the ISO failed to show that it was just and reasonable to apply a 125% multiplier to commitment cost bid caps derived using supplier-submitted costs.

"Specifically, the commission stated that 'whereas a multiplier applied to an index captures deviations from an average cost, and therefore may account for resource-specific cost deviations from the index, a multiplier applied to supplier-submitted costs would provide additional headroom on top of verifiable actual costs' and that CAISO had not provided sufficient evidence to support this upward adjustment," FERC wrote.

In its revised proposal, CAISO altered its methodology, including eliminating the multiplier from its plan. Instead, it submitted changes that let suppliers request adjustments to their ISO-calculated commitment costs — their start-up and minimum load costs — and to their energy-price reference levels to more accurately reflect their costs.

"CAISO asserts that the proposed revisions will provide a just and reasonable method for verifying a supplier's request to increase a resource's reference levels when its actual or expected costs will be greater than CAISO-calculated costs based on verifiable contemporaneously available information," FERC wrote.

"CAISO explains that these procedures will enable it to use fuel or fuel-equivalent prices in calculating reference levels that reflect suppliers' actual or expected fuel or fuel-equivalent costs," it said. "CAISO contends that this, in turn, will provide CAISO with more efficient resource schedules and dispatches and will ensure that suppliers are adequately compensated."

FERC agreed with CAISO's assessment.

"CAISO's proposal to adjust the reasonableness threshold in response to inter-day fuel price increases in a fuel region, and in response to persistent conditions faced by a resource, will … ensure that its markets accurately reflect natural gas price volatility, which in turn will result in dispatching resources more efficiently," FERC said.

"Additionally, we find that CAISO's proposal to exclude existing commitment cost and default energy bid multipliers from the calculation of a resource's adjusted reference level is just and reasonable and addresses the concerns that led to rejection of the 2019 CCDEBE proposal," it said. "Under CAISO's proposal in this filing, reference level adjustments will be based on a resource's actual or expected costs and will not provide additional headroom above a resource's verifiable actual or expected costs." ■

PG&E's natural-gas fired Colusa Generating Station | *PG&E*

ERCOT News

ERCOT Technical Advisory Committee Briefs

Staff Promise Action to Reduce Errors Causing Price Corrections

ERCOT staff told stakeholders last week they are working to reduce errors following two recent unrelated events that led to price corrections and resettlements.

Kenan Ögelman, ERCOT's vice president of commercial operations, shared with the Technical Advisory Committee the speaking points he will deliver to the Board of Directors during its Oct. 12 meeting. He said the grid operator has several initiatives that will cut down on errors and price corrections and will also elevate testing, "which is kind of our last line of defense."

"We're making additional revisions and [instituting] controls around market changes that impact pricing," Ögelman said during the TAC's meeting Wednesday. "We're reviewing all of our manual processes … especially around resettlement items."

Ögelman said several revision requests are being drafted to address the problem. ERCOT is also evaluating protocol language to address recent discussions the Public Utility Commission has had in open meetings. While discussing a telemetry error that led to a price correction Sept. 14, PUC Chair DeAnn Walker said, "We shouldn't wait for there to be a really huge event." (See *Texas PUC Rejects Call to Reprice Error*.)

In February, staff updated the network model by adding dynamic ratings for three transmission transformers. A software error erroneously applied the new ratings to three unrelated 345/138-kV transformers in addition to the intended transformers. ERCOT didn't discover the cause of the error and the affected transformers until July, when it issued a *market notice*.

Staff reviewed all binding transmission constraints in the day-ahead market between Feb. 14 and July 7, finding 67 operating days that had at least one constraint binding on one of the transformers. They also found one instance of binding transmission in the real-time market.

Staff will ask the ERCOT board to review day-ahead and real-time prices for the June and July operating days that are eligible for repricing, as required by the grid operator's protocols. David Maggio, ERCOT's director of market design and analytics, said the pricing changes were "fairly minimal," but balancing account changes resulted in an overpayment to load of about $8,000 for June and an underpayment to load of approximately $15,000 for July.

ERCOT's Kenan Ögelman listens to the discussion during a 2016 TAC meeting. | © *RTO Insider*

The real-time constraint resulted in a *net settlement* to counterparties of almost $47,000.

More recently, a manual update to the network model *inadvertently disabled* a remedial action scheme for four day-ahead market operating days in August. Staff were able to correct the prices before they became final during the last day and will ask the board to review the other three operating days.

Members Reject Ancillary Service NPRR

Members rejected a Nodal Protocol revision request (*NPRR1025*) that would remove the real-time online reliability deployment price (RDP) from ancillary service imbalance calculations. The measure was approved by an 18-10 margin, with two abstentions, but its 64% approval fell short of the two-thirds threshold for endorsement.

ERCOT's Independent Market Monitor reiterated its opposition to the NPRR as written, citing what it said were two flaws.

"The first, and most important, is that it breaks a foundational principle in the market, that dispatch sent out by ERCOT should be the most profitable dispatch, given their offers and limitations. With this NPRR, in times of high ERS [emergency response service], that won't be true anymore," the IMM's Steve Reedy said.

"Secondly, the [operating reserve demand curve] adder calculation is not affected by the ERS deployment," he said. "That weight is carrying right now by the RDP adder. If you take that away from resources … that should raise the ORDC adder. We would support this with those associated indifference payments, which would be smaller than the megawatt implications in effect right now."

The NPRR was drafted by the Lower Colorado River Authority. John Dumas, the public utility's vice president of market operations, said it was driven by the divergence between the value of real-time reserves and day-ahead ancillary service prices during ERCOT's 2019 energy emergency alerts, caused by including

ERCOT News

the RDP in the price of real-time reserves.

"LCRA believes that only the ORDC adder should be included in the price of real-time reserves," Dumas said. "This removes what we believe is an undue risk to loads and generators for participating in the day-ahead ancillary service market. It removes the real-time deployment price adder and removes risk and cost."

2% Solution: Monitor to Draft NPRR

Based on discussions with TAC leadership and the IMM, the Monitor will draft an NPRR to address a desk procedure left over from ERCOT's zonal market, Ögelman said.

Several stakeholders had suggested such action when staff brought forward a discussion of the "2% rule" to the August TAC meeting. An artifact from the zonal market, which was replaced by the nodal market in 2011, the rule says generating units with shift factors of less than 2% should not be dispatched by the real-time market in response to transmission overloads. (See *ERCOT Technical Advisory Committee Briefs: Aug. 26, 2020*.)

The IMM in August said it believes the 2% rule should be eliminated and all congestion priced in real time, regardless of generation's effect. "Prices matter," IMM Director Carrie Bivens said during the discussion.

"I presume [the Monitor will] be putting the [shift-factor] percentage at zero, and we'll see how that progresses," Ögelman said. "Stakeholders can modify that as they see fit."

He said ERCOT will take a position on the issue when comments are filed.

Under the rule, if a transmission constraint exists for which there are no generator shift factors of at least 2%, ERCOT operators must verify that a mitigation plan or temporary outage action plan exists for the contingency, and they are to review the plans with the affected transmission owner. If no plans exist, then the operators are to develop a mitigation plan with ERCOT's operations support engineer. If no plans have been developed within 30 minutes, the operations desk issues a transmission watch, a step down from an emergency.

TAC Adds 10 Change Requests to List

TAC Chair Bob Helton complimented the committee for its virtual work this year, noting that it has passed 79 revision requests, with 65 more in the pipeline, while working from home.

"That says a lot about how we've progressed in troubled times," Helton said.

The committee then passed a combination ballot, with an abstention, that added 10 more RRs to the approval list.

In a separate vote, the TAC approved the annual update to the *major transmission elements list*. Four members abstained from the vote.

One of the endorsed changes, a revision to the Planning Guide, will likely be appealed during the October board meeting. The change (*PGRR077*) clarifies that ERCOT's transmission planning analysis will assume DC tie flows are curtailed when necessary to meet reliability criteria.

Shams Siddiqi, with Rainbow Energy Marketing, said the current $23/MWh transmission charge for DC tie exports during summer off-peak hours is a significant barrier to exporting energy. It also suppresses the market's opportunity to address the allocation of sunk costs, adversely affecting decisions to consume or export, he said. Only the Public Utility Commission can modify the DC tie export's Tariff, he said.

"Until and unless the PUC eliminates or significantly reduces the DC tie export tariff, the only equitable treatment of DC tie load is to treat DC tie load as other load in the ERCOT reliability transmission planning process," Siddiqi said in filed comments. "If the PUCT were to eliminate the DC tie export tariff … [it] would remove an inefficient barrier to trade."

Staff told Siddiqi he could appeal the revision request when it comes before the board next month. Helton noted that at least one PUC commissioner will call in to the meeting.

"If parties or stakeholders want to do it, they can file a petition for a rulemaking at the PUC," said Katie Coleman, who represents Texas Industrial Energy Consumers. "The issue of transmission allocations is a really old issue that's come up multiple times. I think the PUC is aware of these issues and can address them, if [it] wants to."

The combo ballot included six other NPRRs, two changes to the Nodal Operating Guide (NOG) and a system change request (SCR):

- *NPRR999*: Revises protocol language on DC tie schedules and creates a section related to ramp limitations on DC ties. It is intended to clarify that when ERCOT determines system conditions show insufficient ramp capability to meet the sum of all DC ties' scheduled ramp, it will curtail schedules on a last-in, first-out basis. Before curtailing DC tie schedules, ERCOT, with enough time, may request one or more qualified scheduling entities to voluntarily resubmit e-tags with an adjusted ramp duration.
- *NPRR1033*: Specifies that ERCOT does not have an obligation to pay interest on former market participants' cash collateral balances upon its determination that financial security is no longer needed to cover the terminated participant's potential future obligations.
- *NPRR1035*: Requires ERCOT to publish all DC tie schedules 60 days after the operating day.
- *NPRR1036*: Clarifies some processes associated with late payments and payment breaches and aligns protocol language on market participants' registration and qualification with language in the standard form market participant agreements.
- *NPRR1037*: Corrects switchable generation resources' (SWGRs) settlement when instructed to switch from a non-ERCOT control area to the ERCOT control area. The NPRR includes the SWGR's operational costs in the non-ERCOT control area in calculating switchable generation operating cost for resources with approved verifiable costs.
- *NPRR1038*: Establishes a limited exemption from reactive power requirements for some energy storage resources (ESRs). The exemption is available only to an ESR that achieved initial synchronization before Dec. 16, 2019, and applies only to the extent the resource is unable to comply with the reactive power requirements when it is charging. To qualify, the ESR's operator must submit a notarized attestation to ERCOT that says the ESR would be unable to comply with the requirements without making physical or software changes.
- *NOGRR214*: Describes ERCOT's process for collecting geomagnetically induced current monitor and magnetometer data to satisfy requirements of NERC Reliability Standard TPL-007-3 (Transmission System Planned Performance for Geomagnetic Disturbance Events).
- *NOGRR218*: Removes the requirement that disturbance-monitoring equipment owners annually submit their databases to ERCOT.
- *SCR811*: Adds a predicted five-minute solar ramp to the resource-limit calculator's formula for calculating the generation-to-be-dispatched value. The solar ramp rate will be calculated from the intra-hour PV power forecast and the short-term PV power forecast. ■

— Tom Kleckner

ERCOT News

NRG to Mothball Petra Nova CCS Plant

By Tom Kleckner

NRG Energy advised ERCOT on Sept. 21 that it plans to mothball its Petra Nova Power plant, centerpiece of the *world's largest carbon-capture facility*.

NRG issued a notification indicating that the plant will shut down on Dec. 20 but will be available for annual seasonal operations between June 1 and Sept. 30. ERCOT market participants have until Oct. 12 to file comments on any possible reliability effects from the suspension.

Operations at the plant have been *suspended* since May 1. NRG cited the global economic downturn and the low price of oil.

The plant, which has a summer capacity of 71 MW, was retrofitted at a cost of $1 billion to capture carbon from one of the nearby W.A. Parish Generating Station's coal-fired units. Post-combustion carbon-capture technology reduces Petra Nova's carbon emissions by 90%. The captured carbon is funneled through an 80-mile pipeline to a nearby oil field.

NRG intends to mothball its Petra Nova carbon-capture project. | *NRG Energy*

Petra Nova became operational in December 2016, on budget and on schedule. NRG said the plant delivered more than 1 billion tons of captured CO_2 within its first 10 months. *Power Engineering* honored the project in 2017 as its Coal-Fired Project of the Year. Industry analysts don't expect the plant to return to operation until oil prices stay consistently above $50 or $60/barrel.

Despite the project's carbon-capture pedigree, NRG has remained a target of environmentalists. Chrissy Mann, the Sierra Club's Beyond Coal Campaign representative, said that even when the Petra Nova project was operational, the Parish facility was the No. 1 source of particulate matter and No. 2 source of sulfur dioxide in the state of Texas.

"As NRG seemingly ends its carbon-capture project, NRG needs to take steps to address its dangerous air and water pollution," Mann said. "It definitely makes economic sense that NRG is moving away from this continued investment in coal." ■

ISO-NE News

Maine Makes Record Renewable Procurement

By Jason York

Maine's sunshine will soon provide more than just lighting for viewing the fall foliage.

The Maine Public Utilities Commission last week announced a procurement of renewable energy, and solar developers were the clear winners, claiming 14 of the 17 projects selected. It is the PUC's largest procurement of renewable energy since restructuring more than 20 years ago.

The *selected projects* were evaluated through a competitive bidding process based on expected value to Maine's consumers and economy. Solar will account for 482 of the 546 MW of the approved projects, with wind (20 MW), hydroelectric (4.5 MW) and biomass (39 MW) making up the remainder.

The biggest projects are Swift Current Energy's 100-MW solar farm in Hancock County, which signed a term sheet with Versant Power, and Granite Apollo's Canton (65 MW) and Roxbury (55 MW) projects, which signed agreements with Central Maine Power.

Maine currently has about 93 MW of solar power, *according* to the Solar Energy Industries Association, ranking it 43rd among states.

PUC Chairman Philip Bartlett told *RTO Insider* that this process "reflects just how much renewable energy potential there is in Maine and the benefits to Maine's economy from moving forward aggressively."

Winning bidders estimated the projects would reduce greenhouse gas emissions by approximately 500,000 tons per year. They have also committed to providing more than 450 full-time jobs during the construction phase and more than 30 full-time-equivalent positions in each operational year.

"It's really important that as we are transitioning to a clean economy that we recognize the important economic benefits to Maine people and the jobs that can be created," Bartlett said. "I think it's certainly beneficial that there'll be a lot of jobs during the construction phase as well. That will help at a time when the economy is struggling, so hopefully, the combination of those things will have a meaningful long-term impact."

The projects promise more than $145 million in initial capital spending. In addition, the ReEnergy Livermore Falls biomass project will generate payments to Maine-based contractors for the harvest of wood fuel averaging $11 million to $12 million annually during the 20-year contract term.

"I think that's an indication of how strong a market signal this was, and we're excited about this procurement, which is the first to not just look at the price that comes with these projects, which in this case was very competitive, but also look at the economic benefits," Dan Burgess, director of Gov. Janet Mills' Energy Office, told *RTO Insider*. "It's pretty innovative to have those built-in directly into the contracts and the term sheets; I think it's a guaranteed positive impact for an economy."

The first-year energy prices for the 15 new projects awarded term sheets ranged from $29.75 to $40/MWh, with a weighted average price just under $35/MWh.

These projects are the first since Mills signed legislation last year to increase the state's renewable portfolio standard to 80% by 2030 and set a goal of 100% renewable energy by 2050.

Another round of procurement bids for renewable resources is due in mid-January, and developers that were not initially selected can enter again. The two procurements must equal 14% of the state's 2018 retail electricity sales. The awards announced last week represent 9.4% of 2018 sales. ■

Thomas College solar roof in Waterville, Maine | *Coastal Enterprises*

ISO-NE News

NEPOOL Reliability Committee Briefs

Greater Boston Project Costs up by 1/3

The cost of the Greater Boston Project is expected to increase by $191 million (33%) primarily because of the underground Wakefield-Woburn, Mystic-Woburn and Sudbury-Hudson lines, Eversource Energy *told* the New England Power Pool Reliability Committee on Wednesday.

The cost of the three components is increasing by $147 million, to $352 million (72%).

The remaining 30 components' cost is rising from $367 million to $411 million, a 12% increase over the transmission cost allocations supported previously by the RC and approved by ISO-NE.

Eversource said 25% of the increase is resulting from the need to underground the 115-kV Sudbury-Hudson line. It was initially proposed as an overhead line, but Eversource was unable to secure property leasing rights from the Massachusetts Bay Transportation Authority (MBTA). The proposed underground line is estimated at $91 million, more than double the original cost of $45.3 million, and has an in-service date of December 2023.

Eversource performed an updated alternative analysis and found that a new 9-mile, 115-kV underground transmission line within an MBTA right of way was the "most cost-effective and constructible alternative." The two alternatives analyzed — a new 10.3-mile, 115-kV underground transmission line entirely in roadways ($110.4 million), or multiple upgrades to convert a 14.5-mile, 69-kV line to 115 kV, reconductor 11.6 miles of other 115-kV lines and upgrade seven substations ($116.1 million) — had higher costs.

The Wakefield-Woburn and Mystic-Woburn lines are increasing to a combined $260.6 million from $160.2 million, representing 50% of the total cost increase. Eversource said additional restrictions on the design and construction required a realignment of underground construction within roadways to avoid interference with existing utilities. Restrictions on work hours and the number of crews also increased the construction bids, the company said.

| © RTO Insider

The matter is slated for a future committee vote.

ISO-NE, NYISO Propose Revision to Coordination Agreement

ISO-NE *proposed revisions* to its Coordination Agreement (CA) with NYISO to eliminate the need to make a FERC filing when the grid operators update their description of shared interconnection facilities.

The grid operators share three interconnections: the NY/NE Northern AC Interconnection (comprising the PV-20, K7, K6, E205W, 393, 690/FV and 398 interties); the Norwalk Harbor-Northport, NY, Cable (NNC Intertie) and the Cross-Sound Cable Interconnection (CSC Intertie).

