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ComEd on Hot Seat at ICC Hearing

ICC Chair also Under Fire

By Rich Heidorn Jr.


ICC Chair Carrie Zalewski | *© RTO Insider*

Commonwealth Edison officials apologized to the Illinois Commerce Commission, while ICC Chair Carrie Zalewski defended herself against conflict-of-interest allegations Wednesday in the wake of the company's bribery scandal.

The ICC questioned ComEd officials for 90 minutes during its open meeting over the company's agreement 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 parent Exelon's money-losing nuclear plants.

The U.S. Attorney's Office in Chicago filed a one-count information on July 17 alleging that ComEd arranged no-work jobs for Madigan associates including former Chicago Alderman Michael R. Zalewski, the father-in-law of the ICC chair, to influence legislation favorable to the company.

The allegations came several weeks after radio station WBEZ reported that it had obtained emails showing Madigan's top aide recommended Zalewski for the ICC in December 2018, about four months before Gov. J.B. Pritzker named her to a five-year term as chairwoman. (See *How ComEd Got its Way with Ill. Legislature*.)

Continued on page 26

FERC Rejects SPP's WEIS Tariff

February Launch Threatened

By Rich Heidorn Jr. and Tom Kleckner

FERC on Friday sent SPP back to the drawing board, saying its proposed Tariff for its Western Energy Imbalance Service (WEIS) market fails to respect transmission rights of non-participants and could improperly burden reliability coordinators. The commission also cited shortcomings on supply adequacy, market power protections and line-loss calculations (*ER20-1059, ER20-1060*).

"We recognize the potential benefits that the WEIS market could bring to utilities and customers in the Western Interconnection … and we appreciate the efforts by SPP and the market participants to develop regional solutions," FERC said. "… Although we reject SPP's proposed WEIS Tariff, we do so without prejudice and provide guidance on other aspects of SPP's proposal that may require revisions to ensure SPP's proposal is just and reasonable."

SPP said it is reviewing the order and plans to "address [FERC's] concerns" in a subsequent filing.

On Monday, SPP's Market Monitoring Unit (MMU) posted a market power study on the WEIS market that concluded it presents "significant structural market power concerns" for energy and imbalance energy that should be addressed before the market's implementation.

The MMU said market share, supplier concentration, residual supply index (RSI), and pivotal supplier analysis all indicate "high potential structural market power in the WEIS Market."

Given its "substantial concerns," the MMU recommends SPP and WEIS market participants consider developing a system-wide mitigation measure and using cost-based offers if the

Continued on page 32

US Analyzing Iowa Storage Pilot as Potential Model

By Amanda Durish Cook

Enel X battery storage | *Enel X*

An agricultural hub of about 8,000 in the northeast corner of Iowa seems an unlikely choice for a state-of-the-art battery storage project, but the Department of Energy thinks it could become a template for other American towns.

The DOE is chipping in $250,000 on a $2.5 million, 2.5-MW battery storage pilot project in Decorah, Iowa, to increase the city's capacity for rooftop solar. Alliant Energy will build the project; Sandia National Laboratories will provide technical support and collect data. The Iowa Economic Development Authority (IEDA) is also contributing a $200,000 grant.

Those groups, and others, will analyze the

Continued on page 21

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In this week's issue

FERC/Federal News

Senate Energy Committee Discusses Carbon Management

By Michael Yoder

Sen. Lisa Murkowski (R-Alaska) | *Senate ENR Committee*

The Senate Energy and Natural Resources Committee last week called attention to federal efforts to encourage emerging technologies aimed at carbon dioxide management, including removal, utilization and storage.

In a hearing July 28, Chairwoman Lisa Murkowski (R-Alaska) said carbon management is a subject that should "captivate us all." In less than a decade, she said, the idea of carbon dioxide removal has moved from focusing on planting trees to realistic approaches of technologies to permanently remove it from the air and the ocean that are needed and "worth pursuing."

"Carbon management will very likely prove to be an important option for reducing emissions and the impacts of climate change," Murkowski said.

To help scale up the government's efforts, Murkowski announced she will introduce a bill with Sen. Kyrsten Sinema (D-Ariz.), the CREATE Act, which would establish an executive committee at the White House's Office of Science and Technology Policy to coordinate interagency efforts on carbon removal research and development.

Sen. Joe Manchin (D-W.Va.) | *Senate ENR Committee*

Ranking Member Joe Manchin (D-W.Va.) said technology that captures carbon from both power plants and out of the ambient air could be deployed anywhere in the world once it has "matured," providing both economic and environmental benefits to the U.S. He touted his own *bill* introduced last year, the EFFECT Act, which would advance carbon removal technologies through federal funding of research projects.

Manchin said simply capturing carbon is not enough in the process and that technology needs to include additional applications. He said scientists at the National Energy Technology Laboratory are working on novel ways of using carbon, including decontamination of personal protective equipment and other medical equipment.

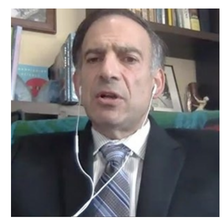
"We are seeing more and more opportunities for carbon dioxide use from commercial, industrial and defense purposes," Manchin said. "This is where innovation can help the economies of fossil fuel-rich states like West Virginia while also helping to address our climate challenge."


Steven Winberg, DOE | *Senate ENR Committee*

Steven Winberg, assistant secretary for fossil energy at the Energy Department, told the committee that work is ongoing to enhance large-scale carbon management. He said the department has provided about $85 million this year for five projects through the Carbon Storage Assurance Facility Enterprise (*CarbonSAFE*) Initiative to develop geological storage sites that can hold a minimum of 50 million metric tons of CO_2 from industrial sources. The department is also getting ready to announce plans for up to $46 million for engineering-scale testing of next generation carbon capture technologies for coal and gas generation plants, he said.

The *Coal FIRST* initiative is developing coal power plant designs with carbon-neutral and net-negative emissions when coal and biomass are combined with carbon capture, utilization and storage programs, Winberg said, adding another layer of technological advances.

"These plants will have the flexibility that allows them to support our evolving electricity grid, and some will be able to produce hydrogen, which can play a significant role for electricity production, manufacturing and transportation," Winberg said.


Julio Friedmann, Center on Global Energy Policy | *Senate ENR Committee*

Julio Friedmann, a senior research scholar at the Center on Global Energy Policy at Columbia University, told senators that innovation remains the "nation's strong suit" and called for continued financial support by the federal government in carbon management. He said "dramatic increases" in funding for both carbon capture and storage (CCS) and carbon removal follows recommendations contained in a 2019 Energy Futures Initiative *report*, which laid out specific line items and budgets for U.S. agencies.

Friedmann said one of the next steps needed for industries like power generation to adopt carbon management practices more widely is more effective tax incentives. He said recent *analysis* found that for utility-owned gas-fired power plants to deploy CCS, they would require $80/ton in incentives and closer to $110/ton for merchant power plants, which is in line with existing renewable tax credit provisions.

The greater the incentives, Friedmann said, the more carbon capture systems will be deployed and the more tons reduced or removed.

"This is the climate counterstrike, and I ask the committee to think about CO_2 removal as the biggest market of all time," Friedmann said. ■

FERC/Federal News

WIRES Conference Talks Order 1000, Tx Incentives

Clark Sees Shift on Fixed vs. Volumetric Rates from Pandemic

By Rich Heidorn Jr.

Tony Clark, Wilkinson, Barker & Knauer | *WIRES*

The impact of the coronavirus pandemic on electric demand could lead some state regulators to reconsider their transmission rate structures, former FERC and North Dakota Public Service Commissioner Tony Clark told WIRES' virtual Summer Meeting on Thursday.

Clark, a former president of the National Association of Regulatory Utility Commissioners, said state regulators took a "do no harm" approach at the beginning of the pandemic by suspending service cutoffs for nonpayment.

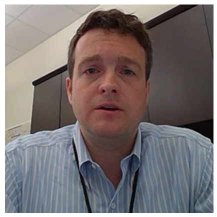
Now, utilities and regulators are trying to determine how to deal with the bad debts that have mounted as many unemployed become unable to pay their electric bills. Utilities will likely be permitted to create regulatory assets for those debts and then engage with regulators in proceedings about recovering the debts, Clark said.

"Either government steps in and picks up the tab for all this societal debt that the utilities are holding, or … you allow the utilities to recover that through rates over some period of time," Clark said. "But there really aren't a lot of other options besides some variation of those two concepts."

The long-term impact, he suggested, could be a change in the "political tradeoff" that has seen many jurisdictions collect much of their utilities' fixed costs through volumetric charges.

"When you have something like the pandemic hit and volumetric usage drops off dramatically, at least for some classes of customers, that means you're going to have a utility cost-recovery system that doesn't work anymore," Clark said. "So, this is what regulators will be dealing with: trying to figure out what the new normal is … in terms of volume. I think it leads regulators to a place where they begin to look more seriously at trying to recover fixed costs through fixed charges and variable costs from variable charges, which is probably where we should have been all along."

Clark said commercial and industrial customers' subsidization of residential ratepayer use also could be reconsidered.



Zach Smith, NYISO | *WIRES*

Zach Smith, vice president of system and resource planning for NYISO, said New York power demand is about 7% lower than normal following the "astounding" 33% drop in GDP in the second quarter.

While a typical recession is often followed by two years of recovery, this downturn is the result of the "externality" of COVID-19, Smith said. "So there is a real debate about what that recovery is going to be, [and] it's really a huge question mark as to how this energy demand is going to recover."

Chatterjee on Order 1000 Disappointment

FERC Chair Neil Chatterjee, speaking via satellite phone from Montana, briefed the conference on the commission's May order on return on equity and its Notice of Proposed Rulemaking on transmission incentives.

Chatterjee said he was confident Opinion 569-A on ROE "better reflects investor expectations … and is also legally durable so that it will stand up if challenged in court." The commission said it would consider three inputs in its ROE calculations: the risk premium model, the discounted cash flow and capital asset pricing model. (See *FERC Ups MISO TO ROE, Reverses Stance on Models*.)

The chairman said he was eager to review comments due in mid-August on FERC staff's June white paper on cybersecurity incentives (*AD20-19*). (See *FERC Seeks Comments on Cyber Investment Incentives*.)

Chatterjee said "one of his great disappointments and frustrations" has been the inability to address Order 1000's failure to produce the "innovation and cost discipline" he hoped would result from opening transmission development to competition.

"We're at a point now where I think Order 1000 clearly isn't delivering the results that were initially envisioned," he said. "That, unfortunately, is where the agreement ends. What to do about it is a very challenging thing.

"What I've just come to recognize [is that] with all of the other complex challenges that we are facing, to try and reopen Order 1000 right now would be biting off more than we could chew. So, what I'm focused on is interacting with stakeholders to see if there are targeted fixes that the commission can examine."

Transmission Incentives NOPR

FERC's controversial NOPR on transmission incentives, which generated much comment and criticism in its docket in July, was the subject of WIRES' final panel, moderated by Nina Plaushin, vice president of ITC Holdings. (See *Tx Incentive NOPR Leaves Many with Sticker Shock*.)

NARUC Executive Director Greg White, a former Michigan regulator, said he welcomed a fresh look at the policy. "I'm not convinced that FERC's past incentives have been very effective," he said, noting he was speaking for himself and not on behalf of NARUC.

White was particularly critical of the adder for participation in an RTO, which FERC has proposed increasing from 50 to 100 basis points. He agreed with Commissioner Richard Glick's observation that transmission owners are unlikely to leave RTOs and noted that some states require their utilities to participate.

Julia Frayer, managing director of London Economics International, spoke about her *white paper*, which WIRES submitted with its comments on the NOPR. The paper contends TOs take on risks by joining RTOs because of the grid operators' "governance and operational nature." The paper also made the case for a transmission technology incentive.

Julien Dumoulin-Smith, managing director at BofA Securities, gave a passionate, highly caffeinated seven-minute speech, beginning with his argument for why "people's historical understanding of how to establish ROEs are upside-down."

He ended by urging transmission planners to begin thinking about the role hydrogen could play under electrification that doubled renewables and the size of the grid.

"How do you see the hydrogen role evolving? Is it a midstream industry? Do you do things [with hydrogen] and then send it on electricity? It's an open question. We've seen these tensions between gas — gas by wire and gas midstream itself," he said.

Transmission planning should reflect how "you think about a distributed or centralized hydrogen economy 30 to 40 years from now," he said. "I throw that out as my big-picture thought. Take it or leave it." ■

CAISO/West News

EDAM Design Could Undermine Tx Rights, Critics Say

DA Market will not be as Voluntary as EIM, CAISO Acknowledges

By Hudson Sangree

The proposed expansion of CAISO's Western Energy Imbalance Market to a day-ahead market won't be as voluntary as advertised, some stakeholders argued last week during calls on the ISO's plans.

CAISO released the straw proposal for its Extended Day-Ahead Market (EDAM) on July 20, followed by stakeholder calls July 27 and 29. (See *CAISO Proposal Sets Course for EIM Day-ahead*.)

A part of the plan that calls for participants to dedicate transmission capacity to the market drew ire.

Mark Holman, managing director of power with Powerex, said the EIM had proven widely popular because of its wholly voluntary nature. Having more mandatory components in the EDAM could make the market less attractive, he said.

"I think we really need to identify that this is not entities joining a multistate RTO with a corresponding design and governance model," Holman said. "The EIM has worked well residing in parallel with other market opportunities."

The proposal for the EDAM kicked off two years ago after the last failed attempt to create a Western RTO led by CAISO. (See *CAISO Takes Step Toward EIM Day-ahead Market*.)

Western entities have been happy to do business through CAISO's EIM — which has reaped *$1 billion* in benefits for participants, CAISO said July 28 — but they are wary of giving Californians too much control.

| FERC

To allay concerns, CAISO has made the EDAM's voluntariness a centerpiece of its efforts, stressing that the EDAM would be much like the EIM and not like an RTO.

"The approach contemplated in this effort does not require full integration into the CAISO balancing authority area as participating transmission owners, nor does it require formation of or participation in regional transmission organization," the ISO said at the start of its *straw proposal*.

In his *presentation* July 28, Don Tretheway, the ISO's principal for market design policy, said one of the proposal's main principles is that the EDAM will be a voluntary market and won't assume responsibility for transmission planning, resource procurement and other key functions of an RTO.

However, CAISO said the EDAM will require a different approach to transmission usage than the EIM.

"EIM participants make transmission available to support energy transfers through contributions of interchange rights holders or available transmission capacity," the straw proposal said. "This transmission supports energy transfers between balancing authority areas at no transmission usage rate."

In contrast, "transmission to support EDAM transfers must have the same curtailment priority as internal load in each balancing authority area in order for energy and capacity schedules from the source balancing authority area to the sink balancing authority area to assure confidence for the sink balancing authority area," it said.

'Turn them over to the EDAM'

Jeff Spires, director of power with Powerex, said entities that rely on transmission to reach customers could get sidelined by the EDAM's protocols.

Powerex markets BC Hydro's excess hydroelectric power, much of it to California. The company chafed under EIM market rules in the past because of transmission constraints at the U.S.-Canada border. (See *Troubled Waters for Powerex in EIM*.)

Spires gave an example July 28 of potential problems with EDAM's transmission model involving transfers through the Bonneville Power Administration's BAA, which covers a vast swath of the Pacific Northwest. Transfers from Canada to California pass through BPA's territory. BPA is slated to join the EIM in 2022.

"If you were to take a balancing authority area like the Bonneville Power Administration, they have many third parties in their BA," Spires said. "They have many different transmission customers, and between BPA and some of the other service providers, there's about 8,000 MW of transmission capacity from the BPA system down to California.

"If BPA were to join the EDAM, then under this design, all of those transmission customers would no longer have the ability to use their physical transmission rights under the [open access transmission tariff] in order to deliver their resources to California," he said. "The only way that they could make use of those rights is to instead turn them over to the EDAM for market use."

Such a scenario is incompatible with a voluntary market, he said.

Tretheway told Spires, "You should still be able to self-schedule from your resource all the way to CAISO under the EDAM."

Spires responded, "I just don't think we share the same perspective on this."

Mark Rothleder, CAISO vice president for market policy and performance, said ISO managers were still working on the EDAM's transmission design.

"We hear what you're saying, and we understand your concerns," Rothleder told Spires. "I don't have an answer at this point. This is a little bit of a tough nut to crack on this one."

The straw proposal addresses only the first "bundle" of topics in CAISO's EDAM initiative: resource sufficiency rules; use of transmission; and the distribution of congestion and "transfer" revenues — the last being a new concept introduced in the plan to accommodate flows across BAAs in the West.

Comments on the first-phase straw proposal are due to CAISO by Sept. 10. The ISO's Board of Governors and the EIM Governing Body are scheduled to take up the EDAM plan next year. ■

PG&E Reports Steep Q2 Loss on Bankruptcy, Fire Costs

First Post-bankruptcy Call Promises Financial Growth, Fire Safety

By Hudson Sangree

In its first post-bankruptcy earnings report, PG&E Corp. said Thursday it expects stronger financial performance going forward, as it improves its wildfire-prevention efforts and employs more limited public safety power shutoffs this fire season.

PG&E reported GAAP losses of $3.73/share in the second quarter, driven mainly by $2.5 billion in costs to exit bankruptcy and help pay for the 2019 Kincade Fire.

The earnings call was led by PG&E Director and interim CEO Bill Smith, who replaced Bill Johnson after he retired June 30. (See *PG&E Names New Board of Directors*.)

It was the first live earnings report in many months. PG&E, one of the nation's largest utilities, filed for bankruptcy in January 2019 following two years of devastating wildfires ignited by its equipment. It emerged from Chapter 11 reorganization July 1.

"Today's call marks a milestone for us, and we're excited to share our post-emergence vision for the coming years," Smith said. "We've emerged from bankruptcy as a stronger company. The complex legal matters are now resolved, and major regulatory cases establishing our revenues are either approved or settled."

Smith said PG&E plans to return to investment-grade status after credit ratings agencies reduced its corporate debt to junk bond status during bankruptcy.

Even in June, as the company prepared to exit bankruptcy, the three major ratings agencies — S&P Global Ratings, Fitch Ratings and Moody's Investors Service — assigned sub-investment-grade status to billions of dollars in PG&E debt, including $4.75 billion in new debt it issued to help pay for its nearly $60 billion reorganization plan.

Share Price Lags

The company's stock rose slightly during Thursday's 11 a.m. ET earnings call from $9.12/share at the start of trading to $9.48 at 11:15 a.m., before falling back to $9.29 by 4 p.m.

PG&E's share price has lagged since the COVID-19 crisis started in March. It fell further in June as the company prepared to issue more than $5 billion in new equity, diluting its existing stock value.

The company is hoping to recover billions of dollars in lost value.

A month before the Northern California wine country fires of October 2017, PG&E's stock had hit a high of $70.64/share. It plunged as the utility's equipment appeared the likely cause of most of the 21 major fires during dry, windy conditions in Napa and Sonoma counties.

The company's stock fell further after it acknowledged one of its aging transmission lines likely started the Camp Fire in November 2018, killing 85 people and leveling much of the town of Paradise, Calif. The corporation pled guilty to 85 felony counts in December related to the fire. (See *PG&E Sentenced; Bankruptcy Plan Approved*.)

Shares hit a then-low of $7.23/share after the company announced it would declare bankruptcy and reached a historic low of $3.80 on Oct. 28, 2019, three days after another of its transmission line appeared to have caused the Kincade Fire, which tore through the Sonoma County wine region, burning nearly 78,000 acres and destroying 374 structures.

The California Department of Forestry and Fire Protection on July 16 said that its investigation had determined a PG&E high-voltage line running from a geothermal plant near the town of Geyserville had started the fire.

The company still faces lawsuits and a possible criminal investigation from the blaze. In its *quarterly report* to the U.S. Securities and Exchange Commission on Thursday, PG&E said its "financial condition, results of operations, liquidity and cash flows could be materially affected as a result of the 2019 Kincade Fire."

Fire-prevention Efforts

With California's late summer and fall fire season just around the corner, PG&E's worst enemy would be a new fire started by its equipment. The ratings agencies said in June that the risk of another catastrophic wildfire was a primary reason for keeping PG&E's credit rating so low.

In Thursday's earnings report, Smith and other PG&E executives cited ongoing efforts to reduce the risks of wildfires, including grid hardening and enhanced weather monitoring.

PG&E said it is on track to meet the goals it laid out in its 2020 Wildfire Mitigation Plan, submitted to the California Public Utilities Commission.

The utility said it has completed more than half of the system-hardening work it committed to this year by undergrounding or installing stronger poles and covered conductor along 122 circuit miles, a small portion of its huge system.

PG&E owns 106,681 circuit miles of distribution lines and 18,466 circuit miles of transmission lines. More than 50% of its 70,000-square-mile service territory is in high fire risk areas.

The company also said it has completed 70% of its enhanced vegetation management program this year.

"PG&E has reviewed more than 1,200 miles of distribution and lower-voltage transmission lines and taken necessary action to trim or remove hazards and expand rights-of-way," it said in a news release.

The utility said it fell behind on its "situational awareness" efforts because of supply-chain disruptions caused by the pandemic but still installed 144 weather stations and 60 high-definition cameras in fire-prone areas.

Advanced analytics and artificial intelligence are being added to its fire-prevention arsenal, PG&E said, along with technology from Australia that can de-energize a falling overhead line before it hits the ground, sparking dry vegetation.

The company has promised it will try to keep its public safety power shutoffs shorter and more limited geographically this fire season. Last year, the company shut off power to hundreds of thousands of customers, for as long as a week in some cases, prompting a public and political backlash. (See *California Officials Hammer PG&E over Power Shutoffs*.)

The company remains under threat of a government takeover should it fail to meet state safety requirements. (See *Governor Signs PG&E 'Plan B' Takeover Bill*.)

PG&E understands that vows to change, apologies and financial settlements with fire victims will no longer be enough, Smith said in a statement Thursday.

"We know that what's needed now is action," he said. "We will continue to work tirelessly to combat the growing threat of wildfires and keep our customers and communities safe." ■

CAISO/West News

CPUC Questions CAISO Day-ahead Capacity Plan

By Robert Mullin

CAISO's proposal to develop new capacity products through its day-ahead market enhancements (DAME) initiative could radically transform California's resource adequacy landscape while not yielding expected benefits, a key skeptic of the plan said last week.

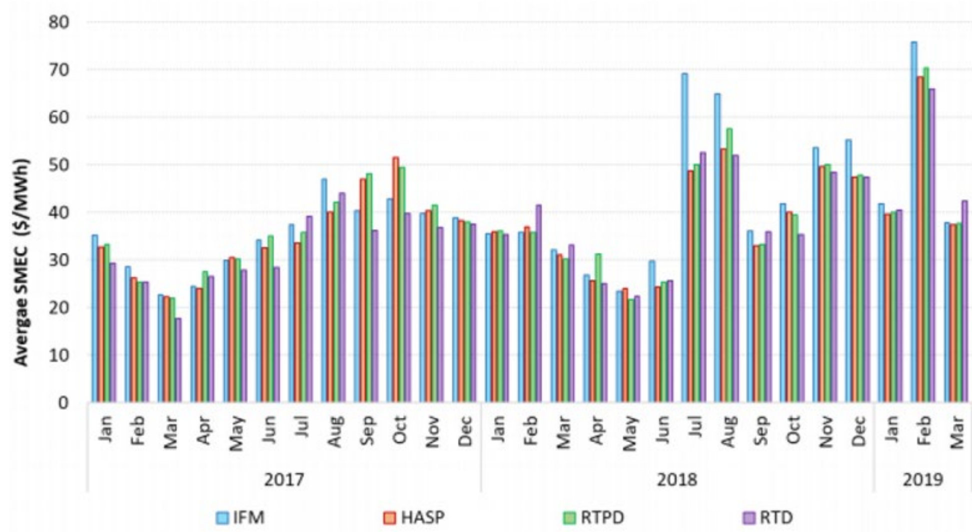
"I agree that in the vast majority of situations having a market price is an extremely valuable thing [and] I'm not trying to come down on either side of this one right now. I'm just saying it's a philosophical change in the way these [RA resources] are being paid that we should think about," Mike Castelhano, an analyst with the California Public Utilities Commission, said during discussion of the proposed capacity products at a CAISO Market Surveillance Committee (MSC) meeting Thursday.