Rather than maintaining the detailed list of interconnection facilities in Schedule A of the CA — which requires a FERC filing for any changes — the grid operators are proposing to update the list on their external websites. The addition or removal of an interconnection would still go through the grid operators' stakeholder processes and filed with FERC.

ISO-NE said it and NYISO sought the change after the addition of a new transmission substation and common metering point modified one of the interties in the NY/NE Northern AC Interconnection. The change replaced the Pleasant Valley substation and common metering point in New York with the Cricket Valley substation and common metering point on the 398 Intertie.

Although the change did not alter the makeup of the NY/NE Northern AC Interconnection, current rules required that it be filed with FERC. "ISO-NE and the NYISO recognized that such ministerial revisions to the ISO-NE/NYISO CA place an unneeded burden on the respective ISOs, their stakeholders and the FERC," ISO-NE told the committee.

The grid operators plan to file the revised CA with FERC at the end of 2020 and expect an effective date of early 2021. NYISO will go through a similar stakeholder process, which it expects to complete in November or December, according to ISO-NE.

The RTO requested that the RC vote in support of the proposed modifications at its Oct. 20 meeting.

Tie Benefits and ICR Recommended by Vote

The RC voted to recommend that the Participants Committee support ISO-NE's tie benefits and installed capacity requirements (ICR) and related values for Forward Capacity Auction 15. (See *ISO-NE Sees 722-MW ICR Jump for FCA 15*.)

The Hydro-Québec Interconnection Capability Credit (HQICC) values for FCA 15, which is associated with the 2024/25 capacity commitment period, is 883 MW, and the ICR is 34,153 MW with a net ICR of 33,270 MW.

The following megawatt values were also recommended for support: Southeast New England Local Sourcing Requirement (10,305), Maine maximum capacity limit (4,145) and Northern New England maximum capacity limit (8,680).

The PC will vote on the ICR and related values on Oct. 1, with a FERC filing expected by Nov. 10.

Winter Readiness, Gas Infrastructure Surveys Added to OP-21

The RC voted to recommend that the PC approve changes to *Operating Procedure 21* to add the generator winter readiness survey and natural gas critical infrastructure survey.

OP-21 is being renamed "Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency" to reflect the additions.

The annual generator survey process enhances situational awareness of pre-winter generator preparations, while the natural gas survey ensures critical infrastructure of the interstate natural gas system is not on electrical circuits subject to automatic or manual load-shedding schemes.

ISO-NE distributes the generator survey before Nov. 1 each year, and it is due back no later than Dec. 1 unless specified otherwise.

The RTO distributes the natural gas survey to representatives of each interstate natural gas pipeline company operating in New England, as well as the Canaport and Everett LNG facilities. It is typically completed in June. ■

— Jason York

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

Proposed Study Conditions to Meet Challenges in Transmission Planning

ISO-NE presented the Planning Advisory Committee on Thursday with potential *study conditions* to identify transmission needs under increased penetration of distributed energy resources, renewables and energy storage resources (ESRs) and increasing imports via HVDC interconnections.

In addition to responding to different system conditions in this "future grid," planners also will need to consider new approaches to data collection to ensure accurate modeling, said Dan Schwarting, transmission planning supervisor for ISO-NE.

The RTO said the discussion Thursday was the first of many it plans with stakeholders this year; studies with new assumptions may begin in 2021.

While the RTO's current study methods and assumptions work well, Schwarting said, they may be inadequate in a decade, when these new resources become increasingly ubiquitous.

With a higher penetration of DERs, primarily solar PV, and continued offshore wind generation development, Schwarting said, "what we're finding is that as time goes on, and these trends continue to accelerate — we continue to see more wind interconnections and more distributed energy resources — we really need to rethink some of these approaches."

For example, ISO-NE lacks visibility on, and control of, storage assets on the distribution system. New England currently has less than 5 MW of solar PV connected to its distribution systems, but by December 2029, that will increase to 7,796 MW, according to the 2020 Capacity, Energy, Loads, and Transmission (CELT) report.

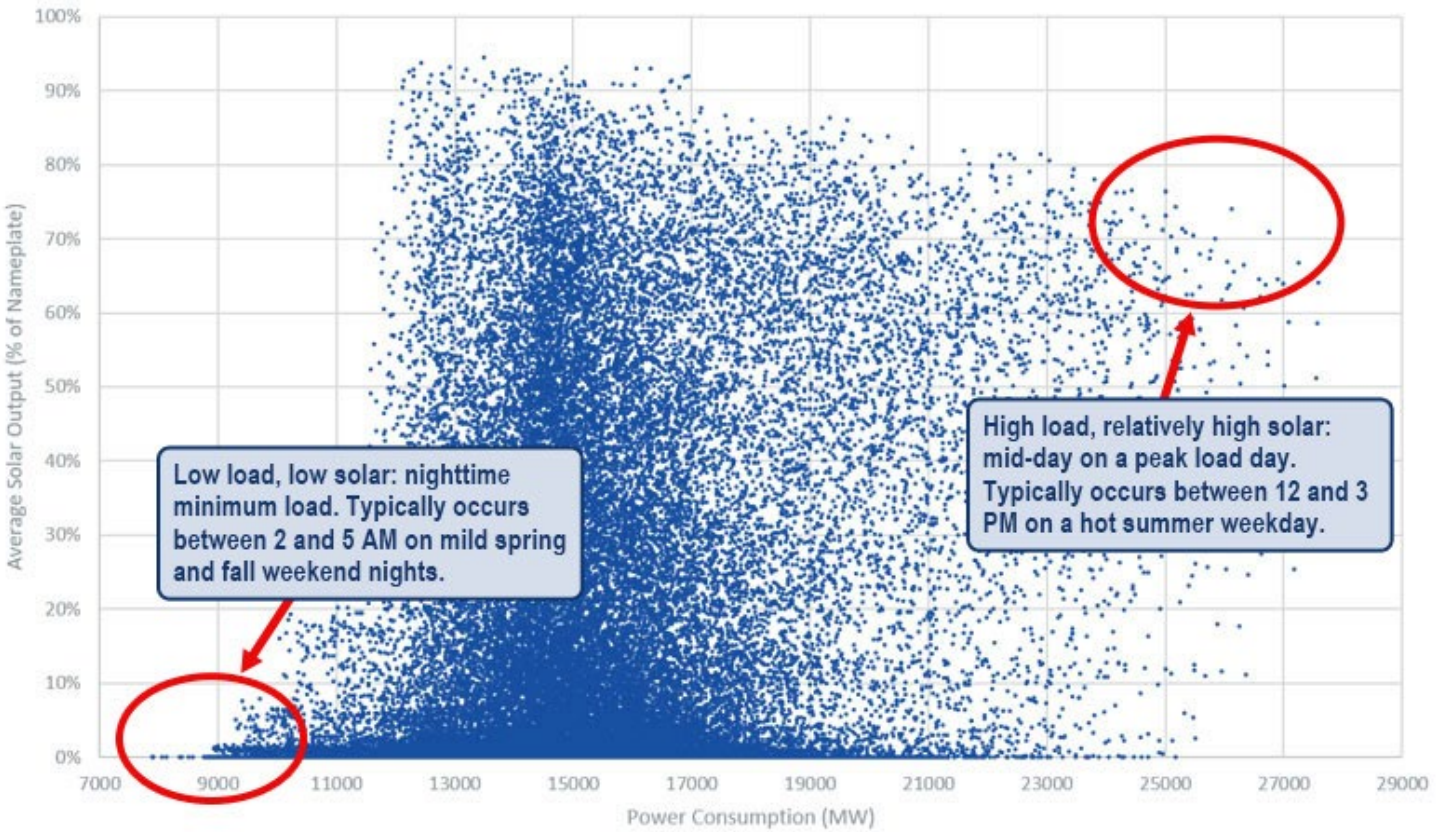
In addition to the 30 MW of offshore wind generation currently in service, an additional 1,504 MW have secured state contracts, with 156 MW committed through the Forward Capacity Market and another 1,600 MW of state contracts under negotiation.

To date, New England's planned offshore wind interconnections are located in southeastern Massachusetts and Rhode Island.

"There's not a real lot of geographic diversity yet," Schwarting said. "That may change further down the road."

Low wind production at peak load could lead to high imports for the Southeast Massachusetts/Rhode Island region, while high wind and solar production at low load levels could lead to high exports. High wind production could also lead to voltage control challenges because of a smaller number of synchronous generators online.

As DER penetration increases, Schwarting



Each blue dot in this scatterplot represents a single hour of solar output as a percentage of nameplate rating (vertical axis) and gross load data (horizontal axis) from 2012-2018. | *ISO-NE*

ISO-NE News

said, net load will not accurately define system conditions. He cited two examples of an 8,000 MW net load level: at 3 a.m. on a mild spring night with 8,000 MW consumed and no solar, versus 1 p.m. on a mild, sunny spring day when 14,000 MW is consumed but is partially offset by 6,000 MW of solar.

The revised assumptions will be used in future needs assessments and solutions studies in addition to studies of market efficiency and public policy transmission upgrades.

Studies already underway will continue under existing planning assumptions and not restarted, Schwarting said. Solutions already planned or under construction based on previous studies will not be re-examined either.

"There's still a lot of different areas that we have to explore. We don't think that we'll be ready to start a new study with these assumptions for at least quite a few months at this point, so we don't want to put all of our existing studies on hold, especially those that are discovering time-sensitive needs," Schwarting said. "We also don't expect that a lot of the upgrades that we're identifying will be significantly different under the new proposal."

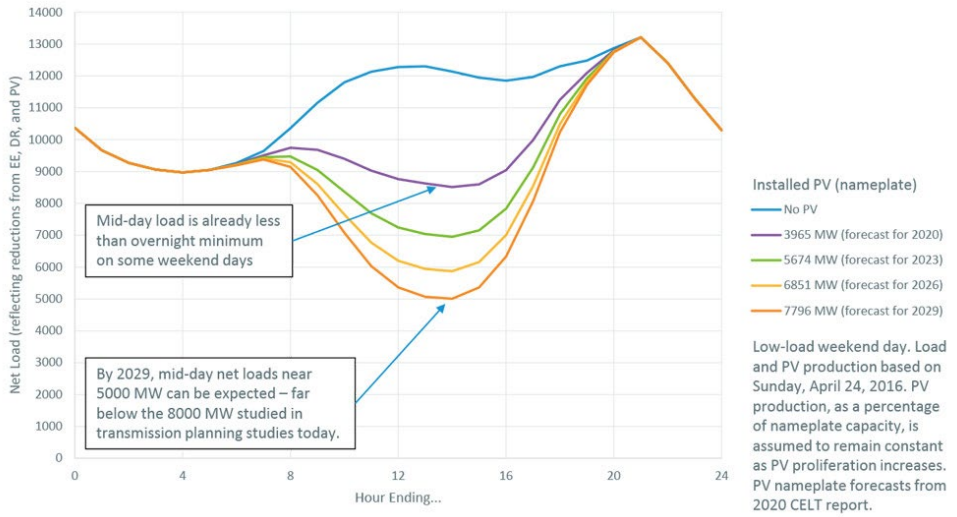
ISO-NE is *taking feedback* from stakeholders on the proposals until Oct. 9, with further discussion slated for future PAC meetings. In the meantime, RTO staff will continue their development of study assumptions concerning ESRs; areas with noncoincident peak loads; conventional generator outages; interface transfers; and light and shoulder load conditions in proposed plan application studies. Staff will also talk to distribution providers to obtain data on DERs.

Lower Maine 2030 Needs Assessment Draws Questions

Transmission planning engineer Meena Saravanan gave the committee a *presentation* on the scope of work for the Lower Maine 2030 Needs Assessment, which ISO-NE *announced* on Sept. 10.

The assessment is intended to evaluate the reliability and identify needs in Lower Maine under future load conditions reflecting the 2020 CELT report; resource changes based on Forward Capacity Auction 14 results; and reliability over a range of generation patterns and transfer levels. It also will seek coordination with needs assessments in Upper Maine and New Hampshire.

ISO-NE began a statewide needs assessment in June 2017 but split it into Upper and Lower Maine studies because of the need to consider the proposed New England Clean Energy Connect (NECEC) HVDC transmission line. RTO staff are conducting a solutions study based on the results of the Upper Maine assessment, which was completed in March.



Load served by ISO-NE transmission system with varying levels of behind-the-meter PV on a low-load weekend day, based on load and PV production for Sunday, April 24, 2016. (PV production, as a percentage of nameplate capacity, is assumed to remain constant as PV penetration increases.) | *ISO-NE*

The Lower Maine assessment could not proceed until NECEC's system impact study was completed and its required system upgrades were known, Saravanan said.

The primary triggers for the Lower Maine assessment were compliance with reliability standards; transfer capability; short-circuit performance; and system performance considering delist bids and cleared demand bids.

One area that drew a sharp line of questioning from a stakeholder was the 2030 peak load assumptions for Phase II HVDC, from Quebec to New England, which was given a dispatch range of 950 MW.

Bruce McKinnon, who represents the Norwood Municipal Light Department in Maine, said Phase II normally carries at least 1,200 MW.

"I find that to be a little bit of a problem," McKinnon said. "I can understand maybe doing some studies with it one way or the other. But the fact that you're not pushing it to what it is normally contributing to the system, I think, is a failure of an assumption — and I'd like the minutes to say so too."

Schwarting acknowledged that the line has operated at higher levels. "The 950 MW is essentially everything that we can contractually count on," he said.

Comments on the work scope will be collected until Oct. 9. The assessment is expected to be completed and presented to the PAC in the first or second quarter next year.

SWCT 2027 Solutions Study Concludes

ISO-NE *told* the PAC that the Southwest Connecticut 2027 Solutions Study is complete because the time-sensitive needs identified in the corresponding needs assessment have been addressed by Eversource Energy's Glenbrook static synchronous compensator (STATCOM) asset condition project.

The assessment's minimum load analysis found four buses with N-1-1 high-voltage violations for contingency events that included the loss of both STATCOMs at Glenbrook and the loss of a 345-kV reactor in the region.

Eversource presented its proposed solution at the July PAC meeting, saying maintenance or refurbishment of the existing STATCOMs — which were installed in 2004 and have an availability rate of only 81% — was not feasible.

The *project* replaced the two Glenbrook STATCOMs by repurposing the existing STATCOM building and outdoor equipment. The replacement STATCOMs, which would have the same reactive capability as the existing STATCOMs under normal operating conditions, eliminate the common mode failure.

The project is estimated at $21.6 million and has a targeted in-service date of April 2021. ■

— Jason York

ISO-NE News

Mass., Conn. Seek Federal Partner on Decarbonization

NE Electricity Roundtable Talks Environmental Justice

By Jason York

Stronger federal leadership and changes to wholesale electricity market rules are needed to supplement New England's decarbonization efforts, Massachusetts Secretary of Energy and Environmental Affairs Kathleen Theoharides and Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection, told Raab Associates' New England Electricity Restructuring Roundtable.

Theoharides and Dykes were the *keynote speakers* at the virtual event Friday, which drew an audience of more than 450 people.

There has been "no hint of politics in the way we approach this work," Theoharides said about Massachusetts, whose Republican Gov. Charlie Baker committed the state to a target of net-zero emissions by 2050.

Theoharides said one approach to meeting that goal is the *Transportation and Climate Initiative* (TCI), a collaboration of 12 Northeast and Mid-Atlantic states and D.C.

TCI would set a limit on carbon dioxide emissions from diesel and gasoline vehicles and allow states to invest proceeds from the sale of carbon allowances to support the goals of the program, such as electric vehicle chargers and electric buses.

The initiative estimates a cap that cut emissions 25% from 2022 levels by 2032 would produce $10 billion in public health benefits (2017$) while covering almost three times the Regional Greenhouse Gas Initiative cap, which includes the New England states, New York and more recently New Jersey and Virginia. Transportation represents 43% of emissions in the TCI region, and total transportation-related carbon emissions are nearly twice as large California's, Theoharides said.

TCI expects to finalize a *memorandum of understanding* setting its targets this fall, when each jurisdiction will decide whether to sign the MOU and participate.

"It is a capital investment program," Theoharides said. "It is a point of regulation far upstream from the consumer at the wholesale or fuel-supplier level. Credits would be auctioned off in each state, and the proceeds would go back into the states, much as they do in RGGI, to invest in clean transportation solutions that give people the option to choose transportation that reduces air pollution and that provides mobility for more residents."

Clockwise from top left: Eugenia Gibbons, Health Care Without Harm; Chris Cook, city of Boston; moderator Jonathan Raab; Hal Harvey, Energy Innovation; and Hannah Pingree, Maine Governor's Office of Policy Innovation and the Future | *Raab Associates*

Amid the COVID-19 pandemic, TCI has the potential to reduce the public health impact of environmental pollution significantly, Theoharides added.

"The pandemic has highlighted the connections between air pollution and respiratory diseases, and TCI is a way to ensure sustained investment in transportation that gives people better, more affordable choices for getting to work, school and health care services while cutting the pollution that makes people sick and makes them more vulnerable to disease," Theoharides said.

Connecticut has *pledged* to cut carbon emissions by 80% from 2001 levels by 2050 and 100% in the electricity sector by 2040. Dykes said it is "long past the moment for significant changes in the wholesale electricity markets to ensure that Connecticut can either secure the resources that we need to meet our clean energy goals in-market, or that we can get credit for what we have had to procure outside of the market in order to meet our goals."

Dykes said a "unified approach" is needed to meet the decarbonization mandates.

"We are not even in an acceptable place in terms of having a proactive transmission planning process that ensures adequate competition in our RTO," Dykes said about ISO-NE. "For the transmission investments, when you look at the dollars spent per mile deployed, New England is at the bottom of the heap in terms of providing … value for our ratepayers. Transmission service costs are more than twice the average of other RTOs and ISOs."

Dykes thinks that improving the transparency and accountability of ISO-NE and institutions like the New England Power Pool that are "core to the design and implementation of our wholesale markets" is a "necessary and essential step" to achieve affordable decarbonization that uses competition and minimizes risk to ratepayers. She said the current structure reflects that states do not have adequate input and accountability in the design and structure of the RTO's governance.