The ISO launched the DAME effort earlier this year to expand its day-ahead market with two new nodal product offerings that would significantly alter market operations:

- a reliability capacity (RC) "up/down" product to help the ISO match its net load forecast (the load forecast minus the variable energy resource forecast) with sufficient non-VER supply for one-hour intervals; and
- an imbalance reserves (IR) product procured for 15-minute intervals "to provide flexible capacity to accommodate the increasing uncertainty and variability of real-time net load."

Both products would be offered on a nodal basis, an approach CAISO thinks will best guarantee those supplies will be available when and where they're needed to ensure flexibility on a grid increasingly dependent on VERs. The DAME *straw proposal* envisions co-optimizing procurement of both new products — along with day-ahead energy and ancillary services — to improve scheduling efficiency.

That new process would replace the existing residual unit commitment (RUC) process for ensuring resource sufficiency, in which the day-ahead market procures the incremental capacity needed to meet reliability requirements after the ISO has run its co-optimized integrated forward market (IFR) for day-ahead energy and ancillary services. The incremental capacity obtained through RUC represents the delta between what the IFR has cleared from economic bids and "the amount needed for reliability based on the net demand forecast and potential uncertainty," the ISO notes in the straw proposal.



Graph illustrates price differences for the same intervals among CAISO's day-ahead (blue), hour-ahead (orange), 15-minute (green) and 5-minute markets (purple). The ISO's DAME initiative is particularly aimed at closing the discrepancies between day-ahead and 15-minute prices. | *CAISO*

"The disadvantage of this sequential RUC process is that the capacity it procures is not co-optimized with the resource commitment and energy schedules produced by the integrated forward market," CAISO said in explaining the move to the new model.

'Vanilla' RUC vs. Spot Market

While CAISO has counterposed two methods for compensating suppliers of the two new products, it clearly favors one option over the other.

Under the "vanilla RUC model" (as ISO Market Design Policy Specialist James Friedrich put it), resources that have been awarded contracts under the CPUC's RA program could offer into the market at zero price and forego being paid market clearing prices for RC and IR. In that scenario, CAISO would assume the prices of RA contracts — which subject holders to a must-offer obligation (MOO) in the ISO market — "would, in part, reflect owner expectations about magnitudes and frequency of short-run costs incurred to provide RC/IR."

According to the ISO, the RUC model approach to compensating the new capacity products would be the least disruptive to California's current RA system because it wouldn't require renegotiation of existing RA contracts, changes in CPUC rules around cost recovery for RA assets or revisions to CAISO's MOO Tariff provisions. It would also avoid the need to mitigate market power for RC/IR offers.

Those advantages notwithstanding, CAISO — and the MSC — are advocating implementing a "spot market model" as much as possible to compensate providers of the new capacity products, with the hope that short-term market offers will more precisely reflect variable costs for making capacity available, including natural gas costs and the opportunity costs of not bidding into the real-time market. That arrangement would provide suppliers a stronger incentive to make resources available, according to the MSC.

Use of that model would also eliminate the must-offer obligation for contracted RA resources, which should reduce the number of zero-price offers and increase clearing prices (while also increasing the risk of double-payment before RA contracts can be renegotiated, CAISO acknowledged). That would have the upshot of opening up California's capacity market to non-thermal resources, helping the state achieve its ambitious carbon reduction goals, one MSC member noted.

"One of the characteristics of the current design is that ... demand response can't compete to provide RUC capacity because thermal RA units are free," said the MSC's Scott Harvey. "And they're not really free, but it gets rolled into the RA price, so you don't see a separate price signal for [whether] demand response [could] provide this RUC capacity, which is really back-up capacity that we don't need but we want to have in reserve in case we do need it. And that's probably an ideal role for demand response … so that's another long-run goal that could be achieved if we make this change."

MSC member Jim Bushnell said a long-term focus of the committee is providing "short-run marginal incentives to reward units that provide truly valuable reliability capacity" and incentivizing resource availability.

"The problem with RA has been that we don't know a year in advance and a month in advance exactly when and what types of units provide what type of value. That's constantly changing, so the importance for short-run incentives is large here," he said.

CPUC Concerns

CPUC's Castelhano said he understood Harvey's concerns about DR being unable to function as RA capacity in the CAISO market. But Castelhano noted that the RA zero-bid requirement is a CPUC capacity designation rule and not "really a RUC rule." He cautioned CAISO against making changes that could alter the zero-bid practice in the wholesale market or pushing to revise market rules in a way that would allow DR to function as RA in California.

"The rules for RA and DR are not as well-developed, and that's a process that's ongoing, and I think we have to recognize that's not something that should change at the CAISO necessarily," Castelhano said.

"I wasn't arguing for a change in the rules regarding DR that is RA capacity," Harvey said, clarifying that his focus is on enabling DR — "whether or not it's RA capacity" — to compete to provide RUC. "That's the CAISO issue."

Castelhano also called out CAISO for not discussing how transformative the ISO's changes could be for California RA, potentially transforming the program from a structure based on contracts to one reliant on a spot market.

"Sure, it gets the costs out of the RA contracts, potentially, but it also then pays a market mechanism-based price to everybody that clears in that market, whereas right now the RA costs are individual" and cost based, said Castelhano. A system based on a clearing price could allow some suppliers to earn inframarginal rents — where a supplier gets paid above its costs in an otherwise competitive market.

MSC Chair Ben Hobbs acknowledged that consumers could benefit if the utilities contracting for RA hold prices down because of monopsony market power and pass on those savings. But he said it is not clear that would happen because visibility into RA contract prices "is not exactly a strong point" in California's market.

"RA contracts tend to be near some market-clearing level, but from an efficiency point of view, hearkening all the way back to the early days of the California market of pay-as-bid versus market-clearing price, folks who have been on the MSC have tended to favor [a] single market-clearing price for its transparency and incentives," Hobbs said. "But you might have a point. If the utilities can price-discriminate on RA perhaps there will be less ability to do that in the future, which might conceivably increase what consumers pay and provide more of the inframarginal rents to resources."

Castelhano also questioned CAISO's presumption that the new capacity products would reduce some of the "guesswork" behind calculating the costs of RA contracts because income for RA resources would be based on actual short-run costs rather than on a longer-term estimation of those costs.

"My speculation is that it would go very much in the opposite direction because right now part of the RA contract depends on one variable stream of income from sales into the ISO market, and you're going to create another possibly more variable stream of income," he said.

Hobbs countered that the proposal's provision allowing RA resources to buy out their must-offer obligation or bid costs in the ISO market would reduce the cost risks of having a fixed MOO negotiated far in advance of potential deliveries.

"I guess that needs some more analysis, but I don't agree with what you're saying there," Hobbs said.

Castelhano concluded with "a really big concern" that CAISO is considering limiting the participation of energy storage resources in the imbalance reserve markets. He noted that the CPUC's integrated resource planning process is assuming that storage resources will play a key role providing flexibility needed to integrate variable renewables.

"If [storage] resources are not able to participate in this imbalance reserve market, then I'm very concerned about that," Castelhano said. "If we're paying hourly dispatchable resources instead of the stuff that can move really fast, then that's another concern." ■

ERCOT News

Private Equity Group Closes EPE Purchase

NRC Resolves Late Issues Raised

By Tom Kleckner

The privately held Infrastructure Investments Fund (IIF) completed its acquisition of El Paso Electric (EPE) on Wednesday following a final regulatory check by the Nuclear Regulatory Commission, the companies said in a *statement*.

The statement came after FERC on July 22 approved EPE's and IIF's market power mitigation plan and rejected rehearing requests challenging the commission's approval of the deal (*EC19-120*). (See *FERC OKs El Paso Electric Mitigation*.)

The commission in March approved the transfer to IIF of EPE's license for the company's share of Palo Verde, but it recently sent a letter to the organizations with questions about the ownership (STN 50-528, STN 50-529, STN 50-530, 72-44).

NRC had questions about possible "foreign ownership, control or domination" of EPE's 15.8% share in the renewed operating license for the Palo Verde nuclear plant in Arizona. On July 28, however, the agency said in a letter to the utility's interim CEO that a previous order approving the transaction still stood.

Staff said that following a brief review, they had determined not to modify, suspend or revoke the order, but that "future changes to the … partnership agreement that affect the restrictions on passive limited partner investors may constitute an indirect transfer of control of the Palo Verde licenses that would require prior NRC approval."

Scott Burnell, an NRC public affairs officer, told *RTO Insider* in an email that staff began reviewing the EPE and IIF responses July 27 to determine whether the agency needed to take further action on the transferred license.

Burnell noted that staff recently learned about the possible foreign ownership ties to IIF entities linked to the transaction through filings the private equity group made with the U.S. Securities and Exchange Commission and the Federal Communications Commission.

The company said Wednesday its new board of directors had appointed Kelly Tomblin as its new CEO. Tomblin joins the company after more than 30 years of leading utilities in the U.S. and internationally. She was most recently CEO of INTREN, a utility solutions provider with 14 regional offices across the U.S.

"EPE plays a critical role in the communities [it] serve[s], and I look forward to making this community my own," Tomblin said in a statement.

EPE and IIF announced the transaction in June 2019. IIF is a $12.5 billion private investment vehicle advised by a dedicated infrastructure company investment group within J.P. Morgan Investment Management.

IIF is the umbrella name referring to the three master partnerships that hold all of its investments: IIF US Holding 2, IIF US Holding and IIF Int'l Holding. IIF US Holding 2 owns Sun Jupiter Holdings, which has formed a corporation to merge with EPE, with the utility as the surviving entity.

EPE shares disappeared from the New York Stock Exchange on Wednesday. The stock closed at $68.25 on July 28, up $1.85 since hitting $66.40 on July 20 before FERC's final approval. ■

El Paso Electric owns 15.8% of the Palo Verde nuclear plant (pictured). The Nuclear Regulatory Commission had raised questions over the private Infrastructure Investments Fund's foreign interests.

ERCOT News

ERCOT Technical Advisory Committee Briefs

Members Endorse Slew of Protocol Changes

ERCOT's Technical Advisory Committee continues to refine its virtual voting practices, reverting to a combined ballot to reduce the number of roll-call votes and make the best use of members' time.

Last week, that resulted in the unanimous approval of a ballot loaded with 23 revision requests, two key topics/concepts from the Battery Energy Storage Task Force (BESTF) and seven other items.

Only two nodal protocol revision requests (NPRRs) were voted on separately during TAC's July 29 meeting. Both were easily endorsed. *NPRR984* adds a fourth standard contract term per year for emergency response service (ERS), and *NPRR1020* allows energy storage resources with integrated loads that cannot be metered as designed to use internal sensors in calculating the loads.

ERCOT granted the latter change urgent status because it affects ongoing interconnections. The revision will be sent to the Board of Directors for its Aug. 11 meeting.

Staff added clarifying comments to NPRR1020 for the required annual audit of the congestion revenue rights' (CRR) allocation methodology by the resource entity calculating its ESR's auxiliary load value. They said their revisions "simply require the audit to confirm that the resource entity's calculation of auxiliary load 'does not understate the load value,' rather than specifying a band of allowable measurement error."

ERCOT has estimated it will cost between \$175,000 and \$225,000 to make the change. Staff said resource limitations on software developers will delay work on the change until early next year. System implementation would also require revisions to the settlement metering operating guide.

NPRR1020's sponsor, Tesla, said the urgent status will help it "achieve regulatory certainty and allow its investments to move forward."

"I think we've got Tesla a level playing field with everyone else," said Bob Wittmeyer, who represented energy-storage developer Broad Reach Power during the early stages of the revision request's progress through the stakeholder process.

The measure passed without an opposing vote. EDF Trading North America abstained.

Clayton Greer, Morgan Stanley | © *RTO Insider*

TAC endorsed NPRR984 28-1, with independent power marketer Morgan Stanley voting against the motion. Morgan Stanley representative Clayton Greer also indicated he would vote against tabling the change or moving it to the combination ballot, forcing the roll-call vote.

"I'll vote no on everything with ERS," he said.

ERCOT said changing the ERS standard contract terms would allow it to better align with typical seasonal conditions and help improve the service's procurement.

Members, Staff Debate RR Development Budget

TAC approved *two key topics/concepts* (KTCs) from the BESTF, an initiative to address how to integrate ESRs into the ERCOT system.

Staff first had to allay stakeholder concerns that ERCOT is running out of time and money to incorporate the task force's work, along with that of the Real-Time Co-optimization Task Force and other projects.

The Advanced Power Alliance's Walter Reid called for the BESTF and distributed generation to be placed at the top of the ISO's priority list of development projects

"The work the BEST Force has been doing to get batteries into the protocols needs to be finished," he said. "We need to facilitate that [investment] … For DG, getting that done is critical."

ERCOT currently allocates \$4 million from its capital project budget to fund revision requests' development. It has the flexibility to "exceed the target for priority needs," spokesperson Leslie Sopko said in an email.

"We really do need to consider if there's some way to relax that \$4 million [limit]," Reid said.

Kenan Ögelman, the grid operator's vice president of commercial operations, cautioned stakeholders against increasing the \$4 million allocation.

"Expanding that doesn't necessarily get [Reid] the relief he wants. The limits … are also resource limits," Ögelman said. "You also have to look at expanding a budget in this environment of low interest rates and economic uncertainty. The only two options are to move dollars from elsewhere into the \$4 million or expand the budget. I think you are at risk of moving dollars out of things ERCOT is doing behind the scene to deliver DG and BEST."

Staff promised a prioritized list of projects on Aug. 3, with a follow-up discussion during a Protocol Revision Subcommittee meeting on Aug. 13.

The two endorsed KTCs are:

- *KTC 15-7*: Restricts ESRs from withdrawing energy during a Level 3 energy emergency alert and addresses ancillary service responsibility compliance related to the charging suspensions.
- KTC 15-8: Grandfathers *NPRR989* 's reactive power requirements.

ERCOT Updates Price-correction Issue

Dave Maggio, ERCOT's director of market design and analytics, told the committee staff expects to complete in two weeks a review of day-ahead and real-time market prices following the discovery of erroneous dynamic ratings for three 345/138-kV transformers.

Ratings from unrelated transformers were applied to the three transformers, possibly causing or missing congestion, on operating days between Feb. 12 and July 7, he said. Staff developed a software fix to resolve the issue on July 14.

ERCOT was able to issue a price correction for affected July 7 day-ahead prices. Should staff discover a need for price corrections during the historical period, which is outside the normal 30-day notification period, they will ask the Board of Directors to approve corrections, Maggio said.

Maggio said staff also discovered in May that a software glitch prevented the operating reserve demand curve (ORDC) from properly calculating certain resources' capacity. Staff corrected the error with a software patch and conducted a detailed review of the ORDC calculations back to when it went live in 2014. They found no additional errors, Maggio said.

ERCOT staff is proposing a revision request to remove requirements that modify DC-tie load zones requiring board approval and a 48-month waiting period after approval. The issue stems from American Electric Power's recent retirement of a DC tie near the Mexican

ERCOT News

border in South Texas.

"I think the majority of sensitivity around changes to typical load zone boundaries is because entities serving load to those areas potentially have long-term contracts," said Reliant Energy Retail Services' Bill Barnes. "There's no load served there. It's just used for export and import [of energy]."

TAC OKs Consent Agenda's 23 Changes

TAC added *NPRR1030* to the combination ballot after agreeing on a desktop edit provided by Greer. Or, as one member jokingly surmised, language provided by a ghostwriter.

"I had some help," Greer acknowledged.

The measure changes the CRR auction revenue distribution allocation methodology from a peak 15-minute settlement interval to load ratio share based on adjusted metered load totals for each month. It also makes parallel changes for the CRR balancing account and certain block load transfers for consistency and ease of implementation.

Greer offered language that provided market participants will not engage in DC tie export transactions "that are reasonably expected to be uneconomic in consideration of all costs and revenues associated with the transaction." The language excludes CRR auction revenue distribution and CRR balancing account allocations.

By making clear such transactions would violate the Protocols, TAC was able to agree on accepting ERCOT's comments, whose complexity extended to the measure's implementation timeline from an estimated three months to 12 months. Staff corrected and clarified settlement formulas and corresponding variable definitions.

The edits will be temporarily "gray boxed" and eliminated with NPRR1030's implementation.

The combination ballot included seven other NPRRs, a Load Profiling Guide revision (LPGRR), four changes to the Nodal Operating Guide (NOGRRs), four other binding document revisions (OBDRRs), a pair of changes to the Planning Guide (PGRRs), three revisions to the resource registration glossary (RRGRR) and one change to the verifiable cost manual (VCMRR).

It also included committee and subcommittee goals, a list of other binding documents and the 2021 meeting calendar. TAC will continue holding monthly meetings on the fourth Wednesday of the month to avoid conflicts with the Texas Public Utility Commission open meetings.

- *NPRR996:* Aligns the Protocols' hub bus names with the substation names within the ERCOT model.
- *NPRR1000:* Removes the term "dynamically scheduled resource" from the Protocols.
- *NPRR1002:* Establishes energy storage resource "single model" registration and charging restrictions during emergency conditions.
- *NPRR1003:* Replaces all remaining references to the resource asset registration form (RARF) with more general language in anticipation of the RARF's elimination.
- *NPRR1004*: Creates a new process for determining the congestion revenue rights (CRR) auctions and day-ahead market clearing load-distribution factors by using load forecasting models and existing validation/error correction.
- *NPRR1015*: Clarifies the market system's submission and reporting changes necessary to complete *NPRR863*, implement changes to responsive reserve service (RRS) and add ERCOT contingency reserve service.
- *NPRR1016*: Clarifies important reliability requirements for distribution generation resources (DGRs) seeking qualification to provide ancillary service(s) and/or participation in security-constrained economic dispatch.
- *LPGRR067*: Streamlines the assignment of oil and gas profiles by eliminating current processes that are no longer applicable. The revision validates weather sensitivity only for non-interval data recorder electric service identifiers that request the oil and gas flat profile; removes the "TOU Schedules" and "Non-ERCOT Profile IDs" worksheets; and changes the distributed generation profile segment assignment process.
- *NOGRR195*: Addresses the Texas Reliability Entity's audit recommendations for ERCOT and modifies generator voltage control tolerance bands.
- *NOGRR208:* Aligns the Nodal Operating Guide with the nodal Protocols as modified by NPRR1002. An alignment NOGRR for energy emergency alert will be filed following NPRR1002's approval to align with the Protocols.
- *NOGRR209:* Replaces all remaining references to the RARF with more general language to align with NPRR1003.
- *NOGRR212:* Aligns the Guide with NPRR1016's revisions and clarifies DGRs' reliability requirements.
- *OBDRR018*: Aligns the procedure for identifying resource nodes with NPRR1003's changes by replacing all remaining references to the RARF with more general language.
- *OBDRR019*: Aligns the requirements for aggregate load resource participation in the ERCOT markets with NPRR1003's changes by replacing all remaining references to the RARF and updates the process' change control process with similar other binding documents.
- *OBDRR021*: Aligns the language in the calculation of RRS limits' procedures for individual resources with the Protocols following NPRR863's Phase 1 implementation. Also corrects inadvertent errors in the formulas for calculating droop performance to determine RRS limits.
- *OBDRR022*: Incorporates minor edits to the initial other binding document previously approved in conjunction with *NPRR933*.
- *PGRR076:* Changes the generation resource interconnection or change request (GINR) process to specify that the proposed commercial operations date in the initial GINR application must be at least 15 months after the date of the application; redefines the security screening study output; creates separate reports for the full interconnection study; coordinates reactive study; and clarifies when the dynamic data model should be submitted to meet the quarterly stability assessment prerequisite deadline.
- *PGRR079:* Aligns the guide with NPRR1003's changes by replacing all remaining references to the RARF.
- *RRGRR023:* Establishes the guide's provisions and requirements for ESRs identical to those already in place for generation resources and settlement-only generators.
- *RRGRR024:* Aligns the glossary with NPRR 1003's changes by replacing all remaining references to the RARF.
- *RRGRR026:* Adds a new data point to support implementation of an interim solution representing DGRs and distribution ESRs in the ERCOT network operations model.
- *VCMRR029:* Aligns the manual with NPRR1003's changes by replacing all remaining references to the RARF. ■

— Tom Kleckner

ERCOT News

Texas Public Utility Commission Briefs

NextEra, Rayburn Country Withdraw CCN Transfer over ROFR Legislation

The Texas Public Utility Commission last week approved the withdrawal of a certificate of convenience and necessity (CCN) rights transfer between NextEra Energy Transmission Southwest and Rayburn Country Electric Cooperative (*48071*).

The two entities had agreed in 2017 that NextEra would acquire Rayburn Country's rights to own and operate a 30-mile segment of a 138-kV transmission line in East Texas. But the companies now say the transaction has been rendered moot by 2019 legislation that gave incumbent transmission companies the right of first refusal to build new transmission lines. (See *Texas ROFR Bill Passes, Awaits Governor's Signature*.)

The transaction had been approved by a PUC administrative law judge in January 2019. However, that May, the state legislature passed *Senate Bill 1938*, which grants CCNs to build, own or operate new transmission facilities "only to the owner of that existing facility."

In their *request* to withdraw their joint application, the companies said the legislation "precluded the PUC from granting the application." NextEra and Rayburn Country also said an asset purchase agreement behind the application had been terminated, thereby mooting the transaction.

Hanna Restoration Efforts Continue

The commissioners complimented AEP Texas and several other utilities for their restoration work following Hurricane Hanna's July 24 landfall in South Texas.

"They've done a fabulous job of getting people back on," said PUC Chair DeAnn Walker. She noted outages peaked at 297,000 but had dropped to nearly 2,800 by the July 31 open meeting.

AEP Texas President Judith Talavera, who called into the meeting, said crews have been repairing 700 distribution poles, 280,000 conductors and 35 transmission structures. The company has asked residents in the Rio Grande Valley to conserve electricity until Aug. 14 while it rebuilds a two-mile stretch of a 138-kV transmission line damaged by the storm.

Magic Valley Electric Cooperative said Hanna "*dealt a heavy blow*" to its system, and it has warned customers about prolonged outages.

PUC Chair DeAnn Walker enjoys a lighter moment during the commission's July 31 open meeting. | *Texas PUC*

ERCOT's Virtual Meetings OK'd

The PUC granted *ERCOT* 's expedited request to amend its bylaws, waiving a requirement that a proposed order be served 20 days before considering the application at an open meeting (*50918*).

The order clears the way for the grid operator to expand its definition of urgent matters so that its board of directors and its subcommittees can meet virtually during the COVID-19 pandemic. ERCOT stakeholder groups have already been meeting virtually since March.

"When the bylaws were written, COVID-19 didn't exist, and we didn't know this was going to happen to us," Walker said. "These meetings have been awkward at best. I appreciate [ERCOT's] efforts to fix this."

PUC Looking at EV Charging Stations

In other actions, the PUC approved staff's solicitation of comments as they *review issues* relating to electric vehicles in advance of next year's state legislative session (*49125*).

The commission is considering which companies can own or operate EV charging stations, how their costs would be recovered and whether their operation would constitute retail sales.

"I appreciate everyone staying plugged in," Commissioner Shelly Botkin said, before acknowledging her unintended pun.

"We know this is not the sum total of EV things we'll have to address before the session starts," Commissioner Arthur D'Andrea added.

The commission also:

- Gave staff the go-ahead to begin work on a proposed rule change broadening the pool of candidates eligible to serve as the ERCOT wholesale market's reliability monitor. The *Texas Reliability Entity* currently fills that role (*50602*).
- Approved distribution cost recovery factors for AEP Texas (*50733*) and Oncor Electric Delivery (*50734*). AEP Texas' DCRF was based on an annual revenue requirement of $39.1 million after adjustment for load growth. Oncor was granted an incremental increase of $69.9 million to its DCRF revenue requirement. ■

— Tom Kleckner

ISO-NE News

Mass. Nixes Separate Offshore Tx RFP

By Michael Kuser

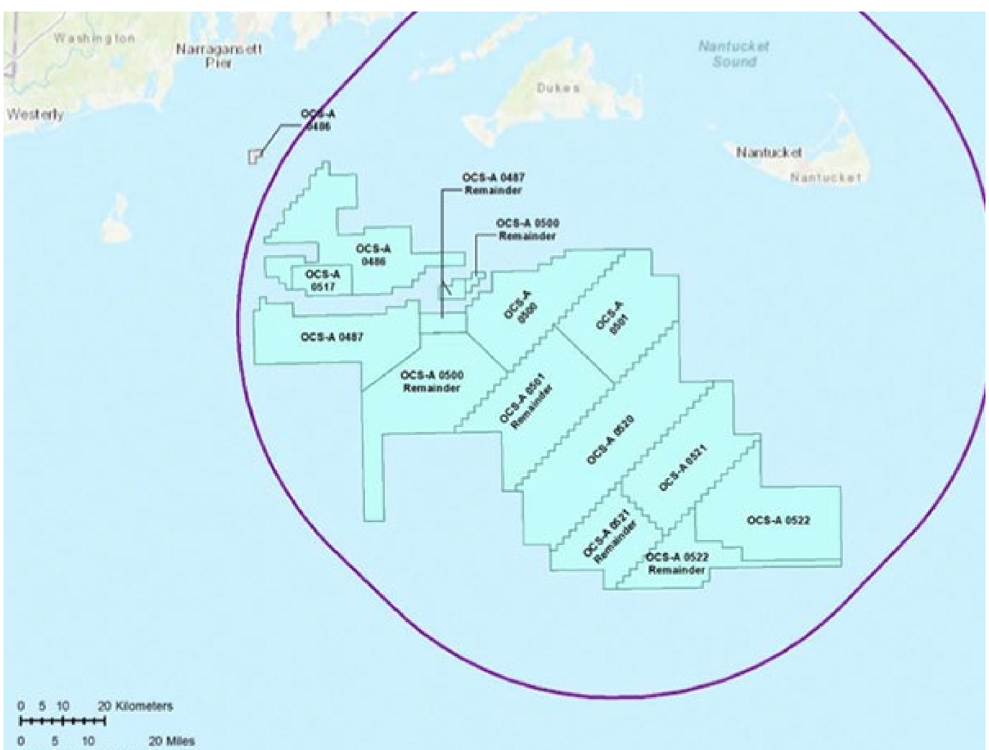
The Massachusetts Department of Energy Resources (DOER) said last week it will not require the state's electric distribution companies to solicit proposals for a coordinated independent transmission network for the 1,600 MW of offshore wind energy already procured, but recommended bundling transmission in its next OSW solicitation.

"Following a thorough investigation, DOER finds that the costs and risks of a solicitation for independent offshore wind energy transmission outweigh the potential benefits that could be captured by 1,600 MW of transmission capacity," Commissioner Patrick Woodcock said in a letter to the legislature's Joint Committee on Telecommunications, Utilities and Energy. DOER said it feared the solicitation could delay upcoming OSW generation procurements and complicate contracting and permitting issues.

Instead, the agency is recommending a bundled solicitation of 1,600 MW of generation and transmission, which it said could reduce cabling and use onshore interconnection points efficiently. The state — which has selected Mayflower Wind and Vineyard Wind 1 to build the first 1,600 MW of offshore wind in federal leasing areas south of Martha's Vineyard — initially planned two additional 800-MW procurements.

DOER said that a larger solicitation for bids up to the full 1,600 MW currently authorized would allow developers greater flexibility in project design. First, a larger solicitation would allow developers the option of using HVDC cables, which can transmit up to 1,400 MW on a single cable versus 400 MW for HVAC cables, for offshore wind, the agency said. Second, a larger solicitation would allow developers the option to interconnect onshore at the maximum capacity allowed by ISO-NE (1,200-MW single contingency limit), which could help ensure that the limited number of onshore interconnection points in Massachusetts is used to maximum potential.

"In sum, a larger solicitation would give developers maximum flexibility to use transmission infrastructure efficiently, thereby helping ensure ... bids that minimize the environmental and socioeconomic impacts of siting offshore wind structures in the ocean and on land and achieve many of the potential benefits of the independent transmission solicitation without the added costs and risks," DOER said.



The purple line marks the cables and pipelines geographic analysis area for the Vineyard Wind project. | *BOEM*

DOER also said it would consider joining with neighboring states on a backbone transmission plan.

A network transmission "initiative could be achieved more effectively at a larger scale of offshore wind build-out and with regional coordination among New England states … than through a single state procurement with limited size," Woodcock said.

Comments in Favor

Massachusetts hosted a technical conference in March to explore whether it should solicit proposals for a transmission network for offshore wind generation. (See *Mass. DOER Explores Transmission for OSW*.) The planning choice was between generators developing the transmission — the generator lead line, or radial system — and independent transmission construction and ownership, or a network system.

The DOER letter noted significant stakeholder support for a networked or backbone-independent transmission approach at a larger capacity.

Included in a second round of stakeholder comments published April 22, State Rep. Patricia Haddad, speaker pro tempore of the Massachusetts House of Representatives, said in a letter to DOER that "we have been successful with the two recent offshore wind bids with generator lead lines. I feel the next procurement should include crucial shared transmission opportunities."

The Responsible Offshore Development Association (RODA), a fishing industry group, submitted a letter urging independent transmission development if it would mean using less cable and having fewer environmental impacts.

Upping the Target

Meanwhile, the Massachusetts House amended its climate change bill Friday to increase the amount of offshore wind energy the state and utilities must contract from 3,200 MW to 3,600 MW. It also would cut the time between procurements from 24 months to 18 months.

Earlier last week, the Senate amended its economic development bill to mandate procurement of an additional 2,800 MW of OSW by 2035, which would raise total authorization to 6 GW.

The two houses will have to reconcile their differences in conference committee. ■

ISO-NE News

Eversource Sees Conn. Rate Increase Suspended

By Michael Kuser

Eversource Energy on Friday *reported* how well it is managing the impact of COVID-19 on its financials, just as Connecticut regulators suspended a July 1 rate increase set to boost its bottom line.

The company posted second-quarter earnings of $252.2 million ($0.75/share), up from $31.5 million ($0.10/share) in the same period a year ago. The increase was due primarily to last year's results including a $0.64/share impairment charge related to the Northern Pass transmission project, which failed to win regulatory approval in New Hampshire.

"The vast majority of our employees who either had tested positive for COVID-19 or were self-quarantined are now back to work," CFO Philip Lembo said Friday in an earnings call.

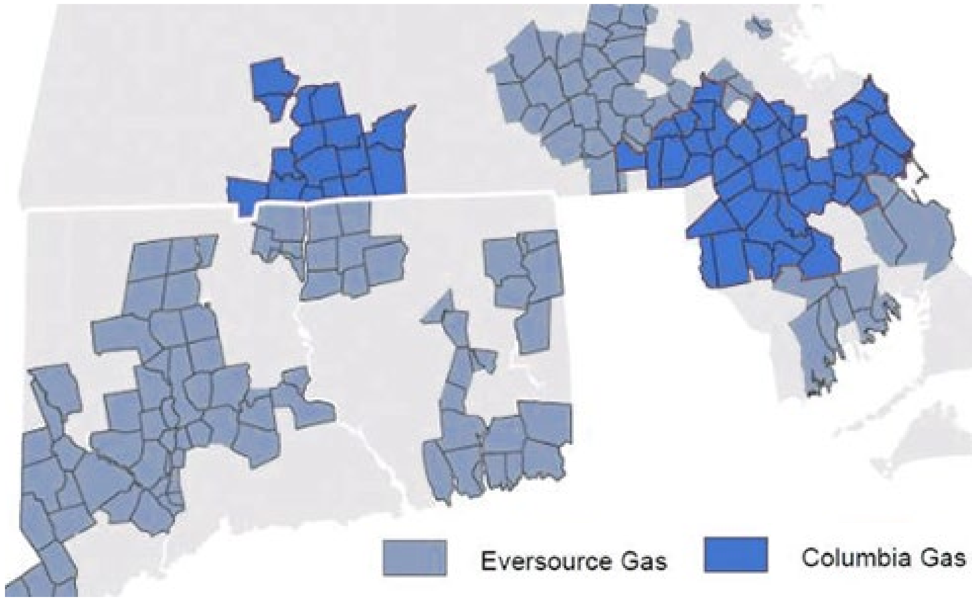
Eversource is New England's largest utility company, with subsidiaries supplying electricity, natural gas and water service to approximately 4 million customers in Connecticut, Massachusetts and New Hampshire.

In terms of usage, kWh sales in the second quarter were down about 1.4% overall compared with last year. But in New Hampshire, which is not decoupled, sales were up 1.8%, the company said.

A 26% June spike in residential usage in Connecticut compounded the effects of a July 1 rate increase, resulting in consumer complaints and legislator calls for action and prompting the state's Public Utilities Regulatory Authority (PURA) Friday to *suspend* the rate increase to allow for reexamination.

The order specifically affected Connecticut Light and Power's revenue decoupling mechanism charge, which had gone up from -0.011 cents/kWh to 0.182 cents/kWh; the transmission charge, up from 2.356 cents/kWh to 3.395 cents/kWh; the non-bypassable federally mandated congestion charge, up from 1.423 cents/kWh to 2.729 cents/kWh; and the electric system improvements tracker charge, up from 0.171 cents/kWh to 0.299cents/kWh.

"We're not shutting off customers, and we're working diligently to help customers in this pandemic situation," Lembo said, referring to press reports of customer complaints. "The rate overall on a customer's bill is only up about 3.5%, mostly driven by this record level of usage."



Eversource Gas and the service areas gained in the $1.1 billion acquisition of Columbia Gas's 320,000 natural gas customers in Massachusetts. | *Eversource Energy*

He also cited the utility's contract to provide payment "and subsidy, some might say, to Millstone Nuclear Plant" as a contributing factor.

The Connecticut Department of Energy and Environmental Protection in December 2018 negotiated a 10-year contract for about 50% of the plant's output after deeming it to be at risk of retirement. (See *Conn. Zero-Carbon Awards Include Nukes, OSW, Solar*.)

Grid Mod

Lembo also highlighted the company's plans to file three proposals that day in PURA's grid modernization proceeding to help the state reduce its carbon footprint by at least 80% by 2050.

The company plans over the next five years to replace 800,000 meters with automated meter infrastructure; wire 2,500 homes for electric vehicle charging and build 3,000 additional charge stations in the state over a period of three years; and incentivize installation of 30 MW of residential energy storage and 20 MW of commercial storage.

In Massachusetts, the company continues to implement the grid modernization plan authorized by regulators more than two years ago, he said.

"We expect to complete the authorized projects, including infrastructure to connect 3,500 charge ports and utility storage projects on Cape Cod and Martha's Vineyard, in 2021," Lembo said. "In mid-2021, we'll be filing a new three-year plan with implementation in the 2022 through 2024 time period."

In other matters, the company expects to receive regulatory approval by Sept. 30 for its $1.1 billion acquisition of Columbia Gas's 320,000 natural gas customers in Massachusetts.

Lembo also cited the June 9 release of the Bureau of Ocean Energy Management's (BOEM) supplemental environmental impact *statement* for the Vineyard Wind project, which also affects development of about 22 GW of offshore wind generation off the Atlantic coast.

"This was an important step in BOEM's evaluation process for the different applications that have been filed to date, including two of our joint proposals with Ørsted, one of those being [130-MW] South Fork, the other [704-MW] Revolution Wind," he said. (See *Developers Seek 1-Mile Spacing for Vineyard Wind*.)

The company expects BOEM later this summer to release its schedule for review of South Fork, though it is "very unlikely" that South Fork will enter service before the end of 2022. It still expects Revolution Wind to be in service by the end of 2023, Lembo said.

The joint venture's 880-MW Sunrise Wind project in New York is slated to go into service at the end of 2024, he said. ■

Call transcript courtesy of Seeking Alpha

ISO-NE News

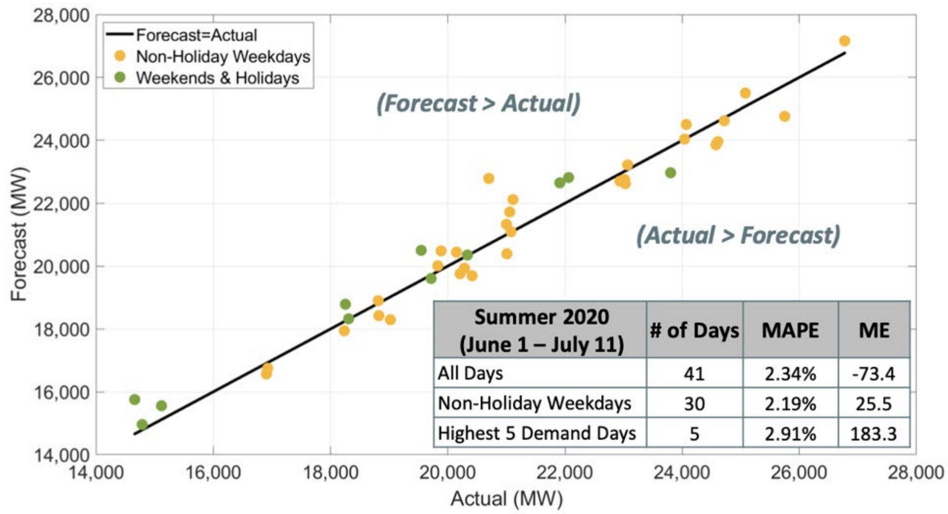
ISO-NE: Minor COVID Impacts on Summer Load, Forecasts

By Michael Kuser

ISO-NE's preliminary *analysis* suggests that summer demand from June 1 to July 11 was consistent with the 2020 Capacity, Energy, Loads and Transmission (CELT) forecast despite the economic impact of the COVID-19 pandemic on New England.

The RTO ran this year's CELT models with numbers from Moody's Investors Service's June economic forecast in order to estimate how much the pandemic-related economic disruption might affect preparation for the upcoming 2021 CELT forecast, Load Forecasting Manager Jon Black told the New England Power Pool's Power Supply Planning Committee on July 28.

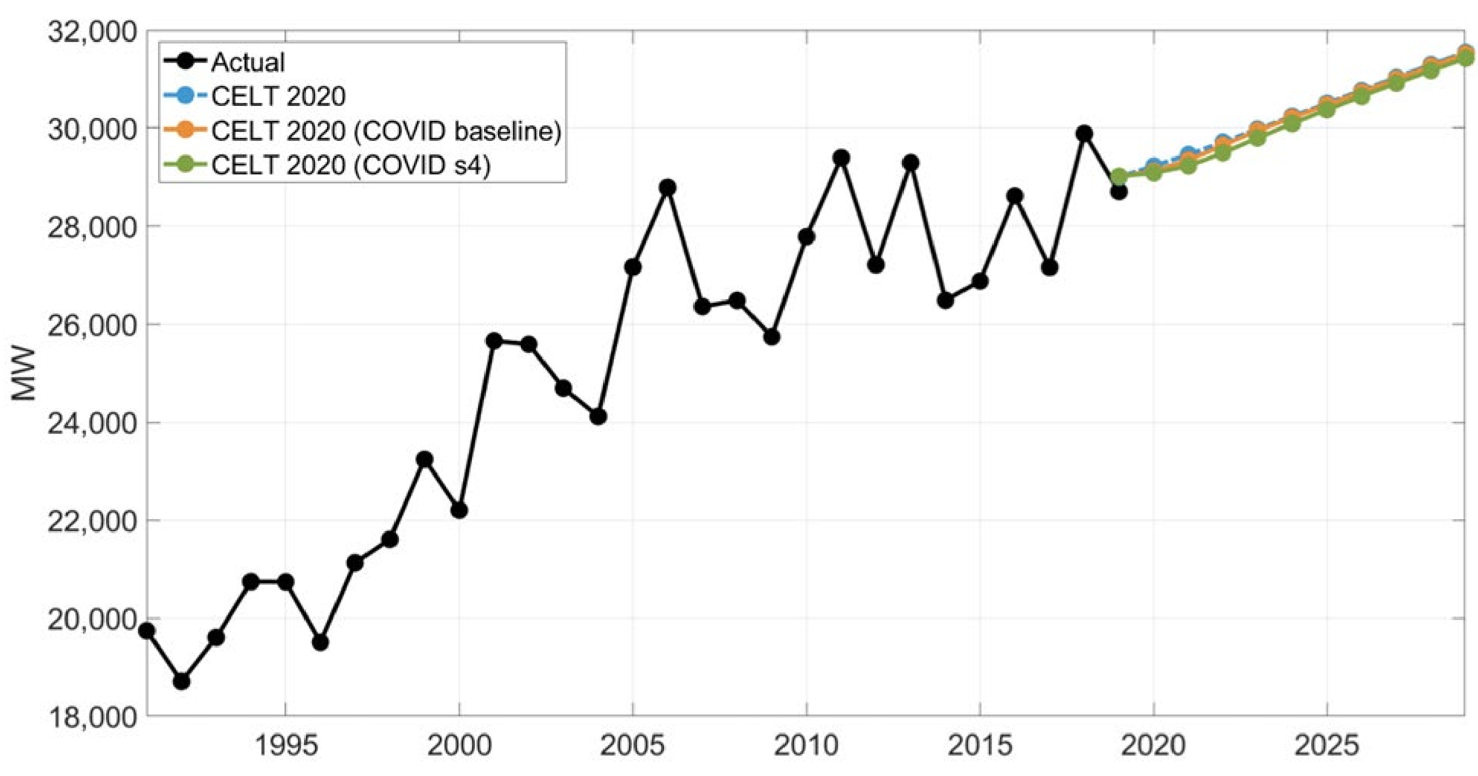
"The main takeaway here, based on the first 41 days of the summer: I don't see any real, systematic issues with the CELT 2020 peak forecast models, even at 183 MW of mean error for the highest peak demand days," Black said.



Preliminary review of summer 2020 peak days gross demand forecast vs. actual (June 1–July 11) | *ISO-NE*

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

The error represents less than 1% of the CELT 2020 50/50 gross peak load forecast and does not indicate the forecast deviating from actuals in a systematic way, he said.



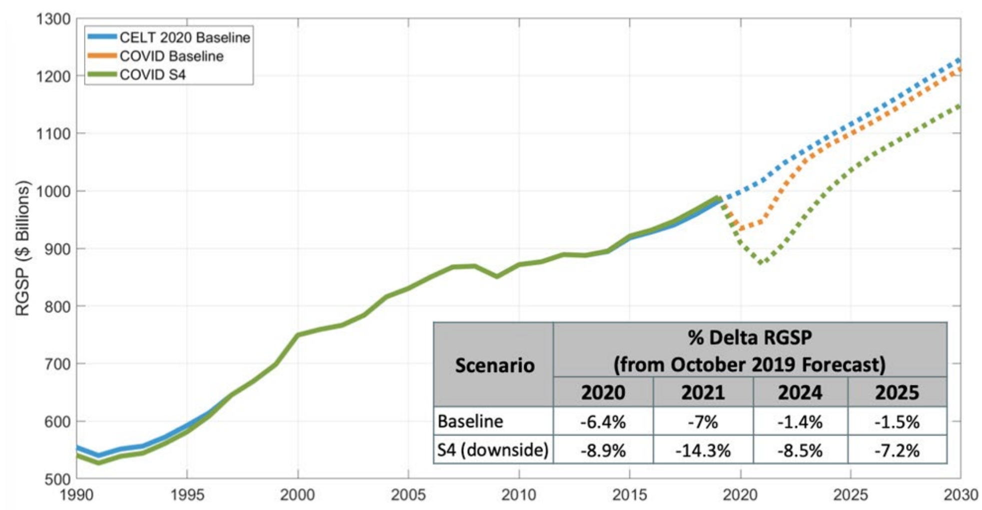
Gross 50/50 summer peak forecast: CELT 2020 vs. COVID scenarios | *ISO-NE*

ISO-NE News

"We've seen a strong rebound in summer demand," Black said. "Early on in the April-May time frame, when weather was mild, we did see relatively significant reductions in demand and energy, but from a summer peak perspective, we're not seeing that throughout the first 41 days of summer."

The results also align with those of ISO-NE's recent weekly analyses of COVID-19 demand impacts, performed by the System Operations Department, Black said.

The RTO used the October 2019 (i.e., pre-COVID) Moody's macroeconomic forecast in the development of CELT 2020 and expects to use the Moody's October 2020 macroeconomic outlook to develop CELT 2021.



Scenario	% Delta RGSP (from October 2019 Forecast)			
	2020	2021	2024	2025
Baseline	-6.4%	-7%	-1.4%	-1.5%
S4 (downside)	-8.9%	-14.3%	-8.5%	-7.2%

Regional gross state product (RGSP) forecast for New England | *ISO-NE*

Graphing the Data

ISO-NE's June baseline scenario assumed a 50% probability of worsening U.S. economic performance, no second wave of infections that would cause states to shut down again and nationwide confirmed cases of 2.4 million — with new infections peaking in April, a 6% confirmed case fatality rate and 10% hospitalization rate.

The downside scenario assumed a much higher-than-expected incidence of new infections and deaths in the latter part of 2020 causing businesses to reopen much more slowly than anticipated, with consumer spending not rebounding, especially in air travel, retail and hotel stays. It also assumed 4.1 million confirmed cases, new COVID-19 infections peaking in May, with 12% confirmed case fatality rate and 17.5% hospitalization rate.

Compared to the CELT 2020, the new expected (i.e., baseline) macroeconomic outlook results in a summer demand forecast that is approximately 113 MW lower in 2021 and 26 MW lower in 2025. However, consideration of a lower probability, greater downside economic risk scenario suggests greater summer demand impacts in 2021 (-232 MW) and 2025 (-127 MW).

When compared to the October 2019 macroeconomic forecast used in the CELT 2020, the June 2020 forecast for regional gross state product (RGSP) is approximately 7% lower in the near term (2021) and recovers to 1.4% lower in 2024.

Black also noted the connection between how these assumptions are modeled and what the economic fallout of that is, saying it's not just the COVID-19 stats that are important.

"We'll be getting the October vintage of this forecast for CELT 2021, just like we always do, so it will be interesting to see how different that outlook is three months from now," Black said.

The deltas of both the baseline scenario and the greater downside potential scenario are within the realm of confidence bands for a long-term load forecaster, he said.