Moderator Jonathan Raab said both Massachusetts and Connecticut have plans and policies in place to meet "really bold decarbonization mandates." He then asked Theoharides and Dykes if New England states can be "fully decarbonized without strong complementary federal action on numerous fronts" and what the federal government could or should do to facilitate the region's decarbonization efforts.

Dykes said the impact of climate change on the economy and public health is "accelerating faster than we had anticipated." She said there is a severe disconnect between states and the federal government, which, Dykes said, is "walking away or even making our climate progress more difficult."

"We have companies in a private market that can accelerate and deploy climate solutions so quickly and cost-effectively," Dykes said. "I think the tragedy of all this disconnect at the federal level is that it's preventing the incredible strengths and advantages of our country

ISO-NE News

from being applied at the scale that we need to solve this climate crisis."

Theoharides added: "It matters that we have a target as a nation we're shooting for; it's not just a handful of states which have mandatory emissions targets; we need a federal target, and we need every state to be pulling its weight to get us there. That leadership needs to come from the top."

Decarbonization Takes the Whole Village

The conference's second session featured a four-person panel with representation from local and state governments plus a global nonprofit and think tank. The presentations touched on some of the same topics that Theoharides and Dykes broached earlier and delved into job creation and the social justice aspects of decarbonization.

Hal Harvey, CEO of Energy Innovation, said it is not true "that one has to sacrifice economic vitality in order to have a clean environment." The financial upside of clean energy is good jobs, lower costs and less local pollution, he said. There were 3.3 million clean energy jobs in the U.S. at the start of 2020, representing more than 40% of the energy workforce, Harvey said.

"The fastest two growing careers in America are solar installer and wind installer," Harvey said. "The opportunities do not require college degrees. … Roughly half of Americans do not have a college degree; we need an energy strategy that gives them great jobs."

Hannah Pingree, director of policy innovation and the future for Maine Gov. Janet Mills, said the first-term Democrat had made climate progress one of her top agenda items, especially in job creation.

Clockwise from top left: Katie Dykes, Connecticut DEEP; Jonathan Raab, Raab Associates; and Kathleen Theoharides, Massachusetts EEA. | *Raab Associates*

"Maine is embarking right now on an offshore wind project, trying to launch the first floating turbine in the next couple of years, so obviously that's one of the many exciting things we think could bring jobs and economic prosperity," Pingree said.

While climate change can drive job creation, Chris Cook, chief of environment, energy and open space for the city of Boston, said it also affects socially vulnerable populations. One of the city's major initiatives this year is creating Community Choice Electricity, which was recently approved by the Massachusetts Department of Public Utilities. The program will allow the city to buy electricity for residents and businesses through its combined buying power to provide affordable and renewable electricity to those who participate in the program.

"If we provide a clean economy [and] a decarbonization pathway that doesn't expand equity opportunities for our most socially vulnerable residents, then we will have failed," Cook said. "It's not about what we do. It's about who we do it for. They are our neighbors; they are our friends. They are the people that we are charged with at the city level to take care of, and they need to be actively part of the solution."

Eugenia Gibbons, Boston director of climate policy for Health Care Without Harm, a global nonprofit that works to reduce the health care sector's environmental footprint, said climate solutions like decarbonization must benefit historically marginalized communities.

"Essentially we are coming from a place of understanding that climate justice will only be achieved if policies that are enacted bring about concrete improvements in the health and lives of communities that continue to bear the burden of environmental and climate pollution," Gibbons said. "Equity absolutely has to be a factor in designing, implementing and evaluating policy and program solutions. Otherwise, the disparity will just be perpetuated and exacerbated."

In the absence of federal leadership, "we absolutely have to demonstrate at the state and local level what is possible and what we are capable of achieving [and] ensure that we are not leaving anybody behind when we move forward with this pathway to decarbonization," Gibbons added.

When Raab asked the panel for closing thoughts, Harvey said 2020 is an inflection point.

"If we use this decade well, we can land at a reasonable climate future, but this is the decade that matters. This is where we have to stop all new fossil installations, period, and much more rapidly change the direction that we are on," he said. "I can say now it's cheaper to save the Earth than to ruin it, because it is. We better get busy, because if we don't do it this decade, it isn't going to happen." ■

MISO News

Utilities Pledge to Build Largest EV Charging Network

By Amanda Durish Cook

Six Midwestern energy companies have banded together in the hopes of developing America's largest interstate electric vehicle charging network by the end of 2022.

Consumers Energy, DTE Energy, Evergy, Oklahoma Gas & Electric, Ameren Illinois and Ameren Missouri announced last week that they had signed a memorandum of cooperation, pledging to construct charging stations across five states. The companies said the network will facilitate clean transportation and bolster range confidence for long-haul EV trips.

The agreement doesn't say how many charging stations will be built. Ameren spokesperson Jenny Barth said each energy company will "build a program that works best for their area."

The utilities said more companies could join the effort. They added that network construction is dependent on regulatory approval from each utility's state.

"By partnering in the creation of a multistate electric charging network with energy companies outside of our own footprint, we are able to help our customers safely and economically travel to far-ranging destinations," Ameren Missouri President Marty Lyons said in a *release*. "Detroit to Oklahoma City or St. Louis to Denver, we are supporting our customers, our communities and our country with cleaner driving."

Ameren said transitioning to electric transportation can help "dramatically" lower carbon emissions, allowing the utility to meet carbon-reduction goals.

"Our focus in joining this multistate coalition is to develop a charging infrastructure that will help reduce 'range anxiety' and lead to broader adoption of electric vehicles," Ameren Illinois President Richard Mark said.

The Edison Electric Institute estimates that there are more than 1.5 million EVs currently on the nation's roadways, with just 100,000 public charging stations to support them. The trade association forecasts nearly 19 million electric cars on the road by 2030. To achieve that growth, EEI estimates that 9.6 million public charging stations will be needed.

"Expanding the use of electricity in transportation saves customers money, improves the environment by reducing emissions and enhances quality of life for everyone," EEI President Tom Kuhn said. "By deploying charging infrastructure and accelerating electric transportation, EEI's member companies, including Ameren and the other companies collaborating on this initiative, are working together to build a cleaner and stronger economy for the future."

While there are about 40 EV models today, the Electric Power Research Institute expects automakers to have more than 130 models to choose from in just two years.

"Consumers Energy is committed to building the backbone of the charging network for electric vehicles across Michigan," Senior Vice President Brian Rich said. "We know we can play an important role in charging the growth of EVs in our state and region, and know that will be good for Michigan's economy, our communities and the environment."

| *Evergy*

DTE Electric CEO Jerry Norcia also said his utility "has a significant role to play in helping make EVs a viable option for many."

Evergy, which serves portions of Missouri and Kansas and was formed by the merger of Westar Energy and Kansas City Power and Light, *tweeted* that it was "excited" to partner with the other utilities. Evergy Chief Customer Officer Chuck Caisley said the network will make it "convenient and easy for EV drivers to charge their vehicles no matter where they are throughout the Midwest." ■

MISO News

MISO Sets Candidate Slate for Board Elections

MISO's Board of Directors has three seats up for grabs in December, though the new board is only guaranteed one new face.

The RTO's Nominating Committee advanced current Directors Theresa Wise and Robert Lurie for member consideration, along with newcomer Jody Davids. Formerly chief information officer for PepsiCo, Davids has also served as CIO for Agrium, Best Buy and Cardinal Health. She currently sits on the board for Premier, a Charlotte, N.C.-based health care improvement company.

Wise and Lurie are both rounding out their first terms and applied for reappointment. Lurie served the one-year remainder of former Director Thomas Rainwater's term, which expires at the end of December.

Jody Davids | *Premier*

Longtime Director Baljit Dail will not make a reappearance at MISO's U-shaped board table next year. Dail spent 12 years on the board — three more than technically allowed — through a special waiver that allowed him an extra term so the board could retain a person with technology expertise.

MISO's 139 voting-eligible members were to begin casting ballots for candidates at 8 a.m. Thursday. The electronic polls will close at 5 p.m. Oct. 30. Board elections require a minimum 25% participation rate to achieve quorum.

Members can vote for or against any of the candidates, or abstain. Candidates must earn a majority of votes cast to be installed. MISO will announce election results in mid-November.

The board voted unanimously during its Sept. 17 meeting to retain Phyllis Currie as its chairman in 2021. ■

— Amanda Durish Cook

MISO News

MISO Moves to Constrain Mid-queue Fuel Changes

By Amanda Durish Cook

MISO is considering how to restrict generation developers' ability to change the fuel type of proposed projects in the interconnection queue.

The move comes after a recent FERC order exposed the RTO's lack of protection against switching fuel sources for projects in the queue's definitive planning phase (DPP).

Ryan Westphal, manager of probabilistic resource studies, said MISO has concerns that allowing DPP fuel-type changes could delay studies and "create gaming opportunities."

"It just essentially encourages the submission of premature and speculative projects," he told stakeholders during a Interconnection Process Working Group teleconference Sept. 22.

The issue stems from a Leeward Renewable Energy Development wind project currently in the DPP. The developer wants to convert the project to solar energy while also retaining its position in the queue.

FERC on Sept. 17 said that MISO's Tariff was silent on whether a generation project can switch from wind to solar while in the interconnection queue. The commission also said that there was no requirement in Order 845 that requires grid operators to study projects that opt to switch fuel types. (See *FERC: No MISO Rules on Mid-queue Fuel Change Studies*.)

Westphal *said* MISO is evaluating how fuel changes fit into the Tariff's permissible technological advancements.

"Unstructured submission of multiple fuel-change requests during a single queue cycle creates cost and timing risks that may not be obvious from evaluating individual requests in the abstract," he said, adding that the accumulation of several fuel-type requests could seriously alter a queue cycle.

A fuel-type change can also alter dispatch assumptions, throw off site control requirements and affect system studies coordination with other RTOs, Westphal continued. Staff are seeking a standardized method to handle fuel-type changes that keeps the queue on time, he said. MISO is already contending with a record queue of 719 projects, totaling 108 GW of capacity.

"If we have to evaluate these on an *ad hoc* basis, then it's kind of a queue-within-a-queue," Westphal said. Instead, the grid operator is considering making a new filing with FERC to explicitly disallow fuel-type changes, among other options.

Otherwise, Westphal said MISO could introduce a "check box" on interconnection requests where a customer could preserve its option to switch fuel types. The uncertainty would have staff studying the interconnection request at 100% dispatch of the most conservative fuel type until the customer can confirm its fuel type, probably at the queue's first decision point.

"If we're going to do this — allow this — then the decision point seems like a good place to start," Westphal said. MISO could go a step further and study all interconnection requests at a 100% output, but he said that could result in unnecessary network upgrades.

Multiple stakeholders said studying all queue customers' projects at full output would be too detrimental to project costs and would be a nonstarter.

Westphal said MISO could simply require customers to nominate fuel type at a fixed point, "before we get too far in the process."

"The question was, 'Could we allow a fuel-type change before a kickoff meeting?' And the answer was 'yes,'" Westphal said. "We're asking about other points too. When can we allow a fuel-type change and disrupt the process as little as possible?"

EDF Renewables' Arash Ghodsian said a deadline prior to DPP kickoff made the most sense.

"I think that a fuel-type change is tremendously disruptive to the DPP process and it affects other interconnection customers," WEC Energy Group's Chris Plante said. "Maybe it shouldn't be allowed." He asked whether there are other customers like Leeward seeking to change fuel sources on existing project proposals.

"We've gotten several customers asking how to do this," Westphal confirmed.

He asked that stakeholders submit more written opinions on fuel-type changes by Oct. 2. He expects MISO and stakeholders to work on a solution through early 2021. ■

Rooftop solar in Indianapolis | © *RTO Insider*

MISO News

MISO Planning Advisory Committee Briefs

Members Endorse MTEP 20

MISO members have recommended that the RTO's 2020 Transmission Expansion Plan (MTEP 20) proceed to final approval in December.

Without discussion, eight of MISO's 10 sectors with voting rights approved MTEP 20, comprising 514 new projects costing $4.06 billion, during the Planning Advisory Committee teleconference Wednesday. The portfolio investment level is similar to MTEP 19's.

The State Regulatory Authorities and Eligible End-User Customers sectors both abstained from voting.

MTEP 20 is now before the Board of Directors' System Planning Committee for consideration and an October vote. The PAC's recommendation vote came about a month early this year, as MISO wanted to give the board more time to review the plan. The board has approved about $36 billion in annual transmission buildout since 2003.

The RTO's executive director of system planning, Aubrey Johnson, said earlier this year that "a preponderance" of projects is in the Central planning region. Most of those are baseline reliability projects: transmission upgrades necessary to meet NERC standards.

Coordinated Planning Effort Continues

Some stakeholders continue to be dissatisfied with MISO's first suggestion to coordinate its interconnection upgrade studies and planning studies under MTEP.

The RTO and stakeholders have been working on coordination in the hopes of approving more multifunctional transmission projects. (See *MISO Processing Heftiest Interconnection Queue Ever*.)

| © RTO Insider

Staff have offered to perform an economic evaluation of certain generator interconnection upgrades that show promise. That offer is only open to the network upgrades of generation projects that already have a signed generator interconnection agreement in place. (See *MISO Unveils 1st Proposal to Consolidate Tx Planning*.)

The grid operator last week also suggested that interconnection upgrades pass screening criteria before they can be evaluated as possible market efficiency projects. The criteria include a $50,000 to $100,000/MW cost minimum on network upgrades and exclude line rebuilds and interconnection substation work.

Some stakeholders say the proposal is not enough to prevent generation projects from dropping out of the interconnection queue when they balk at high upgrade costs. Many stakeholders said waiting for an economic evaluation after a GIA is signed wastes time.

"It's challenging from a commitment timeline to wait until that moment," EDF Renewables' Arash Ghodsian said.

The Sustainable FERC Project's Lauren Azar asked that MISO keep a reasonable per-megawatt cost threshold so that generation developers aren't dissuaded from GIAs by high costs. She also reminded stakeholders that an interconnection upgrade being cleared for MISO economic analysis isn't a guarantee that it will proceed to regional cost sharing.

Other stakeholders said MISO shouldn't be so quick to exclude line rebuilds, because a project could only slightly overload the original line. That would leave a lot of headroom for other flows on rebuilt lines.

Clean Grid Alliance's Natalie McIntire also urged the grid operator to think about network upgrades that may negate the need for future reliability projects.

MISO has framed its proposal as a first step in better linking transmission upgrades unearthed in the interconnection queue with annual transmission planning.

"The fact of the matter is that these processes have been in place for a number of years. We can't change them overnight; there are too many moving parts and complications," MISO's Neil Shah said.

"I agree that these processes were designed when there were 5 to 6 GW in the queue. Now there is more than 100 GW," Ghodsian said.

Shah also said MISO has to work out the board approval process of interconnection upgrades-turned-economic projects.

The Coalition of MISO Transmission Customers attorney Kevin Murray has said a consolidated transmission approach's incorrect assumptions could lead to needless transmission.

"We have concerns about building transmission paths to nowhere," Murray said during an Aug. 19 Advisory Committee meeting.

But the Union of Concerned Scientists' Sam Gomberg said planning models have gotten better, continue to evolve and can usually pinpoint the most useful projects.

Several stakeholders have said that cost allocation under coordinated planning must be handled to appropriately charge cost-causers and beneficiaries.

Board OKs 1st Major Interregional Project

The board on Sept. 17 approved MISO's and PJM's first major interregional transmission project, a year after it was first recommended by the RTOs.

The $22 million *reconstruction* of the 138-kV Michigan City-Trail Creek-Bosserman line in the northwestern corner of Indiana was identified last fall in the 2018/19 MISO-PJM coordinated system plan. (See *MISO, PJM Poised for 1st Major Interregional Project*.) The project is a tie line between Northern Indiana Public Service Co.'s service area in the MISO footprint and American Electric Power's territory on PJM's side. The project boasts a 3.12:1 benefit-to-cost ratio. MISO stands to pay just under 11% of project costs at $2.35 million.

Director Nancy Lange asked whether future interregional projects with PJM will be approved more quickly now that a cost allocation method is in place.

"These reforms certainly make it easier for projects. It should be a more expeditious process in the future," said Jesse Moser, director of economic and policy planning.

PJM's Board of Managers approved the project during its December 2019 meeting. MISO's nine-month lag came because the grid operator does not have a cost-sharing plan in place for its interregional market efficiency projects. (See *Another Rejection for MISO Cost Allocation Plan*.) ■

— Amanda Durish Cook

MISO News

4th Time No Charm for MISO-SPP Interregional Study

RTO Officials Pin Hopes on New Joint Interconnection Study

By Amanda Durish Cook

MISO and SPP have once again failed to identify any beneficial cross-border transmission projects after a fourth interregional study.

RTO executives broke the news during a virtual meeting of the MISO-SPP Interregional Planning Stakeholder Advisory Committee (IPSAC) on Friday. Stakeholders were unsurprised by the announcement after already hearing indications that the fourth coordinated system plan (CSP) study would be fruitless. (See *MISO, SPP Close to Ruling out Joint Projects Again*.)

"All the work that we put into the study, I feel like it's a building block for future studies," SPP's Neil Robertson told stakeholders, adding that the studied flowgates would most likely show up in future interregional studies.