"The load forecast is the result of what we've been seeing year over year as time has marched on: that economics are driving demand lower, especially summer demand, from one CELT forecast vintage to the next," Black said. "We have a much smaller margin of downside potential here, even with changes in the macroeconomic expectations." ■

ISO-NE News

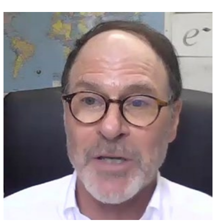
Experts Discuss Clean Energy Transition in CGEP Webinar

Clockwise from top left: Peter Fox-Penner, Boston University; Richard Kauffman, NYSERDA; Cheryl LaFleur, ISO-NE; Melissa Lott, Center on Global Energy Policy; and David R. Hill, NYISO. | *Center on Global Energy Policy*

By Michael Kuser

Energy experts and officials from New England and New York on Wednesday debated how the power sector can deliver clean, affordable electricity as society moves to a low-carbon and increasingly electrified economy.

All but one of the four panelists were affiliated with Columbia University's Center on Global Energy Policy (CGEP), which hosted the webinar.



Peter Fox-Penner, Boston University | *Center on Global Energy Policy*

The exception was Peter Fox-Penner, founder and director of Boston University's *Institute of Sustainable Energy*, who set up the discussion by summarizing his recent book, "Power after Carbon: Building a Clean, Resilient Grid," *published* in May by Harvard University Press.

CGEP senior research scholar Melissa Lott moderated the panel and invited the audience to vote on questions, such as whether the lack of a coherent federal decarbonization policy is the biggest obstacle to progress in transitioning to a clean economy. (Forty-two percent of respondents said "yes.")

Melissa Lott, Center on Global Energy Policy | *Center on Global Energy Policy*

Following is some of what we heard at the meeting.

A Bigger Boat

"We're going to need a power industry about half again as large as we have [by 2050], maybe as large as double if you take all of current uses," Fox-Penner said. "If you account for the greater efficiency that electrification brings, and you apply it to every single BTU of energy use in the United States, you about double electricity use."

Variable factors on power sector growth include how much electricity is used to produce hydrogen or for direct carbon extraction from the atmosphere, he said.

"We have a big job ahead of us, but that amount of growth in the size of the power grid in 30 years is very manageable," Fox-Penner said. "The power industry in fact has grown that fast; during the 1940s and '50s and '60s, it grew almost exactly that fast, so we know we can do that. But it's not easy, and it takes planning."

Distributed energy resources alone will not be able to supply the power needed in the coming decades, he said.

"There are no surprises here; it's going to come from resources of wind and solar PV," Fox-Penner said. "I think advanced nuclear will play a role, and certainly current nuclear is playing a role, accounting for 20% of our supply. Gas with carbon capture and storage is coming along strongly."

Many other resources will contribute less, he said, and then there are "important balancing resources such as large-scale, storage-flexible load and the grid itself, all of which are really far and away the most important and difficult part of achieving a decarbonized grid."

Willingness to Sacrifice

Cheryl LaFleur, ISO-NE | *Center on Global Energy Policy*

"I start from the premise that the U.S. has achieved far less decarbonization than we're capable of, given our financial, technical and natural resources," said former FERC Commissioner Cheryl LaFleur, now a CGEP fellow and member of the ISO-NE Board of Directors.

ISO-NE News

LaFleur cited several big, systemic issues impeding progress.

"The first one ... is the lack of a national consensus that climate change is a problem and thus the lack of a strategy or goal," LaFleur said. "Quite simply, if you're not trying to do something, it should be no surprise that you're not getting maximum success."

The second factor is disaggregated decision-making among the different federal agencies and state and local governments, all pursuing policies that are sometimes working at cross-purposes, she said.

"In particular, a lot of people have the say over what gets built, where it gets built and who pays for it," LaFleur said. "Finally, I think there's a mismatch between people's expressed support for climate action and their willingness to do something about it, and I don't mean just not using plastic straws, but allowing resources, whether they're utility-scale renewables or transmission to connect renewables, to be built near them."

One of the more difficult problems will be developing cost-effective, carbon-free resources to balance renewables, but even the so-called "easy" things like solar and wind are difficult to site and build, she said.

LaFleur quoted Fox-Penner's book as recommending "improved cost allocation and interregional planning for transmission," saying "those were the exact words in FERC Order 1000, which is nine years old ... but has been very little utilized in practice, particularly in states agreeing on the allocation of costs for public policy resources and also the introduction of competitive transmission processes."

Regarding planning among states, LaFleur said that if Congress wants to require regional planning, people should make use of regional planning structures that already exist and do some things well.

In a side panel on the webinar screen, energy analyst Matthew Wittenstein asked, "What is your view on CAISO's proposed Extended Day-Ahead Market for the Western Interconnect? Is it an alternative to a Western RTO, a stepping stone to one or a detour?" (See *CAISO Proposal Sets Course for EIM Day-ahead*.)

"I don't know if it's a stepping stone or an alternative to an RTO, but I strongly believe that the best thing is to let them decide," LaFleur said. "I'd love to see it develop from an imbalance market to a day-ahead or something stronger, but even if it stays at one of those stops, it's still a big improvement on using resources over a broader geography, which is especially needed in the West."

On a separate question as to whether she was worried about the differences between RTO and non-RTO regions when it comes to regional policy, LaFleur said, "Yes, every time FERC upped the ante and required another thing for the RTOs to change their tariff in a slightly different way, I worried we were creating more and more of a divide between the two different Americas, in the organized markets and in the bilateral markets."

Don't Wait; Act Now


Richard Kauffman, NYSERDA | *Center on Global Energy Policy*

CGEP scholar Richard Kauffman, chair of the New York State Energy Research and Development Authority and board chair of San Francisco-based *Generate Capital*, said he prefers market forces over regulatory fiat.

"By market forces, I'm not talking about FERC-like wholesale market structures, which are quite anachronistic to the power sector. I'm talking about market forces that exist elsewhere in the economy," Kauffman said. "Our sector has been in a kind of bubble, away from forces affecting other sectors of the economy."

Investment banker and project consultant Gary Krellenstein said that Kauffman correctly pointed out that the system capacity factor in New York is only 54%. "But given the physical constraints on usage, such as seasonality and weather, won't using more renewables further decrease system capacity factor? More reliance on intermittent renewables implies a lower capacity factor and higher capital costs."

Kauffman agreed that if the regulatory and utility business model doesn't change, average capacity utilization will indeed go further down.

"We may not like flying, but the industry has moved from 50% to 90% average capacity utilization as a result of technology adoption, business model change and flexible pricing," Kauffman said. "This has resulted in much lower costs for customers. The same lessons are true for the chemical and other manufacturing industries. We need to adopt these lessons to the regulatory utility sector, which has been protected by the golden cage of regulation."

On the other hand, energy efficiency and demand response are not businesses, but activities forced on utilities by regulators, he said.


David R. Hill, NYISO | *Center on Global Energy Policy*

David R. Hill, CGEP fellow and a member of the NYISO *Board of Directors*, recommended avoiding making the same mistakes that led to stranded asset costs in some cases when regulators opened transmission development to competitive markets.

"I'm a skeptic of grand master plans, and I think it's a mistake to hold our breath and wait for them, or to use the lack of one as the reason why we're not doing things," Hill said. "Instead, there are so many tools we already have and have available, some of which we haven't tried to use here in terms of coming up with the least-cost, fastest, most effective way of solving some of the problems we're talking about."

Hill agreed with Kauffman on looking for market-based solutions.

"In the New York ISO, we're trying to put forward a carbon-pricing initiative as a part of the ISO's program, and of course we're trying to slog through what it takes to get support for that to make it happen," Hill said. "FERC is having its carbon pricing conference in September, and there's a lot that could be done with existing authority. Waiting for Congress to pass laws or to do something else — we should not wait on that."

Fox-Penner said he is "convinced that markets work much better if government does a certain amount of planning and a certain amount of adjudication of the markets."

Hill said it would pay to go back to the fundamentals of why wholesale power markets were opened in the first place, which was to solve problems. The electricity market effort was not a complete success, but the industry can learn from experience and not make the same mistakes as transportation electrification gets underway, he said.

"The lack of innovation on the consumer side of the electric business is amazing," Hill said. "We need to think about what are the models that can best bring about the innovation. ... So much of what happens on the wholesale side now is walled off from consumers, leaving them unable to see it or participate in it." ■

MISO Cost Allocation Plan Wins OK on 3rd Round

By Amanda Durish Cook

The third time's a charm for MISO getting FERC approval of its sweeping, cost-allocation overhaul for large economic transmission projects.

The commission on July 28 accepted MISO's proposal to lower the voltage threshold for market efficiency projects (MEPs) from 345 kV to 230 kV, add two new benefit metrics and eliminate the current 20% postage stamp allocation in favor of allocating full project costs to benefiting transmission pricing zones (*ER20-1723*).

In the latest iteration, MISO removed all mention of the local economic project category that FERC twice rejected. The small project type was a sticking point in the earlier filings because the commission took issue with a proposal to measure the value of such a project on a regional basis but cost-share only locally. The category was intended for smaller, economically driven transmission projects between 100 and 230 kV, in which 100% of costs would be allocated to the local transmission pricing zone containing the line. (See *Local Projects Axed from MISO Cost Allocation Refile*.)

Now such projects will again be consigned to MISO's "Other Project" category, which has no regional benefits test and prescribes that smaller economically beneficial projects be allocated to the transmission pricing zone in which they are located.

In keeping with its previous orders, the commission found no problems with MISO's plan to add new benefit metrics for savings if a project can reduce dependency on the RTO's transmission contract path with SPP or eliminate needs for other reliability projects. The two new savings calculations will join MISO's existing adjusted production cost savings metric in project evaluation.

"We find that the cost allocation resulting from the application of the three benefit metrics will be more precise at determining benefits," FERC said.

The new rules will also provide limited exceptions to the competitive bidding process if a transmission project were needed immediately for the sake of reliability.

Dairyland Power Cooperative argued that the 230-kV threshold is still too high and "unduly discriminates against areas of the MISO footprint that do not utilize the 230-kV voltage class." The co-op said MISO was dismissing the idea that smaller transmission projects could deliver regional benefits. It said 2018's *Old Dominion Electric Cooperative v. FERC* — in which the D.C. Circuit Court of Appeals ruled that FERC erred when it prohibited cost-sharing for a class of high-voltage projects that demonstrated significant regional benefits — should be applied as caselaw, even for lower-voltage facilities in MISO.

But the commission pushed back on that assertion, saying, "Unlike the situation in *ODEC*, neither MISO nor the commission … has made the finding that MISO projects between 100 kV and 230 kV produce 'significant regional benefits.'"

No 100-kV Threshold

FERC declined another request for a 100-kV MEP threshold in a separate order issued the same day (*EL19-79*).

LS Power last June asked FERC to compel MISO to lower the threshold for competitively bid transmission projects from 345 kV to 100 kV and outline a procedure for identifying beneficiaries. (See *Complaint Seeks Bigger Role for Smaller MISO Projects*.)

The company argued that "MISO's transmission planning process fails to provide a path for development of regionally beneficial economic enhancements that do not currently qualify as [MEPs] and … this failure has resulted in unnecessary congestion costs and unjust and unreasonable rates."

FERC pointed out that it just accepted MISO's plan to lower the MEP voltage threshold to 230 kV. But even if it didn't accept the allocation proposal, LS Power didn't have a strong enough argument, the commission said.

"Although the concurrent … order lowers the market efficiency project voltage threshold to 230 kV, we nevertheless find that LS Power has failed to demonstrate that the then-existing 345-kV voltage threshold … and the current cost allocation method for economic other projects is unjust and unreasonable," FERC said.

FERC said LS Power's examples of hypothetical 100-kV projects that could benefit the footprint regionally also didn't meet the burden of proof. ■

| MISO

Max Gen Event Managed Efficiently, MISO Says

By Amanda Durish Cook

MISO control room transmission map | *MISO*

MISO said last week it quickly regained control during its first maximum generation emergency July 7 during a lasting heatwave.

"Uncertainty in both load and supply, impacted by COVID-19, created some challenges that I think we successfully managed," MISO Executive Director of Real-Time Operations Rob Benbow said during a July 30 Reliability Subcommittee meeting.

Since 2016, the RTO has not completed a single year without a maximum generation event, amassing 10 emergency events in four years. However, summertime emergencies are relatively rare for the grid operator, representing only two of the 10 events.

Benbow said MISO needed "abnormal and emergency procedures" from July 1 through July 20 to navigate tight conditions.

The RTO and its members operated under a hot weather alert July 1-10 and a capacity advisory and conservative system operations — where maintenance outages are asked to be put on hold — July 6-10.

MISO declared a maximum generation event July 7 as high temperatures collided with an unusually large number of unavailable generators in the RTO's North and Central regions. The *emergency* lasted from about 1:00 to 5:30 p.m. Load peaked at 116 GW, below the 120-GW forecast.

Benbow said MISO anticipated the hot weather and communicated with its members as early as possible.

After the RTO had committed all available resources, almost all of the 600 MW in emergency resources called upon stepped up, he said. MISO also recalled some scheduled transmission outages during the day.

MISO maintained good communication with neighbors PJM, SPP, Tennessee Valley Authority and Southern Co. during the event, Benbow said. The RTO discussed temporarily raising the 2,500-MW MISO South to Midwest regional transfer limit with its southern neighbors, but it ultimately wasn't necessary.

Following the July 7 event, the RTO again declared a hot weather alert July 16-20 for its Central region.

"Especially the North and Central regions were in the mid-90s for most of early July," Benbow said.

He noted that MISO would return to the Reliability Subcommittee in August with more information on generation outages and emergency resource performance.

Multiple stakeholders said while the emergency declaration communications to members were clear, it was less clear when MISO terminated its conservative operations and hot weather alerts during July.

Some stakeholders asked if unavailable nuclear generation played a role in the emergency because nuclear plant operators tend to be older and more susceptible to severe COVID-19 infection. Benbow said while one nuclear plant was out during the emergency, he suspected it was "because of mechanical reasons."

Mild June in MISO

June operations were a different story for the grid operator, with load peaking at just 107 GW on June 30.

June 2020 in the footprint registered at one degree Fahrenheit above NOAA's 30-year average, according to MISO.

Low natural gas prices also kept prices low during the month.

"The real-time LMP was $18/MWh for the second straight month, a 25% decrease over 2019," MISO Executive Director of System Operations Renuka Chatterjee reported during a July 21 MISO Informational Forum.

Chatterjee also said load — subdued by the pandemic since mid-March — has gradually begun to rebound. The RTO load bottomed out to about 10% below normal levels during May; the impact has since decreased to about 5%.

"June and July data suggests [that] COVID-19 impact on load and energy is diminishing due to warmer weather, recovering to more historical levels," Benbow said.

MISO is still using its back-up control center at its Carmel, Ind., headquarters, he said. To date, no operators have tested positive for the novel coronavirus.

Benbow also said its non-core operations employees can now return to MISO offices on a voluntary basis. The RTO currently has no plans to make in-person work mandatory for non-operations staff, but it will likely reevaluate sometime in the fall if the pandemic crisis abates.

Meanwhile, MISO is still rearranging some generation outages after virus-induced bare-bones work crews caused some utilities to hold off on scheduled spring maintenance outages.

MISO Outage Coordinator Trevor Hines said the RTO is connecting with market participants to discuss rescheduling outages in the fall.

"If you have flexibility to adjust your outage schedule, please reach out to MISO," he asked members. ■

MISO News

US Analyzing Iowa Storage Pilot as Potential Model

Continued from page 1

storage project's operations, looking for a cost-effective model that can be used elsewhere on the grid.

Decorah Mayor Lorraine Borowski said the Decorah grid currently doesn't have the capacity to accommodate future customer-owned solar projects. She said the town expects the battery will yield savings on avoided distribution system investments.

Alliant hopes to have the *Enel X* battery in service by the end of year, though COVID-19 has slowed development.

"This grid has become a lot more complex in the last couple of years," DOE Director of Energy Storage Research Imre Gyuk said during a July 30 DOE webinar on the project. "We now have an appreciable amount of renewable energy … and for good reason because we need to worry about the world warming up and pollution … You can't just put photovoltaics or other renewables on the grid without expecting disturbances."

Gyuk said electric vehicles and on-site generation is also complicating once cut-and-dried load patterns.

Decorah's "typical small Midwestern town" façade belies Iowa's status as a storage trailblazer, Gyuk said. In 2006, he noted, Iowa Associated Municipal Utilities and the Iowa Stored Energy Project tried to install a 200-MW compressed air energy storage project in an aquifer before project leads *discovered* the sandstone terrain was unsuitable.

"It's time for Iowa to get back in the game," Gyuk said. But he said Iowa and other states still need appropriate regulatory frameworks to develop a grid containing high renewable penetration.

"What we look for is strong local support. You need a local champion," Gyuk said of finding the right location in small-town Iowa. "You need people who are committed and will stick with the thing to make it work."

The City of Decorah is providing leased space for the project in a public park.

Borowski said Decorah's residents are often out-of-state imports and like-minded about a renewable-dominant future. And Decorah's hard-rock topography of bluffs and hills makes line-building a challenge, Borowski said. She called the pilot program a "natural fit."

Alliant Energy Solutions Engineer Sarah Martz said the Norwegian cultural hotspot famous for its eagle-hatching camera is on par to reach its distributed generation hosting capacity limit in a few years.

Rather than wait for the limit to approach, Martz said, Alliant wants to create capacity now in an innovative way.

Traditional line and substation upgrades to host the distributed energy could cost from $1 to $10 million, a wide range of uncertainty. The $2.5 million investment in the battery will have the added benefit of being able to manage voltage and real power flows on the circuit.

"Some of these hosting capacity issues cannot be solved by traditional line and substation upgrades," Martz said, adding that voltage increases on a circuit still can't manage backflows from distributed generation.

Martz said Alliant will also monitor the project to make a blueprint for other communities the utility serves.

Martz said Alliant is interested in offering the battery's services into the MISO market once MISO has approved market rules for storage devices. The RTO's market participation model for storage resources is set to go live in mid-2022. (See *More Time Needed for Storage Compliance, MISO Says*.)

Last May, the IEDA's energy office released the *Iowa Energy Storage Action Plan,* which encourages such pilot programs.

"We really understand that you have to walk before you can run. We have to have these pilot programs for lessons learned," said Brian Selinger, director of the energy office.

"Iowa really is on the cutting edge of the transformation of the grid," Director of Iowa State University's Electric Power Research Center Anne Kimber said. Iowa State also plans to study the project's effectiveness. She said the real-world data gathered from the Decorah battery project and distribution system will be extremely useful.

"We can use the Decorah feeder data … to make better models to predict voltage stability under certain conditions," Kimber said.

The university will also use the project to study battery health and performance over time. ■

MISO News

FERC Upholds Cost Allocation on MISO BRPs

By Amanda Durish Cook

FERC on July 28 rejected transmission customers' complaint over MISO's seven-year-old cost allocation plan for baseline reliability projects (BRPs).

The commission said the Coalition of MISO Transmission Customers, Industrial Energy Consumers of America and competitive transmission developer LS Power failed to show that MISO's current allocation for BRPs is unjust and unreasonable (*EL20-19*).

The groups filed the joint *complaint* early this year, alleging that MISO's location-based cost allocation methodology doesn't square with the commission's principle that beneficiaries of transmission projects should pay for them. (See *Groups Lodge Complaint over MISO BRP Allocation*.) In MISO, BRP costs are allocated only to local transmission pricing zones where project facilities are physically located.

They said MISO's BRP allocation fails to identify all beneficiaries, arguing that the RTO should return to a cost allocation based on a line outage distribution factor (LODF) methodology, the BRP method in place prior to 2013. The LODF method would expand the number of projects eligible for competition under FERC Order 1000, they said.

But FERC said the arguments weren't enough to upend its previous finding that the transmission pricing zone where a BRP is located enjoys "most of the benefits provided by that project."

"Therefore … assigning all of the associated costs to that pricing zone results in an allocation of costs that is roughly commensurate to the distribution of the project's benefits," FERC said.

The commission also said the complainants didn't refute its finding when it approved MISO's classification of BRPs as local transmission facilities that the "spillover of benefits to other zones is modest enough to make the local allocation of costs 'roughly commensurate' with the allocation of benefits."

"While multiple court decisions acknowledge the difficulty of measuring benefits to assess adherence to the cost-causation principle, courts 'have never required a ratemaking agency to allocate costs with exacting precision' and have not required, as a rule, 'that the commission has to calculate benefits to the last penny, or for that matter to the last $1 million or $10 million or perhaps $100 million,'" FERC said, citing the D.C. Circuit Court of Appeals.

The commission also said there was a difference between local transmission facilities built to meet reliability standards, such as BRPs, and transmission projects in an RTO's regional transmission expansion plans. BRPs wouldn't be a good fit for competitive bids, FERC said.

"Because the issues that BRPs are designed to address are specific and localized, we find that complainants have not demonstrated that it is no longer just and reasonable for MISO to maintain its current BRP cost allocation method," the commission wrote.

The complainants said BRPs could be compared to its cost allocation plan for a local economic project category that would be tested for regional benefits, then only cost-shared on a local basis, which FERC rejected twice. (See *Another Rejection for MISO Cost Allocation Plan*.) (See related story, *MISO Cost Allocation Plan Wins OK on 3rd Round*.)

FERC said the two were not alike.

"Unlike the 2019 regional cost allocation order, the complaint does not allege that MISO's BRP cost allocation method identifies BRP benefits and chooses to disregard them for purposes of cost allocation. Rather, complainants argue that the current BRP cost allocation method does not attempt to identify benefits outside the BRP's local transmission pricing zone. However, we reiterate that complainants have not met their burden to show that the current cost allocation method does not result in an allocation of costs that is at least roughly commensurate with the distribution of benefits," the commission said.

The complaint was met with mixed reactions earlier this year from MISO's stakeholder community. Some said the complaint sought to circumvent the RTO's stakeholder process. Others said it would be irresponsible to open reliability projects to competitive bidding. Others still said reliability is a state responsibility and argued that BRPs largely demonstrate only local benefits. Regulators from the Organization of MISO States largely opposed the complaint.

MISO itself argued that the LODF methodology is a measure of impacts rather than benefits. ■

| *MISO*

MISO News

New MISO Sector Gets FERC OK — with a Catch

By Amanda Durish Cook

A MISO Advisory Committee meeting in December | © *RTO Insider*

MISO on July 28 won FERC's approval to create an 11th stakeholder sector for hard-to-categorize members despite some misgivings about the equity of the new arrangement.

The commission's order means the grid operator can alter its bylaws and Transmission Owners Agreement to include an "Affiliate" sector, which will serve as a repository for new members that can't be pigeonholed into other sector groups (*ER20-1926*). The Affiliate sector would also serve as a home for any member that isn't participating in another sector. Prospective members must declare a sector affiliation before they can join the RTO.

Commissioner Richard Glick dissented in part from the order, saying it was odd and inappropriate for the commission to greenlight rules that it recognized as unfair.

MISO's Advisory Committee in spring voted to create the sector with the blessing of the RTO's Board of Directors, which cautioned that the move should be considered a temporary measure and charged the committee with developing a holistic ruleset on how new sectors are created and new members are admitted to them. The board said the AC should ensure all members have full participation in the stakeholder process. (See *Board OKs 11th MISO Sector, Orders Redesign*.)

The AC has until March to draft a fuller solution for incoming and increasingly diverse MISO members. In the meantime, the committee recommended that the new sector not be allowed a vote in either its or Planning Advisory Committee matters but have one designated non-voting seat for its meetings and be allowed to offer opinions during the its quarterly discussions on industry current events.

The committee began debating the merits of a new member sector last year when Lignite Energy Council (LEC), a North Dakota coal lobbying group, approached MISO about membership. The company did not fit neatly into any of MISO's existing 10 *sectors* and was likely to be designated as an "other" in the Environmental and Other Stakeholder Groups sector.

Some AC members said it wasn't fitting that a sector group would contain entities with diametrically opposed views, contending that a new sector was necessary to ensure the current Environmental sector could have a singular voice.

Coal trade organization America's Power, coal and iron mining organizations, and some chambers of commerce are also interested in joining the Affiliate sector, according to LEC.

The commission said the proposal seemed to be a "good-faith attempt to provide America's Power and Lignite Energy Council with an opportunity to participate in the stakeholder process, albeit on an unequal footing, while MISO and its Advisory Committee examine options for a more permanent arrangement for its sector system as a whole."

FERC also said that because America's Power and LEC made filings themselves to support the new sector design, it was "reluctant to second guess what is likely a deliberate, informed decision by the interested parties."

But the commission also warned that it was awaiting a second filing next March on a more permanent solution. It said that if MISO doesn't make a filing, it may institute a proceeding under Federal Power Act Section 206 against the RTO.

The commission also said that because it couldn't know what MISO's new sector design would be, it couldn't honor America's Power and LEC's request to be allowed to block "new entrants with nonaligned viewpoints" from the Affiliate sector.

Glick: Can't Have it Both Ways

It was FERC's warning that it would investigate the arrangement if let unrevised that prompted Glick to issue a partial *dissent* to the order.

"The commission, with one hand, is accepting MISO's revisions to the MISO Bylaws and Transmission Owners Agreement to create a new stakeholder sector for MISO's Advisory Committee and, with the other hand, is suggesting that the revisions are, in truth, not just and reasonable or unduly discriminatory and thus should be modified," Glick said.

He added that the FPA requires FERC to only accept tariff modifications that are just and reasonable.

Glick was quick to note that he thought the arrangement was fair, affording America's Power and LEC an opportunity to participate in the MISO stakeholder process.

But he said the other commissioners took an "Orwellian turn" when they cautioned MISO that further revisions were needed to the sector setup: "The Federal Power Act does not permit us to have a foot in each camp. Either something is just and reasonable and not unduly discriminatory, or it is not. I cannot join an order that so blatantly ignores this irrefutable law of nature. If my colleagues believe MISO's proposed revisions do not meet [FPA] Section 205's requirements, they must reject the proposal. After all, it goes without saying that the commission may initiate a proceeding pursuant to Section 206 of the Federal Power Act if my colleagues believe further revisions are required. What they cannot do is have it both ways." ■

MISO News

MISO, SPP Regulators Mull Seams Recommendations

RTOs Say They're Ready for Better Cooperation

By Amanda Durish Cook

SPP CEO Barbara Sugg | © *RTO Insider*

MISO and SPP regulators are close to asking the RTOs for improvements to transmission operations on their seam as their market monitors wind down a study on the subject.

The short list of recommendations could arrive at an opportune time, with both RTOs signaling a willingness to usher in a new era of cooperation.

The Organization of MISO States (OMS) and SPP's Regional State Committee (RSC) will discuss which recommendations could be most beneficial when their Seams Liaison Committee (SLC) meets on Aug. 10 and Sept. 14. Texas Public Utility Commission Chair DeAnn Walker, who leads the RSC side of the SLC, said July 27 that the committee is moving from the study phase to recommendation selection.

The MISO Independent Market Monitor and the SPP Market Monitoring Unit have recently *summarized* what they believe are the more effective actions the RTOs can take based on the study.

The SLC has indicated it will urge the RTOs to work together and quickly apply the easiest fixes that don't entail major software upgrades. The improvements could include implementing a test based on the available flow relief an RTO can provide the other, an automated means to control power swings on constraints, and better testing and activation of flowgates near the seam.

The monitors said the RTOs cause large power flows on each other's systems. Better managing them could save more than $30 million of the $150 million in annual congestion costs that the RTOs' flowgates have accrued.

An Age of Teamwork?

SPP CEO Barbara Sugg has prioritized a better relationship with MISO since assuming her leadership position in January. That could bode well for the RTOs' willingness to implement seams improvements, should the SLC recommend them.

During SPP's quarterly stakeholder meeting July 27, Sugg said she's "decided to take ownership of [seams issues] and work directly with MISO." Sugg, joined by COO Lanny Nickell, has met several times with MISO CEO John Bear and President Clair Moeller.

"I have high hopes for the two companies working together to resolve issues on the seams and that the discussions will be very beneficial to both sides," Sugg said.

"I commend her for working with John Bear on that relationship, which quite frankly has been lacking in the past," Walker told SPP stakeholders. "Part of a goal of mine — and some of that has already been accomplished — has been better interaction between MISO and SPP staff, and now the boards."

SPP Board Chairman Larry Altenbaumer concurred, saying the SLC "was a bit of a catalyst to try and foster an improved relationship at all levels with SPP and MISO."

MISO also confirmed it was meeting with SPP senior leadership to "discuss opportunities to work more collaboratively on key seams items," according to spokesperson Allison Bermudez. She said MISO looks forward to providing feedback on the recommendations and would possibly route some of them to stakeholder groups for solution development.

The monitors' study also concluded that SPP should improve its modeling of MISO's market-to-market (M2M) constraints. MISO, on the other hand, should eradicate its generator shift factor for low-voltage constraints and M2M constraints, the study said.

But the monitors didn't find significant value in a joint dispatch model, saying the RTOs might save about $17 million per year, or 0.1% of the region's total production costs. MISO Monitor David Patton said he believes that the benefits of joint dispatch aren't being fully captured because MISO assumes optimized congestion management across the seams.

But Patton has said the RTOs could be close to implementing better interface pricing, if SPP will actively model MISO's transmission constraints at the seams. Patton said MISO's interface pricing with SPP could be better than its pricing with PJM because SPP is generally better at modeling the MISO transmission system than PJM.

"SPP has a pretty good depiction of the MISO system," Patton said during July's Market Subcommittee meeting.

Both monitors concluded this spring that a coordinated transaction scheduling process, like MISO uses with PJM, doesn't stand to help much unless the RTOs rethink fees they impose on one another. (See *Monitor Casts Doubts on MISO-SPP CTS Benefits*.)

On the other hand, SPP's MMU found that unreserved use charges are rare along the seams and don't negatively impact the systems' efficiency.

Charges that occur are usually because of outages or extreme weather events, MMU Executive Director Keith Collins said during a recent study update. ■

Tom Kleckner contributed to this report.

NYISO Management Committee Briefs

COVID-19 Impacts Board Selection

NYISO has formed a selection subcommittee to find replacements for board members Tom Ryan and Jim Mahoney, whose terms are expiring, CEO Rich Dewey told the Management Committee on Wednesday.

"The process will be very similar to what we've done in the past, with the exception of the complications we have as a result of the pandemic and potential restrictions on when and how we can conduct the various interviews," Dewey said. "If we need to push things a little bit later to accommodate a more effective in-person interview as opposed to doing it online, we will."

Even if the process is delayed a couple months, the intent is still to have the new members on the board in April, he said.

Demand Curve Reset

The Analysis Group's final report on the demand curve reset will be posted next week for review at upcoming meetings, along with the ISO management's draft report, Dewey said. He encouraged people to read and offer feedback on the reports by the August 24 deadline, ahead of discussion at stakeholder meetings in October and a FERC filing in November.

Dewey also mentioned stakeholder concerns that projects coming through the pipeline were appropriately included in consumer impact analyses.

As part of its Grid in Transition initiative, the ISO in April recommended that it implement market design changes through 2024 regarding carbon pricing; comprehensive mitigation review; participation models for distributed energy and storage resources; enhancement of energy and shortage pricing; energy and ancillary services product design review; enhancement of resource adequacy models; revision of resource capacity ratings to reflect reliability contribution; and adjustment of capacity demand curves. (See "Planning the Future Grid" in *NYISO Launches Fuel Security Effort*.)

Dewey said the ISO had attempted to speed up project development by working on the items piecemeal, but some market participants requested a package approach instead, which the ISO will do.

He said they are committed to doing the impact analyses for the grid reliability and resilience and ancillary service shortage pricing *initiatives* and getting them to the market participants in the first part of September.

The last item Dewey brought up was the ISO's project prioritization process in conjunction with the budget.

Because of a "very challenging" budget this year, Dewey said the ISO will not be able to complete implementation of its distributed energy resources software by the 2021 completion date. "So, we are going to move it to 2022," he said.

Given the "challenging year," the Management Committee also voted not to conduct a new cost of service study during late 2020-2021 to help determine whether to modify the 72%/28% cost allocation between withdrawal billing units and injection billing units.

Hot Weather Operations OK

The ISO has been operating satisfactorily through the heat and humidity of recent weeks, its first summer without Indian Point Two, the Somerset coal station in western New York, and the Cayuga generating facility north of Ithaca, said Vice President of Operations Wes Yeomans. "And we're gaining operating experience with the very brand-new Cricket Valley 1,000 MW combined cycle plant … so we thought this would be an interesting summer," he said.

The state has had three heat waves in July — defined as three consecutive days of 90 degrees. "It feels like they're all blending together at this point," Yeomans said.

The first heat wave, between July 4 and 11, hit upstate in the Syracuse, Rochester and Buffalo areas, with cooler weather downstate. Buffalo hit 97 degrees for only the third time in 100 years. Syracuse had seven consecutive days over 90, only the fourth time that has happened in the last century, Yeomans said. The state saw a peak of 29,902 MW.

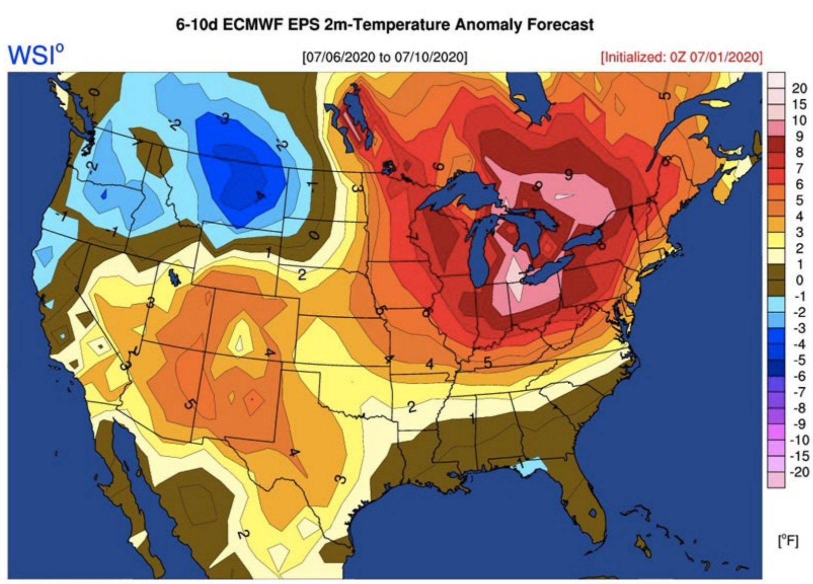
That changed later in the month with higher temperatures in southeastern New York, Long Island and New York City, he said.

A short heat wave in mid-July ended with a tropical storm across New York City, Long Island and Connecticut, which passed quickly "and was basically a non-event for the bulk power system," Yeomans said.

The third wave in late July resulted in a peak of 30,660 MW on July 27. "At this point in time that's the summer peak for 2020, but there's still a lot of summer ahead of us, and we may exceed that," he said.

The performance of the generation and transmission system infrastructure has been "fantastic," he said, promising a more comprehensive hot weather operations presentation at the September Operating and Management committee meetings. ■

— Michael Kuser



A heat wave from July 4 to 11 caused record-tying high temperatures in the Syracuse, Rochester and Buffalo areas and a peak load of 29,902 MW, which was surpassed July 27 with a peak of 30,660 MW when another heat wave hit New York City. | *NYISO*

PJM News

ComEd on Hot Seat at ICC Hearing

ICC Chair also Under Fire

Continued from page 1

Republican activist Jesus Solorio calls for the resignation of ICC Chair Carrie Zalewski (center on dais). | *Illinois Commerce Commission*

In opening remarks, Republican Commissioner Sadzi Martha Oliva said she was concerned by the "optics" of the hearing.

"I believe the allegations surrounding the bribery scheme may conflict with Chair Zalewski's ability to do her job effectively by adversely affecting the confidence of the public," Oliva said. "Holding this hearing in this manner is not good for the integrity of the commission while attempting to restore trust from ratepayers. I fear that not raising my concerns to the public and on the record makes me complicit in failing to restore the public's trust."

"I have not done anything wrong," Zalewski, a Democrat, shot back. "To suggest otherwise [is] both disingenuous and irresponsible. I perform my duties ethically, honestly [and] with integrity. I came from the [state] Pollution Control Board, where I earned that reputation for nine years — never been questioned."

Public Comments

Several people also spoke about the scandal during the public comments section of the meeting.

Republican activist Jesus Solorio said Zalewski should resign or that her fellow commissioners should demand she recuse herself from any matters regarding ComEd, calling her a member of "one of the most politically connected families in Illinois."

Solorio said Zalewski's husband, Democratic state Rep. Michael J. Zalewski, "received thousands of campaign contributions from Commonwealth Edison and voted for the legislation that we now know involved a criminal conspiracy orchestrated by Mr. Madigan and his friends. We also know that Commonwealth Edison gave Ms. Zalewski's father-in-law a $5,000/month contract around the same time Mr. Madigan recommended Ms. Zalewski to be Commonwealth Edison's regulator. We cannot pretend this cloud over the commission's integrity is not a problem. We deserve more than empty assurances."

Illinois PIRG Director Abe Scarr | *Illinois Commerce Commission*

Federal officials say ComEd's bribes aided passage of the 2011 Energy Infrastructure Modernization Act (EIMA) — which approved a formula rate mechanism — and the 2016 Future Energy Jobs Act (FEJA), which authorized subsidies for Exelon's Clinton and Quad Cities nuclear generators.

"In many ways, this corruption is not news. It's been plain to see to anyone willing to look. ComEd and Exelon have used political power to corrupt utility regulation in Illinois," said Illinois Public Interest Research Group Director Abe Scarr, who called for a "comprehensive audit" of the utility.

"Many benefits ComEd promised in EIMA have not arrived," Scarr said. "Without proper examination, we have no way to know if customers are getting real value for the 40% increase in delivery rates they have paid since 2011 or if alternative investments would have brought more value at lower costs."

Jeff Scott, associate state director for AARP Illinois, said FEJA should be repealed and EIMA — which he said guaranteed ComEd automatic rate hikes — allowed to expire. He also called on the state to repeal retail choice in response to the threat posed to nuclear and renewable generation by PJM's expanded minimum offer price rule. (See *Clock Ticking on Exelon Illinois Nukes Under MOPR*.)

"Rather than create a new complicated capacity procurement mechanism on top of the already complicated PJM, Illinois should instead end retail choice and restructuring altogether, end deregulation and again allow the utilities to own generation fully regulated by the ICC with an open, transparent and honest planning process."

ComEd Promises Reform

ComEd CEO Joe Dominguez said he was saddened that "a few" ComEd officials responsible for the bribery scheme tainted the work of thousands of utility workers who have continued to provide "world class service" despite the coronavirus pandemic.

"There are no excuses for our conduct, and I will offer none today," he said.

Dominguez said the deferred prosecution agreement ComEd signed did not allege that EIMA "was bad policy or the investments didn't benefit customers."

"I simply don't agree that those investments were not carefully reviewed and were not deemed to be prudent in every measure for the customer. We've done studies about the

PJM News

Commonwealth Edison CEO Joe Dominguez | *Exelon*

David Glockner, Exelon executive vice president of compliance and audit | *Exelon*

cost-benefit analyses of things like the installation of smart meters and our energy efficiency programs.

"Residential customer bills today are less than they were 10 years ago. I want to emphasize that that is not adjusted for inflation … and if you were to adjust it for inflation, it's 20% less than it was a decade ago."

Critics have said lower bills are a result of lower wholesale power costs, not delivery-service rates, which are the only component covered by formula rates.

Dominguez said Exelon hopes to restore ComEd's reputation by its *hiring* in March of former Assistant U.S. Attorney and former Securities and Exchange Commission Regional Director David Glockner as Exelon's executive vice president of compliance and audit.

"I don't think there is a person better suited" for the job, Dominguez said, citing Glockner's "impeccable reputation."

Glockner cited Exelon's new policies regarding interactions with public officials and the vetting and monitoring of lobbyists and political consultants.

All employment and vendor referrals or requests from public officials must be tracked and referred to the utility CEO, general counsel and compliance department under the new rules. "The request can be approved only if everybody in that process signs off," he said.

"There were policies that the company had that were in place that prohibited this sort of conduct that occurred here, but in retrospect, it's clear that those policies alone weren't enough and the interactions with public officials are an area where we need to give employees more detailed guidance. We need more controls and most importantly more eyes on decisions that are often difficult and where there can be a real risk of … misconduct."

Glockner agreed to return to the ICC to discuss its compliance record. "We realize that there is a significant public trust deficit," he said.

Dominguez assured the commission that ComEd would not seek to recover its $200 million fine or any of the questionable lobbyist spending and no-work jobs from ratepayers.

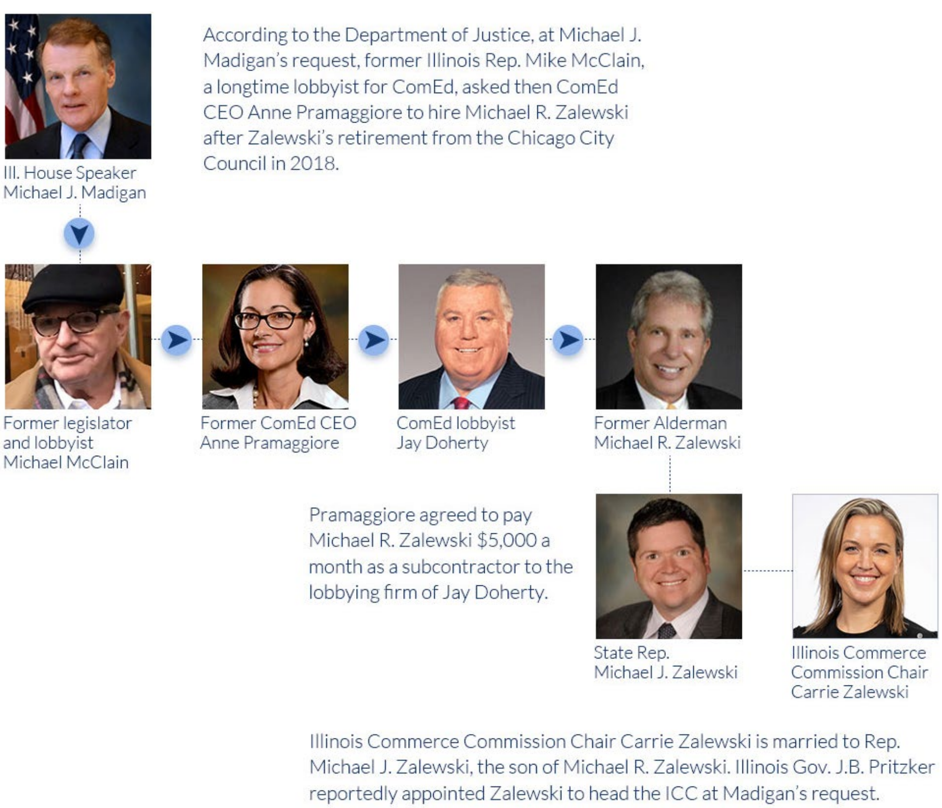
"The commission obviously is going to be exploring this issue for a while and take actions in the interests of ratepayers," Zalewski said in closing the meeting.

Legal Bills

The chair's husband has spent nearly $75,000 in campaign funds on legal services since his father's home was raided by federal agents, radio station WBEZ reported last week.

"In early June 2019, I engaged Jones Day for legal counsel. I wanted to ensure legal compliance in case any investigatory agency sought my cooperation," Rep. Zalewski said in a statement, declining to comment on whether he had been contacted by federal law -enforcement officials. "As several investigations are ongoing, I'll have no further comment at this time."

WBEZ said the state representative had been Madigan's point man on negotiations for a gambling bill last year but relinquished his role after complaints that he was conflicted. WBEZ said a review of state lobbyist-disclosure documents showed Zalewski's law firm had more than 30 clients with interests in gambling legislation the state. ■



| © *RTO Insider*

PJM News

Householder Removed from Ohio Speaker Post

Officially Indicted in Alleged Bribery Scandal

By Michael Yoder

Ohio Speaker Larry Householder declined to comment as he left federal court in Columbus, Ohio, after his arraignment July 21. He was removed as speaker July 30. | *WKYC*

On the same day Larry Householder (R) was voted out as speaker of the Ohio House of Representatives, the longtime legislator was officially indicted by a federal grand jury on a racketeering conspiracy charge related to the alleged $61 million bribery scheme by FirstEnergy to pass and maintain a billion-dollar nuclear plant bailout.

In a unanimous decision, House members voted to remove Householder from the powerful position more than a week after his arrest for his alleged involvement in a three-year scheme resulting in the passage of House Bill 6, which authorized zero-emission credits for FirstEnergy Solutions' (FES) Perry and Davis-Besse nuclear plants. (See *Feds: FE Paid $61M in Bribes to Win Nuke Subsidy*.)

The members quickly approved the measure without any debate in the Thursday morning session. Householder, who still retains his seat in the house despite calls for his resignation, was not present for the vote. Rep. Bob Cupp, a former Ohio Supreme Court justice, was elected speaker by a 55-38 vote.

Republican House leaders, including Speaker Pro Tempore Jim Butler, who was vying for Householder's position, issued a statement after the vote.

"Today's strong bipartisan vote to remove Larry Householder as speaker of the Ohio House of Representatives is not a decision any member of the House took lightly, but it was clear that Mr. Householder is unable to effectively lead the House," the statement said. "This is an opportunity to move the House forward and continue our work to move Ohio forward."

Legislators on the other side of the aisle were also quick to tout Thursday's vote for removal.

"The criminal allegations detailed last week and the indictment handed down today made it clear that Larry Householder could no longer serve as speaker of the People's House," said House Minority Leader Emilia Strong Sykes (D). "His removal is the first step toward restoring public trust, which for the second time in three years has been eroded by Republican leadership that sees itself as above the law."

Thursday's action follows a call late last week by Ohio Gov. Mike DeWine (R) to repeal H.B. 6 and a denial of any wrongdoing by FirstEnergy CEO Charles Jones. (See *Ohio Gov. Calls for Repeal of Nuke Bailout* and *FirstEnergy, AEP CEOs Deny Wrongdoing*.)

Grand Jury Indictment

Coming immediately after the House vote, U.S. Attorney David M. DeVillers, of the Southern District of Ohio, announced the grand jury indictment of Householder and four others, including: Matt Borges, a lobbyist who previously served as chair of the Ohio Republican Party; Jeff Longstreth, Householder's longtime campaign and political strategist; Neil Clark, a lobbyist who owns and operates Grant Street Consultants and previously served as budget director for the Ohio Republican Caucus; and Juan Cespedes, a multiclient lobbyist.

Jennifer Thornton, a Department of Justice spokeswoman, said the charges in Thursday's indictment were the same as the ones issued in the July 21 criminal *complaint*.

According to the indictment, from March 2017 to March 2020, the "enterprise" headed by Householder received millions of dollars in exchange for his help in passing H.B. 6. "Company A," which references FirstEnergy in the indictment, filtered nearly $61 million to a 501(c)(4) nonprofit organization called Generation Now, created by Longstreth and controlled by Householder, to elect him to the speaker role and to support House candidates loyal to him.