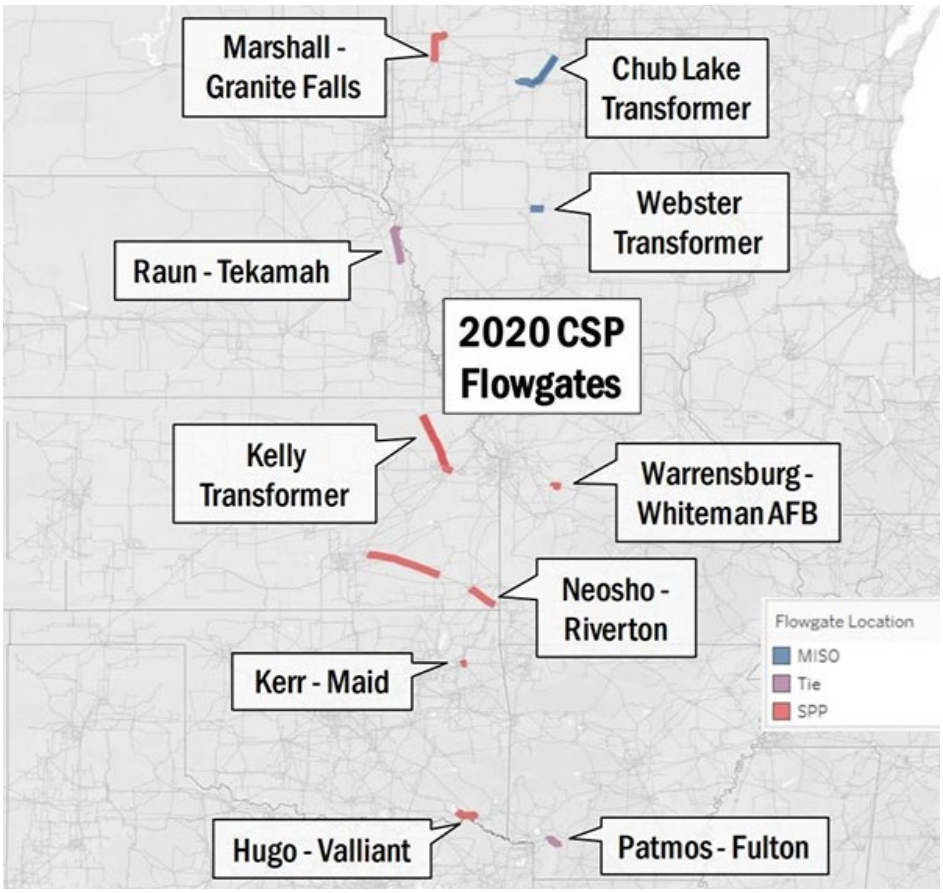
This year the RTOs focused on 10 routinely congested flowgates in Minnesota, Iowa, Nebraska, Kansas, Missouri, Oklahoma and Arkansas.

"I fully anticipate that we'll be seeing these constraints again," Robertson said, citing expanding renewable generation flows between the RTOs. "The increase in interregional flows are only trending one way, and that's up."

MISO and SPP planners said the RTOs' transmission planning futures scenarios — both updated this year — will probably yield larger project benefit ratios in future joint studies.

The study also turned up discrepancies in the RTOs' separate project cost estimates, Robertson said. The grid operators will work together to produce more consistent cost estimates in the future, he said. (See *SPP Seams Steering Committee: Sept. 17, 2020*.)

"We intend to reach a lot more consensus about how cost estimates are determined in the interregional studies. Cost estimates are essential … to figuring cost-benefit ratios, and we're going to make sure they're not a roadblock in future studies. I want to stress that this will be a priority," he said.



Congested flowgates studied under the 2020 CSP | *MISO, SPP*

Robertson noted that MISO and SPP haven't worked out exactly how they'll make their cost estimates line up better.

"The local [transmission owners] have a perspective; the RTOs have a perspective; even the stakeholders have a perspective. Those are the things you have to kind of talk out," he said.

However, Robertson stressed that differing cost estimates didn't prevent any project candidates from "crossing the finish line" this year.

"Cost estimates were not the determining factor in a project not getting approved," he said.

The Advanced Power Alliance's Steve Gaw asked if the RTOs suffer from a process issue in which they're not examining solution candidates thoroughly enough.

Robertson said MISO and SPP studied more project candidates than the 34 they *presented* to stakeholders.

The RTOs have somewhat assuaged stakeholder concerns by announcing a new joint study targeting generation interconnection challenges. (See *MISO, SPP to Conduct Targeted Transmission Study*.) That study could yield new transmission capacity and thus facilitate development of the renewable generation in the RTOs' interconnection queues.

Robertson said MISO and SPP have yet to determine the scope of the study, the geographic areas to be studied or whether the study will affect the possibility of a 2021 CSP study. The RTOs plan to hold an annual issues review in the first quarter of 2021 where they will discuss possible needs for transmission solutions.

"All of those questions are yet to be answered. … We'll share details as soon as we possibly can," Robertson said. "But please keep in mind that the vast details of the study have yet to be determined."

MISO Director of Planning Jeff Webb said he expects study results to roll in at the end of 2021.

Stakeholders have repeatedly asked how this study will differ from MISO and SPP's CSP studies.

"I think that's a fair question. We'll have to lay that out more clearly at the kickoff meeting," Webb said at the MISO Planning Advisory Committee's meeting Wednesday, though he added that the study will target needs for interconnecting generation, something the CSP studies don't consider. ■

NYISO News

NYISO Management Committee Briefs

Addressing Demand Curve Reset Misalignment

NYISO CEO Rich Dewey told the Management Committee on Wednesday that staff are determining whether a technical problem related to the 2017-2021 installed capacity (ICAP) demand curve reset violates the ISO's Tariff or constitutes a market problem.

"When we're confident that the software is accurate and reflecting the right impacts ... we commit that we will share that with market participants as soon as possible," Dewey said. "Look for a meeting invite by the end of this week."

NYISO acknowledged earlier in the month that the model used to estimate net energy and ancillary services revenue earnings for the hypothetical peaking plant resulted in a misalignment of natural gas prices with the actual delivery date associated with such prices. (See *NYISO ICAP/MIWG Briefs Sept. 14, 2020*.)

Staff's final demand curve reset recommendations, *posted* Sept. 9, said that "based on the review of stakeholder feedback and discussions with the data vendor, the model has been updated to reflect that gas prices published by the vendor for a particular date reflect the price to utilize gas on the specified date (e.g., gas prices published with a Friday date represent the cost to utilize gas on that Friday)."

When no gas price is reported, the model will use the next available day on which data are published. For a non-holiday weekend, the gas price published for Monday will be used as the gas price for Saturday, Sunday and Monday, the ISO said.

Although it is too early to know the magnitude of the impacts from the software issue for the 2017-2021 period, delaying the October ICAP spot market auction is not an option, Dewey said. While NYISO has obtained a revised version of the model, it must be tested for unintended consequences, he said.

Peak Load of 30,660 MW on July 27

When Vice President of Operations Wes Yeomans reported satisfactory hot-weather operations to the MC on July 29, he said the three heat waves that month were starting to blend into one another. But the excessive heat did not continue into August, leaving the peak load of 30,660 MW recorded July 27 as the record for summer 2020. (See "Hot Weather Operations OK," *NYISO Management Committee Briefs: July 29, 2020*.)

In his *report* on Wednesday, Yeomans said the peak load represented 95% of the 50/50 forecast of 32,296 MW. Daily mean temperatures in New York were above the 20-year average in June, July and August, and below average in May, with the highest temperatures recorded in Central Park (96 degrees Fahrenheit) and Albany (95 F), Yeomans said.

The ISO also operated satisfactorily through its first summer without Indian Point Unit 2, the Somerset coal station in western New York and the Cayuga generating facility north of Ithaca. It was also its first summer with the 1,000-MW Cricket Valley combined cycle plant.

Gov. Andrew Cuomo declared a state of emergency Aug. 5 after outages from Tropical Storm Isaias affected 920,000 customers, mainly on Long Island and around New York City.

"We did have multiple bulk electric system transmission elements tripped ... mostly transmission lines over 100 kV, so the majority of the multiple transmission elements we had were 138 kVs that either tripped and came right back, or they tripped and locked out and the [transmission owner] was able to get them back quickly. ... Some others, which had damage ... took time to get back," Yeomans said.

Steam up in NYC

The committee approved increasing the exemption from real-time generation penalties for units that supply the New York City steam distribution system by 10 MW to a total of 533 MW. The electricity output of the plants is driven by the city's steam requirements, making the units unable to follow NYISO dispatch instructions.

The Business Issues Committee endorsed the change earlier this month. (See *NYISO Business Issues Committee Briefs: Sept. 9, 2020*.)

Chris Hargett of Consolidated Edison *presented* the same slides as at the BIC on increasing the exemption for the company's East River Units

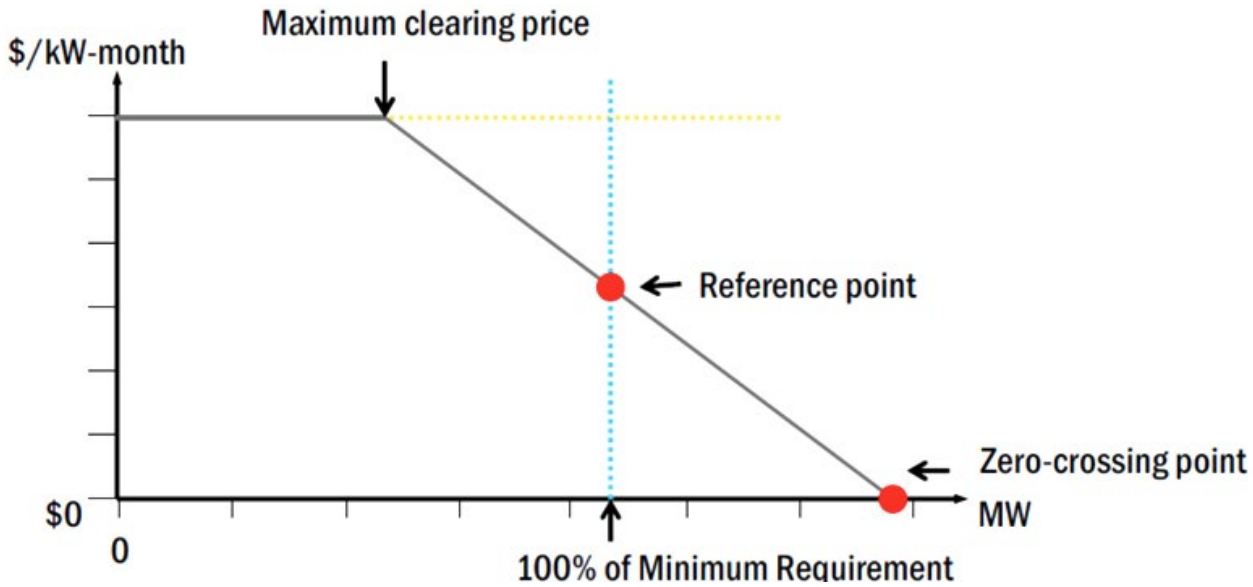


Illustration of demand curve slope, wherein the zero crossing point represents the point at which the value of additional capacity declines to zero | *NYISO*

NYISO News

1, 2 and 6. The increase was needed because a number of projects completed over the past several years have increased the efficiency and output of Unit 6, Hargett said.

If the Board of Directors approves the revisions in October, NYISO will submit them to FERC under Federal Power Act Section 205.

2021 Draft Budget down $600K from 2020

For the second year in a row, NYISO is proposing a decrease to the budgeted revenue requirement, with the draft budget allocating $167.4 million across a forecast of 147.3 million MWh for a Rate Schedule 1 charge of $1.137/MWh, down from the 2020 budget of $168 million allocated across 154.3 million MWh ($1.089/MWh).

Alan Ackerman of Customized Energy Solutions, chair of the Budget and Priorities Working Group, *presented* the draft budget, reporting that the ISO is holding the number of staff positions steady. Every line item except computer services in support of projects and corporate insurance were cut from the 2021 projections made during the 2020 budget cycle. Major cuts in approved spending for 2020 have come through deferring some capital expenditures, such as $5 million to renovate the control room.

The ISO made a special effort to hold spending flat in light of the economic challenges facing many market participants as a result of the pandemic, Ackerman said.

The MC expects to vote on the final draft budget in October before it goes before the board for final approval in November.

Yes to ESR Bidding Rules

The MC recommended the board approve proposed capacity market bidding rules for energy storage resources (ESRs) reflecting their energy-duration limitations.

Market Design Specialist Sarah Carkner *presented* the Tariff revisions specifying that such ESRs bid or schedule a bilateral transaction for their full injection range for all hours during the peak load window and to bid their full withdrawal range for all hours outside of the peak load window, or notify the ISO of a derate.

Given board approval, the ISO will later this year or in early 2021 submit the revisions to FERC and update the ICAP Manual with the new rules.

A Place for Solar in Dispatch

The MC also recommended the board approve expanding market rules for wind energy resources to also encompass solar resources.

The Tariff revisions would require dispatchable solar resources to submit flexible day-ahead and real-time offers and require them to respond to economic curtailment signals from the ISO. They would not be eligible for day-ahead margin assurance make-whole payments.

"Proposing the Tariff revisions at this time allows us to give as much notice as possible to new solar resources and existing ones as they look to understand what's required to participate in NYISO markets going forward," analyst Cameron McPherson said in *presenting* the revisions.

The rules would allow solar resources to indicate their economic willingness to generate, reducing the need for out-of-market curtailments and self-directed curtailments, he said.

If the board approves them, the ISO will file the revisions at FERC in November or December and look to implement them in 2021.

Committee OKs Credit Policy Enhancements

The MC recommended that the board approve *changes* to NYISO's policy on extending unsecured credit to public power entities and government entities.

The Tariff revisions would make government entities eligible for up to $1 million in unsecured credit, as public power entities are currently. The credit would only be available for entities with investment-grade debt ratings.

FERC in April granted the ISO a nine-month waiver allowing it to grant up to $1 million in unsecured credit to government entities that do not meet the current Tariff definition of a public power entity, said Sheri Prevratil, the ISO's manager of corporate credit.

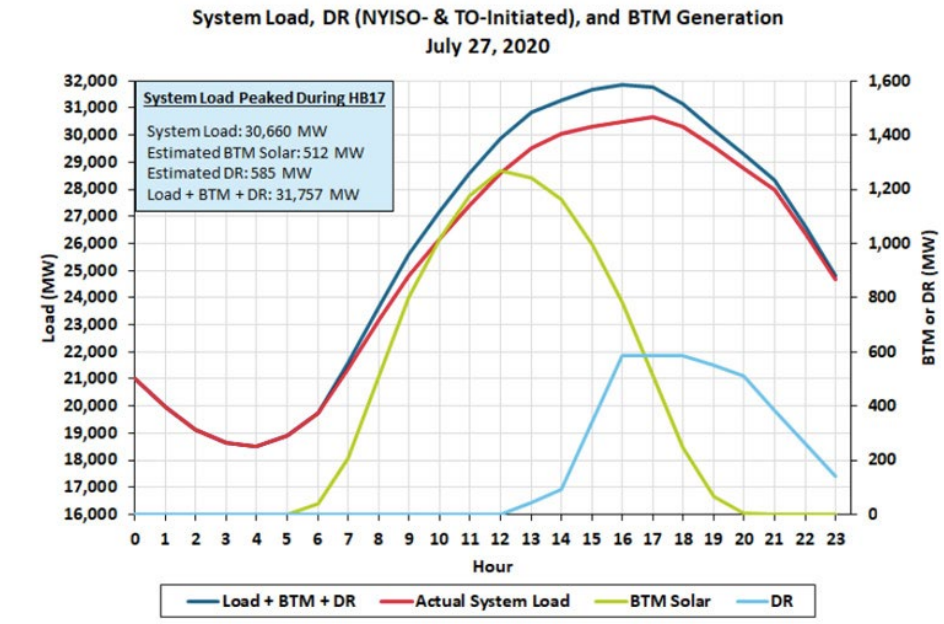
If the NYISO board approves the revisions in October, the ISO will make a Section 205 filing with FERC.

The MC also recommended board approval of proposed *changes* to the ISO's transmission congestion contracts (TCC) credit policy to address concerns raised by GreenHat Energy's default in PJM's financial transmission rights market. The changes would allow for earlier recalculation of the collateral requirements for the second year of a two-year TCC.

NYISO also would use market clearing auction prices to calculate credit requirements for TCCs instead of congestion rents over the prior 90 days. The ISO said market-clearing prices, "which are forward looking, provide a more appropriate predictor of future payments due than historic congestion rent values."

If the board approves them, the ISO will submit the changes to FERC in the fourth quarter. ■

— Michael Kuser



Load profile for peak load day July 27 (30,660 MW) includes dark blue line to show what load would have been without BTM solar and demand response | *NYISO*

NYISO News

NY Utilities, Developers Tweak Storage Procurement Terms

By Michael Kuser

New York's investor-owned utilities are working with government officials and project developers to fine-tune the processes and contract terms of state-mandated energy storage solicitations.

Approximately 60 energy storage developers participated Thursday in a technical conference hosted by the New York State Energy Research and Development Authority (NYSERDA), anonymously questioning a panel of three utility executives on matters such as expanding timelines for requests for proposals beyond the current six months; extending payment terms and contract duration up to 10 years; modifying in-service dates out to 2025; reducing the storage duration requirement from four hours to one; and providing developers the option to sell a project to the utility upon completion.

The New York Public Service Commission's December 2018 storage *order* required Consolidated Edison to procure at least 300 MW of storage capacity and each of the other utilities (Central Hudson Gas and Electric, New York State Electric and Gas, Niagara Mohawk Power, Orange and Rockland Utilities, and Rochester Gas & Electric) to procure at least 10 MW each, with assets to be operational by Dec. 31, 2022, on contracts up to seven years.

The RFPs started in 2019 and are to continue annually as needed to meet individual utility storage goals. New York state now has about 93 MW of advanced energy storage capacity deployed with 841 MW in the pipeline toward meeting its goal of 1,500 MW deployed by 2025 and 3,000 MW by 2030. The 1,400 MW of traditional pumped hydro storage in the state does not count for the goal totals.

Each utility has conducted its initial RFPs and is developing the next round of solicitations after having notified bidders of first-round results.

"We're looking for feedback from the participants during this *session* as well as through a follow-up *email* [with comments due Oct. 8], and this will culminate in a filing with the commission, which will allow for more formal comments for commission action," said Stephen Wemple, Con Ed vice president of regulatory affairs. The next round of RFPs is expected in the second quarter next year.