Money from Generation Now was also used to fund television advertisements and mailers supporting H.B. 6, according to the indictment. Finally, money was used to defeat a ballot referendum that sought to overturn the law — including bribes to those working for the referendum.

The affidavit filed in support of the criminal complaint also alleges that money passed from "Company A" through Generation Now was used to pay for Householder's campaign staff, which would otherwise have been paid by his candidate committee, Friends of Larry Householder. It also alleges Householder received more than $400,000 in personal benefits, including funds to settle a personal lawsuit, payments on a house he owns in Florida and to pay off credit card debt.

The racketeering conspiracy charge is punishable by up to 20 years in prison. Thursday's indictment also seeks forfeiture of any property derived from the racketeering activity and the proceeds from several different bank accounts of Generation Now.

"Dark money is a breeding ground for corruption," DeVillers said in a statement. "This investigation continues."

Second Repeal Effort

Meanwhile, two Democratic House members last week proposed repealing part of the state's two-year budget bill that allows FirstEnergy's Ohio utilities — Ohio Edison, Cleveland Electric Illuminating Company and Toledo Edison — to consider the profits made by all three subsidiaries averaged together when determining whether they have earned "significantly excessive" profits.

Cleveland.com *reported* that the provision was added by an unknown House member to the budget bill signed by DeWine last year. ■

PJM News

PJM Fuel-cost Policy Changes Approved by FERC

By Michael Yoder

FERC approved changes to PJM's fuel-cost policy (FCP) rules on July 28, replacing annual reviews with a new periodic review process and eliminating the requirement for zero-marginal-cost units to submit FCPs (*ER20-1764*).

The deadlines for reviewing FCPs were also changed, giving the Independent Market Monitor an initial 10 business days to review a policy and an additional five business days when a market seller revises the policy. PJM will have 20 business days to review a policy and an additional five business days for reviewing revisions, although that time frame can be changed if agreed to by the RTO and the market seller.

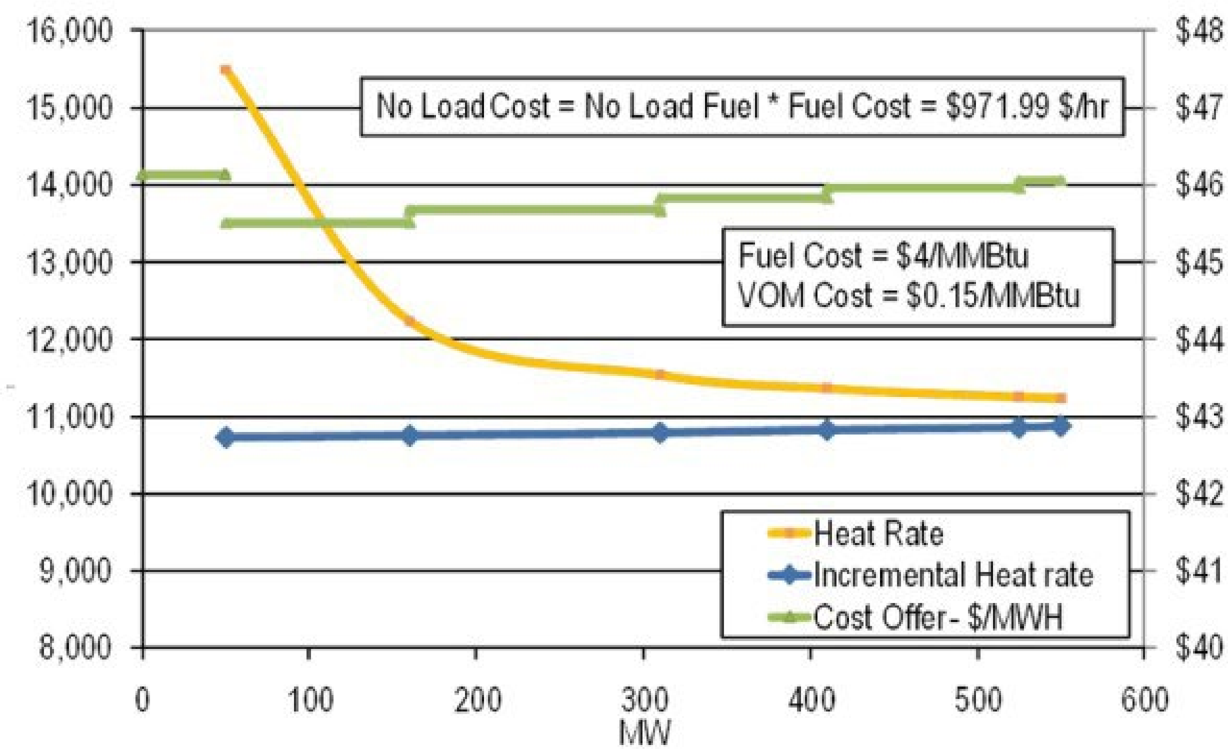
The revisions are set to take effect on Sept. 1. They were proposed by the PJM Industrial Customer Coalition and endorsed by the Members Committee in March. (See *Revised Fuel-cost Policy Approved by PJM MC*.)

"We find that the revisions reduce administrative burdens on market sellers and PJM and afford certain flexibility without jeopardizing the purpose of requiring fuel-cost policies," the commission said. "We also find that PJM's proposal provides additional transparency regarding the conditions under which PJM will expire or terminate a fuel-cost policy and affords market sellers additional time within which to make modifications to a fuel-cost policy."

PJM proposed six main revisions to its FCP rules. They include:

- Replacement of the annual review process with a periodic review process, easing the administrative burden of reviews while ensuring policies don't become outdated. PJM anticipates setting a three-year expiration date for each policy.
- Removal of the requirement for resources with zero marginal costs to have FCPs. PJM argued it is an "unnecessary burden" to require market sellers of resources with no marginal fuel costs to submit FCPs to avoid a penalty because their fuel costs will always be zero.
- Allowance of a temporary cost offer methodology when a market seller does not have an approved FCP. PJM said the proposed methodology would allow a market seller to offer a "conservatively estimated, cost-based offer" while its FCP is under review by the RTO and the Monitor.
- Replacement of the revocation provision, with the ability for PJM to expire FCPs. The RTO cited three scenarios that would allow for the expiration period under consultation with the Monitor, including changes in governing documents, an inconsistent cost estimation method or the failure to update a generation transfer to another market seller.
- Revisions to the existing penalty calculation, including reduction of penalties for noncompliant cost-based offers where there is no market impact or the market seller self-identifies an error in the cost-based offer.
- Elimination of the penalty for noncompliant cost-based offers if the reason for fuel pricing or cost estimation deviation is because of an "unforeseen event" outside of the control of the market seller, its agents or affiliated fuel suppliers.

FERC determined that PJM's revisions to the penalty calculation structure will "diminish the potential volatility in the current penalty amount while not limiting the deterrent effect of the penalties." The commission also said it believed the penalty structure revisions will "appropriately represent the overall market impact a market seller's noncompliant cost-based offer may have had on the market over the time period of noncompliance." ■



Heat rate and cost curves for 550-MW natural gas-fired team unit | *PJM*

PJM News

Dominion Names Blue as CEO in Earnings Call

By Michael Yoder

Dominion Energy announced Friday it is moving forward with its leadership succession plan, promoting Executive Vice President and Co-COO Robert Blue to president and CEO by Oct. 1.


Thomas Farrell | *Dominion Energy*

The news came during Friday's second quarter *earnings* call, with current Chairman, President and CEO Thomas Farrell continuing to lead the Board of Directors as executive chair. Farrell joined Dominion in 1995 and was promoted to president and CEO in 2006 and chairman in 2007.

Farrell said the board believed it to be "an appropriate time to take the next step in our management transition" with the sale earlier in July of Dominion's natural gas assets to Berkshire Hathaway for $10 billion and a path for the company to achieve net zero carbon dioxide and methane emissions from its power generation and gas infrastructure operations by 2050. Ferrell said there is no set timeframe for his new role as executive chair.

"The primary goal of our succession planning process has been to ensure continuity of our strategy, public policy, corporate values and operational excellence," Farrell said. "As executive chair, I will continue to represent the company, engaging with key stakeholders, industry groups and others that will be particularly focused on continuing to develop our strategic plan and Dominion's leadership in the new clean energy economy."


Diane Leopold | *Dominion Energy*

Blue joined Dominion in 2005 and has held several executive roles since his promotion to an officer in 2007, including vice president of state and federal affairs and president of Dominion Virginia Power. Prior to joining the company, Blue served as a counselor and director of policy for Virginia Gov. Mark Warner and a law clerk for the U.S. District Court in the Eastern District of Virginia.


Edward Baine | *Dominion Energy*

Diane Leopold, executive vice president and co-COO, will become the company's sole COO with responsibility for all of Dominion's operating segments. Edward Baine was promoted to president of Dominion Energy Virginia.

Earnings

During Friday's earnings *presentation*, Dominion CFO Jim Chapman announced the company reported a second-quarter loss of $1.2 billion ($1.41/share) on revenue of $3.59 billion, compared with a net gain of $54 million ($0.05/share) on $3.97 billion in revenue for the same period in 2019. He said the loss was impacted by worse-than-normal weather in its service territories and impairment-related charges associated with the cancellation of the Atlantic Coast Pipeline and *Supply Header* projects.

Operating earnings for the second quarter were $706 million ($0.82/share), compared with operating earnings of $619 million ($0.77/share) in 2019. The results beat Wall Street operating results expectations, with the average estimate of 81 cents per share for earnings among four analysts surveyed by Zacks Investment Research.

For the third quarter, Dominion expects its per-share earnings to range from 85 cents to $1.05 and a full-year earnings in the range of $3.37 to $3.63 per share.

Company Initiatives

After cancelling the long-disputed $8 billion Atlantic Coast Pipeline in July with its partner, Duke Energy, followed by the sale of its natural gas assets to Berkshire Hathaway, Dominion is now following its plan to grow its renewable energy capacity by more than 15% annually for the next 15 years. Farrell said the company has already achieved its 3,000-MW targets for renewable generation in service or under development in Virginia, a year and a half ahead of schedule.


Robert Blue | *Dominion Energy*

He also highlighted Dominion's growing solar portfolio, which makes it currently the third-largest owner of solar capacity among utility companies in the country. And Dominion's pilot wind project off the coast of Virginia is scheduled to begin generating electricity in the third quarter, Farrell said, with the rest of the $8 billion, 2.6-GW full-scale offshore wind project continuing on schedule.

Energy Company Controversies

Recent bribery scandals involving two of the biggest energy companies in the country, Exelon and FirstEnergy, played into Friday's earnings call. In the question-and-answer period, Farrell was asked about Dominion's own contributions to 501(c)(4) nonprofit social welfare organizations and whether the company has any plans to modify its political lobbying strategies considering the federal investigations going on with Exelon and FirstEnergy.

He said Dominion has "fully disclosed" its 501(c)(4) contributions for several years. Over the last five years, the company's contributions to 501(c)(4)s have been under $500,000, with 70% of that total going to an organization associated with American Petroleum Institute that supports pipeline projects.

"We have no intention of changing our practices because they are perfectly appropriate [and] completely compliant with every state in federal law by wide margins," Farrell said. "We have nothing to be concerned about with respect to any of our political giving or giving to these so-called 501(c)(4)s." ■

PJM News

PSEG Seeking to Sell Fossil, Solar Generation

By Michael Yoder

Public Service Enterprise Group (PSEG) is putting its solar and fossil fuel generation on the block as it seeks to transform into a primarily regulated electric and gas utility, company officials announced Friday during its second quarter earnings call.

In his *presentation*, PSEG CEO Ralph Izzo said the company is "exploring strategic alternatives" for its non-nuclear-generating fleet, which includes more than 6,750 MW of fossil generation in New Jersey, Connecticut, New York and Maryland, and 467 MW of solar generation in 17 states.

"Our intent is to accelerate the transformation of PSEG into a primarily regulated electric and gas utility — a plan we have been executing successfully for more than a decade," Izzo said in a *statement*.

Izzo noted that separating its non-nuclear assets would reduce PSEG's business risks and earnings volatility and that it would continue to improve its credit profile by investing in clean energy, methane reduction and zero-carbon generation. He said work is underway to market a potential transaction beginning in the fourth quarter of 2020 with closing sometime in 2021.

Izzo said a "shift in investor preference" toward owning regulated utility businesses without commodity exposure to merchant generation and related earnings volatility has been gaining momentum in the energy sector.

"We're excited to explore the opportunities that will shape PSEG's future," Izzo said. "It is a future focused on advancing our business as a sustainable customer-focused provider of essential electricity and natural gas service, delivered by a regulated utility and contracted businesses."

PSEG Generation's Future

PSEG intends to retain ownership of its existing nuclear fleet under its PSEG Power subsidiary, Izzo said. Its nuclear fleet includes the 2,285-MW Salem and 1,173-MW Hope Creek Nuclear plants in Lower Alloways Creek Township, N.J., and part ownership in the 2,549-MW Peach Bottom Nuclear plant in York County, Pa.

Izzo said the Salem and Hope Creek nuclear plants produce more than 90% of New Jersey's zero-carbon electricity and are a "cost efficient necessary component" of the state's transition to 100% clean energy by 2050, which was outlined in the *New Jersey Energy Master Plan* finalized in January.

The New Jersey plants receive zero-emission credit (ZEC) state subsidies, he said, which added $0.02 a share in earnings in the second quarter. ZEC applications for the next three-year period are due in the fall with a decision by the New Jersey Board of Public Utilities (BPU) expected in April 2021.

"As we begin the second round of the ZEC program by filing our applications this fall, it's important to note that the financial need for ZECs is more critical than ever," Izzo said.

PJM's day-ahead power prices have remained in the mid-teens to low $20s per MWh most days during the second quarter, with recent temperatures in the mid-80s to mid-90s only causing prices to cross the $30/MWh threshold twice in the last 30 days in the PSEG zone.

Izzo said PJM day-ahead prices have declined from where they were just two years ago, when forward around-the-clock prices for the PSEG zone were approximately $30/MWh to just more than $25/MWh today. He said the lower prices reflect current market conditions, characterized by reduced loads, inexpensive natural gas and abundant generation.

"This market environment is the reality we face at our nuclear stations and is the driver behind ZECs," Izzo said.

Besides its nuclear fleet, he said PSEG is continuing to evaluate potential investments in offshore wind, including a decision regarding the opportunity to acquire a 25% interest in Ørsted's 1,100-MW Ocean Wind project later this year. (See *Orsted Wins Record Offshore Wind Bid in NJ*.)

The company is also evaluating participation in upcoming offshore wind solicitations in New Jersey and other Mid-Atlantic states. On July 21, New York opened a solicitation for up to 2,500 MW of offshore wind power generation capacity.

Earnings

Dan Cregg, PSEG's executive vice president and CFO, *announced* a second-quarter profit of $451 million ($0.89/share), compared to $153 million ($0.30/share) last year.

Non-GAAP operating earnings were $404 million ($0.79/share), compared to $294

PSEG CEO Ralph Izzo | © *RTO Insider*

million($0.58/share) in 2019. The operating earnings beat the average estimate of five analysts surveyed by Zacks Investment Research of 59 cents per share.

PSEG expects full-year earnings in the range of $3.30 to $3.50/share.

Transmission Projects

Analysts on the earnings call asked about any transmission capital expenditures that could be on the horizon for PSEG.

Izzo said its subsidiary, Public Service Enterprise & Gas, continues to make progress on its portfolio of capital improvements, including several key transmission projects. In the second quarter, the company energized the second phase of its $739 million Metuchen-Trenton-Burlington Project and upgraded the transmission circuits between the Brunswick and Trenton stations.

The company also expects to complete work on a 6-mile upgrade of a 230-kV overhead transmission circuit running between the Aldene station and the Linden variable frequency transformer station by end of the 2020, having already completed approximately half of the project.

Most of the large transmission projects that came out of the PJM Regional Transmission Expansion Plan (RTEP) are "pretty much complete or near complete," Izzo said. There is also the possibility of increasing transmission investment as New Jersey continues pursuing offshore wind.

"One of the things that the BPU is talking to all utilities, not just us, about is the possibility for accelerating some of the infrastructure programs that we want to do to help create some economic stimulus. And just given the age of our transmission infrastructure, and age of our gas infrastructure, that is something that could provide further opportunities for us as well," Izzo said. ■

SPP News

FERC Rejects SPP's WEIS Tariff

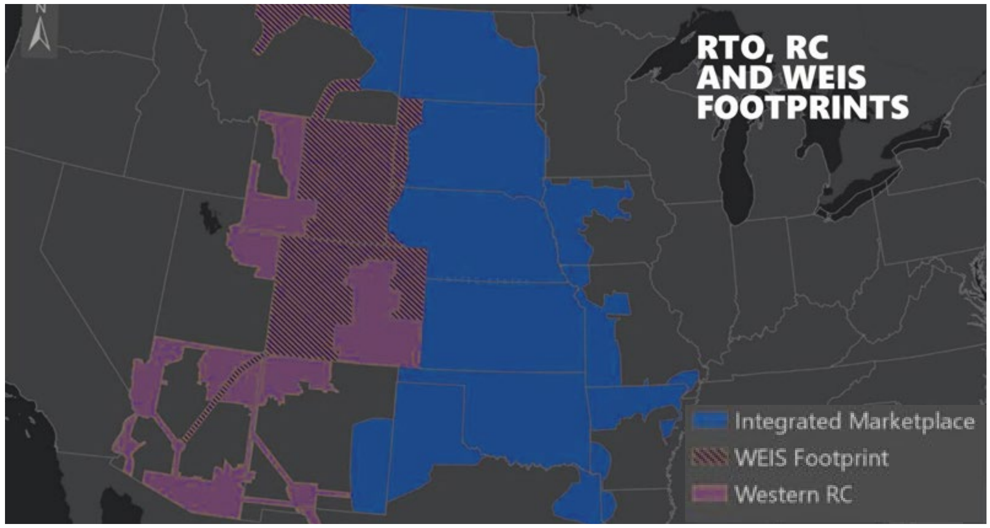
February Launch Threatened

Continued from page 1

mitigation measures cannot be implemented before the market goes live.

SPP had hoped to launch WEIS in February. At launch, WEIS will include eight members and cover the Western Area Power Administration's (WAPA) Colorado Missouri (WACM) and Upper Great Plains West (WAUW) balancing authority areas.

During the July 27 quarterly stakeholder update, Bruce Rew, SPP's senior vice president of operations, said the RTO has received interest in WEIS from "a couple of other entities" who would sign on after the launch. Staff was preparing to begin market trials in August. (See "WEIS Market 'At Risk,' Waiting on FERC Approval," *SPP Briefs: Week of July 20, 2020*.)



| *SPP*

Use of Non-participants' Transmission

Colorado utilities Xcel Energy-Colorado, Colorado Springs Utilities, Platte River Power Authority and Black Hills Energy, all of which plan to join CAISO's Western Energy Imbalance Market, protested the WEIS filings. They contend that an existing and neighboring joint dispatch agreement could be impaired by the WEIS market dispatch and that its market flows may harm the Western Interconnection Unscheduled Flow Mitigation Plan. They also contend SPP's proposal disregards the Northwest Power Pool's activities and could island Xcel's balancing authority area from the NWPP reserve sharing group.

The commission agreed with some of those concerns, saying SPP proposed using non-participating entities' transmission in a manner that would violate Orders 890 and 890-A.

"Under the pro forma OATT, a transmission customer must reserve and pay for transmission service on a transmission provider's system. Although SPP indicates its intent to use transmission that is reserved and contributed by participating entities, SPP also argues that it appears just and reasonable to allow all unused transmission capability within participating [balancing authority areas], whether reserved or otherwise unused on an intra-hour, as-available basis, to be made available to the WEIS Market's least cost dispatch."

FERC disagreed with arguments by SPP and WAPA that because the balancing authority is currently permitted to use any transmission in the WACM and the WAUW BAAs to serve imbalance, the WEIS market could also use all available, unused transmission in these BAAs.

"Although non-participating entities who take imbalance service from WAPA under existing contracts may currently have an expectation of WAPA's use of their transmission to serve imbalances on their systems, SPP has not justified its proposal to alter WAPA's current use of transmission to serve customers' imbalance needs to a potentially more expansive use of transmission for the WEIS market," FERC said. "As Xcel points out, this proposal would allow the WEIS market to use a far greater amount of a customer's transmission capacity than the customer's amount of imbalance in order to serve other customers.

"In fact, as Black Hills Service Co. asserts, it appears that under the proposal the WEIS market could use non-participating entities' transmission capacity without compensation, even when those non-participating entities have no need for imbalance service in a particular hour, because the reorganized dispatch will likely involve wheeling of power across multiple transmission systems. SPP's proposal therefore may limit the use of non-participating entities' transmission capacity that is currently available for other purposes, such as the [Public Service Co. of Colorado joint dispatch agreement]."

The commission said any future proposal should ensure that the WEIS market respects the transmission capacity of non-participating entities with appropriate constraints in its security-constrained economic dispatch (SCED). "If SPP is not able to reach an arrangement with non-participating entities to use their transmission capacity, SPP must include constraints in its market model to appropriately respect the transmission rights of non-participating entities when calculating the market solution," it said.

The commissioners noted that CAISO's Western EIM offered a memorandum of understanding among the ISO, Bonneville Power Administration and PacifiCorp to ensure that EIM transfers would not adversely impact non-participants. "We encourage SPP to coordinate proactively with its neighbors to address these operational concerns prior to resubmitting any proposal," FERC said.

Role of Reliability Coordinator

FERC also found SPP presumptuous in expecting that reliability coordinators and transmission operators will provide WEIS with data on the availability of transmission, saying the RTO had not proven its proposal will ensure accurate, real-time information about available transmission and congestion.

"While this obligation is not currently a concern because SPP is both the reliability coordinator and market operator for the entire WEIS footprint, SPP states that the WEIS market is flexible to operate across multiple reliability coordinator footprints. If the market expands to include participants that are not within the SPP West RC footprint, it could potentially impose an obligation on neighboring reliability coordinators to act as a conduit for market-

SPP News

related information in a way that is outside of the role for reliability coordinators envisioned by NERC," the commission said.

It said SPP could propose a different arrangement to obtain information on transmission availability and other system conditions that do not rely on roles defined by NERC.

Other Issues

FERC also said it was unclear how SPP's proposal would incentivize market participants to maintain supply adequacy.

"While the NERC reliability standards establish requirements for the reliable operation of the bulk electric system, it is not clear that reliance on these standards and after-the-fact reporting to the commission is sufficient to avoid market participants excessively leaning on the other market participants for energy supply," it said. In the Western EIM, it noted, CAISO limits the imbalance imports of EIM entities that fail a resource sufficiency test.

SPP's proposal to use the "average cost" method of accounting for line losses also was criticized by the commission, which cited prior rulings finding that under LMP, the use of marginal losses "better represents the optimal and efficient solution for settlements."

It said SPP should consider including marginal losses in dispatch and LMP to "minimize imbalance costs, provide prices that accurately reflect marginal costs and preserve resources' incentives to follow dispatch. The omission of marginal losses from dispatch prevents production costs from being minimized and could result in a less efficient market solution, especially in a geographically large market such as the WEIS market."

Finally, FERC called for more assurances on market power mitigation.

"Other than an unsupported reference to the SPP [Market Monitoring Unit's] analysis of six hubs, SPP has not provided any justification for its proposal to automatically increase the threshold below which energy offer curves are not subject to mitigation and the LMP impact threshold," it said. "… SPP should either remove the automatic increase provisions or otherwise justify their inclusion."