The PSC on Sept. 17 *modified* dynamic load management implementation plans for the six utilities, all related to storage, saying the initial plans "resulted in a bias towards short-term, low-capital investment solutions" because of their yearly performance structure (*18-E-0130*). (See "DLM Incentives Extension," *NYPSC Accepts CLCPA Environmental Review*.)

Time and Negotiations

The feedback indicated that six months is very compressed for an RFP, from posting to final selection, and that developers need more time; whether a month or more is yet to be determined, said James Mader, manager of smart grid programs at NYSEG.

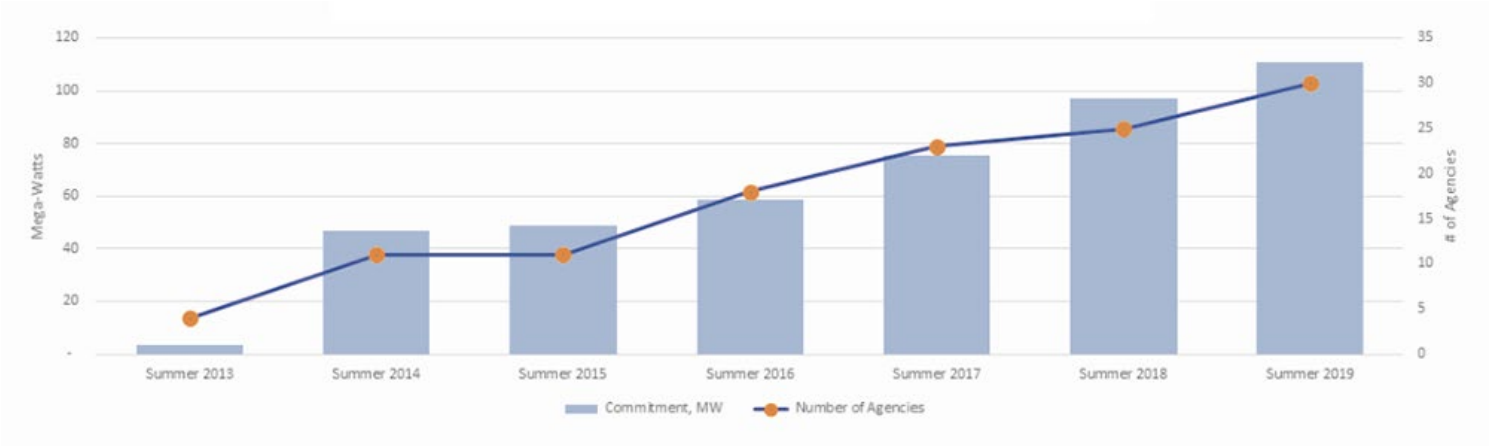
Mader addressed these questions: How does the current process flow? Does it start with bidders who have potential projects, or does the RFP require those opportunities to be concrete and ready to go?

"The current process was you'd look at the RFP and submit your bid once you received bidding approval, and then we would analyze and review what we received," Mader said. "Moving forward, that's something we're looking to potentially tweak or adjust."

Stephen Wemple, Con Edison | *NYSERDA*

The RFPs also required developers to have site control and to have applied for their interconnection agreement, which utilities factored into the viability of a project, Wemple said. "We want to go through a process; we want to select bidders that are well positioned to deliver and complete their projects in the time frame required."

The first round of RFPs "was a learning experience for everybody, and the idea is to have a value-based bid cap — what is the utility actually going to get — and developers are going to give their best proposal in there," said Schuyler Matteson, senior energy storage project manager at NYSERDA.



New York City's Demand Response and Load Management Programs with Con Edison rely on real-time metering for analysis of energy usage. | *NYSERDA*

NYISO News

"For the utilities who are still under contract negotiations, and that includes Con Ed, we hope to make an announcement in the near future. ... We don't want to bias those negotiations, but there were a couple of utilities that did not have any finalists," Wemple said. "I know that included my affiliate O&R."

Central Hudson also reported no bidders that met the bid ceiling, while NYSEG said it was still in negotiations. National Grid did not take part in the panel but did participate in the conference planning and had a manager listening in, Matteson said.

Utilities received feedback that high pre- and post-commissioning security requirements increased bid prices; large upfront payments caused difficulties with financing for some developers; and annual payments did not cover operations and maintenance costs.

"From our perspective, we didn't see anything that really jumped out at us to indicate that one offer or another was assuming things that were significantly different from anyone else," said Jeffrey May, energy resource manager at Central Hudson. "To speak to the spread in pricing, there was nothing obvious to us that indicated a driver as to why some bids might have been significantly higher than others. ... There were no offers that met the bid ceiling, so maybe if we had gotten into a deeper dive, we might have seen where some of those differences were, but there was nothing on the surface from our evaluation matrix."

Tech Specs and COD

Utilities determined that a commercial operation date of Dec. 31, 2022, is not feasible for resources being procured in 2021 and proposed to move the date out three years to year-end 2025.

Jeffrey May, CHGE | *NYSERDA*

One question on that issue was whether the utilities could begin payments if a project comes online ahead of the date set by regulators. Wemple said Con Ed would.

Several developers provided feedback that uncertainty in the post-contract market led to attributing little or even negative value to merchant "tail" years, and that extending the contract duration from seven to 10 years would spread costs over a longer period while increasing potential contract revenue.

Developers said that removing the four-hour duration requirement would bring in a wider range of bids and address concerns related to buyer-side mitigation issues.

"I think the expectation is that a shorter-life battery, while perhaps not getting as much or any capacity value, could make up for it on its relative 'less cells to pay for' by providing regulation or other ancillary services," Wemple said.

One commenter said that requiring a maximum number of cycles over the course of a year might be a good way to give bidders a sense of how the storage asset might be used.

Another commenter was concerned about "trying to align the NYISO class year process with knowing what the NYISO assignment of system upgrades are, because that impacts interconnection costs."

"Hopefully we'll get a little better clarity from the ISO on what their timing for the next class year process will be, and at least try to see if we can work that into this [RFP] process," Wemple said.

One proposed revision to the RFP process would let the developer provide O&M services for a defined period (e.g., five years) and to mitigate uncertainty in post-contract market revenues by having the developer sell the project to the utility at the COD.

One developer asked whether the utilities are sure they can own storage in the first place.

"Certainly, with a commission order ... the commission can allow us to do lots of different things, and actually in many cases, we already own storage as part of prior non-wires solicitations," Wemple said. ■

NYISO News

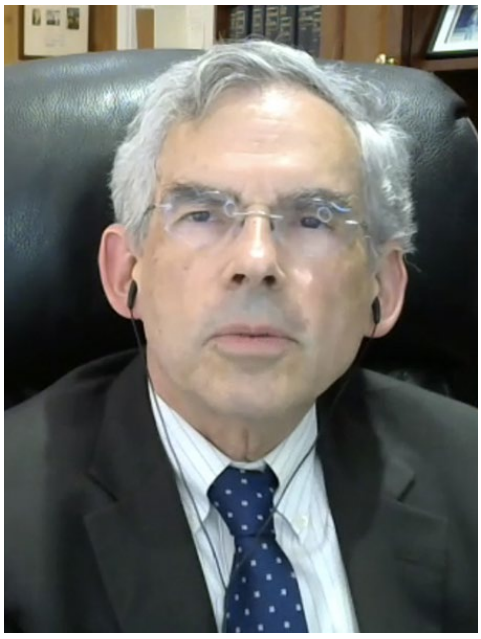
IPPNY Talks Methane Emissions, Carbon Price

By Michael Kuser

The elimination of coal-fired electric generation means that New York's battle against climate change must now focus on natural gas, Columbia Law School's Michael Gerrard told the Independent Power Producers of New York (IPPNY) in the *keynote* address at the organization's 35th annual Fall Conference on Sept. 15.

"Far and away the largest source of greenhouse emissions in New York state is natural gas, and more of it comes from electricity production than anywhere else," said Gerrard, a member of the Climate Leadership Council (*CLC*) and the founder of Columbia's Sabin Center for Climate Change. "This is a blinking red light."

The state's last coal-fired generator, the Somerset plant on Lake Ontario, ended production in March. But while New York has banned fracking within its borders, *more than half* of its generating capacity is at natural gas-fired power plants, and a recent study concluded that its GHG emissions in 2015 were virtually unchanged from 1990 levels when considering upstream impacts and the role of methane from drilling sites producing the state's fuel. Methane is about 80 times as potent at trapping heat as CO_2 in its first 20 years. (See *NY Study Highlights Rising Methane Emissions*.)



Michael Gerrard of Columbia Law School delivered the keynote address at the 35th annual IPPNY Fall Conference on Sept. 15. | *IPPNY*

"The climate reality is that global temperatures will continue to go up until we achieve net-zero [GHG] emissions," said Gerrard, who spoke in place of his friend and colleague, CLC founder and CEO Ted Halstead, who had died in a hiking accident in Spain the week before the conference.

Economywide Carbon Tax?

The CLC's 2017 climate change proposal called for an economywide fee on CO_2 emissions starting at $40/ton and increasing by 5% every year, with all the revenue distributed to people in quarterly dividends.

But Congress hasn't made a serious attempt to address GHG emissions since the failure of the Waxman-Markey cap-and-trade bill in 2009, leaving New York and other states to ratchet up their own efforts to address climate change.

The Climate Leadership and Community Protection Act (*CLCPA*) signed by New York Gov. Andrew Cuomo in July 2019 set ambitious clean energy goals — 100% zero-emission electricity by 2040 and an 85% cut in emissions by 2050 from 1990 levels — but did not include all the measures that will be needed to reach them.

A bill introduced in the state legislature last year that would impose a $35/ton carbon tax, rising after 11 years to $180, has not made it out of committee after previous failed attempts dating back to the legislature's 2015-16 session (*S3608*).

"I'm not holding my breath that we'll have either a nationwide or a New York state economywide carbon tax," Gerrard said. He said the most promising initiative in the state may be the joint task force on carbon pricing created by NYISO and the state's Public Service Commission in 2017, which resulted in a *proposal* published last December that would have the commission set the social cost of carbon to be used in any state policy.

Electrifying Everything

Gerrard said that while there is no unanimity on this issue, he thinks that FERC has the authority to consider climate change when acting on matters like the NYISO carbon pricing proposal.

"FERC makes its decision based on its view of the public interest, a phrase that appears about 50 times in the Federal Power Act. In the words of current FERC Commissioner Richard Glick, 'climate change must factor directly into the commission's permitting responsibilities, which generally require the commission to determine whether the relevant facilities are consistent with the public interest.' Simply put, it is hard to imagine a consideration more relevant to the public interest than the existential threat posed by climate change," Gerrard said.

Extreme heat kills more people than does extreme cold, he said, showing a National Weather Service heat index map that indicated extreme danger at 40% humidity and 110 degrees Fahrenheit, the highest temperature on the map.

"They don't go higher than that, but we've seen actual temperatures in the last month that go literally off the charts," Gerrard said. "The appropriately named Death Valley, Calif., experienced 130 degrees just a couple weeks ago, which may have been the warmest temperature ever recorded on the planet."

Preventing the atmosphere from warming more than 1.5 degrees Celsius above pre-industrial levels, as recommended by the U.N. Intergovernmental Panel on Climate Change, will require electricity decarbonization, energy efficiency, carbon capture and electrification of transportation and everything else run by fossil fuels, Gerrard said.

Matt Schwall, IPPNY director of market policy and regulatory affairs, asked what the regulatory chances are of FERC approving a New York carbon pricing plan.

"I think it only happens if we have a change in administrations, and a change therefore in the composition of FERC," Gerrard said. "I think it only happens with strong support from New York state. ... If there is all of this support, and it's clear we're not going to have federal carbon pricing, there's a good chance that FERC would approve it."

Such a ruling could withstand an appellate challenge, he said, "because there is lots of precedent within FERC for considering [GHG] in a variety of contexts."

Still, he added, surviving the challenge "depends in part on what panel is randomly drawn at the D.C. Circuit [Court of Appeals] to hear it." ■

NYISO News

62% of New Yorkers Support NYISO Carbon Pricing

By Michael Kuser

More than 60% of New Yorkers said they approve of NYISO's carbon pricing plan after learning of the advantages of such a price in the state's wholesale electricity markets, according to a poll released by the ISO on Monday.

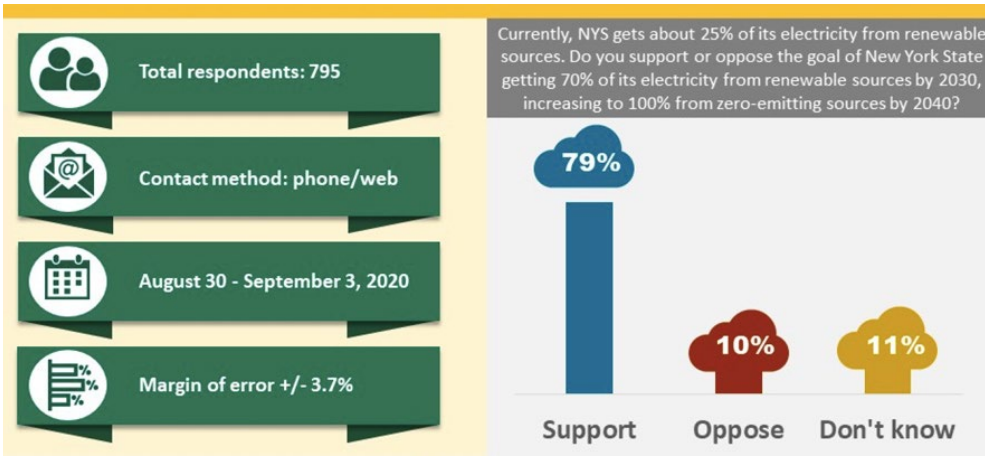
A joint task force between NYISO and the state's Public Service Commission issued a *proposal* last December that would use the social cost of carbon (SCC) as a baseline for such a price.

The *poll* conducted by Siena College Research Institute (*SCRI*) showed how an informed opinion increased support for carbon pricing.

When respondents were initially asked about NYISO's proposal, 47% said they were in favor, 36% opposed and 17% expressed no opinion. But after respondents were informed of the plan's benefits — including replacement of polluting power plants with cleaner generators and the economic boost from adopting clean technologies — support grew to 62% and opposition fell to 27%, while 11% had no opinion.

"At least a plurality of every demographic found each of these potential outcomes making it more likely to support" carbon pricing, SCRI Director Don Levy said.

NYISO released the poll two days before a technical conference on carbon pricing at FERC.



The SCRI poll shows broad support for New York getting 70% of its electricity from renewable sources by 2030 and increasing to 100% zero-emitting sources by 2040. | *SCRI*

"We view this poll result as a validation of New York's efforts to develop an innovative solution to the state's renewable energy goals," CEO Rich Dewey said in a press conference.

The fact that FERC invited him to testify at the technical conference along with Rana Mukerji, the ISO's senior vice president for market structures, shows that carbon pricing is "increasingly recognized" as a vehicle to transition the power industry toward renewable energy, Dewey said.

Asked what he hoped to accomplish at the technical conference, Dewey said, "These investments are going to be made in renewable resources. He wants FERC "to understand and accept that a state policy element, appropriately designed and controlled, fully transparent and open, does have an effective place in helping markets position themselves to achieve those goals as efficiently and as effectively as possible."

The commission earlier in September rejected the ISO's proposal to make it easier for public policy resources to clear its capacity market, specifically helping those resources in New York City and capacity zones G-J to avoid buyer-side mitigation if enough existing capacity exits the market, or if demand increases enough to boost capacity requirements. (See *FERC Rejects NYISO Bid to Aid Public Policy Resources*.) ■

PJM News

NJ BPU Outlines 'Shared Responsibility' EV Charging Plan

By Rich Heidorn Jr.

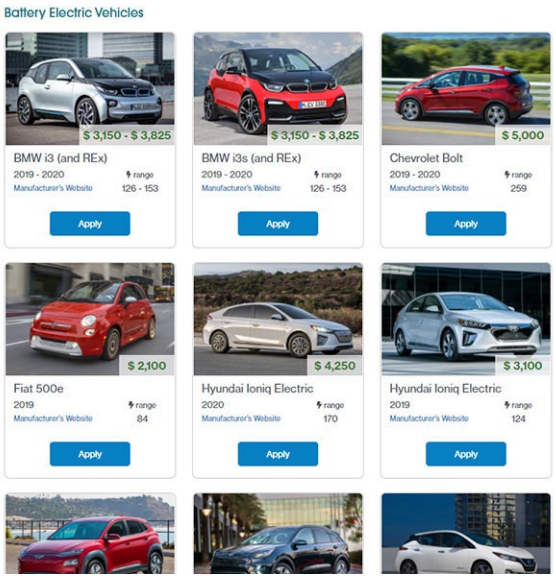
New Jersey regulators on Wednesday approved a "shared responsibility" model for building a public electric vehicle charging network that will have utilities provide the wiring infrastructure and private investors owning the charging equipment in most instances (*QO20050357*).

The New Jersey Board of Public Utilities' order will have ratepayers fund the utility investments in "make ready" infrastructure for light-duty EVs. Non-utility entities — site owners, property management companies and EV service equipment companies — install and operate charging stations using private capital.

Electric distribution companies (EDCs) would only be allowed to own the charging equipment in areas of "last resort" — locations that fail to generate private sector requests for make-ready infrastructure after at least 12 months.

The BPU's action implements the Electric Vehicle Act of 2020, which set a goal of registering at least 330,000 light-duty, plug-in EVs by the end of 2025, at least 2 million by 2035, and 85% of all new light-duty vehicles sold or leased by 2040.

According to the state's *Energy Master Plan*, transportation generates 42% of the state's net greenhouse gas emissions, making EV adoption essential to meeting the state's goal of 100% clean energy and an 80% cut in emissions from 2006 levels by 2050.



New Jersey residents purchasing or leasing a new electric vehicle are eligible for subsidies of $25/mile of EPA-rated all-electric range. The maximum payment is $5,000 for vehicles with a range of more than 200 miles. | *Center for Sustainable Energy*

NJ Lags

"To date, the private sector has not made a business case to install EV chargers without a critical mass of EVs on the road, and consumers hesitate to purchase EVs without the ability to charge away from home," the order said. "As a result, the adoption of EVs has lagged. The circular problem continues as the EVSE [electric vehicle service equipment] infrastructure companies are disinclined to develop publicly available charging sites where there is an uncertain amount of demand for their services. ...

"While New Jersey ranks near the bottom of EV adoption, stakeholders generally agree that an investment in charging infrastructure to address range anxiety coupled with the BPU's new EV incentives will serve to spark EV adoption and confidence in the emerging technologies."

New Jersey is also encouraging the transition by offering residents purchasing or leasing a new EV a subsidy of $25/mile of EPA-rated all-electric range. The maximum payment is $5,000 for vehicles with a range of more than 200 miles.

'Make Ready'

EVSE infrastructure companies or site hosts would notify their EDC of their intent to install EVSE at a location. The EDCs would develop and own the transformers, meters and other make-ready infrastructure.

The order says such sites will be deemed "used and useful" — allowing EDCs to recover their investments — even if the make-ready site is not immediately used. "While this does not exempt the utility from showing that it was prudent in the manner in which it made the site charger-ready, the utility should not be at financial risk for putting in an installation that was duly authorized pursuant to this order," the board said.

EDCs will be permitted to begin work without board review for any make-ready installation expected to cost less than $100,000. Projects estimated between $100,000 and $250,000 will be subject to a "soft cap" requiring the EDC to notify board staff and the New Jersey Division of Rate Counsel; it will be allowed to begin work unless staff or another party objects to the project within 60 days. Projects expected to exceed $250,000 will be subject to a "hard cap" requiring board approval.

The order sets the minimum filing requirements for light-duty EV infrastructure proposals from EDCs and requires them to file their plans by Feb. 28, 2021. EDCs must propose ways to minimize the barriers to EV adoption created by demand charges. Filings from two utilities, Public Service Gas and Electric and Exelon's Atlantic City Electric, are already under review by the BPU.

The Electric Vehicle Act of 2020 set the following goals for plug-in vehicle (PIV) adoption:

- At least 25% of state-owned non-emergency light-duty vehicles will be PIVs by Dec. 31, 2025.
- At least 400 DC fast chargers (at least 50 kW) available for public use at no fewer than 200 charging locations by Dec. 31, 2035.
- At least 1,000 Level 2 chargers shall be available for public use across the state by Dec. 31, 2025. The state currently has more than 400.
- At least 15% of all multifamily residential properties shall be equipped with EV chargers by Dec. 31, 2025.
- The Department of Environmental Protection, consulting with the BPU, will establish goals for electrification and infrastructure development for medium- and heavy-duty vehicles such as transit and school buses by Dec. 31, 2020.

The board acknowledged concerns that EVs will not contribute to the Transportation Trust Fund, which generates revenues for maintenance and road repairs through a tax on gasoline and diesel sales. Staff said stakeholders' consensus was to develop a user fee for EV drivers; it pledged to work with the state Department of Transportation to address the issue.

The board adopted staff's recommendation that it allow charging infrastructure owners flexibility to adopt payment methods that meet their needs, noting that the 2020 law established sale of electricity at an EV charger as a service, not a regulated sale of energy. ■

PJM News

Consumer Advocates Challenge PJM Board on Exelon, FE

Continued from page 1

Jones has said that the parent company contributed only one-quarter of the $61 million. FirstEnergy gave up ownership of the nuclear plants when FES emerged from bankruptcy in February as a new company, Energy Harbor. (See *FirstEnergy, AEP CEOs Deny Wrongdoing*.)

Roberts said the incidents went beyond mere wrongdoing, resulting in outcomes that "completely wreaked havoc" with the PJM markets.

She said the current stakeholder discussions about resource adequacy could mostly be attributed to state legislation resulting from the bribery scandals.

"This is something that has a direct impact on PJM and its members, and PJM really needs to look into this," Roberts said. "Any member charged with this kind of wrongdoing should be assessed and investigated by PJM. And if there's clear wrongdoing affecting PJM's operations, there should be repercussions for that."

As the two scandals started unfolding this summer, Roberts said she was reminded of when GreenHat Energy in 2018 defaulted on 890 million MWh of FTRs and racked up hundreds of millions of dollars in losses.

Roberts said PJM executives have indicated to stakeholders they didn't know GreenHat executives were "bad players" before doing business in the RTO, and that having knowledge of their past would have impacted how the RTO handled the situation from the onset. (See *Report: 'Naive' PJM Underestimated GreenHat Risks*.)

"Now you know some members are bad players, and we need to address it and see what to do about it," Roberts said. "You can't just ignore it. You need to take leadership on this issue."

Tyson Slocum, Public Citizen | © *RTO Insider*

Roberts said she hoped her comments could be used to start a constructive conversation with the PJM board that will "lead to positive outcomes" for all stakeholders. An open dialogue could lead to a discussion of independence, balance of power and transparency in the stakeholder process, she said.

She and other advocates agree with the commitment to independence by PJM and its board, she said. Her goal was to start a conversation about the complexity of independence in PJM's stakeholder process.

"PJM's expertise in markets and transmission planning is an asset to the process," Roberts said.

'Reprehensible Conduct'

Tyson Slocum, Public Citizen's energy program director, eschewed giving a presentation at Wednesday's meeting and instead sought dialogue with the board members.

Public Citizen and the Union of Concerned Scientists (UCS) sent a *letter* earlier this month to PJM board Chair Ake Almgren calling on the board to censure Exelon for its dealings in Illinois. The request called for suspending Exelon's rights in the stakeholder process for three years.

"PJM has made expressly clear that legislation that is the subject of Exelon's bribery scheme directly impacted PJM market design," the letter said. "The establishment of zero-emission credits in Illinois legislation is repeatedly cited by PJM as an initiating cause for PJM to pursue the extension of the minimum offer price rule (MOPR) to existing generation [and] policy-supported generation."

No one from FirstEnergy or Exelon spoke during the meeting with the board, but Exelon on Sept. 18 urged the board to take no action in response to the letter from Public Citizen and UCS, saying it "contains factual errors, misleading characterizations, and a misunderstanding of PJM's Operating Agreement."

"Exelon and all of its affiliates are deeply remorseful for the events that transpired at ComEd," *wrote* Kathleen Barrón senior vice president of government and regulatory affairs and public policy. "… The PJM board should and must operate in accordance with the PJM governing agreements, which provide no basis for board action or authorization for the requested remedies."

Slocum said Exelon, in its deferred prosecution agreement with the Department of Justice, admitted to engaging in "reprehensible conduct."(See *How ComEd Got its Way with Ill. Legislature*.) He said PJM board members have "pledged their independence" but have remained silent on the issues surrounding Exelon.

"The company admitted that it engaged in a decade-long bribery scandal that has significantly impacted policies and operations of the PJM markets and Tariff design," Slocum said. "We need to hear from the PJM board how you're going to deal with such reprehensible conduct by a member."

Almgren said the board has met to discuss Slocum's letter after it was sent to the RTO on Sept. 14 and plans to further discuss the matter. He said the board will officially respond to the letter but didn't give an exact timeline.

"The board is dismayed regarding the conduct of ComEd as set forth in the deferred prosecution agreement's statement of facts," Almgren said. "These activities contravene our values as found in our Code of Conduct."

Almgren said the board recognizes its role in ensuring no member "exercises undue influence" over the operations of PJM and that the RTO is "very keen" on staying independent and continuing to take actions to protect markets.

Slocum asked if the board would agree to a public posting of the synopsis of its private meetings, similar to the posted proceedings of the Federal Reserve's Board of Governors. "Public disclosure always improves market functions, and I think that applies to the operations of the Board of Managers," he said.

PJM CEO Manu Asthana said the RTO values transparency and encouraged Slocum to present a specific proposal on meeting transparency for the board to examine. He also said he respects the views of the advocates and that listening to stakeholders was one of his most important goals upon taking the helm at PJM, citing the fact that the RTO held nine different listening sessions for members before its FERC filing in the MOPR docket.

The listening sessions help inform PJM's perspectives on the MOPR issue, Asthana said.

"Obviously we applied our independent judgment, but we are putting a lot of time into listening, and we're not getting it right 100% of the time," Asthana said. ■

PJM News

Indiana City Wins Ruling on Station Power

FERC Orders PJM to Examine Tariff on Netting Provision

By Michael Yoder

FERC on Sept. 17 ruled that generating facilities that are not online and producing energy must pay for their station power at retail rates subject to state jurisdiction and directed PJM to consider changing its Tariff accordingly (*EL20-30*).

The commission said an offline generator that requires power to operate its lighting, air conditioning and other facilities "is consuming electricity as an end user and thus, consistent with the boundaries of the commission's jurisdiction under the [Federal Power Act], the provision of station power is a retail sale subject to state jurisdiction."

The commission's ruling came in response to a complaint filed by Lawrenceburg, Ind., and the Indiana Municipal Power Agency against the RTO, American Electric Power Service and Lawrenceburg Power seeking to void the power self-supply monthly netting provisions of the RTO's Tariff.

The city's Lawrenceburg Municipal Utilities has an exclusive franchise for supplying electricity within city limits and says Lawrenceburg Power's 1,160-MW combined cycle plant in the city must take station power service from the city because Indiana law does not allow it a choice of retail supplier. The plant is interconnected with AEP transmission facilities under PJM's operational control.

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

While the commission disclaimed jurisdiction over the supply of station power, it rejected the petitioners' request for a declaratory order finding the station power monthly netting provision in *section 1.7.10(d)(i)* of the PJM Tariff null and void.

Instead, FERC instituted a new proceeding, requiring PJM to propose changes to its Tariff consistent with the order or show cause why changes are not necessary (*EL20-56*). The RTO has 60 days to respond.

FERC said PJM's proposed revisions should clarify that the monthly netting provision in section 1.7.10(d)(i) "does not determine whether a retail sale of station power has occurred in that month." It also said Tariff provisions should clarify that PJM has no responsibility for the determination of any state-jurisdictional retail rates.

"Because the PJM Tariff's self-supply monthly netting provision can be read to — and indeed has been relied on by certain PJM generators to assert the right to — determine whether a retail sale of station power has occurred and avoid the retail purchase of station power, which is inconsistent with the commission's jurisdiction, we find that PJM's Tariff may be unjust, unreasonable, unduly discriminatory or preferential," FERC said.

Lawrenceburg Power told FERC that Lawrenceburg Municipal Utilities has attempted to charge the generator a minimum of $845,000 annually "even if Lawrenceburg Power does not consume any station power in the entire year" and that it prefers self-supplying its station power under the PJM Tariff.

"Arguments about the justness and reasonableness of the retail rates, and about what entity within the state of Indiana has authority to provide retail service, are more appropriately raised before the relevant state regulatory body," FERC said. "The commission does not have the authority to determine when, and on what terms, a retail sale of station power is made."

The ruling is likely to have impacts on other merchant generators.

Among the intervenors in the case were Buckeye Power, which said it and one of its member cooperatives, Washington Electric Cooperative (WEC), are involved in a dispute with Waterford Power, a merchant generator located within WEC's service territory, regarding WEC's right to supply Waterford's station power. ■

| *Lawrenceburg Municipal Utilities*

PJM News

FERC Again Rejects LG&E-KU Mitigation Exit

By Michael Yoder

FERC on Sept. 17 denied LG&E and KU's request for rehearing of its order rejecting the company's proposed transition for exiting from market power mitigation measures, though it did alter the terms of its exit (*ER19-2396, ER19-2397*).

The commission imposed rate de-pancaking provisions to resolve horizontal market power concerns after Louisville Gas & Electric and Kentucky Utilities merged into a single company in 1998 and left MISO in 2006. In March 2019, the commission agreed the provisions could be removed because loads located in the LG&E/KU market would have access to enough competitive suppliers.

FERC conditioned the removal on a transition mechanism to protect Kentucky municipal customers that had relied on MISO transmission service. In its original September 2019 rejection, it identified several of these customers, including the city of Falmouth, located in the north of the state near its border with Ohio. (See *FERC Orders Expanded Mitigation for LGE-KU*.)

LG&E/KU, however, argued that Falmouth had joined East Kentucky Power Cooperative, a PJM member, in 2018 and thus should not be included in the transition mechanism. FERC acknowledged that it had erred and ruled that the city "should not be a transition customer."

The commission otherwise rejected all of LG&E/KU's numerous arguments, including that it ignored evidence that charges under certain MISO schedules are not pancaked charges, and that it erred by rejecting the company's proposal to eliminate de-pancaking for exports to MISO.

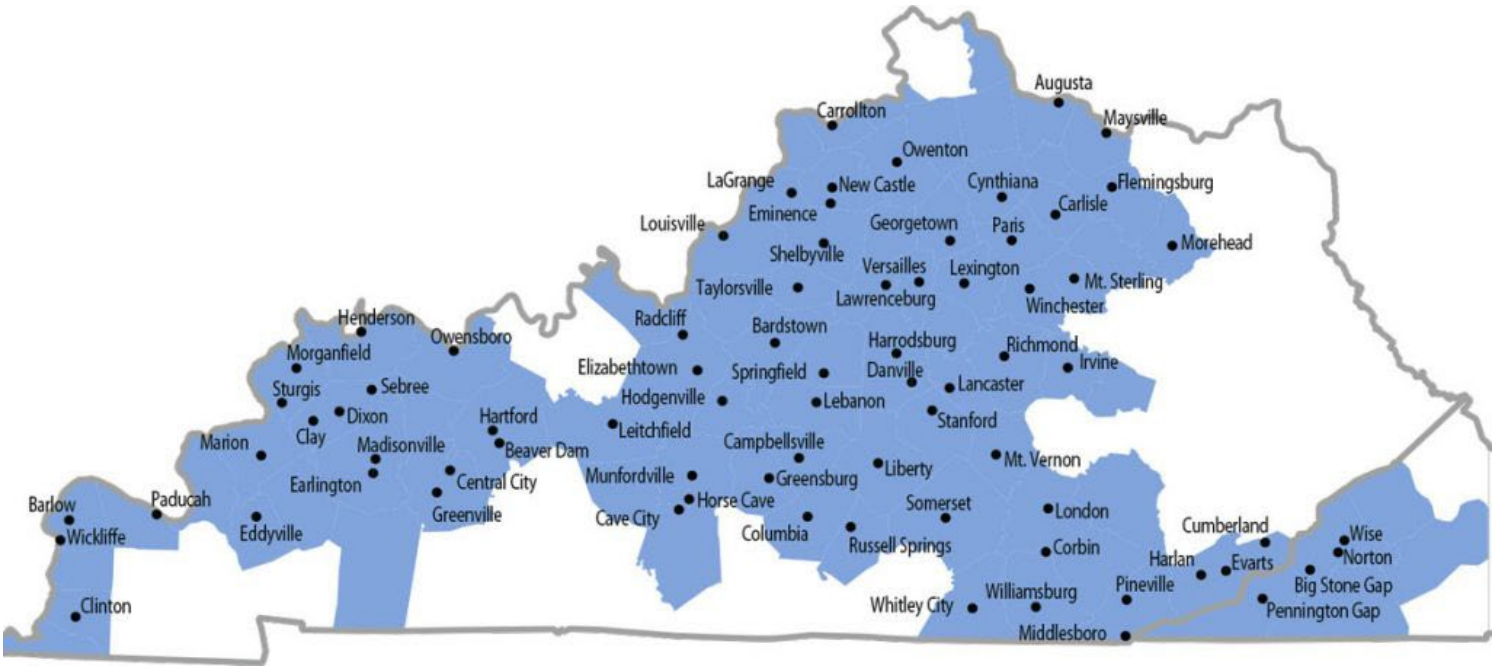
"We find that LG&E/KU's arguments overly simplify the context of this proceeding," FERC wrote in its ruling.

In a separate but related ruling on rehearing, the commission also clarified its use of the "initial term" framework regarding the transition mechanism to Kentucky Municipal Power Agency's (KMPA) ownership in the Prairie State Energy Campus project and the "take or pay" power sales agreements between it and its members (*EC98-2-002, ER18-2162-001*).

FERC had ruled that the transition mechanism would be "limited to the initial term of the power purchase agreements entered into by customers in the LG&E/KU market in reliance on the de-pancaking mitigation prior to the issuance of the March order." But it said the agreements between KMPA and its members have no readily apparent "term" in the "same sense as the power purchase agreements discussed by the commission in the September rehearing order."

It determined that the Prairie State agreements will be subject to the transition mechanism for a period of 10 years.

"We find a 10-year framework to be appropriate for the transition mechanism for power purchase or sales agreements with no initial term because, otherwise, the de-pancaking mitigation would continue in perpetuity in contrast to the March order, which directed that the de-pancaking mitigation can terminate," the commission said. "We find that 10 years from the date of the issuance of the March order is a reasonable period of time to allow KMPA to plan for alternative supply choices before its power supply agreement is no longer subject to the transition mechanism." ■



LG&E and KU service territory | *LG&E and KU*

SPP News

SPP SPC Takes on Congestion-hedging Issues

Stakeholders Unable to Reach Consensus on 11 Proposals

By Tom Kleckner

With SPP stakeholders unable to reach consensus on how to modify the RTO's congestion-hedging practices, the Strategic Planning Committee has taken matters into its own hands and will see if it can come up with a solution.

At issue is the Holistic Integrated Tariff Team's recommendation last year to add counterflow optimization (CFO), limited to excess auction revenues, to SPP's market mechanism that hedges load against congestion charges. (See *SPP Board Approves HITT's Recommendations*.)

The Market Working Group took up the charge, reviewing *11 different proposals*, including the status quo. Seven of those received support from either the RTO, the MWG or the Market Monitoring Unit, but not enough to reach consensus. The remaining four proposals were not supported by anyone.

"We've been informed by the MWG that, while [it] worked diligently to address this issue, [it] has concluded [it] can't bring specific issues back to the table with broad-based support," SPP Board of Directors Chair Larry Altenbaumer said during a Sept. 16 meeting of the Strategic Planning Committee, which he also chairs.