In its market power study Monday, the MMU said its RSI analysis revealed that if the WEIS market's largest supplier was removed, generation can still meet demand about 50% of the time.

"This result can provide a basis for implementing mitigation measures for system-wide market power, similar to those implemented in other markets," the MMU said, using as an example an ISO-NE mechanism that identifies system market power. "This approach … can act as a blueprint for the WEIS Market."

"The mitigation measures in the proposed tariff and in the response to [FERC's] deficiency letter will provide sufficient protections for participant conduct to exercise of market power with implementation of system wide mitigation measure(s) as recommended in this study," the Monitor said.

The MMU said it relied primarily upon FERC precedent in assessing structural market power for approval of market-based rate authority applications in conducting its study. The MMU analysis defined relevant product market(s) and a relevant geographic market as two components of the market. It then assessed structural market power with the help of market concentration, market share, RSI and pivotal supplier analysis metrics within those defined product and geographic markets. ■

SPP News

Wind May Soon Be SPP's No. 1 Fuel Source

Providing 33.8% of Generation Mix Halfway Through 2020

Wind energy is on track to be SPP's No. 1 fuel source this year, executives said last week during the grid operator's quarterly stakeholder update.

Wind production averaged 11 GW for the month of June and has accounted for 33.8% of the grid operator's fuel mix halfway through the year. During the last three months, SPP has set footprint records for the amount of wind energy produced (18.3 GW on July 17) and the amount of wind in the fuel mix (73.2% on April 27).

"The wind continues to blow," SPP CEO Barbara Sugg told stakeholders July 27.

Over the last 12 months, wind has provided an average of 31.2% of the fuel mix, compared to 29.8% and 26.6% for coal and natural gas, respectively.

That has caused Bruce Rew, the RTO's senior vice president of operations, to reconsider his prediction of when wind energy would become the No. 1 fuel source.

"I used to say wind would be our No. 1 fuel in 2021, but wind should become our No. 1 fuel this year," he said. "It seems to be happening quite a bit faster than we thought."

SPP currently has 24 GW of installed wind capacity, a figure it expects to grow to 27 GW by the end of the year.

Rew said the RTO's electricity demand had fallen as much as 8 to 10% below forecasts as the COVID-19 pandemic took hold. Load has since returned to normal, he said.

New and old wind technology | *Oklahoma Municipal Power Authority*

SPP CEO Barbara Sugg delivers her quarterly report. | *SPP*

In her CEO's report, Sugg said cancelling in-person meetings and stopping business travel in March is expected to result this year in the over-recovery of $12 million in system administrative fees. That could contribute to reductions in SPP's 2021 net revenue requirement, she said.

Sugg assured stakeholders the RTO is committed to remaining affordable and will continue holding most of its meetings virtually next year.

"Cost containment is a big item for me," she said.

Sugg spoke from an empty conference room at the company's corporate center in Little Rock, Ark. "It's much better wi-fi than at home," she said.

The corporate center has been closed to most of SPP's staff since March. Sugg said she is hopeful of allowing employees to voluntarily return after Labor Day but said the campus won't be fully staffed until sometime next year, "hopefully earlier, rather than later."

Complicating matters is that Arkansas has become one of the country's COVID-19 hot spots. The state has recorded more than 43,000 cases and 458 deaths through Aug. 1, with cases still trending up.

"You can't go anywhere else unless you quarantine first," Sugg said. "It's not something we're proud of."

SPP has had several positive cases but no hospitalizations. The operations staff remains unaffected, Sugg said.

"Our employees are able to work from home, and work effectively," she said. "It's a lot of strain on our company, but things are going really well."

RSC Approves Tx Allocation White Paper

Meeting before the quarterly stakeholder update, the Regional State Committee narrowly endorsed the Cost Allocation Working Group's (CAWG) *white paper* evaluating the RTO's cost allocations for transmission projects between 100 and 300 kV that are primarily used to move power out of SPP's local transmission pricing zones

The RSC signed off on the white paper 6-5, with commissioners from Arkansas, Louisiana, New Mexico, Oklahoma and Texas in opposition.

SPP refers to lower-voltage economic and reliability projects as byway projects, with 33% of the costs regionally funded based on member utilities' load-ratio share and 67% funded by the facility's transmission pricing zone. Projects above 300 kV are considered highway projects and regionally funded according to load-ratio share.

Following a year of work, the CAWG report recommends establishing a "narrow" cost-allocation review so that the revenue requirements for certain facilities with byway voltage levels can be fully distributed on a regionwide basis.

The group also recommended that the review process include new and existing Schedule 11 facilities and that the review criteria be based

SPP News

on the use or expected use of the transmission facility. Schedule 11 rates reflect the costs of facilities whose costs are shared in whole or in part on a regional postage stamp basis. The rest of the costs are allocated to the facility's transmission pricing zone.

The CAWG's recommendations would apply to facilities with notifications to construct issued after the 2010 implementation of SPP's highway/byway methodology. The methodology includes an exception for base plan upgrades below 300 kV and associated with wind generation. In that instance, 67% of the upgrade costs are allocated to the region, and the remaining 33% are directly assigned to the transmission customer requesting service.

The white paper would allow affected entities to request a waiver from the allocation methodology. Directly assigned facilities would not be eligible. The CAWG used the Tariff's language on dual-voltage transformer waivers, based on their usage, as a model for the byway cost-allocation waiver process, noting only four transformer waivers have been requested.

The CAWG said that in some zones with more generation than load, upgrades identified through SPP's transmission-planning process "are being used regularly on a more regional basis."

"In such cases, allocating 67% of the cost of an upgrade may not be roughly commensurate with the benefits received and thus it may be more appropriate that such lines be regionally cost allocated," the group said in the white paper.

"I keep hearing it's a surgical approach and that not very many people will apply, but that's only an assumption," said Oklahoma Commissioner Dana Murphy, asking for more time to build consensus.

Texas Public Utility Commission Chair DeAnn Walker said two of her state's three largest utilities have concerns with the issue and questioned whether they had been heard during the stakeholder process.

"I don't disagree … that there has been a lot of work on this and that it has high potential," she said. "I know concerns have been voiced to me that people believe a lot of entities will end up applying for this. I would like to see language added to try and make sure the words 'narrow process' are truly that."

Al Tamimi, vice president of transmission planning and policy for Sunflower Electric Power, has spent the last several years pushing to resolve the issue facing utilities in wind-rich areas, like his in western Kansas. He applauded the CAWG's white paper, which includes a Sunflower presentation, and noted the importance of revising allocation ratios based on "the ratio of power exported to other zones versus local-zone usage."

"It's actually the right solution at this moment," he said. "We have pricing zones sitting out there in generation-rich areas that export three to four times their load through byway facilities. We've been working for three years on this. We brought data and we brought facts to come up with this conclusion. This process helps sustain the highway/byway methodology as it is."

Albrecht Honored for 6 Years of Service

Stakeholders gave former Kansas Commissioner Shari Feist Albrecht a virtual send-off after six years on the RSC. Albrecht, having served eight years, cycled off the Kansas Corporation Commission after her term ended in March.

"I'm humbled and honored by the recognition. My success can only be measured [by] and credited to the people I was surrounded by," said Albrecht, who presided over the RSC in 2018. "I found myself to be a much better commissioner, a better-informed commissioner, as a result of my service on the RSC."

Walker, who has replaced Albrecht as the RSC lead on the liaison committee working with MISO regulators to resolve seams issues between the RTOs, put on her best Bear Bryant impression in honoring her former colleague. (See *MISO, SPP Regulators Mull Seams Recommendations*.)

"I agreed, reluctantly, to step into her shoes. I don't think I'll do as good a job as her, but I will try," she said, borrowing a page from the legendary football coach and his equally legendary propensity for "poor-mouthing." ("Bryant … elevated it to such an art that listeners would wink and smile at his dire pregame evaluations," *Sports Illustrated* wrote in 1994.)

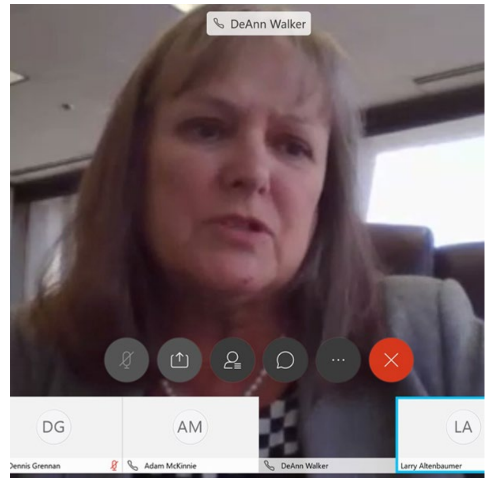
Albrecht's RSC seat has been filled by Andrew French, who was appointed to the KCC in June. A commission staffer for five years, French has worked with the CAWG and RSC.

"He has SPP blood in his veins," said SPP Board Chair Larry Altenbaumer.

Two Revision Requests Approved

In other business, the RSC endorsed a pair of revision requests and approved a clean audit of the committee's 2019 budget.

RR373 includes base plan funding for transmission upgrades identified by SPP's generator retirement process. The process includes screening criteria to filter out resources that do not require analysis before retirement. Resources that meet the criteria would be assessed by both planning and operations staff to identify potential system impacts.



DeAnn Walker, Texas PUC | *SPP*

The Transmission and Operating Reliability Working Groups agreed during the July Markets and Operations Policy Committee meeting to modify the measure's language for a planned filing at FERC in October. (See "Work Continues on Resource Retirement Process," *SPP MOPC Briefs: July 15-16, 2020*.)

Murphy addressed the use of reliability must-run policies that would keep a generator operating. She noted utilities tend to follow regulatory orders requiring a shutdown.

"Given a choice between breaking the law and breaking SPP's rules, they'll break SPP's rules," Murphy said.

RR404, previously approved by MOPC, defines the requirements for demand response programs and behind-the-meter generation to ensure their availability for meeting resource adequacy requirements and winter season obligations. The change addresses whether the resources are treated strictly as an offset of a load-responsible entity's load or as a resource with capacity, specifying which resources can or cannot reduce load.

RSC President Dennis Grennan of the Nebraska Power Review Board said Arkansas' Kim O'Guinn will chair a nominating committee that will bring the RSC's 2021 officer candidates to the October meeting. Murphy and New Mexico's Jeff Byrd will also participate on the committee. ■

— Tom Kleckner

SPP Board of Directors/MC Briefs

Board, Members Finally Agree to 2021 ITP Futures Weighting

SPP's Board of Directors last week approved a staff recommendation that resolves six months of uncertainty over the weighting of futures in the 2021 transmission planning assessment.

Staff said a 50/50 weighting of the two futures in the 2021 Integrating Transmission Planning (ITP) study would acknowledge the lack of consensus over each future's relative probability. They also suggested that any project that could not be justified under a 60/40 weighting be highlighted for further consideration.

The Markets and Operations Policy Committee earlier in July rejected the 50/50 weighting and two other suggestions during its third fruitless attempt to approve an issue that left stakeholders flummoxed. (See "Members Unable to Agree on Weighting Futures in 2021 Tx Plan," *SPP MOPC Briefs: July 15-16, 2020*.)

The Economic Studies Working Group (ESWG) in January recommended a 60/40 split between Future 1 and Future 2, respectively. The "business-as-usual" Future 1 reflects current trends, while the "emerging technologies" Future 2 case assumes that distributed generation, demand response, energy efficiency and energy storage will have a major effect on load and energy growth rates.

The Members Committee approved the recommendation 13-5, with a mix of transmission owners and users in opposition.

Stakeholders have struggled over Future 1's assumption of 32 GW of installed wind capacity in 10 years and where the primarily renewable resources would be sited. SPP has said it will have 27 GW of wind capacity by the end of this year.

Oklahoma Gas & Electric's Greg McAuley, one of five members to oppose the motion, advocated for a 70/30 weighting of the futures that leans more toward uncertainty.

"If you assume solar begins to expand at the same rate wind has over the last 10 years, is it reasonable to assume that expansion will take place in similar locations or be closer to load?" he asked. "These assumptions about resources, without associated firm transmission, kind of leaves us exposed. We will have built transmission to accommodate resources no longer available to the market.

"If you put transmission in the ground, we're committed to it. Our customers will be paying for those facilities for a long time," McAuley said.

Board Chair Larry Altenbaumer | *SPP*

SPP Vice President of Engineering Antoine Lucas pointed out that either weighting would not have affected the last three ITPs' project portfolios.

"The best way to address this is to focus more on the sensitivity analysis of individual projects and the assumptions that drive the benefits for those projects," he said. "If [a project] says more wind [will result], we believe we should run sensitivities around it and test the assumptions. We already do that, whether it's the amount of wind or fuel prices."

"What staff has proposed is to basically provide all of us with a bit of a safety net," said Board Chair Larry Altenbaumer during the July 28 web meeting. "If there is something that is justified in the 50/50 weighting, but not in the 60/40, that allows us to dig into more detail to understand the ramifications, [then] this has taken us a step in the right direction, while recognizing there are more steps we need to take."

Agreement on Competitive Project's Path Forward

Stakeholders were able to reach an agreement over the suspension of a competitive project that SPP agrees would provide numerous benefits to the eastern edge of its footprint, where congestion remains a problem.

Several members wanted to lift the suspension and issue a request for proposals. However, staff cautioned the move would open a seven-day window during which they would have to issue the RFP. The RTO would also be within an 18-month window to issue funds for the project.

The 345-kV Wolf Creek-Blackberry project in Kansas and Missouri with Associated Electric Cooperative Inc. (AECI) was approved by the board last year and was included in the *2020 SPP Transmission Expansion Plan* passed in January. Part of the 105-mile project, projected to cost $152 million, would be on the AECI transmission system and constructed by the cooperative. SPP cannot allocate funds to AECI without FERC approval.

The board in April suspended the project, pending negotiations with AECI and FERC's approval of a cost-and-use agreement. Staff said AECI has reached a verbal agreement but has not yet provided SPP a signed document. (See "Directors Suspend Competitive Upgrade," *SPP Board/Members Committee Briefs: April 28, 2020*.)

General Counsel Paul Suskie said several risks preclude lifting the suspension. "First, whether or not we can reach a timely agreement with AECI," though he admitted an agreement is expected within days.

Other risks include FERC's perspective after a pre-filing meeting with commission staff and potential protests that could delay a final order, Suskie said.

"Once an agreement is signed and filed at FERC, we're in a much better position when we see whether any protests are filed," he continued. "The risks are further minimized as we move further out on the timeline."

SPP News

Altenbaumer suggested members wait until the agreement is executed and filed with FERC "as soon as possible." That would open a 20-day period for any protests, during which time SPP staff could prepare the RFP.

"One thing I'm concerned about is if challenges are made to that filing, and not knowing what those objections are or FERC's action on that filing, and how they could undercut the AECI agreement," Altenbaumer said. "We will then have been out there with an RFP that would not be a viable RFP."

By late August, he said, "we'll know … more information than where we are with the FERC filing."

"We can work with you on trying to find a path forward," said Evergy's Denise Buffington, who helped pen a *letter* from four member utilities asking that the suspension be lifted. "Keep in mind this project is likely to be delayed even if the RFP is issued by Oct. 1. We are looking for an outside date of Oct. 1, and the path you have outlined will accommodate that."

Evergy was joined by American Electric Power, Liberty Utilities and City Utilities of Springfield (CUS) in asking the directors to issue the RFP no later than Oct. 1. The signatories said the suspension's initial rationale was that the cost of the AECI Blackberry termination point was unknown and noted that "these costs are now known, negotiations are complete, and the [agreement] … is about to be filed.

"Because of the critical importance of the proposed line and the benefits provided to SPP customers, the board should not further delay the RFP process," the companies wrote.

"We own the Wolf Creek substation. It will take a minimum of four years to get work done inside the substation. The longer the delay on the NTC, the less likely we will get that in time," Buffington said during the discussion. "We're also worried there will be protest … we think the FERC proceeding should be resolved by the time the RFP is issued.

"All the information needed to issue the RFP is available to SPP today. As the letter points out, there are a bunch of reliability issues at stake," she said. "This project was very, very close to being a reliability project. If it gets restudied, it could be a reliability project."

Board OKs 4 HITT Recommendations

The board and members approved four recommendations stemming from last year's *Holistic Integrated Tariff Team* report, bringing the total of completed recommendations to eight out of 21.

The board sided with MOPC and the ESWG's recommendation to keep the ITP's benefit/cost ratio for economic projects at 1.0, rather than increase it to a range between 1.05 and 1.25. Members approved the recommendation by a 15-5 vote.

Golden Spread Electric Cooperative's Mike Wise, one of those opposed to the 1.0 B/C ratio, said transmission buildouts are "problematic" going forward when looking at benefits and costs.

"The costs are well-known ahead of time. The real issue here is [that] the benefits are estimated and not well-known," he said. "[The benefits] are engineering estimates 40 years into the future. It's really difficult to grasp the benefits that come from this."

Wise found support from McAuley and Oklahoma Municipal Power Authority's (OMPA) David Osburn.

"This is yet another example of where we are, as Mike would put it, doing this as usual, when business is anything but usual," McAuley said. "At what point do we stop building transmission, so our transmission rates stop going up?"

"I want to stress the point [Mike] made is very valid," Osburn said. "We make these decisions and invest in 40-year assets. We're spending consumers' money here, and I think they would like to see a benefit-to-cost ratio much greater than one, and one that doesn't take 40 years to get there."

While Dogwood Energy's Rob Janssen and NextEra Energy Resources' Holly Carias supported the motion, they agreed the motion warrants further analysis.

"Greg made a good point about looking out at the future and looking at economic projects more broadly," Janssen said.

"I can't disagree with Mike Wise and Greg that we're in a different scenario," Carias said. "We need to reconsider benefits."

The board also signed off on the Cost Allocation Working Group's *white paper* that evaluated SPP's cost allocations for transmission projects between 100 and 300 kV that are primarily used to move power out of the local transmission pricing zones.

The Members Committee approved the motion to accept the white paper by an 11-5 vote. CUS, OG&E Transmission, OMPA, Public Service Co. of Oklahoma and Xcel Energy's Southwestern Public Service Co. (SPS) opposed the motion.

The Regional State Committee earlier voted to endorse the white paper by a 6-5 margin.


Steve Gaw, APA | © *RTO Insider*

SPS President David Hudson asked that the minutes reflect that the white paper "is a controversial issue."

Kansas' Sunflower Electric Power is among those that stand to benefit from the paper's recommendation to establish a "narrow" cost-allocation review that regionally distributes the revenue requirements for the lower voltage levels. Sunflower CEO Stuart Lowry said that while the review would grant waivers from the methodology, "by no means is that a guarantee a waiver will be granted."

"We would have to make that case before MOPC and the Board of Directors," he said. "Bear in mind that action today does not mean byway cost-allocation relief will be granted to Sunflower or anyone else."

Members unanimously approved two other HITT items, a staff report on essential reliability services (ERS) and other reliability services (ORS) and a revision request (*MWG RR402*) that improves the Integrated Marketplace by using near real-time economic dispatch to evaluate intraday reliability unit commitment for committing fast-start resources near real time.

The ERS/ORS report evaluated the region's reliability challenges with a changing resource mix by conducting three separate engineering studies on reactive supply, primary frequency response and flexible capacity supply. The Market Working Group will now be asked to work on an ERS/ORS compensation mechanism.

Gaw's Voice Becoming More Prominent

Advanced Power Alliance's Steve Gaw, a ubiquitous presence at SPP meetings for more than 17 years, took some good-natured ribbing when his name mistakenly appeared on a Members Committee list as the board meeting began.

"Steve Gaw … that's a strange name," Altenbaumer said, taking a jibe at SPP's newest member representative. "I'm not sure why he's on the list, but we'll let it go this time."

A former chair of the Missouri Public Service Commission, Gaw was among the founding members of SPP's Regional State Committee in 2003. He has since frequently voiced the wind industry's concerns in stakeholder meetings, taking advantage of SPP's practice of allowing non-members to add their input during discussions.

When Gaw commented during the ITP futures weighting discussion, he first asked whether he could be heard.

"I hear you fine. I've never had a problem hearing you, Steve," Altenbaumer responded.

The APA, an industry trade association supporting renewable generation and energy storage in SPP and *ERCOT*, recently joined the RTO as its first alternative power/public interest member. As a member, the organization now has a vote and can officially join stakeholder groups. (See "Advance Power Alliance Now an SPP Member," *SPP Briefs: Week of July 20, 2020*.)

SPP said a clerical error resulted in Gaw's name being included among the Members Committee's list of 21 names. The Corporate Governance Committee must first nominate Gaw as representing the alternative power/public interest sector and the nomination be approved before he can cast a vote.

"I can only speak, "Gaw said later, noting he was invited to the board and committee's executive session.

No Virtual Roll Call

With more than 250 persons calling in to the webcast, SPP's Dustin Smith, who facilitated the meeting, declined to take attendance through a roll call.

"That's virtually impossible to do virtually," he said.

Consent Agenda Passes

The board's consent agenda included approval of:

- The Finance Committee's 2021 operating plan, which includes developing a strategic plan for the next five years, implementing the HITT recommendations and completing generator-interconnection study requests from 2019 and before.
- MOPC's approval of *RR404*, which further defines the resource adequacy requirements for demand response programs and behind-the-meter generation, and its recommendation for a $20.7 million cost reduction to Basin Electric Power Cooperative's Multi-Kummer Ridge-Roundup project in North Dakota.
- A waiver of financial obligations under the membership agreement to East Texas Electric Cooperative for its transfer of transmission facilities and load from MISO to SPP and from SPP to ERCOT. The cooperative transferred facilities and load from MISO last year and is scheduled to transfer facilities and load to ERCOT between October and January. ETEC requested the waiver because it will wind up transferring more load into SPP than out, which would have triggered a partial termination.
- Staff's recommendation for out-of-cycle re-evaluations for notifications to construct an Evergy Metro 161-kV project in the Kansas City area and an OG&E 138-kV project.
- Appointment of Omaha Public Power District's Joe Lang to an open transmission owner's seat on the Human Resources Committee. He replaces Nebraska Public Power District's Tom Kent, who in March was promoted to CEO. ■

— Tom Kleckner

Company News

Entergy Beats Expectations with Strong Quarter

Entergy on Wednesday *reported* second-quarter earnings of $361 million ($1.79/share), bettering 2019's second-quarter performance of $236 million ($1.22/share).

When adjusted for nonrecurring items, such as the removal of Entergy Wholesale Commodities when it exits the merchant power business later this year, earnings came in at $276 million ($1.37/share). (See *Entergy Celebrates Sale of Final EWC Nuke*.) Entergy's results beat projections by Zacks Investment Research's survey of analysts, who expected average earnings of $1.23/share.

"We delivered another strong quarter and remain on track to achieve our full-year objectives. Sales were better than expected; we're on pace to achieve our cost savings target for the year; and our capital plan is unchanged," Entergy CEO Leo Denault said in a press release.

The New Orleans-based company is affirming its full-year guidance range of $5.45 to $5.75/share, pinning some of the projection on the petrochemical-heavy regional economy.

Entergy CEO Leo Denault | *Entergy*

"While we have seen some slowdown in industrial activity, our industrial base is among the most economically advantaged in the world," Denault told financial analysts during a conference call. "We expect it to lead the region's recovery in their respective industries."

Executives said Entergy could take an earnings hit of 15 to 20 cents/share following a FERC administrative law judge's July decision recommending the commission return to ratepayers $147.3 million related to nuclear decommissioning tax deductions for the Grand Gulf Nuclear Station in Mississippi (*ER18-1182*).