"My sense is we may be at a point where rather than trying to put this forward for an immediate answer," he said, "we have a chance to step back and take an overall assessment before stepping forward."

To do so, Altenbaumer will be relying on Director Graham Edwards, who served on the HITT; Dogwood Energy's Rob Janssen, who was the team's vice chair; and NextEra Energy Resources' Holly Carias, who chairs the Markets and Operations Policy Committee. Altenbaumer told the SPC that he has asked the three to further study automated counterflow. They will be assisted by SPP staff and receive input from the MMU.

Altenbaumer said the group's only charge is to maintain the HITT's recommendation. They are to present their findings to the board and MOPC in January.

"If the sense is we come back and say the status quo is unbalanced, that's an OK answer. If they say it's good for now, that's an OK answer," Altenbaumer said. "This situation is not unique to SPP. At least one other RTO is working through this process at the same time. Whatever can be gained in conversations with them can be a benefit to us as well."

SPP's current congestion-hedging practice is to allow market participants to nominate counterflow on a voluntary basis. Because it is a charge, participants are less likely to nominate, staff said.

The grid operator has been working since 2016 with participants, who are split over the system's effectiveness, on changes to the market design. SPP supports automated counterflow to solve the current practice's inequity, while the MMU said it is supportive of the status quo only over a solution that uses CFO.

The Monitor broke down the various proposals into two boxes: those using CFO and those not. In the former category, American Electric Power put forth a pre-auction, direct assignment of counterflows with opt-in/opt-out flexibility, while Oklahoma Gas & Electric suggested earmarking CFO dollars from the previous year, with the CFO method to be determined later.

In the non-CFO bucket, Nebraska Public Power District proposed partially modifying the excess auction revenue distribution method. The MMU opted for a more-than-partial modification of the revenue.

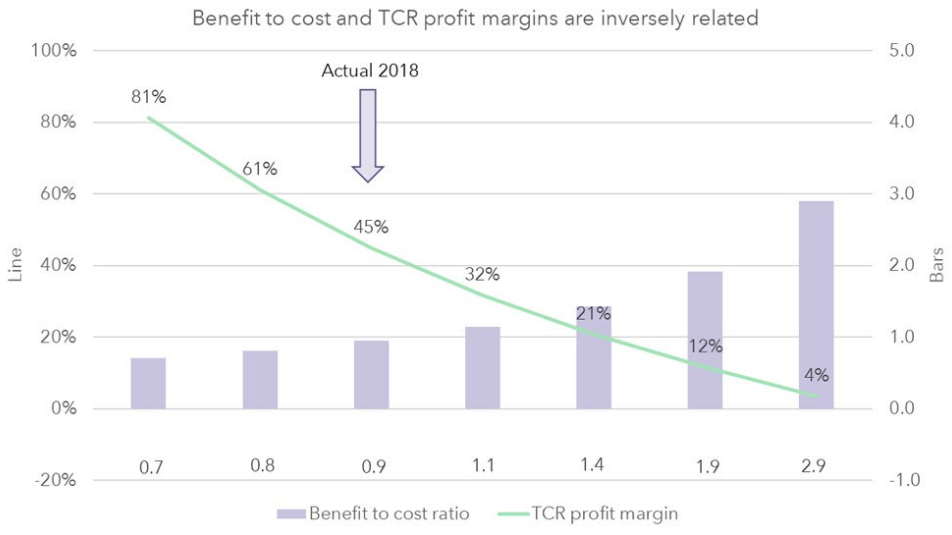
"Without addressing the underlying issues, the MMU believes the solutions being discussed today are really treating the symptoms," the Monitor's John Luallen said. "They have little to do with congestion patterns. They all represent a redistribution of congestion-hedging revenues between participants."

Luallen said all congestion-hedging products derive their value from the day-ahead market's congestion rent, which is unchanged by automated counterflow. He warned that the HITT's proposed framework creates risk because load-serving entities, as a whole, will receive less revenue than they would without the counterflow.

Two factors determine whether automated counterflow creates value for LSEs, Luallen said: the change in the congestion rent received, net of cost, and the change in the auction revenue received.

Altenbaumer agreed with Luallen, saying both proposal categories "may be trying to address the symptoms rather than the underlying issues."

"My desire is to come up with a solution that creates greater overall value or a situation or outcome that produces better efficiency in our markets or creates greater overall fairness in our market," Altenbaumer said. ■



SPP's MMU says automated counterflow may not benefit load-serving entities. | *SPP Market Monitoring Unit*

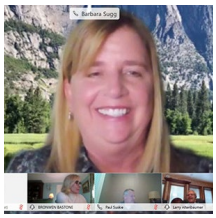
SPP News

SPP Board of Directors/MC Briefs

Technology Hampers Guest Appearance by MISO's Bear

SPP's Board of Directors and Members Committee met virtually Sept. 22 outside of their normal quarterly schedule to consider a number of pressing issues and learn more about the planned joint transmission study with MISO.

Unfortunately, as happens during the new normal, technology got in the way.



Barbara Sugg waits to hear from John Bear during SPP's Sept. 22 board meeting. | *SPP*

MISO CEO John Bear was among those calling in to the meeting, returning the favor after his SPP counterpart, Barbara Sugg, attended his Board of Directors' webinar on Sept. 17. (See "Teamwork with SPP," *MISO Readying Intensive Transmission Planning*.)

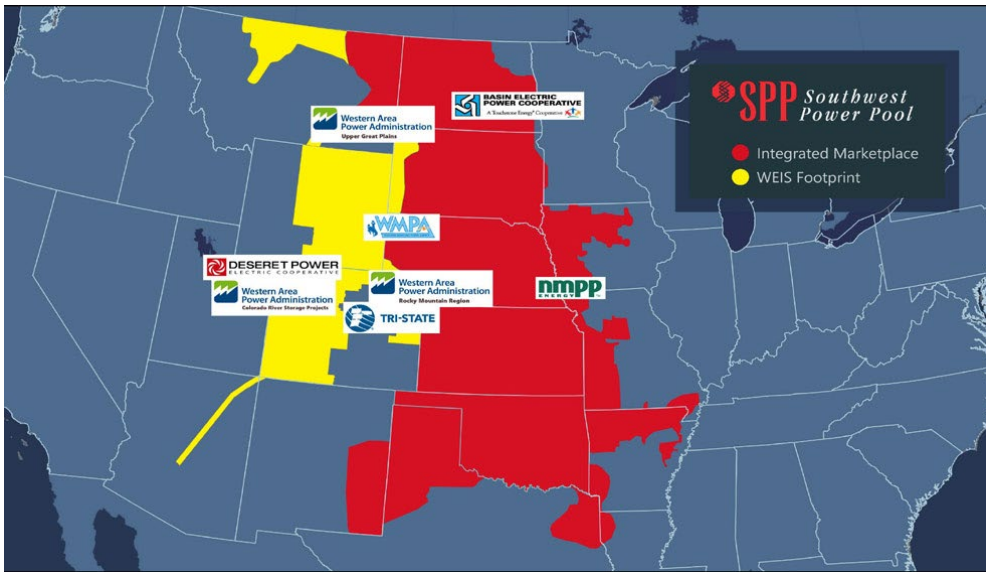
"Happy to be here," Bear said after Chair Larry Altenbaumer, waiting on a quorum, noted his presence.

Altenbaumer and Sugg both praised Bear in introducing him when it came time to discuss the RTOs' study. The grid operators said earlier this month they will collaborate on a yearlong transmission study designed to identify projects with comprehensive, cost-effective and efficient upgrades as they look for solutions to "historical challenges" facing their generator interconnection customers along their seams. (See *MISO, SPP to Conduct Targeted Transmission Study*.)

SPP's board last year set an objective to improve the relationship with MISO, Altenbaumer said. The appointments in January of Sugg as CEO and Lanny Nickell as COO have given SPP a "fresh start" with its neighbor, he said. The détente with MISO comes after a merger attempt in the early 2000s ended in acrimony.

"John's leadership has been front and center on this collaborative approach we've seen over the last few months" between SPP and MISO, Altenbaumer said. "We have far more success where we share common interests and challenges. Hopefully, the joint study will be an example of that."

"He's never hesitated to take a call from me, and he's been very, very open with sharing information," Sugg said. "He's been very responsive to my inquisition of things and how to improve operations and coordination between the two organizations."



SPP's two market footprints | *SPP*

But when it came time for Bear to speak, his words went unheard. After an uncomfortable silence, Sugg spoke for him.

"I know John is excited, and I know John would say the same things I've said," she said. Spying Bear on one of the webinar's video windows, Sugg said, "He's giving a thumbs-up."

Bear later sent an email to Sugg, who shared it with those still involved in the meeting. Bear, she said, thanked SPP and its members for their help as MISO "navigated" two hurricanes and a tropical storm this year.

"He's looking forward to working with you on seams projects that bring value to all of our members," Sugg said.

Technology was otherwise effective during the meeting. SPP changed its meeting registration practices to reduce the number of "nefarious" callers who have been bedeviling the RTO's meetings in recent weeks. IT Vice President Sam Ellis said "anywhere from a few dozen to a few 100 people have been infiltrating the [webinars] and flooding the channels with weird audio.

"We're not sure if they're trying to be disruptive, but we're hopeful this meeting goes smoothly because of the changes we made," Ellis said.

ERCOT encountered similar disruptions in late August and early September but has since resolved the problem.

SCRIPT to Address Transmission Planning

The board formally approved the Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT), a 15-person group comprising directors, members and state regulators tasked by the Strategic Planning Committee to evaluate SPP's transmission planning and applicable cost-allocation processes. (See "SPC Takes Look at Tx Planning," *SPP Briefs: Week of Aug. 31, 2020*.)

The RTO has seven different transmission planning processes that use various cost-allocation structures for transmission upgrades. The SCRIPT will evaluate options to strategically re-engineer those processes and write a final report with high-level recommendations for the board and Members Committee. The report will be conducted separately from the joint study with MISO.

"This will help us strategically address the growing number of transmission requests we are facing and have been dealing with for a number of years," Nickell said. "I don't want to say the planning process is broken or staff isn't doing a good job. They're doing a tremendous job performing the processes that are required of us in our Tariff, but the challenges facing us are ripe for a tremendous opportunity to re-engineer them going forward."

SPP's generator interconnection queue

SPP News

currently contains more than 75 GW of wind, nearly 38 GW of solar and almost 9 GW of battery storage, all under some form of study. The grid operator says expected generation growth will likely create financial pressures on older conventional generation, leading to increased future retirements.

The "unprecedented" amount of generation and SPP's "very iterative" interconnection process has "significantly" delayed processing the queue, Nickell said.

"The outrageously high volumes of [generator interconnection] requests has created stress on our staff and customers, given it takes four to five years [to process studies] and the uncertainty over costs," he said. "As customers drop out, we have to restudy, and as they drop out, the cost allocation changes. We have a tremendous opportunity to export energy, but without enough transmission capacity and the incentive to do so, we haven't been capitalizing on this as well as we could."

John Stephens, with the city of Springfield, Mo., pointed out that the Holistic Integrated Tariff Team's (HITT) recommendations haven't yet been acted upon and said he was concerned about overlap. Five of the HITT's recommendations were related to planning processes.

"There's been discussion in the membership that instead of doing everything at the same time, let's wait and see the effect of those [recommendations] on these processes," Stephens said.

"There is some of this effort that we will need to consider and be aware of as [the HITT recommendations] move forward," Nickell said. "I do believe those won't have any impact on this bigger, more holistic, strategic effort. We need to develop policies and propose policies that result in the consolidation of the [planning] process."

Board Lifts Suspension on Competitive Upgrade

SPP's second competitive project took another step toward reality when the board approved staff's recommendation to lift the suspension of the 345-kV Wolf Creek-Blackberry project and authorized the Oversight Committee to create an industry expert panel (IEP) to evaluate responses to a request for proposals.

The competitive upgrade, SPP's first with a nonmember, Associated Electric Cooperative Inc. (AECI), was approved last year. The board in April suspended the project while staff worked with AECI to complete a cost-and-use agreement. That agreement has since been filed with FERC, where it received no protests during the required 20-day period. (See "Directors Suspend Competitive Upgrade," *SPP Board/Members Committee Briefs: April 28, 2020*.)

Lifting the suspension means the project is once again considered approved for construction. Staff have seven days following the board's approval to issue an RFP.

The project involves a 105-mile transmission line from Kansas into Missouri and is estimated to cost $152 million. Part of the project is on the AECI system and will be constructed by the cooperative. SPP needs FERC approval to allocate funds to AECI.

Oklahoma Gas & Electric's Greg McAuley abstained from the Members Committee vote. He noted the utility is protesting several generator interconnection agreements at FERC related to a separate Wolf Creek project that has been canceled.

"We have a fundamental disagreement with staff over how that occurred. We think it was done contrary to the Tariff," McAuley said. "We've elected not to protest [Wolf Creek-Blackberry] at FERC because we recognize there are reliability issues that need to be resolved that way, even though we think there are better and more economical options than this."

SPP's first competitive project under FERC Order 1000, awarded to Mid-Kansas Electric in 2016, was subsequently canceled because load projections dropped over time. (See *SPP Cancels First Competitive Tx Project, Citing Falling Demand Projections*.)

A third competitive project has already been evaluated by an IEP and will be brought before the board for its consideration in October.

WEIS Tariff to be Refiled with FERC

Bruce Rew, SPP's vice president of operations, said the RTO plans to refile with FERC its Western Energy Imbalance Service (WEIS) tariff and other related documents by the end of the month. The WEIS remains on track to go live on Feb. 1, he said.

The commission rejected SPP's first attempt to secure approval for the WEIS in July. FERC said the RTO failed to respect nonparticipants' transmission rights and could improperly burden reliability coordinators. It also cited shortcomings on supply adequacy, market power protections and line-loss calculations (*ER20-1059, ER20-1060*). (See *FERC Rejects SPP's WEIS Tariff*.)

"FERC did recognize the benefits of the WEIS market and what it could bring to the region," Rew said.

WEIS stakeholder groups met several times before approving in early September the last of four revision requests addressing FERC's concerns. (See *SPP Expands its Western RC Footprint*.) The board approved those changes Sept. 22, allowing SPP to refile the Tariff.

Rew said a couple concerns outside the Tariff's scope remain to be resolved — congestion management in the WECC region and the Northwest Power Pool's reserve-sharing program — but that SPP is committed to working with those entities.

Of more concern to SPP is its Market Monitoring Unit's recent *determination* of "significant structural market power concerns" for WEIS energy and imbalance energy that should be addressed before the market's implementation. The MMU recommended SPP and market participants consider developing a systemwide mitigation measure and using cost-based offers if the mitigation measures cannot be implemented before the market goes live.

Rew said SPP is developing language to address those concerns and ensure pivotal suppliers don't have excess market power.

"The ISO-NE market had a similar issue," he said. "We're modeling our approach to market power mitigation after theirs."

Revisions to Rate Schedules

The board approved revisions to the cost-recovery mechanism from market participants who use and benefit from SPP's services as the RTO prepares to move to an unbundled rate schedule in 2021.

The revision request (*RR413*) clarifies the formula rate template to include the net financial impact of contracts in its overhead calculation and to include a prior period's over- or under-recovery in the rates' calculation for rate-cap purposes.

The board last year approved subdividing SPP's Schedule 1-A into four rate schedules, including a mix of demand and energy charges. Current 1-A charges for transmission service will become Schedule 1-A1 charges, and three market-related charges would be recovered through three energy charges. (See "Board Approves Modernized Cost-recovery Structure," *SPP Board of Directors/Members Committee Briefs: Jan. 29, 2019*.) ■

— Tom Kleckner

Company Briefs

Blackstone Commits $250M to DER Investments

Investment firm Blackstone has formed a new portfolio company, ClearGen, that will finance and own distributed energy assets focused on commercial, industrial and institutional customers.

GSO Capital Partners, Blackstone's credit investment platform, will commit $250 million to ClearGen and offer capital alongside companies that develop and operate distributed infrastructure.

The formation of ClearGen comes after Blackstone led a $850 million recapitalization of Altus Power America to help the distributed generation solar firm build its commercial and industrial portfolio.

More: *PV-Tech*

ChargePoint to go Public at $2.4B Valuation

ChargePoint, one of the world's oldest and largest electric vehicle charging networks, said last week it will go public by merging with Switchback Energy Acquisition in a deal that values the company at $2.4 billion. The deal is expected to close near the end of the year.

ChargePoint operates more than 115,000 charging ports globally, mostly in North America, and said it aims to increase to 2.5 million by 2025.

More: *Reuters*

Entergy Makes Net-zero Carbon Promise for 2050

Entergy last week pledged to reach net-zero carbon emissions by 2050.

The company, which controls regulated utilities across the Gulf region and an 8-GW nuclear generation fleet, first promised to cap greenhouse emissions in 2001. Most recently, it promised to lower its emissions 50% below 2000 levels by 2030.

First on the chopping block is its remaining coal fleet, which provided less than 5% of the company's revenue in 2019. Entergy plans to retire the rest by the end of 2030.

More: *GreenTech Media*; *Arkansas Business*

GE to Stop Making Coal-fired Power Plants

General Electric last week said it plans to stop making coal-fired power plants and exit from the business in the form of divestitures, site closings and job cuts.

"GE's exit from building new coal-fired power — after decades as a leader in this space — is an acknowledgement that growth in the energy sector will no longer be in coal," said Kathy Hipple, a financial analyst at Institute for Energy Economics and Financial Analysis.

More: *Reuters*

IDACORP Appoints New Board Member

IDACORP last week announced the appointment of Odette Bolano to serve on its board of directors.

Bolano is the president and CEO of the Saint Alphonsus Health System, where she provides executive leadership and strategic and operational oversight for a hospital system across Idaho and Oregon. She also serves as a board member of the Idaho Hospital Association, Boise Metro Chamber of Commerce, Boise Valley Economic Partnership, Idaho Business for Education, Boise State University Foundation and Boise State University College of Health Sciences.

More: *Argus Observer*

Nikola CEO Resigns amid Fraud Allegations

Nikola CEO **Trevor Milton** resigned last week amid fraud allegations, saying he was stepping aside because "the focus should be on the company and its world-changing mission, not me."