Entergy is contesting a FERC decision over the Grand Gulf Nuclear Station in Mississippi. | *Entergy*

The company's stock price gained $1.45 during the day, closing at $104.12. The stock price is still down 11.7% for the year, having begun 2020 at $117.93. ■

— Tom Kleckner

Xcel Earnings Overcome COVID-19 Sales Drop

Xcel Energy on Thursday *reported* improved second quarter earnings despite a drop in sales due to the COVID-19 pandemic.

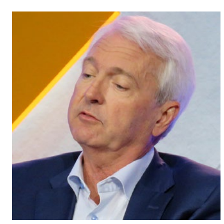
Executives said the Minneapolis-based company had earnings of $287 million ($0.54/share) during the quarter, reflecting lower operations and maintenance expenses, lower income taxes and favorable weather that offset sales declines. That was an improvement from last year's second quarter, when Xcel reported earnings of $238 million ($0.46/share).

Xcel said its operating companies' weather-normalized sales for the quarter were down 7.1% compared to last year. Commercial and industrial sales were down 11.5%, but residential sales were up 5.4%.

While executives acknowledged they are seeing some positive economic signals, the company said in its earnings release that "there continues to be substantial uncertainty related to the impact of the COVID-19 pandemic on the remainder of the year."

The Xcel Energy Center in Minneapolis is home to the NHL's Minnesota Wild. | *Xcel Energy Center*

CEO Ben Fowke said Xcel is still on track with its financial plan and reaffirmed the 2020 earnings guidance of $2.73-2.83/share.



Xcel CEO Ben Fowke | *© RTO Insider*

"We'll continue to monitor and manage through the economic uncertainty of this pandemic," he said.

Xcel recently proposed a $3 billion investment plan in Minnesota. The plan includes $1.8 billion of incremental capital expenditures for repowering wind turbines, a 460-MW solar facility and $1.2 billion of accelerated transmission, distribution and natural gas investment.

Fowke said the plan would create an estimated 5,000 jobs and add more wind and solar to its Northern States Power-Minnesota system.

Xcel's stock gained 27 cents on the NASDAQ Thursday, closing at $69/share. ■

— Tom Kleckner

Company Briefs

Biggest U.S. Coal Carbon Capture Project Halted

The Petra Nova project for capturing carbon dioxide from NRG Energy's W.A. Parish Generating Station southwest of Houston, Texas, is currently in "mothball status" because it needs higher oil prices than the current $40/barrel to make operations financially viable.

NRG Energy and JX Nippon Oil and Gas Exploration Corporation launched the project in 2016 to reduce greenhouse gas emissions. The captured CO2 is used to boost oil production at the West Ranch Oil Field in Jackson County.

NRG said operations will resume once "economics improve."

More: *OilPrice.com*

Chevron to Build Renewables to Power Oil, Gas Facilities

Chevron last week announced it will build 500 MW of renewable energy plants over the next four years to power some of its global facilities.

The oil giant will work with Algonquin Power & Utilities to build the plants at "priority operations sites" in the Permian Basin, as well as Argentina, Kazakhstan and Western Australia. The projects will be co-developed, with Chevron buying the electricity through power purchase agreements.

The initial projects will be sited on Chevron-owned land, with construction to begin in 2021.

More: *GreenTech Media*

CMS Energy Purchases Majority Stake in Texas Wind Farm

CMS Energy last week announced that it has purchased a 51% ownership stake in the 525-MW Aviator Wind farm in central Texas. CMS purchased the stake from funds managed by Ares Management Corporation's Infrastructure and Power unit.

The farm, which is expected to be operational by the fall of this year, will be operated by CMS Enterprises, a subsidiary of CMS Energy. It will generate clean energy for Facebook and McDonald's.

CMS owns and operates 11 independent power plants and more than 1,800 MW of generation nationwide.

More: *MLive*

Georgia Power Forecasts Increased Vogtle Costs

Southern Company last week forecasted that it will cost $149 million more for its share of the Vogtle nuclear expansion project and that Georgia Power could eventually ask regulators to charge customers for the increase.

The company said the COVID-19 pandemic has affected work at the plant, which was already billions of dollars over its original budget and years behind schedule. Still, Southern said it expects to have the two new units operating by November 2021 and November 2022.

More: *Atlanta Journal Constitution*

Microsoft Tests Hydrogen Fuel Cells for Backup Power

In an effort to wean itself off fossil fuels and become carbon neutral by the end of the decade, Microsoft announced last week that it is has been testing hydrogen fuel cells and that some have powered a row of datacenter servers for 48 consecutive hours.

Diesel fuel accounts for less than 1% of Microsoft's emissions, with its primary use supporting continuous operations at datacenters for the company's Azure cloud service. However, recently, hydrogen fuel cell costs have fallen and have become an economically viable alternative to diesel. Furthermore, an engineer said a datacenter outfitted with fuel cells, a hydrogen storage tank and an electrolyzer that converts water molecules into hydrogen and oxygen could be integrated into the grid to provide load balancing services.

The idea of using hydrogen fuel cells came in the spring of 2018 when researchers at the National Renewable Energy Laboratory powered computers with a proton exchange membrane (PEM) hydrogen fuel cell. PEM fuel cells combine hydrogen and oxygen in a process that produces water vapor and electricity.

More: *Microsoft*, *GreenTech Media*

Federal Briefs

DOE Set to Lose up to $225M on Solar Project Bankruptcy

The Department of Energy could lose as much as $225 million on a federal loan guarantee issued in 2011 for the 110-MW Crescent Dunes solar project after owner Tonopah Solar Energy filed for Chapter 11 bankruptcy last week.

The company's proposed restructuring deal would allow Crescent Dunes to keep operating under private ownership and resolve claims stemming from the Energy Department's loan guarantee. It would repay the government $200 million of its $425 million in outstanding public debt and provide the DOE with a $100 million contingent bond.

The project's financiers include an affiliate of Spanish engineering firm ACS Group and developer SolarReserve, which ceased operations at the end of 2019. Crescent Dunes has been unable to generate any electricity since April 2019 because of a leak that is being repaired.

More: *The Wall Street Journal*

EPA Changes Closure Requirements in Coal Ash Rule

EPA last week finalized several changes to regulations for utilities' disposal of coal combustion residuals (CCRs), or coal ash. The changes include giving utilities more time to design clean-up and closure plans for their coal ash storage sites.

The new rule will require all unlined surface impoundments, not just those that have detected groundwater contamination above regulatory levels, to retrofit or close. It also changes the classification of clay-lined surface impoundments from "lined" to "unlined," which means that formerly defined clay-lined surface impoundments need to be retrofitted or closed. EPA is also establishing an amended date by which unlined surface impoundments must stop receiving waste and initiate closure.

Under the new rules, coal ash ponds that were supposed to stop receiving waste by 2021 can keep receiving sludge for up to seven more years. Including the additional time for closing ponds, some pits could remain open as late as 2038.

More: *Power Magazine*, *The Hill*

EPA Moves to Phase 2 of Office Reopenings

EPA will shift its Washington, D.C., headquarters and several of its offices across the country into the next step of its reopening process beginning Aug. 4.

The affected offices moving to Stage 2 of a three-stage reopening plan include Region 1, headquartered in Boston, Mass. Also moving into Phase 2 are offices in Traverse City, Mich.; Duluth, Minn.; Narragansett, R.I.; New Haven, Conn.; Helena, Mont.; Buffalo, Albany, and Syracuse, N.Y.; Wheeling, W.Va.; and Middleburg Heights and Westlake, Ohio. Workers are still not expected in the office, but staffers can return if they wish, according to Administrator Andrew Wheeler.

He said the decision to move forward with the reopenings "is a balancing act, considering both the gating criteria data and decisions being made by state and local public health officials."

More: *Bloomberg Law*

Green Groups Challenge Trump NEPA Rollback

The Southern Environmental Law Center and Earthjustice, which represent more than 35 environmental groups, each filed suit last week challenging the Trump administration's rollback of the National Environmental Policy Act (NEPA). The groups say the administration's actions gut the act, which is designed to weigh environmental and community effects before major construction projects are permitted.

The rewrite of the 50-year-old act removes requirements to consider climate change before proceeding on a project. Protocols for weighing concerns from nearby communities would also become more complex.

The White House Council on Environmental Quality held two hearings on the changes and issued its rule four months after it was proposed, leaving little time to go through the more than 1.1 million public comments. Critics say the administration likely violated the Administrative Procedures Act, which requires the government to provide opportunities for the public to weigh in on rules and consider each comment.

More: *The Hill*

Mountain Valley to Get Permit to Cross Blue Ridge Parkway

In a letter filed last week with FERC, the National Park Service said it will issue a right-of-way permit for the natural gas Mountain Valley Pipeline to pass under the Blue Ridge Parkway atop Bent Mountain in Roanoke County, Va.

Mountain Valley *said* in June that total project work was about 92% complete and projected a full in-service date for the $5.7 billion, 303-mile pipeline in early 2021. But the developer needs the permit to maintain and operate the line. The pipeline still lacks three sets of key permits that must be re-granted if the project is to be finished by early next year. However, Mountain Valley expects the U.S. Fish and Wildlife Service to soon decide whether the pipeline will jeopardize endangered species.

More: *The Roanoke Times*

South Florida Plant Workers Fired over Falsifying Records

At least three maintenance workers at Florida Power & Light's Turkey Point Nuclear Generating Station have been fired for failing to complete a safety inspection of a critical piece of equipment and falsifying records about it, according to NRC documents.

Workers inspecting a valve for wear and tear in the reactor's backup cooling system failed to use specialized equipment to measure signs of weakness, according to documents. The valve must be taken apart and measured with specialized equipment every three years. Investigators found that the maintenance crew hadn't checked out the necessary tools, even though they reported completing the task by writing 2015 measurements on a form in 2019. The valve controls the water flow in the reactors' backup feedwater cooling system. The system is designed to draw heat away from the reactor in case the primary cooling system stops working.

An NRC spokesman said the utility has 30 days to respond to the findings and can elect to go through a disciplinary process or have the issue settled via mediation with an outside party.

More: *South Florida Sun Sentinel*

TVA Releases First Sustainability Report

The Tennessee Valley Authority released its first corporate sustainability report last week and said it is on pace to reduce its greenhouse gas emissions by 70% below 2005 levels by 2030.

Chief Sustainability Officer Rebecca Tolene said the report will serve as the utility's baseline for annual updates.

TVA has shut down most of its 59 coal-fired generators and now gets more than 40% of its power from seven nuclear reactors in Tennessee and Alabama and about 10% from its 29 power-producing dams. TVA said it has reduced carbon emissions by 60% since 2005 and is targeting an 80% reduction by 2040. The company is now looking at ways to eliminate the other 20% of carbon emissions still coming from coal, natural gas and diesel fuel.

More: *Chattanooga Times Free Press*

U.S. Coal Production Lowest in 4 Decades

Data published by the EIA last week showed the U.S. mined 706 million tons of coal last year – its lowest amount since 1978. The total is a 7% drop from 2018 and continues a decade-long decline in overall output since the sector's peak production in 2008.

The sector is on pace for an even bigger drop in 2020, with the EIA projecting mining levels comparable to those in the 1960s. The agency also projected the country will get more power from renewable energy than from coal this year for the first time.

More: *The Washington Post*

State Briefs

ARIZONA

APS Details Cause of Battery Fire, Explosion

Arizona Public Service last week completed its study of an April 2019 battery fire and filed a report with the Corporation Commission that lays out new safety requirements to prevent failures at current and future installations.

A lithium-ion battery container at the company's McMicken facility caught fire, and after first responders opened the door to the enclosure, it exploded, sending several to the hospital. The fire ignited in just one of the 27 racks of batteries, suggesting the layout of the racks isolated them from one another. However, the aerosol fire suppressant did not stop a buildup of explosive gas, which combusted when the responders opened the door and let oxygen into the container.

APS has since shut down its other battery facilities at Festival Ranch, which is a twin of the McMicken system, and a larger one at the desert community of Punkin Center. Before those reopen, they will need to be retrofitted with ventilation systems.

More: *GreenTech Media*

Court Says Corp. Commission. Can Take over Private Company

The state Supreme Court last week ruled 6-1 that the Corporation Commission has the authority to seize managerial control of utilities that pose a risk to public health and safety.

The justices rejected claims by the owners of Johnson Utilities, a water and wastewater company, that there was no constitutional authority for the commission to appoint an interim manager two years ago. However, Justice Andrew Gould wrote for the majority that the constitution allows regulators to step in "to protect the health and safety of a public service corporation's customers, employees and the public at large."

State officials took action over problems including low water pressure and 78 incidents in which raw sewage had overflowed since 2010. Despite the ruling, the justices said Johnson Utilities still has an opportunity to argue that the decision was not reasonable.

More: *Arizona Capitol Times*

Regulators Hit Roadblock on Clean-energy Rules, Abruptly End Meeting

The Corporation Commission abruptly ended its meeting last week when it could not come to an agreement on the state's new clean energy rules.

On the table was a proposal to require 50% renewables between 2030 and 2035 and 100% carbon-free energy by 2050, along with energy-efficiency requirements and a change in how utilities decide which power plants to build. The state's current renewable-energy requirement of 15% of electricity coming by renewables by 2025 is below many other states.

"The Arizona Corporation Commission today missed a historic opportunity to put Arizona on a path toward a cleaner, healthier and more prosperous future by failing to strengthen the state's antiquated energy rules," said Western Grid Group Director Amanda Ormond. "Rules were under consideration for two years, with 10 public meetings, thousands of comments filed and hundreds of hours of engagement by stakeholders."

More: *Arizona Republic*

CALIFORNIA

FERC Sets CAISO RMR for Hearing

FERC last week approved CAISO's reliability must-run (RMR) agreement with a 49.5-MW natural gas-fired cogeneration facility in Sutter County. The contract, effective June 2, is subject to hearing and settlement procedures as requested by the ISO, the Public Utilities Commission and PG&E.

The PUC and PG&E object to a provision that would allow plant owner Greenleaf Energy to terminate the agreement during 2020 as inconsistent with the mandatory nature of RMR designations. PG&E said the company's claim to have voluntarily accepted its RMR designation could result in inconsistent treatment of other RMR resources. The PUC raised questions about the plant's compensation, saying full-cost compensation is appropriate only for mandatory RMR designations, with voluntary designations only eligible for going-forward fixed costs.

FERC noted that no one has challenged the plant needing to meet the 2020 local capacity requirement in the Drum-Rio Oso sub-area of the Sierra local area because no alternatives are available through the end of this year.

More: *ER20-1947*

Sunrun Lands Contract for Backup Battery-solar Project

Community-choice aggregators who last year announced plans to deploy thousands of solar-battery systems to provide backup power to residents have selected Sunrun to handle the installations.

Under the terms of the deal, Sunrun will install up to 20 MW of solar-battery systems in about 6,000 homes served by East Bay Community Energy, Peninsula Clean Energy and Silicon Valley Clean Energy. Sunrun and the CCAs are enlisting customers and hope to deploy the systems as soon as possible, with the aim of getting some installed in time for this year's fire season.

More: *GreenTech Media*

COLORADO

Boulder, Xcel Send Settlement Agreement to City Council

Boulder city officials and Xcel Energy last week came to a settlement on a new franchise agreement that would end the city's attempt to create a municipal utility. For the deal to take effect, a majority of voters would have to support it in a referendum on the November ballot.

The council could vote to send the 20-year agreement to the ballot on first reading next week, with a second reading and public hearing scheduled for Aug. 18.

The proposal satisfies requests to have an enforceable deal that gives Boulder options to leave if Xcel fails to hit key greenhouse gas reduction benchmarks over the next 10 years. The city had been considering condemning the company's local assets to form a publicly owned utility.

More: *Daily Camera*

MINNESOTA

Court Overturns Rejection of Solar Gardens

The Court of Appeals overturned Le Sueur

County's rejection of two solar gardens proposed last year, saying the county's Board of Commissioners did not deny the permits within the 120-day time limit. The county argued that revisions to the initial application extended the time limit, but the court did not agree and automatically approved the permits.

Two subsidiaries of U.S. Solar Corporation applied to construct two 1-MW solar gardens on 10-acre parcels southwest of Waterville in January 2019. The county's board denied the permits that May, citing concerns about their proximity to existing residential properties and anticipated development.

The subsidiaries appealed the denial, saying it came two weeks too late. The county said the clock was reset when the companies resubmitted their site plans. However, the judges decided the applications were "materially" complete when originally submitted.

More: *The Mankato Free Press*

NEW HAMPSHIRE

Liberty Utilities Nixes Plans for Natural Gas Pipeline

Liberty Utilities last week told the Public Utilities Commission it will not build the proposed $340 million Granite Bridge natural gas pipeline after finding a cheaper way to serve customers with existing infrastructure.

Liberty recently learned that Calpine, which used the Concord Lateral to serve its Londonderry power plant, would not renew its contract when it expires next fall. That freed up space for Liberty to agree to a 20-year contract to deliver its own gas to new and existing customers on the lateral. The utility said it will require some upgrades costing about $90 million. The Concord Lateral is owned by Kinder Morgan.

More: *New Hampshire Public Radio*

NEW MEXICO

Gov. Grisham Implores Trump to Oppose Nuclear Waste Site

Gov. **Michelle Lujan Grisham** last week wrote President Trump asking him to oppose Holtec International's plans to build a 173,000-metric-ton underground nuclear waste site in her state and a similar facility proposed in West Texas.

"New Mexico has grave concerns for the unnecessary risk to our citizens and our communities, our first responders, our environment and to New Mexico's agriculture and natural resource industries," the governor's letter said.

Holtec plans to lease 1,000 acres from the Eddy-Lea Energy Alliance to build a temporary repository until a permanent disposal site begins operating.

More: *Santa Fe New Mexican*

PRC Approves All-renewable Plan to Replace San Juan Power

The Public Regulation Commission last week unanimously approved an all-renewable energy plan to replace the coal-fired San Juan Generating Station. The decision gives the go-ahead for the Public Service Company of New Mexico (PNM) to sign power purchase agreements for 650 MW of solar farms in San Juan, Rio Arriba and McKinley counties, along with 300 MW of backup storage. Investment in the new resources could total about $1 billion.

Commissioners said the plan is the best option to meet environmental goals and other requirements specified in the Energy Transition Act (ETA), which requires PNM to transition to 80% renewable energy by 2040 and carbon-free generation by 2045. State regulators approved PNM's request last year to abandon the San Juan plant in 2022 to begin meeting ETA goals.

More: *Albuquerque Journal*

NEW YORK

Environmental Bond Delayed by Coronavirus

Gov. **Andrew Cuomo** last week said the state will postpone plans to place a $3 billion environmental bond on the ballot in November, citing a nearly $14 billion budget deficit stemming from the COVID-19 pandemic.

Cuomo proposed the bond act in January as part of the budget process. The $177 billion budget allowed the bond question to be placed on the Nov. 3 ballot. If approved, it would have allocated funding for a number of projects, including habitat restoration, flood reduction, environmental justice communities, preservation efforts, renewable energy expansion and water quality improvements.

Cuomo said he hopes the measure can be added to the ballot next year.

More: *Bloomberg Law*

NORTH DAKOTA

Tesoro High Plains Oil Pipeline Ordered to Shut down

The Bureau of Indian Affairs (BIA) on July 2 ordered the shutdown of Marathon Petroleum's Tesoro High Plains Pipeline because an easement allowing the line to cross part of the Fort Berthold Indian Reservation expired in 2013. The BIA will also fine Marathon $187 million for damages associated with the trespass.

Marathon said it will appeal the order, which requires the company to "immediately cease and desist" using the segment of its High Plains pipeline system deemed to be trespassing. The line remains operational, according to a Marathon posting.

The BIA gave Marathon 30 days to respond; however, it is still unclear if the company has filed its appeal.

More: *The Bismarck Tribune*

OHIO

Lawmakers Want Offshore Wind Ruling Revisited

A bipartisan coalition of 32 lawmakers has asked a siting board to reconsider conditions it placed on Lake Erie Energy Development Co.'s (LEEDCo) 20.7-MW demonstration offshore wind project. The lawmakers say the board's ruling, which stipulated the company shut down the six turbines from dusk to dawn eight months of the year to mitigate the impact on birds, was a "poison pill" that made the development financially unfeasible.

The letter further argues that the order is "unlawful" because it contradicts the evidence in the four-year case record as well as the formal finding of the U.S. Fish and Wildlife Service; does not offer "compelling evidence" to override the recommendations of the board's staff or the recommendations of the Department of Natural Resources; and requires two separate approvals (one for construction, one to operate at night), which is a violation of rules governing the board's actions.

LEEDCo estimated the project, which would be the first freshwater wind farm in North America, would be worth $250 million to the local economy.

The board does not meet again until Aug. 21.

More: *Energy News Network*

RHODE ISLAND

Judge Reverses Denial of Richmond Solar Farm

Superior Court Judge **Richard A. Licht** last week ruled in favor of Freepoint Solar by reversing the town zoning board's denial of a special-use permit to build a 12,600-panel solar farm on a 64-acre former turf farm.

Licht ruled that the project had met the requirements for the special-use permit, including that it be within two miles of a utility substation.

The board had voted 3-2 in favor of project, but four affirmative votes were needed. The two votes cast against it were based on the contention that though the project was within two miles of an Amtrak substation, it was not within two miles of a National Grid substation. Those who voted against it thought the Town Council had intended it to apply to National Grid substations alone.

Licht disagreed, finding that the ordinance did not specify that the substation must be a National Grid substation, or even one that provides electricity.

More: *Providence Journal*

SOUTH DAKOTA

WEC Energy Group Invests in Wind Farm

WEC Energy Group, the parent company of We Energies, said last week it is investing about $235 million to acquire an 85% ownership in Tatanka Ridge Wind Farm, which is under construction in Deuel County. The transaction is subject to regulatory approval.

The farm, which is expected to begin operations in early 2021, will consist of 56 wind turbines with a combined capacity of 155 MW. Avangrid Renewables is developing the project.

More: *Milwaukee Business Journal*

TEXAS

CPS Energy Moves Forward with Clean Energy Plan

The CPS Energy Board of Trustees last week approved a request for information as part of a planned solicitation for up to 900 MW of solar power, 50 MW of battery storage and 500 MW of firming capacity. The city-owned utility, which currently has more than 5 GW of capacity, expects to solicit formal bids by early 2021.

The trustees also approved a "green tariff" allowing large commercial customers to purchase power from an alternative power provider.

More: *San Antonio Express-News, CPS Energy*

Lone Star Natural Gas Storage Facility Explodes

A Lone Star NGL natural gas storage facility in Mont Belvieu exploded July 29 after a contractor struck an underground pipeline. No injuries were reported.

The explosion sparked a large fire that took firefighters three hours to suppress Wednesday night. Energy Transfer and the Baytown Fire Department conducted air monitoring that night and found no reason for concern.

More: *Houston Chronicle*

VERMONT

PUC Fines NextEra Subsidiary for Solar Project Violations

The Public Utility Commission last week fined Coolidge Solar, a subsidiary of NextEra Energy that operates a 20-MW solar facility in Ludlow and Cavendish, $57,500 for violating its operating certificate. The company was cited for three violations of its certificate of public good, including installing above-ground power cables, conducting drilling and using unapproved equipment.

According to the PUC's report, Coolidge installed more than 8,000 linear feet of power cables above ground instead of burying them. It also used nine 2.7-MW inverters when the project was approved to use 14 inverters with a capacity of 1.67 MW each. Posts at the project were installed by drilling into the ground instead of "the approved method of driving the posts into the ground with the potential use of ground screws or pins."

More: *VTDigger*