A report from Hindenburg Research on Sept. 10 said Nikola's success was "an intricate fraud." The claims included a video showing a truck rolling down a hill to give the impression it was cruising on a highway, and stenciling the words "hydrogen electric" on the side of a vehicle that was actually powered by natural gas.

Hindenburg had taken a short position in Nikola stock, meaning it could profit if the stock went down. Shares in the company lost more than 19% of their value in trading last Monday. Nikola said it contacted the Securities and Exchange Commission, which is looking into Hindenburg's allegations. Reports have said the Justice Department is investigating as well. Nikola said that former General Motors Vice Chairman Stephen Girsky will replace Milton.

More: *The Associated Press*

Pepsi Targets 100% Renewable Energy by 2030

PepsiCo last week said it is transitioning its global operations to source 100% renewable electricity across all its operations by 2030.

The company hopes to expand the effort across its entire franchise and third-party operations globally by 2040, which could help reduce about 2.5 million metric tons of greenhouse gas emissions. To achieve its goals, Pepsi said it has a "diversified portfolio of solutions," which includes expanding its list of onsite wind and solar projects at its facilities.

Pepsi recently became the latest company to join the RE100 initiative, a global initiative led by the Climate Group in partnership with CDP that works to bring together businesses committed to 100% renewable electricity.

More: *Fox Business*

Walmart Aims to End Emissions from Global Operations by 2040

Walmart last week said it is targeting zero emissions from its global operations by 2040 and intends to secure enough wind, solar and other renewable energy sources to power its facilities with 100% green power by 2035.

Walmart is committing to cutting emissions from its own operations, though the target will zero out only 5% of its total emissions. The company has also put forth efforts to address Scope 3 emissions, which are generated by its suppliers and customers, but has yet to set a net-zero target across all scopes.

The company also said it aims to electrify and eliminate emissions from all of its vehicles by 2040.

More: *Bloomberg Green*

Federal Briefs

Brouillette Questions Science on Human Impacts of Climate Change

Energy Secretary **Dan Brouillette** last week questioned the mainstream scientific consensus that humans are causing climate change at a news conference for Pennsylvania's natural gas and petrochemical industry.

When asked how the Trump administration would fight climate change, Brouillette said, "We have a lot to learn about what causes changes in the climate, and we're not there yet." When asked to clarify whether he believed the scientific consensus that human-caused carbon emissions are fueling hotter temperatures, he replied, "No one knows that."

At current emissions rates, the world could reach irreversible levels of climate change by as early as 2030, according to a U.N. panel on climate change.

More: *StateImpact Pennsylvania*

Climate to Reduce GDP by 1% in 2050

The U.S. gross domestic product will be 1% smaller than it would have been in 2050 because of climate change, according to a projection from the Congressional Budget Office.

CBO predicts that between 2020 and 2050, climate change will reduce GDP growth by 0.03 percentage points each year, culminating in a 1% decrease in 2050. The projection was calculated using data from 1995 to 2019 and used the overall historical trends between the changing climate and GDP output. It also took into account how specific natural events might cause damage or premature death.

CBO's findings differ from other recent assessments showing how climate change could have a much larger impact on the economy. A study last year found that the U.S. could see a GDP decrease of up to 10.5% by 2100, while another report said climate change was likely to cause economic instability.

More: *The Hill*

House OKs Energy Bill; Trump Threatens Veto

The House of Representatives last week approved a broad clean energy bill, but its prospects are uncertain in the Senate, and President Trump has threatened a veto.

The Clean Economy Jobs and Innovation Act (*H.R. 4447*) passed by a 220-185 *vote*, with seven Republicans joining Democrats in support and 18 Democrats voting against it, including progressives Alexandria Ocasio-Cortez (N.Y.), Ayanna Pressley (Mass.) and Ilhan Omar (Minn.).

The bill authorizes $135 billion, including research and development for solar, wind, advanced geothermal energy and hydroelectric power and carbon capture and storage. It also includes voluntary building codes to promote energy efficiency. Although it won support from some clean energy groups, the bill was attacked by Republicans as too expensive and by some climate advocates as too timid.

More: *The Hill*; *The New Republic*; *Energy & Commerce Republicans*; *Energy & Commerce Democrats*

Judge Removes Pendley as BLM Boss for Serving Unlawfully

U.S. District Judge **Brian Morris** last week ruled that William Perry Pendley, acting director of the Interior Department's Bureau of Land Management, has been serving unlawfully and blocked him from continuing in the position.

Morris determined Pendley had served for 424 days without being confirmed by the Senate as required under the Constitution. Pendley had been formally nominated by President Trump to direct the bureau in July after being given temporary authorizations to the acting position several times by Interior Secretary David Bernhardt.

Interior spokesman Conner Swanson said the decision will be appealed.

More: *The Associated Press*

Mountain Valley Pipeline Regains Permit to Cross Streams, Wetlands

The Army Corps of Engineers last week reissued three permits for the Mountain Valley natural gas pipeline in Virginia and West Virginia, nearly two years after they were invalidated by a federal appeals court. The Forest Service also released its proposal for the 303-mile pipeline to pass through the Jefferson National Forest, which was struck down in a separate ruling by the 4th U.S. Circuit Court of Appeals.

In a letter to the Justice Department, an attorney for environmental groups sought an administrative stay of the stream-crossing permits.

More: *The Roanoke Times*

Palisades Nuclear Plant Seeks Approval for Repairs

Entergy last week said it is asking the Nuclear Regulatory Commission to approve its plan to fix "indications of cracking" on components used to generate power at its Palisades nuclear plant on Lake Michigan.

Entergy officials discovered the problem during a recent inspection and notified the commission on Sept. 18. The indications of cracking, found on nozzle penetrations for the nuclear reactor vessel head, do not pose a risk to the public. The plant is not currently generating power, as a refueling and maintenance outage began on Aug. 30.

The plant cannot begin generating power again until the indications of cracking are repaired. However, before the company can make repairs, it must submit its plans to NRC for approval. Entergy is asking for approval by Oct. 1. It plans to close the plant in 2022.

More: *MLive*

TVA Installing First Battery Storage System

The Tennessee Valley Authority announced last week it is installing its first owned and operated, grid-scale battery energy storage system in Vonore, Tenn.

The Vonore Battery Energy Storage System will use lithium-ion batteries to store 40 MWh of energy. It is expected to become operational in 2022.

In February, TVA announced a solar project in Lowndes County, Miss., for its Green Invest programs that will include 200 MWh of storage. Both projects were a part of the company's 2019 integrated resource plan.

More: *The Chattanoogan*

State Briefs

ARKANSAS

Fayetteville School Board Approves Solar Project

The Fayetteville School Board last week voted 6-0 to approve Nabholz as the vendor for its new solar project.

Nabholz will use the services of Entegrity to purchase land, as well as install, own, operate and maintain the system throughout the duration of the 28-year contract. The project will include 1-MW and 5-MW solar arrays to be built at two to-be-determined locations.

The project will have no upfront costs to the district and is projected to save more than $9.8 million over the life of its power purchase agreement.

More: *Arkansas Democrat-Gazette*

CALIFORNIA

San Diego Wants $80M for Electric, Gas Franchise Agreement

San Diego Mayor **Kevin Faulconer** last week released the requirements that a utility must meet to win the right to provide the city with electric and gas services, as its franchise agreement is set to expire on Jan. 17. The current franchise agreement, held by San Diego Gas & Electric, has been in place since 1970.

Faulconer's "Invitation to Bid" calls for a new agreement lasting 20 years and stipulates the winner pay at least $80 million upfront — $70 million for the electric franchise and $10 million for the gas franchise. So far, three companies — SDG&E, Indian Energy and Berkshire Hathaway Energy — have expressed interest. Other prospective bidders have until 5 p.m. Oct. 23 to submit offers.

More: *The San Diego Union-Tribune*

SCE Equipment Eyed as Possible Source of Fire Near LA

Southern California Edison last week said federal investigators are looking into whether the Bobcat wildfire near Los Angeles was sparked by its equipment.

In an incident report filed with the Public Utilities Commission last week, SCE said its nearby equipment experienced an issue five minutes before the fire started on Sept. 6. The company has since turned over a section of an overhead conductor from its transmission facility in the area.

More: *The Associated Press*

DELAWARE

Changes Needed to Meet Greenhouse Gas Reduction Goals

Susan Love, Climate and Sustainability Section administrator for the state's environmental agency, last week said if the state maintains its current trajectory, greenhouse gas emissions will be reduced by 25.4% in the past 20 years. In 2005, officials set a goal of a 26% reduction over two decades.

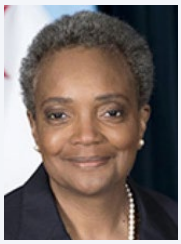
Love also said data indicate that without additional action, emissions will decrease until 2032, when they will begin to rise again because of population and economic growth. However, she did say if mitigation efforts increase, the reduction could be as high as 31.1% in 2025 and 59.7% in 2050.

A consultant suggested a list of 20 mitigation efforts that could be implemented, including increasing renewable energy, promoting energy efficiencies in buildings and increasing use of zero-emission vehicles.

More: *Cape Gazette*

ILLINOIS

Lightfoot Scolds ComEd, Threatens to not Re-up Agreement



Chicago Mayor **Lori Lightfoot** warned Commonwealth Edison CEO Joseph Dominguez last week that the city will not renew its utility agreement with the company unless she receives a "substantive" plan that details goals for ethics reform, an end to residential disconnections, help with the city's clean energy goals and other measures. Their 30-year deal expires at the end of this year.

Lightfoot scolded the utility for not committing to ending all disconnections during the COVID-19 pandemic. In July, she called out Dominguez for the company's role in a federal corruption probe, as ComEd confessed to paying $1.3 million in bribes to associates of House Speaker Michael Madigan.

In a statement, ComEd called Lightfoot's agenda "ambitious" and said, "We welcome the chance to discuss it in detail with the city."

More: *Chicago Sun-Times*

Utilities Extend Shutoff Moratoriums Through March of 2021

The Commerce Commission last week said Ameren Illinois, Aqua Illinois, Illinois American Water, Commonwealth Edison, Peoples Gas, North Shore Gas and Utility Services of Illinois have voluntarily agreed to extend their moratoriums on utility disconnections for low-income customers until March 31, 2021.

MidAmerican Energy also will extend its moratorium for customers who qualify for Low Income Home Energy Assistance Program through March 31, while Nicor Gas and Liberty Utilities agreed to extend their moratoriums for all residential customers through the same date.

More: *WBBM-TV*

MICHIGAN

Whitmer Pledges Carbon Neutrality by 2050

Gov. **Gretchen Whitmer** last week signed an executive directive that outlined a goal of becoming carbon-neutral by 2050 and a 28% reduction below 1990 levels in greenhouse gas emissions by 2025. The state is the ninth to set such a goal.

The order requires the Department of Environment, Great Lakes and Energy to form a strategy to reach the goal across the economy by the end of next year. The Department of Technology, Management and Budget must investigate energy efficiency opportunities when renovating state buildings, while all new renovations and buildings must be carbon neutral by 2040 and existing buildings reduce energy use by 40%. The

Treasury Department will be responsible for making a plan that identifies communities that will be impacted by any change in energy production and work to "minimize those impacts."

More: *Bridge Michigan*

PSC Rejects Consumers' Request to Recoup 2019 Fire Costs

The Public Service Commission last week rejected Consumers Energy's request to increase natural gas bills by $6.8 million to cover some of the costs from the January 2019 fire at its Ray Compressor Station in Macomb County.

Consumers paid nearly $8 million to purchase natural gas during the incident because it couldn't access its own supply. The fire forced the station to shut down, which prompted a statewide natural gas emergency during a week with record low temperatures. The company was also fined $10,000 earlier this year after an investigation found it violated federal safety standards.

However, the PSC did approve the rest of Consumers' request, allowing it to recover an extra $10.9 million from customers, plus interest because some of its expenses unrelated to the fire came in higher than anticipated.

More: *MLive*

MONTANA

Supreme Court Again Finds PSC Unlawful in Solar Dealings

The state Supreme Court last week unanimously ruled that NorthWestern Energy and the Public Service Commission broke the law in setting terms that made the MTSUN solar farm uneconomical. The ruling was the *second time in a month* the justices ruled against the PSC and the utility.

"In reviewing the record and considering each component of the PSC's orders, it is clear that at nearly every step of setting the terms of MTSUN's [purchase power agreement], the PSC chose arbitrary and unlawful methodologies that resulted in deflating the economic feasibility of MTSUN's project," Chief Justice Mike McGrath wrote.

Developers expect the project, which has been five years in the making, to move forward next spring under terms set by the court.

More: *Billings Gazette*

OHIO

AEP Financing Columbus Green-Power Ballot Issue

AEP Energy last week agreed to donate $1.5 million toward Columbus' political campaign to persuade voters to pass a green-energy electricity aggregation program in November.

The contribution is spelled out in a memorandum of understanding signed by the city and AEP on Aug. 17. The payments, for "education and outreach efforts," will go to the Clean Columbus campaign committee and will be paid in three $500,000 installments. The MOU says AEP must work with the city and its aggregation consultant, Trebel, to develop a "master supply agreement" satisfactory to the city's goal of 100% green energy by 2022. That agreement, which would be signed after the election, must be consistent with AEP's written July 6 proposal, which says it would serve "100% of the city's program load from newly built, local wind and solar projects."

If voters approve the program, AEP would lock in most of the city as its power customer for up to 15 years.

More: *The Columbus Dispatch*

AG Sues to Block Nuclear Bailout Money from Being Paid out

Attorney General **Dave Yost** last week filed a civil lawsuit seeking to block Energy Harbor — the owner of two nuclear plants in the state — from receiving any of the $1.3 billion in public bailout funds approved under House Bill 6, the law at the center of a corruption scandal.

The lawsuit doesn't seek to stop the collection of any bailout money, only to block its payment to Energy Harbor. Even if the suit succeeds, Yost said his legal complaint wouldn't affect other parts of HB 6 that authorize subsidies for coal and solar plants, as well as lock in how much money FirstEnergy can collect from residential and commercial customers.

More: *Cleveland.com*

PENNSYLVANIA

Wolf Vetoes Bill that Would Keep State out of RGGI

Gov. Tom Wolf last week vetoed House Bill 2025, which would have essentially stopped the state from entering the Regional Greenhouse Gas Initiative.

The bill passed the House (130-71) and the Senate (33-17), a few votes shy of a veto-proof majority.

Wolf said the bill was "extremely harmful to public health and welfare." However, lawmakers claimed it was more about who has the power to make the decision and not whether the state should join the compact. The Wolf administration plans for the state to join RGGI in 2022.

More: *StateImpact Pennsylvania*

SOUTH CAROLINA

Legislature Elects 4 New Members to PSC

The legislature last week elected Lowcountry planner and conservationist Carolee Williams, Upstate water consultant Mike Caston, Rock Hill-area businessman Headen Thomas and Pee Dee lawyer Delton Powers as the four new members of the Public Service Commission.

The legislature's action is significant because it represents a complete overhaul of the commission since the 2017 V.C. Summer nuclear construction failure sparked outrage about higher power bills associated with the project. The PSC had also been accused of failing to properly oversee rate hikes that helped SCE&G but saddled customers with higher bills to pay for the project.

More: *The State*

TENNESSEE

MLGW Hires Firm to Seek Proposals for Power Sources

The Memphis Light, Gas and Water Division board voted last week to hire consulting firm GDS Associates to begin work on requests for proposals as the utility explores leaving the Tennessee Valley Authority in search of a new power supplier.

Board members said they want MLGW to get monthly updates on the progress. The Memphis City Council will discuss the hiring at its Oct. 6 board meeting.

The firm was hired for up to $520,000, while the process could take as long as two years to complete.

More: *Daily Memphian*

TEXAS

Gibbons Creek Power Plant to be Sold, Decommissioned

The Texas Municipal Power Agency (TMPA) last week said it is finalizing an agreement to begin decommissioning the Gibbons Creek Steam Electric Station and Reservoir.

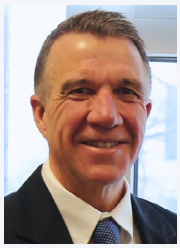
The asset purchase agreement means environmental and maintenance service provider Charah Solutions will take ownership of the 6,166-acre area that includes the plant, the 3,500-acre reservoir, dam and spillway and assume all environmental responsibilities. Its subsidiary Gibbons Creek Environmental Redevelopment Group will then shut down and decommission the plant and complete all necessary environmental remediation work for the site landfills and ash ponds.

TMPA has been negotiating with Charah Solutions since August 2019. If the parties come to an agreement, more details will be made public when it ends up on the agenda for a TMPA board meeting, which is expected to happen within the next few months.

More: *The Eagle*

VERMONT

Senate Overrides Veto of Global Warming Solutions Act



The Democratic-cotnrolled Senate last week voted 22-8 to override Gov. **Phil Scott's** (R) veto of the Global Warming Solutions Act, legislation that requires the state to meet targets for reducing carbon emissions. Because the House of Representatives had already voted (103-47) to override the veto, the measure is now law.

The act requires the state to reduce greenhouse gas pollution to 26% below 2005 levels by 2025. Emissions will need to be 40% below 1990 levels by 2030 and 80% below by 2050. If the government fails to meet these goals, the bill allows individuals to sue the state.

While the legislation sets up new emissions-reduction requirements, it does not say how the state will meet them. Instead, it will form a 23-member Climate Council to come up with a plan.

More: *VT Digger*

WISCONSIN

PSC Extends Shutoff Moratorium

The Public Service Commission earlier this month voted 2-1 to extend the moratorium on residential disconnections and refusal of service for nonpayment until Nov. 1. Prior to the extension, regulated utilities were not allowed to disconnect service for nonpayment until Oct. 1.

The decision comes as the state is approaching its annual moratorium on cold weather disconnections of utility service used for home heating, which begins Nov. 1 and runs through April 15.

More: *Public Service Commission of Wisconsin*